From the writers of
"Companion Guide to the ASME Boiler & Pressure Vessel Code"

CONTINUING & CHANGING PRIORITIES OF

ASME BOILER & PRESSURE VESSEL CODES AND STANDARDS

K.R. RAO, EDITOR







Fully updated, Versatile, and Expanded Edition

Continuing & Changing Priorities of ASME Boiler & Pressure Vessel Codes and Standards

EDITOR
K. R. RAO

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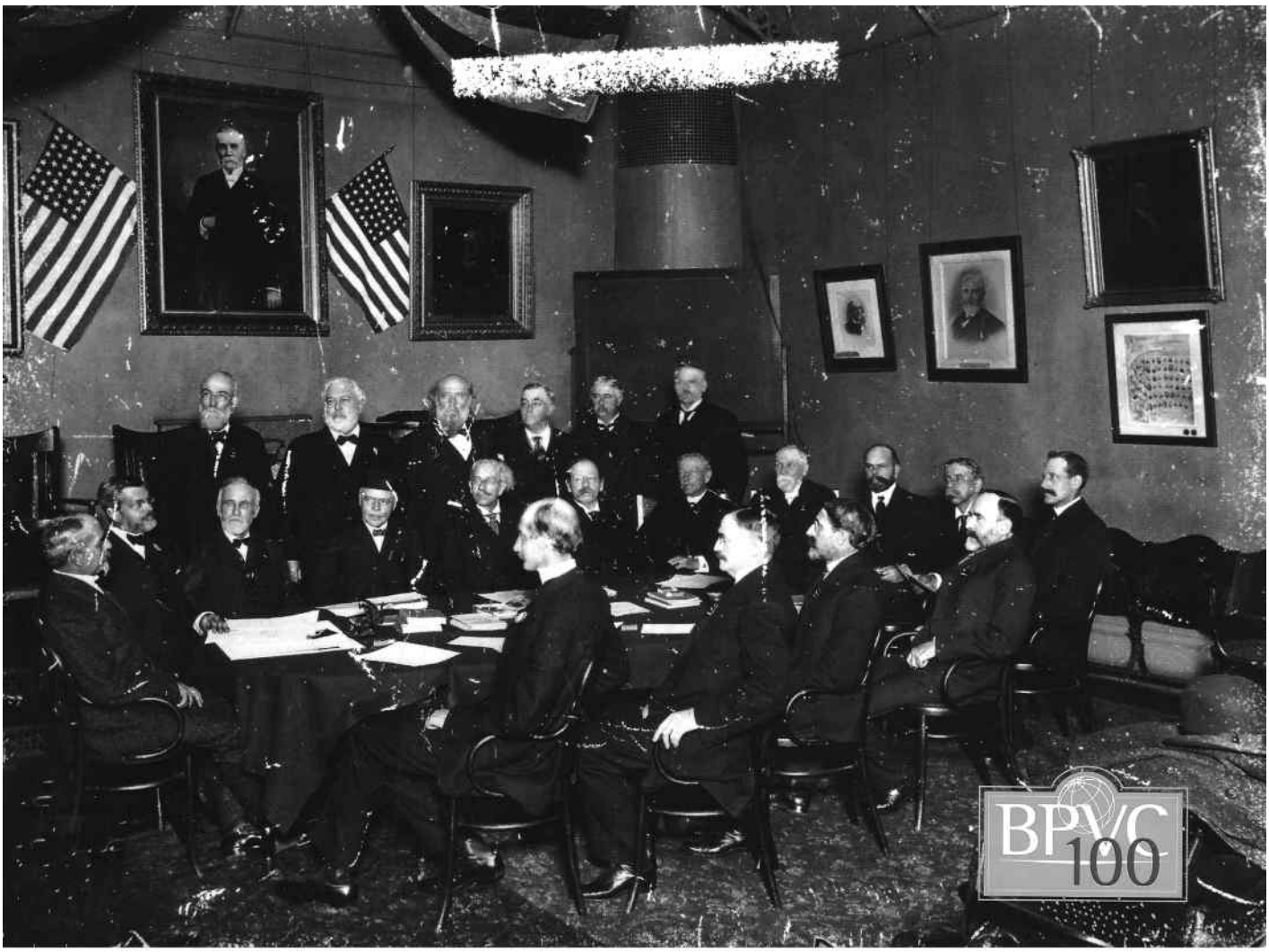
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DEDICATION

This book is dedicated to "one hundred years of boiler code activity" that started with the efforts of pioneers who are pictured below. Essentially their foresight and deliberative acumen resulted in the current boiler code activity that ensures safety, consensus and continuity of changes.

This book that captures continuing and changing priorities of the ASME Boiler Vessel Codes and Standards is mainly due to the efforts of over 1,000 ASME Boiler and Pressure Vessel Code volunteers with the support of several dozen ASME staff. These volunteers meet and deliberate every three months for a period of one week. It is appropriate to recognize these volunteers and staff by dedicating this publication to these group of individuals whose efforts are reflected by the use of boiler and pressure vessel codes and standards around the globe so that "the sun never sets on the ASME Boiler Vessel Codes and Standards".



1914 ASME Code Council. Photo courtesy of ASME

(*Source*: "100 Years The ASME Boiler and Pressure Vessel Code", by Gerry Eisenberg, p. 25, Winter, 2014 National Board Bulletin, National Board.org.)

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ACKNOWLEDGEMENTS

It is befitting that this stand-alone publication of *Continuing and Changing Priorities of Boiler and Pressure Vessel (B&PV) Codes and Standards* by ASME Press would follow the 100th Anniversary of B&PV Codes and Standards which was recently celebrated at Hyatt Regency, Seattle from May 9th through May 15th 2014.

The use of ASME B&PV Codes and Standards and the scope and extent of the third edition of the "Companion Guide" had vastly increased, resulting in a "mammoth" 2,550 page book spread in three volumes. The editor in the Acknowledgements to the third edition paid tribute to the authors who had helped him since the first edition and whose expertise enriched the chapters they authored. Several of them were not merely contributors to the monumental effort, but were in several ways not only the stanchions of the chapters they authored, but also ardent advisors from the onset of this effort. The editor in the third edition acknowledged the efforts of those contributors, who participated from the very beginning and mentioned ". . . to them the editor salutes for their signal contribution, direction and continued support."

This book has four distinct parts, the first being PART 1: CONTINUING PRIORITIES of B&PV CODES and STANDARDS. Several of the contributors such as C. Wesley Rowley, Late Marcus N. Bressler, David E. Olson, W. J. O'Donnell, Michael A. Porter, Stephen R. Gosselin, Frederick J. Moody, William J. Koves, Ronald S. Hafner, and Alan Murray befit the recognition for their effort as continuing contributors from the previous editions, "who had a remarkable influence on shaping this mammoth effort, few of them from the very beginning to this stage." In this category of individuals editor places on record the unstinted support provided by Everett C. Rodabaugh, Anibal L. Taboas, Tony Williams, and Rafael G. Mora who had not contributed to this publication but whose efforts in the previous editions were updated in the current publication by the contributors who took over this onerous task. For this Part 1 of the book editor acknowledges the efforts of replacement contributors such as Richard Stevenson, Anthony W. Paulin Jr., Thomas C. Esselman and Harold E. Adkins who had agreed to revise the chapters requested of them. An additional chapter included in this book primarily because of the reputation of the contributors as much as the pressing need of the times has been authored by Chakrapani Basavaraju and Mohinder L. Nayyar to whom the editor expresses his appreciation.

The second part, PART 2: CHANGING PRIORITIES of B&PV CODES and STANDARDS, has chapters addressed by continuing contributors such as Marty Parece, Hardayal S. Mehta, William J. O'Donnell, Donald S. Griffin, P. T. Kuo, Glenn A. White and Ralph S. Hill III. Editor appreciates these contributors who continued from the previous editions to zealously provide their best updates for the completion of this saga. Past contributions for the chapters in this part by Kaihwa R. Hsu, Timothy J. Griesbach, Pete Ricardella, Sidney A. Bernsen, Fredric A. Simonen, Kenneth R. Balkey, Raymond A. West, John T. Land and Masahiko Kaneda are appreciated. Replacement contributors Keith E. Schwab, Masanori Onozuka, William L. Server who agreed for updating chapters of this Part are immensely appreciated. It is worth highlighting the extra-mile that Hardayal Mehta took to update three of the chapters of this part. James Phillip Ellenberger is a new contributor whose write-up for a chapter in this part is appreciated.

To capture the lessons learned can be extremely challenging, especially if it covers familiar turf of the nuclear power generation. In PART 3: CHANGING PRIORITIES of B&PV CODES and STANDARDS: *Perspectives Lessons Learned* has additional chapters contributed by James C. Sowinski, David A. Osage, Gary Park, John F. Grubb, C. Wesley Rowley, Douglas A. Scarth, Chip H. Eskridge, Joseph F. Ball, Deepak Rao, Chakrapani Basavaraju and Jimmy E. Meyer. It is extremely gratifying to note the efforts of these contributors to unravel the gray areas of B&PV Codes and Standards.

The last part, PART 4: CHANGING PRIORITIES of B&PV CODES and STANDARDS – *Future Discussions*, was selected to address what is not exactly "within the box." Such topics were covered by Jose N. Reyes, Daniel Ingersoll, Alexander W. Harkness, James A. Mahaffey, Brad Nelson, and Irving Zatz, whose notable contributions are thankfully acknowledged.

For any publication such as this which has no parallel, search for contributors can be painstaking. The editor acknowledges the advice of Chakrapani Basavaraju, Stephen Gosselin, Timothy Griesbach, Kunio Hasegawa, John T. Land, Hardayal Mehta, Jimmy Meyer, D. Keith Morton and Richard W. Swayne.

My thanks are especially to my wife, Indira Rao B.Sc. (Hons), M.Sc., M.S., Ph.D., for the sustained support in my editorial effort and participation in several chores at every stage of this book and her efforts are gratefully acknowledged. In addition, I appreciate her tolerating my working on it during several vacations.

The editor thanks the staff of ASME Technical Publications for their continued patience, undivided support and focused effort in aiming once again at this publication's target of zero tolerance for errors and omissions. My personal appreciation as editor is to Ms. Mary Grace Stefanchik and Ms. Tara Collins Smith for their untiring efforts, even on business trips and vacations to keep the line of communication active in the publication of this book that was initiated on 8th February 2013.

Finally, the editor thanks all of you, readers and users of this *Continuing and Changing Priorities of B&PV Codes and Standards* and hopes it serves the purpose of this publication.

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Kenneth R. Balkey is currently a Consulting Engineer in Nuclear Services, with Westinghouse Electric Company in Pittsburgh, PA with over 36 years of service in the nuclear power industry. Mr. Balkey provides consultation and advises technology developments related to Codes and Standards and critical asset protection initiatives. He performed and directed reliability and risk evaluations for nuclear and non-nuclear structures, systems and components over his lengthy career. He has produced more than 100 publications and documents relating to risk evaluations of the integrity of piping, vessels and structures, and the performance of components using state-of-the-art probabilistic assessment techniques.

Mr. Balkey is vice chair, ASME Codes and Standards Board of Directors (June 2008 – June 2011), a member of the ASME Board on Nuclear Codes and Standards, past vice president, Nuclear Codes and Standards (June 2005 – June 2008), and past chair, ASME Board on Nuclear Codes and Standards (June 2005 – June 2008). Mr. Balkey also served as a senior technical advisor to the ASME Innovative Technologies Institute LLC, providing consultation on the development of guidance for Risk Analysis and Management for Critical Asset Protection (RAMCAP™) and working with the U.S. Department of Homeland Security. His honors include ASME's Dedicated Service Award (1991), the Bernard F. Langer Nuclear Codes and Standards Award (2002), the Melvin R. Green Codes and Standards Medal (2008), and several other awards from ASME, Westinghouse, and other institutions. Mr. Balkey earned B.S. and M.S. degrees in Mechanical Engineering at the University of Pittsburgh. Mr. Kenneth R. Balkey is a Registered Professional Engineer.

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Group Piping Design, Working Group Design Methodology, and Special Working Group on HDPE Piping. He published 22 technical papers. He was a contributing author to Chapter B4 and Appendix E2 of Piping Handbook, 7th Edition published by McGraw Hill Book publishing Company, N.Y. He was also a contributing author in updating Chapters 6 and 7 of ASME Companion Guide, 4th Edition published by the ASME, N.Y. He has over 30 years of experience. He is on the technical staff of Mechanical and Civil Engineering Branch of the Division of Engineering, Office of Nuclear Reactor Regulation (NRR) at the U.S. Nuclear Regulatory Commission (NRC).

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Dr. Bernsen, earned his B.S.M.E. in 1950, M.S.M.E. in 1951, and Ph.D. in 1953, from Purdue University. He has been involved in nuclear power activities for over 50 years, initially at Argonne National Laboratory and subsequently with Bechtel Corporation. At Bechtel he held a variety of positions including Chief Nuclear Engineer and Manager of Quality Assurance for Bechtel Power Corporation. Since retirement from Bechtel, after more than 30 years, he has provided consulting services and has remained active in ASME Nuclear Codes and Standards. Dr. Bernsen served as the initial Chair of the ASME Committee on Nuclear Quality Assurance (NQA) and is now an honorary member of the NQA committee.

Dr. Bernsen, was a founding member of the ASME Board on Nuclear Codes and Standards (BNCS) and has continuously served on BNCS since its inception. He was the initial Chair of the ASME Committee on Nuclear Risk Management and completed his second term in 2004. During his tenure, the committee completed and published the first issue of this Standard in April 2002 and the first addendum was published in December 2003. Through his long career, including extensive involvement in licensing and safety, as well as his work in coordinating the development and approval of the Nuclear Risk Management Standard, he has obtained valuable insight into nuclear risk related activities and how they are being and may be applied in the future to ASME Codes and Standards. Dr. Bernsen, an ASME Fellow, has been involved in Codes and Standards for over 35 years.

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Mr. Bressler is President of M. N. BRESSLER, PE, INC., an engineering consulting firm founded in 1977, specializing in codes and standards, quality assurance, design, fabrication, inspection and failure analysis for the piping, power, petroleum and chemical industries. He has over 54 years of experience. He joined TVA in 1971 as Principal Engineer and was promoted in 1979 to Senior Engineering Specialist, Codes Standards and Materials. He took early retirement in 1988 to open up a private consulting practice. His previous experience was with the US Army (1952) where he served as an Industrial Hygiene Engineer; the Babcock & Wilcox Company (1955), where he held the positions of Engineering Draftsman, Stress Analyst, and Boiler Division Materials Engineer; Gulf & Western Lenape Forge Division (1966) where he became Senior Design Engineer, and Taylor Forge Division (1970) as Product Development Manager. At Lenape Forge he developed a design for a quick-opening manway for pressure vessels and piping that was granted a patent in 1971.

Mr. Bressler began his activities in Codes, Standards and Materials in 1960. He has been a member of the ASME B&PV Standards Committee since 1979 to 2009, and is now a member of the Technical Oversight Management Commitee. He is a member and past Vice Chair of the Committee on Nuclear Certification. He is a member of the Standards Committees on Materials and on Nuclear Power, the subgroup on Design (SCIII), the special working group on Editing and Review (SC III), the Boards on Nuclear Codes and Standards and on Conformity Assessment. He is the Chair of the Honors and Awards Committee (BNCS). Mr. Bressler is a member of the ASTM Committees A-01 and B-02 and many of their subcommittees.

Mr. Bressler holds a BME degree from Cornell University (1952) and an MSME degree from Case Institute of Technology (1960). In 1989 he received a Certificate of Achievement from Cornell University for having pursued a course that, under today's requirements, would have resulted in a Master of Engineering degree. He was awarded the ASME Century Medallion (1980), and became a Fellow of ASME in 1983. He is now a Life Fellow. He received the 1992 ASME Bernard F. Langer Nuclear Codes and Standards Award. and is the 1996 recipient of the ASME J. Hall Taylor Medal. He received the 2001 ASME Dedicated Service Award. He is a Registered Professional Engineer in the State of Tennessee (Retired).

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Mr. Ellenberger is an author of three technical Books - Boiler Code Simplified, Piping Code Simplified, Piping and Pipeline Calculations and several technical papers. He is an educator, having taught High School Physics, Pipeline Stress Analysis. He participated at several Technical Seminars in US, UA Emirates and Mexico. His other interests and activities include being Chairman County Historical Commission, TX and Chaired Committee for School District, IA.

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In 1980, Dr. Gorman was a co-founder of Dominion Engineering, Inc., and is still actively working for the company. A significant part of his consulting work has been for EPRI. His work for EPRI has included preparation of many workshop proceedings involving PWR steam generator technology, preparation of topical reports on materials and corrosion issues, and assisting in revision of water chemistry guidelines. He has also worked extensively for utilities and other industrial organizations on materials and corrosion issues, such as evaluation of the causes of failures of pressure vessels and piping, and developing predictions of the probable rate of failure of PWR steam generator tubes. Dr. Gorman is a registered professional engineer and is a member of AMS, NACE and ANS.

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Mr. Gosselin's computational expertise is complemented by over 13 years experience in system engineering and mechanical design analyses at Westinghouse and Combustion Engineering PWR commercial nuclear power plants and 8 years operating experience on U.S. Navy SIC, S5W, and S3G submarine nuclear power plant designs.

Mr. Gosselin is an ASME Fellow and a member of several the American Society of Mechanical Engineers Codes and Standards Committees including: Subgroup Fatigue Strength (SCIII), Working Group Environmental Fatigue Evaluation Methods (SCIII), and Working Group on Operating Plant Criteria (SCXI), Working Group Piping (SCXI), and Special Working Group RIM (SCXI).

Mr. Gosselin has a B.S. degree in Mechanical Engineering from the California State Polytechnic University (1980) and a M.S. degree in Mechanical Engineering from the University of North Carolina at Charlotte (1998). He is a licensed professional engineer in California. Mr. Gosselin has published over 50 papers, articles, and reports in the open literature and is a consulting expert to the International Atomic Energy Agency (IAEA) in the areas of plant life extension, design reconciliation and risk-informed inservice inspection.

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Mr. Griesbach is a member of ASME and the American Nuclear Society, and he has been a member of Section XI since 1989. He is chairman of the Working Group on Operating Criteria whose charter is to develop and maintain the Code criteria for operating pressure vs. temperature limits, operating plant fatigue assessment, and related operating plant issues. He is also a member of the Working Group on Flaw Evaluation and Subgroup on Evaluation Standards.

Mr. Griesbach specializes in evaluation of aging degradation mechanisms for nuclear components, including developing databases and modeling predictions on irradiated materials behavior. He has taught courses on managing the integrity of reactor pressure vessels for extended vessel life, and he has written numerous technical papers on these topics.

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Vessel Code activities include development of design limits for high-temperature and creep buckling, and participation in the Subgroup for Elevated-Temperature Design. Responsible for presentation and resolution of elevated-temperature structural design issues raised during NRC licensing review of CRBRP.

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HAFNER, RONALD S.



Ronald S. Hafner has almost 50 years of experience in a variety of disciplines ranging from radar systems and nuclear instrumentation, to non-destructive testing using gamma-ray sources and electronic devices, to nuclear reactor- and tritium facility-operations, to regulatory issues associated with Department of Energy facilities and the transportation, storage, and disposal of radioactive materials. After a seven-and-a-half year enlistment in the U.S. Air Force, he went to work at Sandia National Laboratories, in Livermore, CA, in 1974, where he specialized in tritium operations and tritium health physics. While at Sandia, he went back to school and earned his Bachelor of Science Degree from California State University, Hayward, CA, in 1983, with a major in Physical Sciences and a minor in Physics. In 1987, he moved to Lawrence Livermore National Laboratory where, for the first four years, he worked in tritium operations and tritium facility management. In 1991, he moved to the Mechanical Engineering Division, where he has been part of an engineering consulting group since that time.

His ASME activities started in 1993, with the Operations, Applications, and Components (OAC) Technical Committee of the ASME's Pressure Vessels & Piping Division (PVPD). Since that time, he has been involved with the development of more than 100 PVPD Conference sessions on the Transportation, Storage, and Disposal of Radioactive Materials. He is a past Chair of the OAC Technical Committee, and a past Chair of the ASME's Pressure Vessels & Piping Division. He is currently a member of the Senate of Past Division Chairs of the ASME's PVPD.

HARKNESS, ALEXANDER W.



Alexander W. Harkness is a Consulting Engineer and Design Lead for the Small Modular Reactor (SMR) development program with more than 23 years of nuclear industry experience covering areas of engineering, plant design, marketing, component design and analysis. In addition to his role with the SMR Program, Mr. Harkness also serves as chair of the company's Technical Leader Review Committee, which oversees development and placement of fellow and consulting engineers and scientists for Westinghouse technical leader positions.

Prior to working on the development of the Westinghouse SMR, Mr. Harkness was a Fellow Engineer in Westinghouse's New Plants Engineering department, which is responsible for the deployment of the AP1000® plant. In this capacity he was responsible for the resolution of technical issues identified during the final stages of design.

Mr. Harkness spent the first 18 years of his career with Westinghouse as an engineer in the Nuclear Services Business Area. During this time, he designed, analyzed, procured and installed replacement nuclear plant components. Many of these components were replaced due to issues associated with aging; however towards the end of his experience in Nuclear Services he worked on the development of a new product, reactor vessel head upgrades which improved the plant's efficiency by reducing the length of the plant's refueling outages. Mr. Harkness was the technical lead for more than two dozen reactor vessel head upgrade projects.

Mr. Harkness is currently a member of the ASME Special Working Group on Reliability and Integrity Management (RIM) Program.

Alex is a graduate of the University of Pittsburgh and Carnegie Mellon University with a bachelor's and master's degree in Mechanical Engineering respectively.

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HILL III, RALPH S.



Ralph S. Hill III, PMP, is a Consulting Engineer with Westinghouse Electric Company in Pittsburgh, PA. He has over 35 years of technical and management experience including more than eighteen years in planning, engineering design, construction, and modification for the nuclear power industry and fourteen years providing strategic planning, system engineering, risk management, process evaluation, and project management consulting services to the U.S. Department of Energy in spent nuclear fuel, radioactive waste management, and nuclear materials disposition-related projects.

At the time of this writing, Mr. Hill is Chairman of the BPV Committee on Construction of Nuclear Facility Components (III) and ASME Vice President Elect Nuclear Codes and Standards where he serves as Chairman of the Risk Management Task Group. Mr. Hill is actively involved in bringing risk-informed probabilistic design methods into the ASME Code and initiatives to support both advanced and next-generation nuclear reactors.

HSU, KAIHWA ROBERT



Kaihwa Robert Hsu earned a B.S. in Civil Engineering from Chung Yuan Christian College, and an M.S. from University of South Carolina. He has thirty years experience applying engineering principles, developing computer codes of corrosion erosion monitoring system, fatigue cycle monitoring system, fatigue crack growth, and fracture mechanics evaluation for nuclear industry. From 1981 until 2003, he worked in Westinghouse and has been involved in the areas of stress analysis, fatigue, fracture mechanics, leak before break, residual stress, primary water stress corrosion crack, and ASME Code related analyses pertaining to PWR. Mr. Hsu is currently a senior engineer with U.S. Nuclear Regulatory Commission (NRC). He is a key member in the development of the review and audit process improvement for aging management reviews. He is an audit team leader for license renewal application, responsible for metal fatigue time-limited aging analyses (TLAA) and aging management programs (AMPs) audit and review.

Publications of Kaihwa Robert Hsu are in the Proceedings of ASME Pressure Vessels and Piping Conference, the Proceedings of 10th Environmental Degradation Conference, and the Proceedings of 8th International Conference of Nuclear Engineering.

HUNT, STEPHEN



Since receiving his BSME from Purdue University in 1995, Steve Hunt has been involved in equipment design, stress analysis and root cause failure analysis of mechanical equipment primarily for the commercial nuclear power and offshore oil industries. This work has included commercial and research nuclear power plants, fossil power plants, floating and fixed offshore oil/gas production facilities, deep diving submersibles, large optical telescopes, tower cranes, paper mills, and chemical plants.

In 1980, Steve Hunt was a co-founder of Dominion Engineering, Inc., and he is currently a Principal Officer. A significant part of Mr. Hunt's recent consulting work has been for the Electric Power Research Institute (EPRI). Major areas of effort have included primary water stress corrosion cracking (PWSCC) of Alloy 600 material, boric acid corrosion, leakage reduction technology, and life cycle management. Publications for EPRI have included many documents related to Alloy 600 PWSCC, the *Boric Acid Corrosion Guidebook*, and most of the Sealing Technology and Plant Leakage Reduction Series reports. Mr. Hunt also works extensively for electric utilities in the areas of Alloy 600 PWSCC failure analysis and strategic planning, life cycle management, and root cause failure analysis. Mr. Hunt also provides technical consulting in the areas of offshore oil production facilities, high pressure sealing technology, large diameter bearings, and pressure vessel failure analysis. Mr. Hunt has authored several hundred reports for a wide range of clients and holds several patents. Mr. Hunt is a registered professional engineer and is a member of ASME and IEEE.

INGERSOLL, DANIEL T.



Dr. Daniel Ingersoll is Director of the Office of Research Collaborations for NuScale Power. He joined NuScale in January 2012 to coordinate and develop R&D partnerships between NuScale and universities, laboratories and industry. Prior to joining NuScale, he was Senior Program Manager in the Small Modular Reactors R&D Office at Oak Ridge National Laboratory where he served as National Technical Director for the U.S. Department of Energy's Small Modular Reactor program. During his 34 years at ORNL, he led several ORNL research groups conducting radiation transport modeling, reactor shielding experiments and reactor physics analysis in support of advanced reactor development, advanced medical therapies, and defense applications.

Dr. Ingersoll received a BS degree in Physics from Miami University in 1973 and a PhD in Nuclear Engineering from the University of Illinois in 1977. He is a Fellow of the American Nuclear Society and former chairman of the ANS Radiation Protection and Shielding Division.

KANEDA, MASAHIKO



Masahiko Kaneda is Senior Vice President of Mitsubishi Nuclear Energy Systems, Inc. He has more than thirty years of experience in development and management of nuclear power plant design in Japan. Mr. Kaneda received a B.S. in Mechanical Engineering from Seikei Univ. in Tokyo, Japan in 1978. From September 2006 to March 2008, he was employed by MHI in Tokyo, Japan as the General Manager of Advanced Pressurized Water Reactor Promoting Department, Nuclear Energy Systems Headquarters. He directed all aspects of the APWR Promoting Department's operations to control activities such as Design Certification of US-APWR, Luminant Project and Potential Customer Engineering. From October 2005 to August 2006, he was employed by MHI in Hyogo, Japan as the General Manager of the Water Reactor Engineering

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Department, Nuclear Energy Systems Engineering Center, Nuclear Energy Systems Headquarters.

Under the direction of Mr. Kaneda, The Water Reactor Engineering Department got involved in the conceptual and basic design of the entire nuclear power plant facility, and consisted of various sections specialized in the system design, layout design, structural and seismic design, electrical design, instrumentation and control design, turbine system design, and water reactor engineering. In this position, Mr. Kaneda directed the entire operations of the Water Reactor Engineering Department and he established the department's annual operational goals, and planned the budget and resources needed for the achievement of annual operation goals.

Thus, Mr. Masahiko Kaneda has nearly three decades of experience related to plant design for nuclear power plants such as Japanese prototype FBR, Monju and many commercial PWRs in Japan. He is not only a specialist for plant layout design but seismic design as well. Currently, as the General Manager of APWR Promoting Department, Nuclear Energy Systems Headquarters in Mitsubishi Heavy Industries, LTD Japan, he is responsible for the promotion of US-APWR.

KOVES, WILLIAM J.



William Koves, Ph.D., P.E., ASME Life Fellow, retired as a Senior Engineering Fellow, distinguished technologist from UOP, a high technology company that develops and licenses process and related equipment technology in the petrochemical, process and related industries.

Dr. Koves has 40 years of experience in the design, analysis and troubleshooting of equipment and structures including air-craft, nuclear reactors, and petrochemical equipment. His specialties include stress analysis, fracture, elevated temperature design, heat transfer, stability, vibration, fatigue, fluid mechanics, and mechanics of granular solids.

Dr. Koves is author of numerous publications in the field and holder of 27 US and 3 European patents. He is the recipient of numerous awards from ASME and UOP including the B31 Forever Medal and the ASME Dedicated Service Award. He has been very involved with numerous ASME and PVRC committees including, Past Chair of ASME B31.3 Process Piping Committee, Past Chair of ASME B31 Mechanical Design Committee, Member of the B31 Standards Committee, Member of ASME Boiler and Pressure Vessel Subcommittee on Design Analysis, Elevated Temperature Design, Special Working Group on Design of Bolted Flange Joints and member of the Post Construction Standards Committee and Subcommittee on Repair.

Dr. Koves was Vice-Chair of the Pressure Vessel Research Council (PVRC), Member of PVRC Committee on Piping and Nozzles, Chair of PVRC Committee on Elevated Temperature Design, Chair of PVRC Subcommittee on Shell Intersections, and Past the Chair of the Post Construction Flaw Evaluation Committee and Member of the Main and Executive committees.

KUO, PAO-TSIN



Dr. Kuo earned an engineering diploma from Taipei Institute of Technology, a MS from North Dakota State University and a PhD from Rice University. He is a Registered Professional Engineer in the State of Maryland. He has been an executive consultant to the regulatory bodies and utilities worldwide for more than five years after his retirement from the US Nuclear Regulatory Commission in 2008. Prior to his retirement, he served as the Director of License Renewal Division, responsible for guidance development and licensing activities of the license renewal program as well as environmental reviews of applications for license renewal and early site permits.

Dr. Kuo was a former member of the ASME Section XI Special Working Group on Plant Life Extension. He was also a former member of the ASME Section III Working Group of Piping Design as well as Task Group on Dynamic Stress Limit. Internationally, he was the Chairman of Working Group I, General Long Term Operation Framework, IAEA Extra Budgetary Program on Safety aspects of Long Term Operation of Water Moderated Reactors.

LAND, JOHN T.



John T. Land, P.E., has been involved in the design, analyses and manufacturing of Westinghouse's PWR nuclear primary equipment products for almost thirty years. His product design experience includes reactor internals, steam generators, presurizers, valves, and heat exchangers. Mr. Land also contributed to the design and development of the AP600 and AP1000 MWe Advanced Power Plants, the Westinghouse/Mitsubishi APWR 4500 MWt Reactor Internals, and many of the currently operating Westinghouse PWR domestic and international reactor internals components. In addition, he has directed and reviewed the design and analysis efforts of engineers from Italy (FIAT and ANSALDO), Spain (ENSA), Czech Republic, and Japan (MHI) on several collaborative Westinghouse international efforts. His experience included five years with Westinghouse as a stress analyst on nuclear valves in support of the Navy's Nuclear Reactor Program. Prior to working for Westinghouse, Mr. Land spent eleven years with the General Electric Company on the design and development of Cruise Fan and XV-5A Vertical Take-Off and Landing aircraft propulsion systems. He also holds eleven patents from General Electric, and Westinghouse. Mr. Land received his BS in Mechanical Engineering from Drexel University and his MS in Applied Mechanics from the University of Cincinnati.

Over the past thirty years, John has been active in ASME B&PV Code work. Mr. Land is currently member of the Working Group Core Support Structures and participates in the rule making and maintenance of Sub-Section NG. John is also a member of Sub-Group Design that oversees Section III and Section VIII Design Rules.

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MAHAFFEY, JAMES A.



Dr. James Mahaffey holds a bachelor of science degree in physics and master of science and doctorate degrees in nuclear engineering from the Georgia Institute of Technology. As a senior research scientist, during his 25-year career at the Georgia Tech Research Institute (GTRI) he directed or worked on projects for the U.S. Defense Nuclear Agency, the U.S. National Ground Intelligence Center, the U.S. Air Force Air Logistics Center, Georgia Power Company, and other government and private industrial organizations, in such areas as nuclear power, non-linear analysis, digital systems design, and cold fusion.

His first funded project at GTRI in 1980 was for the U.S. Nuclear Regulatory Commission and involved the design of a hardened computer system for the Loss of Fluid Test (LOFT) reactor at the Idaho National Energy Laboratory. The final report for this project, *Reactor Safety System Design Using Hardened Computers*, was published as NUREG/CR-2118. This document supplemented a new regulation, NUREG-0696, *Functional Criteria for Emergency Response Facilities*, for use in the design and full implementation of computer systems for the two GE reactors at Georgia Power's Plant E.I. Hatch Nuclear Power Station. Dr. Mahaffey was director and chief engineer for this multi-million dollar, multi-year project. Later work included foreign technology exploitation and theoretical work with non-linear analysis of potential fires in aircraft accidents affecting on-board nuclear devices. His work at Georgia Tech led to two patents and over 30 published reports, articles, and refereed papers. He has delivered invited lectures in Germany, Ireland, and Australia and taught physics at Georgia Tech as a shared appointment with GTRI.

He served as Head of Advanced Research at Nanoventions Inc. in Roswell, Georgia, working in digital nano-optics and entangled-state photon communication systems. He also worked as Director of Technology for AIR2, Maryland, developing acoustic and K-band radar equipment to evaluate power-transmission cross-arms from a stand-off position.

Dr. Mahaffey's first book trade book, *ATOMIC AWAKENING: A New Look at the History and Future of Nuclear Power*, (Pegasus Books, New York, July 2009) has received wide critical acclaim. His six-book reference set for high schools and colleges on nuclear power was published by Facts On File. His second trade book, *ATOMIC ACCIDENTS: A History of Nuclear Meltdowns and Disasters from the Ozark Mountains to Fukushima*, (Pegasus Books, New York, 2014) is also proving popular, giving detailed descriptions and analyses of nuclear mistakes over the past 120 years. He was Contributing Editor to the Mercedes-Benz magazine, *The Star*, and his articles were included in the book *Mercedes-Benz Technical Companion*, Bentley Publishers, Cambridge, MA, 2005. He has written technical articles for *Optics and Photonics News*, Washington, DC, and the *NAWCC Bulletin*, Columbia, PA.

MEHTA, HARDAYAL S.



Dr. Mehta received his B.S. in Mechanical Engineering from Jodhpur University (India), M.S. and Ph.D. from University of California, Berkeley. He was elected an ASME Fellow in 1999 and is a Registered Professional Engineer in the State of California.

Dr. Mehta has been with GE Nuclear Division (now, GE-Hitachi Nuclear Energy) since 1978 and currently holds the position of Chief Consulting Engineer. He has over 40 years of experience in the areas of stress analysis, linear-elastic and elastic-plastic fracture mechanics, residual stress evaluation, and ASME Code related analyses pertaining to BWR components. He has also participated as principal investigator or project-manager for several BWRVIP, BWROG and EPRI sponsored programs at GE, including the Large Diameter Piping Crack Assessment, IHSI, Carbon Steel Environmental Fatigue Rules, RPV Upper Shelf margin Assessment and Shroud Integrity Assessment. He is the author/coauthor of over 50 ASME Journal/Volume papers. Prior to joining GE, he was with Impell Corporation where he directed various piping and structural analyses.

For more than 25 years, Dr. Mehta has been an active member of the Section XI Subgroup on Evaluation Standards and associated working an task groups. He is also a member of Section III Working Group on Core Support Structures. He also has been active for many years in ASME's PVP Division as a member of the Material & Fabrication and Codes & Standards Committees and as conference volume editor and session developer. His professional participation also included several committees of the PVRC, specially the Steering Committee on Cyclic Life and Environmental Effects in Nuclear Applications. He had a key role in the development of environmental fatigue initiation rules that are currently under consideration for adoption by various ASME Code Groups.

MEYER, JIMMY E.



Jimmy Meyer has over 35 years of experience in refining petrochemical, chemical, power generation and industrial facilities. He is a principal engineer at Louis Perry and Associates, a full service engineering and architectural firm in Wadsworth Ohio. Jim is experienced in overall project coordination/management, pressure equipment, piping design, analysis, specifications, support design, mechanical system requirements and documentation requirements. Particular areas of technical competence include ASME piping and pressure vessel codes, stress analysis, and field troubleshooting piping system support, vibration and expansion problems.

Mr. Meyer is a member of ASME and has been involved in the ASME B31.1 and ASME B31.3 Section committees for over 30 years. He is currently Chair of the ASME B31.3 Process Piping

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Section Committee, Chair of the ASME B31 Standards Committee and serves on the ASME Board on Pressure Technology Codes and Standards. Jim has also served as Chair of ASME B31.1 Power Piping Code Section Committee.

Past projects and work experience has involved major oil refineries, petrochemical plants, fossil, nuclear, solar and alternative energy generation as well as cryogenic and vacuum test facilities.

MOODY, FREDERICK J.



Ph.D., M.S., B.S., Mechanical Engineering (Stanford, Stanford, U. of Colorado) Consulting Engineer, Thermal-Hydraulics, GE Nuclear Energy, 41 years with emphasis on fluid mechanics, thermodynamics, heat transfer, and coupled fluid-structure interaction, pertaining to reactor and containment technology. Adjunct Professor, Thermosciences, San Jose State University, 28 years, Instructor, GE Advanced Engineering Programs. Instructor for ASME Continuing Education courses. Invited courses, lectures in U.S. universities and national labs, Rome, Israel, Holland, Japan, India, Germany, Spain, and Taiwan on unsteady thermofluid behavior. National Academy of Engineering, 2001, Induction into Silicon Valley Engineers Hall of Fame, 2000, ASME PV&PD Award (1999), ASME Fellow (1981); George Westinghouse Gold Medal Award (1980), and Alfred Noble Award for technical paper (1967). Has been Committee chair and co-chair, ASME Fluids Engineering Division, PV&P Division and Associate Editor of ASME Journals.

Participated on NRC-appointed peer review groups, and ongoing consulting assignments with several NRC studies and panels. Publications include *Introduction to Unsteady Thermofluid Mechanics,* Wiley, and *The Thermal-Hydraulics of a Boiling Water Nuclear Reactor*, ANS (co-author), and more than 50 publications in technical journals, and symposium volumes.

MORA, RAFAEL G.



Mr. Rafael Mora is a graduate in Civil Engineering from the University of La Gran Colombia, and holds a Master of Business Administration, UNET-UFPS, Venezuela-Colombia. He is a registered professional engineer in Canada.

Mr. Mora has been working for the pipeline industry for over seventeen years that include pipeline operating; integrity consulting and in-line inspection service companies. He recently joined the National Energy Board as a Technical Leader, Engineering within the Compliance Planning and Analysis Team.

Mr. Mora is currently also a professor in the Pipeline Engineering Master Degree program at the University of Calgary. He has taught courses in pipeline integrity extensively within North and South America and has authored a number of technical papers on this subject.

MURRAY, ALAN



Dr. Alan Murray recently retired from the position of Chief Engineer and Chief Safety Officer of the National Energy Board in Calgary, Alberta, Canada. He is an Adjunct Professor in the Mechanical Engineering Department of the Schulich School of Engineering at the University of Calgary and instructs a number of pipeline related professional courses throughout the world.

Alan is a graduate of The Queen's University of Belfast, Northern Ireland in Civil Engineering (Ph.D.) and Mechanical Engineering and has spent most of his career in Design and Development activities mostly in heavy engineering-shipbuilding, pressure vessels and pipelines. He has held a number of senior management positions with a major North American pipeline company and was founding chair of the ASME Pipeline Systems Division in 2000. He is the coauthor of the very successful ASME books Pipeline Design and Construction: - A Practical Approach, and Pipeline Integrity Assurance, and has published 60 papers on a variety of engineering topics. Alan has been active in the ASME since 1982, editing the Proceedings of the Pipeline Symposium of the Offshore Mechanics and Arctic Engineering conference (1993–2000) and chaired the ASME International Pipeline Conference in 2000 and 2002. He is a Fellow of ASME and has twice been a recipient of the Society's Distinguished Service Award. He is a registered Professional Engineer in Alberta and is a Chartered Member of the Institution of Mechanical Engineers in the United Kingdom.

NAYYAR, MOHINDER L.



Mohinder L. Nayyar, P.E. is an ASME Life Fellow and an internationally recognized specialist in the area of piping, valves, materials, and codes and standards.

As a member of the ASME Council on Standards and Certification, Member of Board on Nuclear Codes and Standards, Vice Chair of the ASME Board on Pressure Technology Codes and Standards, member, chair and vice chair of several national and international level code committees, Mr. Nayyar has made invaluable contributions to codes and standards resulting in publication of new standards, new rules and the resolution of numerous technical issues. Mr. Nayyar has been awarded the ASME's highest award, Melvin R. Green Medal for his outstanding contributions to codes and standards. He is the recipient of 2013 ASME B31 Forever Medal for Excellence in Piping, a lifetime achievement award.

He has 46 years of design engineering experience on more than 100 domestic and international mega fossil and nuclear power and other projects. He has worked as Systems Design Engineer for Nuclear steam supply systems (NSSS) both on pressurized and boiling water reactor power plants; performed flexibility analysis of ASME III, Class 1, 2, and 3 systems; developed and updated Bechtel's standards, specifications, and guides; chaired inservice inspection (ISI) Task Force of Bechtel; developed and updated Bechtel ISI Manual; supervised Piping and Valve Engineering

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work on 19 nuclear power plants; worked as Project Engineer to study and evaluate ISI and IST (Inservice Testing) Programs for Nine Miles Nuclear Power Plant; and served as Operations Coordinator at Turkey Point Nuclear Power Plant. In addition, Mr. Nayyar has provided technical guidance and resolved technical issues on operating nuclear power plants and assisted more than 30 Steam Generator Replacement Projects in achieving successful completion and satisfying Owner and regulatory agencies requirements.

As Senior Principal Engineer, prior to retiring from Bechtel at the end of 2011, he has been providing engineering advice and code interpretations to senior management and day-to-day guidance to all business lines of the BECHTEL Corporation, a global design and construction company. He has initiated and implemented numerous innovative ideas to improve working process and quality; developed and conducted training programs for clients and others; published articles on valves, authored the "Pipeline" article for the 7th Edition of Science and Technology Encyclopedia, and he is the author and Editor-in-Chief of *The Piping Handbook*, Sixth and Seventh Editions, (1992 and 1999), published by McGraw-Hill. He is also the author of the first edition of the *Piping Data Book* (2002), published by McGraw-Hill.

Mr. Nayyar has played key leadership roles in planning and programming Bechtel efforts for successfully passing ASME Surveys to obtain ASME Certificate of Accreditation and N-Certificates of Authorization and for their periodic renewals in compliance with ASME BPV Code Section III.

Mr. Nayyar has initiated, developed, and conducted numerous training programs on various topics covered by ASME BPV Code Section III. Section XI, and US NRC regulations for training new and experienced Client and Bechtel engineers working on nuclear power plant projects. These training programs have been videotaped and were/are being used to train engineers at jobsites and other locations within and outside the United States.

Mr. Nayyar has served as Chairman of the ASME B31, Standards Committee on Pressure Piping Code and he is currently serving as the inaugural Chair of the newly established ASME Standards Committee on Nonmetallic Pressure Piping Systems. He has served as Chair of ASME B31.1, Power Piping Code Committee, B16 Committee on Flanges, ASME B16 Materials Technical Committee, ASME B31 Materials Technical Committee and several other committees. He has also served as Vice Chairman, ISO TC5/SC 10, Subcommittee on Metallic Flanges and their Joints, ASME B16 Standards Committee, and also a Member of ISO/TC/153, USA Technical Advisory Group, ASME B&PV Section II Standards Committee on Materials.

Mr. Nayyar has been the recipient of several awards at Bechtel, ASME leadership awards, ASME Dedicated Service Awards and other honors including "MASTER OF POWER PIPING" Award in 2009 for his accomplishments, and he is listed in "Marquis Who's who in America and the World" since 1995.

NELSON, BRAD



Brad Nelson is the chief engineer for the US ITER Project. His group provides engineering support to US ITER, and he interfaces with partner laboratories and the ITER International Organization. He has more than 35 years of experience in the design and analysis of experimental fusion energy research facilities and components and has contributed to the engineering design of several facilities and devices, including the Advanced Toroidal Facility, Large Coil Test Facility, National Spherical Torus Experiment, National Compact Stellarator Experiment, and Quasi-Poloidal Stellarator. He was involved in both the ITER Conceptual Design Activity and the Engineering Design Activity in the areas of design integration, vacuum vessel design, blanket and shield design, and the vacuum vessel R&D program. Brad, who is a registered professional engineer, received bachelor of science and master of science degrees in mechanical engineering from the University of Missouri.

O'DONNELL, WILLIAM J.



Bill O'Donnell has Engineering Degrees from Carnegie Mellon University and the University of Pittsburgh. He began his career at Westinghouse Research and Bettis where he became an Advisory Engineer. In 1970 Bill founded O'Donnell and Associates, an engineering consulting firm specializing in design and analysis of structures and components. The firm has done extensive work in the evaluation of structural integrity, including corrosion fatigue, flaw sensitivity, crack propagation, creep rupture and brittle fracture. Dr. O'Donnell has published 96 papers in engineering mechanics, elastic-plastic fracture mechanics, strain limits and damage evaluation methods. He is Chairman of the Subgroup on Fatigue Strength and a Member of the Subcommittee on Design of the ASME Code. He has patents on mechanical processes and devices used in plants worldwide. He is recognized expert in Failure Causation Analyses. Dr. O'Donnell has given invited lectures at many R&D laboratories, design firms and universities. He is a registered Professional Engineer. He received the National Pi Tau Sigma Gold Medal Award "For Outstanding Achievement in Mechanical Engineering" and the ASME Award for "Best Conference Technical Paper" in 1973 and 1988. The Pittsburgh Section of ASME named Bill "Engineer of the Year." (1988) He was awarded the ASME PVP Medal (1994) and received the University of Pittsburgh ME Department's Distinguished Alumni Award (1996) and Carnegie Mellon University's 2004 Distinguished Achievement Award for distinguished service and accomplishments in any field of human endeavor. He is a Fellow of the ASME and is listed in the Engineers Joint Council "Engineers of Distinction," Marquis "Who's Who in Science and Engineering" and "Who's Who in the World."

OLSON, DAVID E.



Mr. Olson is the current and long standing Chairman of the ASME Operation and Maintenance Subgroup on Piping Systems, the group responsible for writing the OM-3 standard on piping vibration. He has published over 20 papers on vibration and piping dynamics, testing and design and has also given numerous training seminars on these topics. Mr. Olson has been involved in solving piping and rotating equipment vibration problems at over 50 nuclear and fossil power plants. He has managed the design and successful implementation of preoperational and initial startup piping test programs at BWR and PWR plants.

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Mr. Olson is currently a manager in the Nuclear Power Technologies department at Sargent & Lundy LLC, he is a graduate of the University of Illinois – B.S. Mech./Struc. Engineering, and the University of Chicago - MBA, he is a Registered Professional Engineer.

ONOZUKA, MASANORI



Dr. Masanori Onozuka is vice president of Mitsubishi Nuclear Energy Systems, Inc. (MNES), a subsidiary of Mitsubishi Heavy Industries, Ltd. (MHI) of Japan. He has been at MNES since 2007, engaged in nuclear business as it relates to the U.S. market. From the start, he has been heavily involved in the MHI/MNES applications for US-APWR Design Certification (DCD) and the Combined License Applications (COLA). Dr. Onozuka has 30 years of experience in the research, design, analyses, and project management in nuclear related fields, including fusion research. He is currently leading engineering efforts for the US-APWR Standard Plant Design and associated licensing applications. Prior to joining MNES, he served as program manager for nuclear fusion at MHI headquarters in Tokyo. He has extensive experience in both Japanese domestic and international projects. His broad scientific experience includes five years with the International Thermonuclear Experimental Reactor (ITER) in Germany. Dr. Onozuka is an alumnus of MIT, with a degree in the field of plasma engineering. He has authored roughly 100 publications and is a holder of U.S. patents. In addition, he is a member the Sigma Xi, Scientific Research Society, as well as a member of the American Nuclear Society and the Atomic Energy Society of Japan.

OSAGE, DAVID A.



Mr. Osage, President and CEO of the Equity Engineering Group in Shaker Heights, Ohio, is internationally recognized as an industry expert and leader in the development and use of FFS technology. As the architect and principal author of API 579 *Fitness-For-Service*, he developed many of the assessment methodologies and supporting technical information. As the chairperson for the API/ASME Joint Committee on Fitness-For-Service, he was instrumental in completing the update to API 579 entitled API *579-1/ASME FFS-1 Fitness-For-Service*. Mr. Osage provides instruction on Fitness-For-Service technology to the international community under the API University Program.

Mr. Osage is also a recognized expert in the design of new equipment. As the lead investigator and principal author of the new *ASME, Section VIII, Division 2, Boiler and Pressure Vessel Code*, he developed a new organization and writing style for this code and was responsible for introducing the latest developments in materials, design, fabrication and inspection technologies. These technologies include a new brittle fracture evaluation method, new design-by-analysis procedures including the introduction of elastic-plastic analysis methods, and a new fatigue method for welded joints. Mr. Osage has delivered lectures on the new pressure vessel code in Europe and Japan and will be offering a training course highlighting advantages of the new code for use with refinery and petrochemical equipment.

Mr. Osage was a lead investigator in revamping the API Risk-Based Inspection (RBI) technology and software. The main focus of this effort was a clean sheet re-write of API 581 *Risk-Based Inspection* and the development of a new version of the API RBI software. He is currently working on the next generation of RBI technology where Fitness-For-Service assessment procedures will be used to compute the Probability of Failure for Risk-Based Inspection.

As an Adjunct Visiting Assistant Professor at Stevens Institute of Technology, Mr. Osage has taught graduate level courses in strength of materials and elasticity, structural analysis and finite element methods, and structural optimization.

PAPPONE, DAN



Mr. Daniel Pappone is Chief Consulting Engineer in Plant Performance at GE-Hitachi Nuclear Energy. He joined GE in 1978. Mr. Pappone has extensive experience in safety evaluations for BWR accident conditions with a primary focus on the vessel and containment response to Loss-of-Coolant Accidents. He is involved in the ongoing development of the generic extended power uprate programs and has held lead technical positions in several stretch and extended power uprate projects.

Currently, Mr. Pappone has been leading research into understanding the fatigue loading acting on BWR steam dryers. His past responsibilities have included degraded core cooling studies, Emergency Procedure Guideline development, and the design, plant application and installation of safety parameter display and plant monitoring computer systems. He brings an overall integrated perspective to the projects, including analysis, system design, operations, and regulatory aspects. Mr. Pappone holds a B.S. degree in Nuclear Engineering from the University of California, Los Angeles.

PARECE, MARTIN



Martin Parece is Chief Engineer and Vice President, Technology for AREVA NP, Inc. He is responsible for technical oversight and configuration control of pressurized water reactor and high temperature gas reactor designs planned for deployment in North America.

Mr. Parece has B.S. and M.S. degrees in Nuclear Engineering from the University of Illinois and is a member of the American Nuclear Society. During the last 26 years with Babcock & Wilcox, Framatome and AREVA NP, he has gained extensive experience in safety analysis, core reload analysis, plant performance analysis, plant simulation, computer code development, accident mitigation, operator guidance, thermal-hydraulics, plant auxiliary and control systems, Class 1 component design, and licensing. Mr. Parece is the author of numerous papers and topical reports, he also holds a patent on a method and system for emergency core cooling. Mr. Parece is a highly regarded speaker on reactor power uprates, nuclear power plant safety and new reactors.

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PARK, GARY



Gary Park is a Senior Programs Engineer with Iddeal Solutions LLC. Mr. Park has worked in the Nuclear Industry since 1977. He has achieved Level III in many Nondestructive Examination Methods and managed Nuclear Inservice Inspection Program both government and utility. Mr. Park is currently the Chair of the Boiler and Pressure Vessel Standards Committee on Nuclear Inservice Inspection. He sits on the Board on Nuclear Codes and Standards as an Ex-Officio Member. He had been a member of the ASME Committees since 1996. Mr. Park has authored PVP Papers concerning the changes within the ASME Boiler and Pressure Vessel Section XI Code. He has participated in the ASME Nuclear Training Seminars providing presentations on ASME Code Pre-Service and Inservice Inspection and Testing along with Lessons from Past Construction Problems. Mr. Park currently is working with a number of utilities in updating their ASME Section XI Inspection Programs.

PAULIN, JR., ANTHONY W.



Anthony "Tony" Paulin Jr. is president of Paulin Research Group "PRG", and the author of the FE/Pipe™, NozzlePRO™, and PCLGold™ FEA-based modeling and analysis products. PRG was founded in 1991 with the express goal of bringing improved technology to the pressure vessel and piping industries. Tony is the original author and architect of the CAESAR II® pipe stress analysis program. He has been a member of the ASME B31 Mechanical Design Code Committee since 1994 and he is a past recipient of the South Texas ASME Herbert Allen Award for Outstanding Technical Achievement. Tony has published numerous technical and trade articles on the application of FEA and other advanced methods to pressure vessel and piping systems.

Under Tony's direction and guidance, Paulin Research Group conducts ongoing leak, fatigue, and other physical tests to validate the results predicted by the company's FEA software. These results are the basis of Tony's recent work with the ASME Code committees to improve the accuracy of pressure vessel and piping component analysis. Tony feels strongly that this work will benefit the trade, making plant components more dependable and increasing plant safety.

Tony Paulin is a graduate of Texas A&M University with a degree in Mechanical Engineering.

PORTER, MICHAEL (MIKE) A.



Michael (Mike) A. Porter is the Principal Engineer of Porter McGuffie, Inc. In the 40 years since he obtained a Mechanical Engineering degree from the University of Illinois at Champaign/Urbana, he has worked in the natural gas industry, managed a construction firm and served as a consultant to numerous industries in the fields of vibration, thermal and stress analysis. He has published more than 30 ASME conference and journal publications, most of which have been for the Piping and Pressure Vessel Division. His most recent PVP Journal paper "A Suggested Shell/Plate Finite Element Nozzle Model Evaluation Procedure" provides guidance for the application of Finite Element (FE) analysis as it applies to the Boiler and Pressure Vessel Code. He has also authored papers for the Acoustical Society of America and published two books on the application of the FE method of analysis.

Mike has extensive experience in the diagnosis and solution of stress and vibration problems. Much of this experience stems from his work as a technical services engineer at Panhandle Eastern Pipeline Company and as a consultant with Bolt Beranek and Newman. Building on this base, Mr. Porter has established an integrated computational facility for the analysis of mechanical systems and their interaction with fluids. These capabilities include the codes for linear and non-linear stress analysis, computational fluid dynamics and gas/liquid pulsation FE analyses. For the past 15 years, Mike has served as a member of the Design and Analysis Committee of the Piping and Pressure Vessel Division of ASME. He has served as the Technical Program Representative for this committee as well as developing and chairing numerous conference sessions on the subjects of vibration, water hammer, pulsation and stress.

The projects overseen by Mr. Porter cover a broad range of industries and topics. Representative examples include the petrochemical industry (analyses of numerous pressure vessels and components); the aerospace industry (analyses for the International Space Station and FEA training for NASA personnel); and building dynamics (design review and analysis of multi-storied structures for the Environmental Protection Agency and the National Ocean Service, among others). These projects have included linear and non-linear stress analyses as well as computational fluid dynamics, structural dynamics and thermal analyses.

RAO, DEEPAK



Deepak Rao has been with Entergy for over 30 years, during the last 10 years as Supervisor of PRA. He has been representing Entergy for several years at the EPRI Risk and Safety Management Advisory Group as well as the Nuclear Energy Institute's industry Risk Applications Task Force. He is a member of the American Society of Mechanical Engineers.

The Entergy South PRA group led by Deepak Rao is responsible for providing EOOS risk monitor model maintenance and roll-out for the five southern nuclear units (ANO1 & 2, GGNS, RBS and WF3) as well as providing them emergent PRA evaluations such as enforcement discretion, technical specification relief submittals and Significance Determination Process (SDP) evaluation. Under Deepak's direction and guidance, the Entergy South PRA Group successfully supported and obtained regulatory approval for application of the ASME Code Case N-716 which is the EPRI Streamlined Risk Informed In-Service Inspection (RI-ISI) approach using upgraded internal flooding PRA models meeting the ASME/ANS PRA Standard (ASME/ANS RA-Sa–2009). This approach led to a significantly reduced number of piping inspections needed with negligible impact on plant risk. Entergy South's plants were among the first in the industry to successfully use this approach and this has led to substantial cost savings for the

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corporation. The Entergy South PRA group was also the original user of the Model Change Request database concept for managing all of the open issues on a PRA model, as well as the Loss of Offsite Power (LOSP) convolution method to obtain more realistic LOSP treatment. Both of these concepts have now been adopted in a widespread fashion by most of the industry.

Deepak Rao has published two technical papers in PRA applications: Impact of Aging on PRAs – presented at ASME PVP conference (1993), and, Large Early Release Frequency (LERF) risk monitor models – presented at ICONE-6 (2000).

Deepak Rao has been serving on the ASME/ANS Committee on PRA Standards for the past several years. He is a past licensed professional engineer in Louisiana in Mechanical Engineering. He has participated in numerous industry peer reviews of nuclear power plant PRAs for internal events, fire as well as seismic PRAs through the auspices of the PWR Owners' Group. Deepak Rao is a graduate of the Indian Institute of Technology at Kanpur with a degree in Mechanical Engineering. He obtained a Master of Science degree in Nuclear Engineering from North Carolina State University at Raleigh.

RAO, K. R.



KR Rao retired as a Senior Staff Engineer with Entergy Operations Inc. and was previously with Westinghouse Electric Corporation at Pittsburgh, PA and Pullman Swindell Inc., Pittsburgh, PA. KR got his Bachelors in Engineering from Banaras University, India with a Masters Diploma in Planning from School of Planning & Architecture, New Delhi, India. He completed Post Graduate Engineering courses in Seismic Engineering, Finite Element and Stress Analysis, and other engineering subjects at Carnegie Mellon University, Pittsburgh, PA. He earned his Ph.D., from University of Pittsburgh, PA. He is a Registered Professional Engineer in Pennsylvania and Texas. He is past Member of Operations Research Society of America, (ORSA).

KR was Vice President, Southeastern Region, ASME International. He is a Fellow of ASME, active in National, Regional, Section and Technical Divisions of ASME. He has been the Chair, Director and Founder of ASME EXPO(s) at Mississippi Section. He was a member of General Awards Committee of ASME International. He was Chair of Codes & Standards Technical Committee, ASME PV&PD. He developed an ASME Tutorial for PVP Division covering select aspects of Code. KR is a Member, Special Working Group on Editing and Review (ASME B&PV Code Section XI) for September 2007 – June 2012 term.

Dr. Rao is a recipient of several Cash, Recognition and Service Awards from Entergy Operations, Inc., and Westinghouse Electric Corporation. He is also the recipient of several awards, Certificates and Plaques from ASME PV&P Division including Outstanding Service Award (2001) and Certificate for "Vision and Leadership" in Mississippi and Dick Duncan Award, Southeastern Region, ASME. Dr. Rao is the recipient of the prestigious ASME Society Level Dedicated Service Award.

Dr. Rao edited "Energy and Power Generation Handbook: Established and Emerging Technologies" published by ASME Press in 2011. Dr. Rao who founded the annual "Early Career Technical Conference (ECTC) organized the thirteenth ECTC at University of Birmingham, Alabama on Nov. 2–3, 2013.

Dr. Rao is a Fellow of American Society of Mechanical Engineers, Fellow of Institution of Engineers, India and a Chartered Engineer, India. Dr. Rao was recognized as a 'Life Time Member' for inclusion in the Cambridge "Who's Who" registry of executives and professionals. Dr. Rao was listed in the Marquis 25th Silver Anniversary Edition of "Who's Who in the World" as 'one of the leading achievers from around the globe'.

REYES, JOSE N.



Dr. Reyes is the Chief Technology Officer and co-founder of NuScale Power, LLC. He is also the co-designer of the NuScale passively-cooled small nuclear reactor. He is an internationally recognized expert on passive safety system design, testing and operations for nuclear power plants. He has served as a United Nations International Atomic Energy Agency (IAEA) technical expert on passive safety systems. Dr. Reyes successfully established a coordinated research program on natural circulation and passive safety systems for the IAEA and also co-developed and directed a course on natural circulation and passive safety systems at the International Center for Theoretical Physics in Trieste, Italy.

At Oregon State University, Dr. Reyes held the Schuette Endowed Chair and served as head of the Department of Nuclear Engineering and Radiation Health Physics. He directed the Advanced Thermal Hydraulic Research Laboratory (ATHRL) and was the co-director of the Battelle Energy Alliance Academic Center of Excellence (ACE) for Thermal Fluids and Reactor Safety in support of the Idaho National Laboratory mission. Additionally, Dr. Reyes was the OSU principal investigator for the Westinghouse AP600 and AP1000 design certification test programs sponsored by the USNRC, the U.S. Department of Energy and Westinghouse.

Prior to joining the faculty at OSU in 1987, Dr. Reyes worked nearly 10 years as a thermal hydraulics research engineer in the Reactor Safety Division of the U.S. Nuclear Regulatory Commission. He holds Ph.D. and M.S. degrees in Nuclear Engineering from the University of Maryland and a B.S. degree in Nuclear Engineering from the University of Florida. He is the author of numerous technical papers and has given lectures and keynote addresses to professional nuclear organizations in the U.S., Europe and Asia.

RICCARDELLA, PETER C.



Pete Riccardella received his Ph.D. from Carnegie Mellon University in 1973 and is an expert in the area of structural integrity of nuclear power plant components. He co-founded Structural Integrity Associates in 1983, and has contributed to the diagnosis and correction of several critical industry problems, including:

- Feedwater nozzle cracking in boiling water reactors
- Stress corrosion cracking in boiling water reactor piping & internals

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- Irradiation embrittlement of nuclear reactor vessels
- Primary water stress corrosion cracking in pressurized water reactors
- Turbine-generator cracking and failures.

Dr. Riccardella has been principal investigator for a number of EPRI projects that led to advancements and cost savings for the industry. These include the **FatiguePro** fatigue monitoring system, the **RRingLife** software for turbine-generator retaining ring evaluation, **Risk-Informed Inservice Inspection methodology** for nuclear power plants, and several **Probabilistic Fracture Mechanics** applications to plant cracking issues. He has led major failure analysis efforts on electric utility equipment ranging from transmission towers to turbine-generator components and has testified as an expert witness in litigation related to such failures.

He has also been a prime mover on the ASME Nuclear Inservice Inspection Code in the development of evaluation procedures and acceptance standards for flaws detected during inspections. In 2002 he became an honorary member of the ASME Section XI Subcommittee on Inservice Inspection, after serving for over twenty years as a member of that committee. In 2003, Dr. Riccardella was elected a Fellow of ASME International.

RODABAUGH, EVERETT C.



Mr. Rodabaugh has B.S. from Iowa State College, Ames, Iowa (1939) and M.S. from the University of Louisville, Kentucky (1959). He is a Registered Professional Engineer in the State of Ohio.

He has extensive experience in power plant operations and the design of piping and pressure vessels. His previous experience was with Joseph E. Seagram Co., E.I. duPont, U.S. Maritime Service (1943–1946). He was with Tube Turns in Louisville, Kentucky (1946–1961). Mr. Rodabaugh was with Bat-telle-Columbus Laboratories, Columbus, Ohio (1961–1981).

In 1981 he started his own consulting firm and since 1991 he has continued his work on piping and pressure vessels as a consultant.

Mr. Rodabaugh was a member of the original ASME Design Group that prepared ANSI B31.7. He was a member of several ASME Code committees including Section III Committees and Subgroup on Design and Working Group on Piping. Everret Rodabaugh was Chairman of ANSI B16 and its Subcommittees.

Mr. Rodabaugh is also a member of the Pressure Vessel Research Council, Design Division and its Subcommittee on Piping, Nozzles and Vessels. Mr. Rodabaugh published over 60 articles and has written over 100 reports. Everret Rodabaugh is a Fellow in the ASME and received the ASME Bernard F. Langer award in 1998.

ROWLEY, C. WESLEY



C. Wesley Rowley is Vice President, Engineering & Technical Services, with The Wesley Corporation in Tucson, AZ. He has been with TWC since 1985. Mr. Rowley manages engineering and non-metallic structural repair activities for nuclear power plants. He has published numerous reports and technical papers for EPRI, ASME, ICONE Conferences, Pump & Valve Symposiums, and other nuclear industry events. He is a recognized expert on risk-informed Inservice Testing, as well as non-metallic materials and non-metallic structural repairs.

Mr. Rowley has been a member of the ASME Board on Nuclear Codes and Standards for over twenty-five years. He is also a member of the ASME Post Construction Committee, the PCC Subcommittee on Repair & Testing, and the Chairman of the PCC Sub-group on Non-metallic Repair. Additionally, he is a member of the ASME, Operations & Maintenance Committee (and Subgroup ISTE, Risk-Informed Inservice Testing). Also he is a member of the ASME Committee on Nonmetallic Pressure Piping Systems/Subcommittee on Nonmetallic Materials, Subcommittee on FRP Piping Systems, and Sub-group on FRP Materials.

Previously he was the Chairman of the ASME Board on Nuclear Codes and Standards (and ASME Vice President – Nuclear Codes and Standards), Chairman of BPV-II / Special Working Group on Nonmetallic Materials, and past Chairman of the ASME Joint BPV III / XI Project Team for Plastic Pipe.

Mr. Rowley is a retired Submarine Captain in the U.S. Naval Reserve. He has a M.A. degree in International Relations and Strategic Studies from the Naval War College (1986). He also has a B.S. in General Engineering (1965) and M.S. in Nuclear Engineering from the University of Illinois (1967). Mr. Rowley is a Registered Professional Engineer.

SCARTH, DOUGLAS



Douglas Scarth received a B.Sc. and M.Sc. in Mechanical Engineering from the University of Manitoba, and a Ph.D. in Materials Science from the University of Manchester. Dr. Scarth is currently a Technical Director – Fracture Programs with Kinectrics, Inc., in Toronto, Canada. He was previously with the Research Division of Ontario Hydro. His work experience includes structural integrity evaluations of nuclear and fossil plant components containing flaws. Dr. Scarth has been involved in development of methodologies for evaluating the structural integrity of nuclear pressure boundary components, including CANDU reactor Zr-Nb pressure tubes in the areas of delayed hydride cracking, fatigue and fracture toughness. He has participated in development of engineering codes and standards for fitness for service assessments

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of pressure boundary components including Section XI of the ASME Boiler and Pressure Vessel Code. Dr. Scarth is a member of the Section XI Standards Committee on Nuclear Inservice Inspection, and the Section XI Subgroup on Evaluation Standards. He is Chair of the Section XI Working Group on Pipe Flaw Evaluation, and a member of the Section XI Working Group on Flaw Evaluation. Dr. Scarth is also a member of a number of Task Groups under Section XI that are associated with structural integrity evaluations.

SCHWAB, E. KEITH



Mr. Schwab is currently a Principal Engineer at Westinghouse Electric Company in the AP1000® PWR Fluid Systems and Turbine Generator Engineering design group. He has nearly 34 years of diverse experience with the design of utility power, petro-chemical, and industrial facilities. This has included systems design and mechanical equipment sizing for nuclear and fossil fueled power plants including pumps, heat transfer equipment, valves, pressure vessels, and storage tanks. He has also provided on-site engineering and licensing support for various nuclear plant startups, testing, power ascension, and commercial operation.

Since 2005, Keith has worked on the AP1000 PWR nuclear plant project. He is currently the lead engineer for the AP1000 PWR Turbine-Generator, auxiliary systems, and secondary side steam cycle equipment. In 2011 he received a Westinghouse Corporate Signature Award as part of the team for the AP1000 PWR turbine control system design.

Keith has provided support for the development of performance guarantees for the AP1000 plant EPC contracts and proposals, and currently provides technical support for the AP1000 plant projects under construction in the U.S. He is also currently involved with performing engineering design and licensing reviews, and serving as a technical advisor to less experienced engineers on the AP1000 PWR project. Keith has been nominated to be a Westinghouse Fellow Engineer.

SERVER, WILLIAM L.



William Server has more than thirty years of experience in materials applications, failure analyses, and structural integrity evaluations for the electric utility industry. He is internationally known as a technical expert in the areas of small specimen fracture mechanics, management of materials aging issues, and reactor pressure vessel (RPV) surveillance programs. Mr. Server is the founding Principal for ATI Consulting which began business in 1991; staffed employees working in the electric power industry (primarily nuclear with approximately 65% of the projects being conducted for EPRI) and the non-nuclear architect-engineering industry. He has chaired several IAEA coordinated research projects and special technical meetings for IAEA, ASTM, ASME, and others. His current projects include life attainment and license renewal strategies beyond 60 years, application of advanced fracture mechanics approaches, RPV radiation embrittlement and mitigation methods, and decision-making approaches for utility management. He has published more than 100 technical papers and has received several awards for outstanding papers and/or technical sessions; also, approximately 100 conference and invited presentations have been made.

SIMONEN, FREDRIC A.



Fredric A. Simonen earned B.S.M.E. in 1963 from Michigan Technology University and a Ph.D. in Engineering Mechanics form Stanford University in 1966. Since joining Pacific Northwest Laboratory in 1976, and before that at the Battelle Columbus Division, Dr. Simonen has worked in the areas of fracture mechanics and structural integrity. His research has addressed the safety and reliability of nuclear pressure vessels and piping as well as other industrial and aerospace structural components.

Since the early 1980's he has been the lead for several studies for the U.S. Nuclear Regulatory Commission (NRC) of the effects of pressurized thermal shock on the failure probability of reactor pressure vessels. This work has advanced the technology of probabilistic fracture mechanics and has developed methods for estimating the number and sizes of flaws in vessel piping welds. During the 1990's Dr. Simonen was a leader on the behalf of NRC and the American Society of Mechanical Engineers in developing the technology and furthering the implementation of risk-informed methods for the inspection of nuclear piping systems.

Dr. Simonen is a member of the Section XI Working Groups on Implementation of Risk-Based Inspection, Flaw Evaluation, and Operating Plant Criteria. He is also a member of the ASME Committee on Nuclear Risk Management and the ASME Research Committee on Risk-Based Technology. He has published over 200 papers, articles and reports in the open literature.

SOWINSKI, JAMES C.



Mr. Sowinski is a Consulting Engineer for The Equity Engineering Group, Inc. in Shaker Heights, Ohio. He has experience in the refining and petrochemical industries as an owner-user and as a consultant providing engineering support. He provides plant engineering support to maintenance and inspection personnel and performs design/analysis/re-rate calculations of pressure containing equipment to evaluate mechanical integrity and improve reliability. Mr. Sowinski is responsible for Equity's "R" Certificate of Authorization issued by The National Board of Boiler and Pressure Vessel Inspectors.

Mr. Sowinski was involved in the development of the new ASME, Section VIII, Division 2, Boiler and Pressure Vessel Code and was a contributing author of the ASME Section VIII, Division 2, Criteria and Commentary. He is Vice-Chair of the ASME Boiler and Pressure Vessel VIII Subgroup on Design and also serves on the Subgroup on General Requirements.

Mr. Sowinski is a Registered Professional Engineer in the States of Ohio and Texas.

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STEVENSON, JOHN D.



Dr. John D. Stevenson is a Senior Consultant for J.D. Stevenson, Consulting Engineer Co. He has extensive experience worldwide in the nuclear power field where he served as a consultant to the IAEA and several non U.S. utilities and consulting firms. He holds a Ph.D. in Civil Engineering from Case Western Reserve University. He has provided structural-mechanical consulting services to the nuclear power industry in the U.S. and abroad for the past 35 years and has been a member of various committees of ASME and B&PVC Section III for the past 35 years. He is currently also a member of several of American Society of Civil Engineers, American Nuclear Society, and American Concrete Institute committees and consultant to government agencies dealing with the structural-mechanical safety of nuclear facilities.

STEVENSON, RICHARD R.



Richard "Rick" Stevenson has over 39 years' experience with ASME and the National Board Conformity Assessment Programs in the Nuclear Power Industry. He holds MS and BS degrees in Civil Engineering and is a Registered Professional Engineer. He has held various positions within Quality Assurance/Quality Control/Quality Engineering leading up to his current position as Chief Engineer, QA and Nuclear QA Manager ASME III Program for CB&I Stone & Webster, Inc. He has 28 years participation on ASME committees within the Boiler and Pressure Vessel Code committee structure with the majority of those being in leadership roles and received the ASME Dedicated Service Award in 2009. He is currently Vice Chairman of the Board on Conformity Assessment (BCA) with service on BCA since February 1997, and is an Ex-Officio Member of the Board on Nuclear Codes and Standards (BNCS) with service on BNCS since October 2003. He is also the current Chairman of the Committee on Nuclear Certification (CNC) with service on CNC since February 1990, and is a member of the ASME Section XI Subgroup on Repair/Replacement Activities with service since November 1986, the ASME Section XI Working Group on Design and Programs with service since September 1995, the ASME Section III Special Working Group for New Advanced Light Water Reactor Plant Construction Issues with service since November 2010, and the ASME Section III Special Working Group on Regulatory Interface with service since July 2011. He also served on the Boiler & Pressure Vessel (B&PV) Honors and Awards committee from 2003 to 2010.

TABOAS, ANÍBAL L.



Aníbal L. Taboas is an executive generalist who consults on environment, governance, and strategic risk management. His background ranges from nuclear CONOPS, to line management of national laboratories and programs, and conflict resolution. He led various regulatory and legislative initiatives, including changing the disposal limits for transuranic waste. Accomplishments in the federal Senior Executive Service have been recognized by the Vice President's Hammer Award, Secretary of Energy Gold Medal, the University of Chicago Medal for Distinguished Performance, and several Exceptional and Distinguished Service Awards. Taboas has a solid reputation for innovative resolution of regulatory and legislative issues, project management, diversity, and independent peer review. Aníbal actively participates in pro-bono activities, such as the Board of Directors of the Center of Excellence for Hazardous Materials Management, and of the Institute for Regulatory Science, editorial boards, and peer review (e.g., National Science Foundation and International Atomic Energy Agency). Dr. Taboas has a BS in Physics/Theology (Univ. of Dayton), MS in Physics (Indiana State Univ.), MS in Mechanical & Nuclear Engineering (Northwestern Univ.), a PhD *honoris causa* in Environmental Policy (UPAEP), and numerous peer-reviewed publications. Aníbal is Fellow of the American Society of Mechanical Engineers, edited The Decommissioning Handbook, and has served multiple times as Chair of the International Conference on Environmental Management. Aníbal L. Taboas can be reached via electronic mail at: TaboasA2@ASME.org.

WEST, RAYMOND (RAY) A.



Mr. West began his nuclear career in the US Navy in 1971 and then proceeded into its Nuclear Power Program in 1976. He has been a welder, a Level III in several Nondestructive Examination (NDE) methods, and has developed Inservice Inspection (ISI) programs for both Pressured Water Reactors and Boiling Water Reactors. In 1979 he began work in the commercial nuclear industry and he continues to do so today.

His major accomplishments include ASME Engineer of the Year in 1997 in the State of Connecticut for Northeast Utilities, and several other ASME awards including one for the development of the Section XI, Nonmandatory Appendix R, "Risk-Informed Inspection Requirements For Piping," where he served as the ASME Technical Project Manager Responsible for Development and Approval of this Appendix (a 14 year effort), Approved for Publication in the 2005 Addenda of Section XI,

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October 2004. He has also authored or co-authored many technical papers centering on ISI and Risk-Informed Inservice Inspection (RI-ISI) and the latest was for the ASME 16th International Conference on Nuclear Engineering (ICONE16) in May 2008 that was related to the U.S. Nuclear Regulatory Commission's Rulemaking Process and its effects on the Endorsement of ASME Nuclear Codes and Standards in the USA.

Ray is currently the Vice Chair of the ASME Board on Nuclear Codes and Standards (BNCS), the Co-Chair of the BNCS Task Group on Regulatory Endorsement (TG-RE), a member of the ASME Boiler and Pressure Vessel (BPV) Code Subcommittee XI on Nuclear Inservice Inspection ISI, a member of the Section XI Executive Committee, and several of its lower level BPV Code writing groups. He has been involved with nuclear power for over 30 years. His experience has been focused on welding, NDE, and ISI and he is currently a Technical Consultant and the senior ASME representative for his company Dominion Resources, Inc. at the Millstone Power Station in Waterford, Connecticut.

WHITE, GLENN A.



Glenn White is a principal engineer and principal officer at Dominion Engineering, Inc. in Reston, Virginia. Mr. White manages consulting and analysis projects primarily for the nuclear power industry and often related to aging degradation of materials, boric acid corrosion, or thermal performance.

Mr. White was the principal author of the Electric Power Research Institute (EPRI) safety assessment report for primary water stress corrosion cracking (PWSCC) of U.S. PWR Alloy 600 reactor vessel closure head penetrations. In 2007, he was the principal investigator for EPRI's crack growth and leak-before-break evaluation of PWSCC of PWR pressurizer nozzle dissimilar metal welds in response to indications of circumferentially oriented PWSCC at one plant. Mr. White's projects to evaluate materials degradation include nuclear safety and economic risk assessments and apply analytical tools such as probabilistic Monte Carlo simulation, net present value analysis, Weibull statistical modeling, and stress and fracture analyses.

In the area of thermal performance degradation of nuclear steam generators, Mr. White investigates the sources of steam pressure loss, the fouling deposition process, and the effects of tube deposits on boiling heat transfer and corrosion.

Before joining Dominion Engineering, Inc. in 1993, Mr. White received B.S. (summa cum laude) and M.S. degrees in mechanical engineering from the University of Maryland at College Park. Mr. White is a registered professional engineer and is a member of NACE.

WILLIAMS, TONY



Tony Williams is head of the nuclear fuel department of the Nordostschweizerische Kraftwerke AG (NOK), the company responsible for the general management and fueling of the two Beznau PWR units and the Leibstadt BWR in Switzerland. Both plants are renowned for their progressive fuel burnup strategies as well as extensive use of MOX and Reprocessed Uranium fuels.

In addition to fuel procurement, his responsibilities include inhouse fuel assembly and core design, administration of reprocessing contracts, planning of interim off-site storage, flask procurement and transport as well as some aspects of final disposal. He is a member of the Swiss nuclear fuel commission and a board member of ZWILAG, the facility responsible for interim dry fuel storage and waste conditioning in Switzerland. In previous positions he was manager of a research program investigating fuel and core issues related to Pebble Bed Modular Reactors as well as working as a reactor physicist for the British commercial nuclear industry.

Dr. Williams holds a diploma in Business Management, has an honors degree in Physics from Durham University (1981) as well as an M.Sc. and Doctors degree in neutron physics from Birmingham University (1984).

ZATZ, IRVING J.



Irving J. Zatz is a Principal Engineer at the Princeton University Plasma Physics Laboratory (PPPL), which focuses on fusion energy research. In his over 30 years of experience at PPPL, Mr. Zatz has been extensively involved with the structural analysis and design of complex mechanical systems that have operating conditions in both high heat flux and cryogenic environments. His areas of expertise include finite element analysis, non-linear analysis, dynamic (including seismic) analysis, fatigue and fracture life assessments, and materials development and testing. He has participated in numerous domestic and international fusion energy projects and collaborations, including ITER. Additionally, he has been the author of several fusion energy structural design criteria documents. As a member of ASME, he is currently working on a committee tasked with the development of a code case for fusion within the ASME Boiler and Pressure Vessel Standards. He is also an active member of ASCE.

Mr. Zatz is the author/co-author of numerous technical papers appearing in a variety of journals. He has aerospace and spacecraft experience having previously worked at the Grumman Aerospace Corporation. He received both his Bachelors Degree and Masters Degree in structural engineering from Cornell University. He resides in New Jersey.

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PREFACE

This publication follows the phenomenal success of the three editions of the *Companion Guide to the ASME Boiler & Pressure Vessel Codes and Standards* published by ASME Press. ASME Boiler and Pressure Vessel Codes and Standards are arrived at by a consensus process from the deliberations of practicing engineers, professionals, academia, and regulators meeting several times a year.

The first edition of these books in two volumes was published in summer 2002, with the third edition of the "Companion Guide" published in summer 2009, which over time had been broken into three separate volumes. The first release of the latest editions of these books is the fourth edition of the *Companion Guide to the ASME Boiler & Pressure Vessel and Piping Codes*, which addressed Sections I through XII of the Boiler & Pressure Vessel Codes and B31 Codes and Standards in two volumes and was published in summer 2012. The other two, new "stand-alone" separate volumes, which include chapters of the third edition excluded from the fourth edition are: (a) *Continuing and Changing Priorities of ASME B&PV Codes and Standards*, and (b) *Global Applications of ASME B&PV Codes and Standards*.

This book addresses the *Continuing and Changing Priorities of ASME B&PV Codes and Standards* and pursues the intent of the previous editions. *This publication continues to focus on the critical Public Safety issues discussed by experts in the first, and subsequent second and third editions.* Being at the cross-roads of aging nuclear reactors seeking life extension with few on the threshold of new constructions, and even fewer considering permanent shutdown, it is appropriate to chronicle the continuing and changing priorities. Given the changes in the demographics of the ASME Boiler and Pressure Vessel Code Members, it is appropriate to chronicle *Continuing and Changing Priorities of ASME B&PV Codes and Standards* since some Code Members are either seeking retirement or even fading away. It is appropriate to capture the 1634 combined years of the rich professional expertise of 43 contributors about the topics listed in the table of contents. In this Preface a chapter-wise sequential description is provided to highlight the contributors expertise for the chapters assigned to them.

Continuing the premise of the previous editions, this book has 699 pages of text, 527 equations, and 427 graphics including pictures, sketches and 94 tables and 1536 references and annotated bibliographical material. This publication has four parts as enumerated below, which shows the authoritative background of contributors chosen to chronicle the chapters assigned to them.

- *In Part 1, this book has updates by 16 Code experts and recognized professionals who addressed in 14 Chapters with considerable revisions continue the thread of discussions of the third volume of the third edition, which were not included in the fourth edition of the "Companion Guide." The revisions in this part deal with "Continuing Priorities of B&PV Codes and Standards" to recognize the changes in the current Code Editions and ongoing deliberations by the recognized professionals and Code Experts in the following chapters:*
  - *'Code Rules for Accreditation, Certification'* replete with figures new and fresh insights are provided in the revisions by Richard Stevenson PE, a recognized Code Expert with nearly 4-decades of experience in National Board Conformity Assessment and leadership role in Code committee.
  - *'The Maintenance Rule'* is updated by Wesley C. Rowley PE, Code Committee Member who was at the helm of the ASME Board on Nuclear Codes and Standards for over twenty-five years.
  - *'Pipe Vibration Testing and Analysis'* continues to be updated in 38 pages containing 35 graphics and 34 references by David E. Olson PE, current and long standing Chairman of the ASME Operation and Maintenance Subgroup on Piping Systems.
  - *'Stress Intensification Factors, Stress Indices, and Flexibility Factors'* has been updated with 25 equations and 53 references is updated by a new contributor Anthony W. Paulin Jr., PE, versatile in the subject, President of an engineering testing and analysis the group he founded in 1991.
  - *'Code Design and Evaluation for Cyclic Loading – Sections III and VIII'* has been revised in 34 pages with 41 figures and 348 scholastic references by William O'Donnell, Ph.D., a reputed Code Committee member and a recognized expert in Failure Causation Analyses, who authored 96 papers in engineering mechanics, elastic-plastic fracture mechanics, strain limits and damage evaluation methods.
  - *'Perspective on Cyclic Impact, and Impulse Loads'* is revised with 52 references by Michael (Mike) A. Porter, a PV&PD expert in linear and non-linear stress analyses as well as computational structural dynamics.
  - *'Functionality and Operability Criteria'* continues to be authored by Stephen (Steve) R. Gosselin, a Sections III and XI Code Committee expert with 34 years commercial nuclear power industry experience focused primarily on fitness-for-service, structural integrity, safety, and reliability of pressure vessels and piping components; in addition this edition this chapter is co-authored by Thomas C. Esselman Ph.D., a senior executive of a reputed engineering consultancy with wide variety of engineering disciplines, including component

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and structure performance, aging, stress analysis, dynamics, seismic design and analysis, mechanical design, thermo-hydraulics, materials, materials degradation, and failure analysis.

– *'Fluids'* was authored with 201 equations and 40 figures by Frederick J. Moody, an internationally renowned engineer with 41 years of consultancy experience with GE Nuclear Energy, and 28 years as adjunct professor adept in fluid mechanics, thermodynamics, heat transfer, and coupled fluid-structure interaction, pertaining to reactor and containment technology.
– *'Bolted-Flange Joints and Connections'* is authored in 38 pages, 15 figures and 140 equations by William J. Koves Ph.D. PE, a code expert with 40 years of experience in the design, analysis and troubleshooting of equipment and aircraft, nuclear reactors, and petrochemical equipment structures. Author is holder of 27 US and 3 European patents.
– *'The Evolution of U.S. Transportation Regulations for Radioactive Materials – A Retrospective'* is authored by Ronald F. Hafner, the continuing contributor in 24 pages and 33 references. Ronald Hafner has 50 years of experience in a variety of disciplines ranging from radar systems and nuclear instrumentation, to non-destructive testing using gamma-ray sources and electronic devices, to nuclear reactor- and tritium facility operations, to regulatory issues associated with Department of Energy facilities and the transportation, storage, and disposal of radioactive materials.
– *'Pipeline Integrity and Security'* initially co-authored in 'Companion Guide' is updated by Alan Murray Ph.D., PE, the retired Chief Engineer and Chief Safety Officer of a National Energy Board, Canada, an Adjunct Professor in the Mechanical Engineering Department, founding chair of the ASME Pipeline Systems Division in 2000, and coauthor of the very successful ASME books *Pipeline Design and Construction: - A Practical Approach, and Pipeline Integrity Assurance*. This chapter update is replete with 58 scholastic references, 26 equations and 47 figures and is provided with a wealth of authoritative information.
– *'Decommissioning Technology Development'* updated in this book by a new contributor Harold E. Adkins of the US Fluid and Computational Engineering Group at Energy & Environment Directorate.
– *'Seismic Protection for Pressure Piping Systems'* is a new chapter by a an internationally recognized specialist in the area of piping, valves, materials, and codes and standards who has 46 years of design engineering experience on more than 100 domestic and international mega fossil and nuclear power and other projects. He is the Editor-in-Chief of the much acclaimed McGraw-Hill's *The Piping Handbook* (1992). This chapter is co-authored by Chakrapani Basavaraju Ph.D., PE a proficient engineer with USNRC, a member of Section III Code Committee, with insights into seismic aspects of domestic and international plants. Contributors of this chapter provided 22 equations and 14 references.

• *In Part 2, this book has updates by 13 Code Experts and Recognized Professionals who addressed in 9 Chapters with considerable revisions which continue the thread of discussions of the third volume of the third edition which was not included in the fourth edition of 'Companion Guide'. The revisions in this part deal with "Changing Priorities of B&PV Codes and Standards" which recognize the changes in the current Code Editions and ongoing deliberations as listed in the following:*

– *'The leading chapter of this Part 2 of the book has three parts - AP1000® PWR in Part A* addressed by Keith E. Schwab, a replacement contributor with 34 years of diverse experience with the design of utility power, petro-chemical, and industrial facilities who brings wealth of new information for the current update;
in *'Part B: EPR'* is addressed by Chief Engineer and Vice-President of AREVA NP, Inc., responsible for oversight and control of pressurized water reactor and high temperature gas reactor designs planned for deployment in North America; and in *'Part C: US-APWR'* is addressed by recognized and reputed replacement contributor Dr. Masanori Onozuka, vice president of Mitsubishi Nuclear Energy Systems, Inc., who has 30 years of experience in the research, design, analyses, and project management in nuclear related fields, including fusion research. Dr. Onozuka utilized his access to additional information in updating this part of the chapter.
– *'New Generation of BWRs'* has been updated by Hardayal Mehta, Ph.D., PE, who has been with GE Nuclear Division (now, GE-Hitachi Nuclear Energy) since 1978, and currently holds the position of Chief Consulting Engineer. Dr. Mehta is a noted Code Expert, brings to the chapter his 40 years of experience in the areas of stress analysis, linear-elastic and elastic-plastic fracture mechanics, residual stress evaluation, and ASME Code related analyses pertaining to BWR components.
– *'Future Code Needs for Very High Temperature Generation IV Reactors'* has been updated with 31 equations by William O'Donnell Ph.D., and Donald Griffin Ph.D. Dr. O'Donnell, founder President of O'Donnell and Associates, an engineering consulting firm specializing in design and analysis of structures and components evaluation of structural integrity, including corrosion fatigue, flaw sensitivity, crack propagation, creep rupture and brittle fracture is a versatile Code Expert.
– *'License Renewal and Aging Management'* has been updated by Pao-Tsin Kuo Ph.D., PE, retired from US NRS where he was Director of License Renewal Division and is executive consultant to the regulatory bodies.
– *'BWR Reactor Internals & Other BWR Issues'* has been updated by Dr. Mehta details about him are noted above. Dr. Mehta covers in 28 pages, 21 equations, 34 figures and tables, and 132 references, unique ways in which the provisions of Section III and Section XI have been used in addressing the service-induced degradations in the BWR vessels, internals, and pressure boundary piping. Among the items covered are reactor internals, weld overlays, reactor vessel. He states that the most common form of service-induced cracking in the stainless steel and Ni-Cr-Fe components in the BWR pressure boundary is typically due to intergranular stress corrosion cracking (IGSCC).
– *'BWR Reactor Vessel Integrity & Internals Aging Management'* has been updated by Dr. Mehta, (as noted above) with the help of William Server who has more than thirty years of experience in materials applications, failure analyses, and structural integrity evaluations for the electric utility industry.
– *'PWR Reactor Vessel Alloy 600 Issues'* has been updated with 106 references and 26 graphics by Glenn White PE; he was the principal author of the Electric Power Research Institute (EPRI) safety assessment report for primary water

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stress corrosion cracking (PWSCC) of U.S. PWR Alloy 600 reactor vessel closure head penetrations.

– *'PRA and Risk-Informed Analysis';* Ralph S. Hill III, PMP, is a Consulting Engineer with Westinghouse Electric Company in Pittsburgh, PA updated this chapter with 72 references. He has over 35 years of technical and management experience, including risk management, process evaluation, and project management consulting services to the U.S. Department of Energy in spent nuclear fuel, radioactive waste management, and nuclear materials disposition-related projects. Ralph is ASME Vice President Elect Nuclear Codes and Standards where he serves as Chairman of the Risk Management Task Group.
– *'Standardization of Valves, Flanges Fittings, and Gaskets'* is a new chapter included in this book to address "Balance of Plant" issues. This has been contributed by James Phillip Ellenberger, a recognized Code Authority of B16 and B31 Committees. Mr. Ellenberger is an author of three technical Books – Boiler Code Simplified, Piping Code Simplified, Piping and Pipeline Calculations.

• *Part 3 is a new entity in response to the current needs of the nuclear industry. Considering that the industry had over four decades of learning curve and several of the experts engaged in the nuclear field are either retiring or even fading away it is appropriate to capture while the experts are still available to provide to the industry the "lessons learned". In light of that opportunity 11 Experts, most of them associated with the development of the Code have been selected to address in 8 Chapters considered to be of dire importance. Thus, the following are new chapters that deal with "Changing Priorities of B&PV Codes and Standards" which recognize the changes in the current Code Editions and ongoing deliberations as listed in the following:*

The first chapter deals with Section VIII which is the 'mother Code' of the Boiler and Pressure Vessel Codes in vogue to-day, an understanding of the pitfalls in the use if Section VIII can be immense use. As such the contributors selected for this purpose befit their reputation. *In 'Part A: Lessons Learned Based on Section VIII, Division 1* by James C. Sowinski' and in *'Part B: Lessons Learned Based on Section VIII, Division 2'* by David A. Osage' appear as leading Chapter 24 of Part 3. James C. Sowinski PE is a Consulting Engineer for The Equity Engineering Group, Shaker Heights, Ohio. Sowinski was involved in the development of the new ASME, Section VIII, Division 2, Boiler and Pressure Vessel Code and was a contributing author of the ASME Section VIII, Division 2, Criteria and Commentary. David Osage, President and CEO of the Equity Engineering Group, Shaker Heights, Ohio, an internationally recognized industry expert for "*Fitness-For-Service"*. As the lead investigator and principal author of the new *ASME, Section VIII, Division 2, Boiler and Pressure Vessel Code*, he developed a new organization and writing style for this code. David was responsible for introducing the latest developments in materials, design, fabrication and inspection technologies.

– *'Lessons Learned Based on Operating Experience, Section XI' is* by Gary Park. Park has worked in the Nuclear Industry since 1977. Park is currently the Chair of the Boiler and Pressure Vessel Standards Committee on Nuclear Inservice Inspection. His insights on the subject are valuable, him being on the Board on Nuclear Codes and Standards. He had been a member of the ASME Committees since 1996.
– *'Lessons Learned: Industry Experience of Materials'* has been addressed in two Parts. Part A is titled: '*Lessons Learned - Industry Experience of Materials'* is by John F. Grubb Ph.D. PE. who has over 30 years' experience with corrosion resistant alloys with primary areas of expertise being material environmental resistance, behavior and applications. He is co-inventor of several patented corrosion-resistant alloys. He has been active in Section II and Section VIII as Code Committee member and Chair of Sub-Groups.
– Part B is *Lessons Learned: Experience with Nonmetallic Materials in Structural/Pressure Boundary Applications*, by C. Wesley Rowley PE. Rowley is a Vice President, Engineering & Technical Services, with The Wesley Corporation in Tucson, AZ. He is a recognized expert on non-metallic materials and non-metallic structural repairs and chaired several ASME committees and Task Groups on Nonmetallic Materials and has been a member of the ASME Board on Nuclear Codes and Standards for over twenty-five years.
– *'ASME Section XI Developments in Evaluation Procedures for Nuclear Piping Degraded by Flaws and Corrosion Processes in Response to Lessons Learned'* by Douglas A. Scarth Ph. D. provides authoritative insights into subject matter. Scarth is currently a Technical Director – Fracture Programs with Kinectrics, Toronto, Canada and was previously with the Research Division of Ontario Hydro. His work experience associated with structural integrity evaluations of nuclear and fossil plant components containing flaws is very much reflected in his write-up. As Chair of the Section XI Working Group on Pipe Flaw Evaluation and actively involved with Section XI flaw and structural evaluations his write-up could be of immense value to the readers.
– Pressure Relief Valves are extremely crucial in any pressure vessel or other pressure equipment such as boilers, piping, tankage and perhaps more so in nuclear applications which are however not discussed in the chapter titled '*Lessons Learned in The Use of Pressure Relief Devices'* by Chip H. Eskridge PE and Joseph F. Ball PE. Chip Eskridge has over 30 years of experience in the petrochemical and power industries and is currently a Technology Manager for the Jacobs Engineering Group. Being a Chair of a B31.3 Process Piping Sub-Group and Member of ASME B31 Materials and API's Pressure Relief Systems Committee the insights provided by him with the help of Joseph Ball regarding Pressure Relief Valves are of value to the readers. Joseph Ball has worked for The National Board of Boiler & Pressure Vessels Inspectors for 34 years and is currently the Director of the Pressure Relief Department for the organization.
– *'Insights from Nuclear Utility Experience with PRA Applications'* by Deepak Rao PE has been with a noted utility, Entergy for over 30 years. He has been representing Entergy for several years at the EPRI Risk and Safety Management Advisory Group as well as the Nuclear Energy Institute's industry Risk Applications Task Force. Thus, his perspective of lessons learned are considered valuable coming from the utility perspective, considering that Deepak Rao has been serving on the ASME/ANS Committee on PRA Standards for the past several years.
– Another valuable perspective for lessons learned is from the regulators. Chakrapani Basvaraju Ph.D., PE contributed a chapter on '*Lessons Learned: NRC Experience'* in which with 43 equations and 21 references, he dwells extensively on "Fukushima Lessons Learned", and also provides valuable

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insights on Effect of LWR Environment on Fatigue Life of Nuclear Plant Components, Buried Pipe-Leakage Issues, HDPE for Replacement of Carbon Steel Piping In Safety Related Class 3 Buried Piping, BWR Steam Dryers for EPU Operation, RPV Indications In DOEL & TIHANGE NPP, Steam Generator Tube Leaks, and Issues for New Construction.

– *'Power and Process Piping Lessons Learned'* by Jimmy E. Meyer PE with 62 valuable references provides a laudable write-up. We often get wrapped up with piping problems of Class 1, 2 and 3 but in fact process and power piping issues get equal attention of operators of nuclear, fossil or petrochemical plants. Jimmy Meyer with over 35 years of experience in refining petrochemical, chemical, power generation and industrial facilities is perhaps one such person experienced in overall project coordination/management, pressure equipment, piping design, analysis, specifications, support design, mechanical system requirements and documentation requirements of power and process piping. This has been chronicled in this chapter.

To talk about the future is not easy, especially when we are stumbling through the current issues of nuclear power generation. Even ASME Code Committee members were less enthusiastic to spell out the "knitty gritty" details. However, invitation to the top-notch experts in the field worked out exceedingly well, and it is gratifying that in *Part 4: Changing Priorities of BPV Codes and Standards: Future Discussions* are captured in the following two chapters from the contributions of professional experts.

– First chapter deals with *New Deliberations in NUCLEAR – Modular Construction* in two parts A and B. First, *Part A: A Scalable Approach to Commercial Nuclear Power: Nuscale Power's New Approach to Safety and Deployment of Nuclear Plants,* is by José N. Reyes and Daniel Ingersoll. They discuss, a novel deployment approach - the factory-fabricated NuScale Power Module (NPM) that relies on well-known light-water reactor technology, significantly reducing technological and regulatory risks. The principal author for this Part A is Jose N. Reyes Ph.D., Chief Technology Officer and co-founder of NuScale Power, LLC. He is also the co-designer of the NuScale passively-cooled small nuclear reactor. He is an internationally recognized expert on passive safety system design, testing and operations for nuclear power plants. He has served as a United Nations International Atomic Energy Agency (IAEA) technical expert on passive safety systems. Co- author of this Part A is Daniel T. Ingersoll Ph.D. Daniel Ingersoll is Director of the Office of Research Collaborations for Nu-Scale Power. During his 34 years at Oak Ridge National Laboratory (ORNL) he was Senior Program Manager in the Small Modular Reactors R&D Office and National Technical Director for the U.S. Department of Energy's Small Modular Reactor program at ORNL. He is the former chairman of the American Nuclear Society's Radiation Protection and Shielding Division.

In *Part B: New Deliberations in Nuclear Modular Construction — Westinghouse Small Modular Reactor* is described by Alexander W. Harkness. Alexander W. Harkness is a Consulting Engineer and Design Lead for the Small Modular Reactor (SMR) development program with more than 23 years of nuclear industry experience covering areas of engineering, plant design, marketing, component design and analysis.

– The second chapter of Part 4 addresses New Deliberations - Fusion Reactors in three parts: Part A - Theoretical Bases and Scientific Foundations by James A. Mahaffey; Part B: ITER by Brad Nelson; and Part C: Nuclear Fusion by Irving Zatz.

In *Part A:* The fundamental principles of hydrogen fusion make this process seem inevitable as a method of commercial power production. It is a clean power process, producing no harmful byproduct, using an inexhaustible supply of fuel, and hydrogen fusion is the source of all energy release in the larger universe. The rationale of this argument has been expounded James A. Mahaffey Ph. D. with a 25-year career at the Georgia Tech Research Institute (GTRI) where he directed projects for the U.S. Defense Nuclear Agency, the U.S. National Ground Intelligence Center, the U.S. Air Force Air Logistics Center, Georgia Power Company, and other government and private industrial organizations, in such areas as nuclear power, non-linear analysis, digital systems design, and cold fusion.

In *Part B:* of this chapter written by Brad Nelson is a compilation of content from www.ITER.org and is attributable to the ITER team with additional information and figures attributable to the US ITER team, available at www.usiter.org. Brad Nelson is the chief engineer for the US ITER Project. His group provides engineering support to US ITER, and he interfaces with partner laboratories and the ITER International Organization. He has more than 35 years of experience in the design and analysis of experimental fusion energy research facilities and components. He has ten figures and 17 references and easily understandable textual content explaining the definition, description and role of ITER in making fusion reactors a reality!

In Part C: is probably an extension what is explained in Part A in explaining the fusion process that can be found on the Princeton University Plasma Physics Laboratory website (http://www.pppl.gov/about/fusion-basics). Part C has been contributed by Irving J. Zatz who is a Principal Engineer at the Princeton University Plasma Physics Laboratory (PPPL), which focuses on fusion energy research. In his 30 years of experience at PPPL and has Mr. Zatz has been extensively involved with the structural analysis and design of complex mechanical systems that have operating conditions in both high heat flux and cryogenic environments. He has participated in numerous domestic and international fusion energy projects and collaborations, including ITER. He is on an ASME committee tasked with the development of a code case for fusion within the ASME Boiler and Pressure Vessel Standards.

The above expose provides an understanding of the experts who provide in their individual write-up "the continuing and changing priorities" that deserve attention of the readers. For a details of the contributors credentials readers are advised to refer to their "bios" and for a brief abstracts of the coverage in the individual chapters readers, should read the "introduction" part that appears in the 'front matter' of this book. Thus, in my opinion this book is different from all other "Companion Guide Volumes" I edited, especially the fourth edition of the *Companion Guide to the ASME Boiler & Pressure Vessel and Piping Codes,* which addressed Sections I through XII of the Boiler & Pressure Vessel Codes and B31 Codes and Standards published in summer 2012. This is true in case of the above Preface, which is a 'gist' of the priorities of the B&PV Codes covered in this publication that deserve reader's attention.

K. R. Rao Ph.D., PE (Editor)

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INTRODUCTION

This comprehensive work written by ASME Codes & Standards experts was originally published as part of Volume 3 of the *Companion Guide to the ASME Boiler & Pressure Vessel Code*. This fully updated and expanded volume is now a stand-alone publication that addresses Continuing and Changing Priorities for the success of current and the next generation of Nuclear Reactors and Internals, License Renewal, Public Safety, and PRA issues.

This book has four parts, the first part dealing with continuing priorities of ASME Boiler and Pressure Vessel Codes and Standards and the remaining three parts dealing with Changing Priorities of ASME B&PV Codes and Standards.

The first part has fourteen chapters authored by sixteen distinguished code authorities who have updated information pertaining to continuing priorities that cover accreditation, maintenance rule, pipe vibration testing and analysis, stress intensification factors, stress indices and flexibility factors, code design for cyclic loading for code sections III and VIII, dynamic loads, functionality and operability criteria, fluids, bolted-joints and connections, the US transportation regulations for radioactive materials, pipe-line integrity and security, decommissioning technology, spent nuclear fuels and seismic protection for pressure piping systems. Distinctive in this part is the inclusion of new contributors who have provided unique perspective to the material that was published in the third edition of the "Companion Guide". Likewise the authors who have updated the material in the third edition have refurbished with additional information. Addition of a chapter dealing with "seismic protection for pressure piping systems" reflects the importance of the topic especially in regard to aging nuclear reactors.

There are three distinctive parts dealing with Changing Priorities of B&PV Codes and Standards: "Changing Priorities"; "Lessons Learned"; and "Future Directions".

In the part dealing with Changing Priorities in Part 2 of the publication there are nine chapters authored by eleven contributors who are not only Code experts but recognized authorities in the topics covered by them. Several of the chapters in this part deal with high technology aspects of the PWR, BWR, EPR and the US-APWR, new generation of BWRS, and Generation IV Reactors. Considering the current fleet of nuclear reactors the coverage of other chapters include license renewal and aging management; BWR and PWR internals; PWR reactor vessel alloys; PRA and risks analysis. Distinctive feature of this part is the inclusion of a chapter covering "balance of plant" issues of valves, flanges and gaskets.

Part 3 of this book captures the authoritative experience of contributors who have distinguished in the topics addressed by them. Part 3 has 8 chapters authored by 11 contributors addressing "perspectives of lessons learned". Considering the aging nuclear reactors in operation in the US and around the world with need for new reactors in the discussion stage it is appropriate to synthesize the experiences and in that light select topics have been chosen. The chapters in this part are Code Sections VIII and XI; materials; flaws, degradation and corrosion process; pressure relief valves; utility experience with PRA; NRC experience; and process and pressure piping. Cumulatively these topics encompass the perspectives of Code experts, consultants, utility personnel and regulators.

Part 4 of this publication is the culmination of the current thinking process for the use of nuclear energy for power generation. This part addressing "Future Directions" has two chapters authored by five individuals with recognized expertize in the topics and or organizations engaged on the subject matter. The first chapter covers "new deliberations in nuclear modular construction: NuScale, Westinghouse"; and the second chapter is titled "new deliberations: fusion reactors".

A unique feature of this publication is the inclusion of all author biographies and an introduction that synthesizes every chapter, along with an alphabetical listing of indexed terms."

PART 1: CONTINUING PRIORITIES OF BOILER & PRESSURE VESSEL CODES AND STANDARDS

Chapter 1, of this publication, which was initially published as Chapter 33 of the "Companion Guide to the ASME Boiler & Pressure Vessel Code" and was originally authored by the late Marcus N. Bressler, has now been updated by Richard R. Stevenson. Chapter 1 discusses the rules for accreditation and certification and similar issues. This chapter has been revised to address the current 2013 Code revisions and to up-date several accompanying graphics. This chapter is intended to provide an overview of the history of the ASME B&PV Code from its inception through the incorporation of nuclear components to the present. Accordingly the title of the Chapter has also been revised to reflect the scope of the discussions contained in the chapter. From earlier coverage of boilers and pressure vessels, the nuclear initiative required coverage for piping, pumps, valves, storage tanks, vessel internals, and component and piping supports. Rules for repairs and replacements of nuclear components and the use of newer Codes are discussed, including the need for Code reconciliation and commercial grade dedication. The development of certification and accreditation is covered, with emphasis on the new requirements for organizations seeking ASME certification. The globalization of the ASME certificates and stamps is described thoroughly along with a discussion of the requirements for the new ASME Mark.

Marcus, based on his experience working with many Code Committees, was the right person to provide in-depth coverage of

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the various aspects of the Code and connecting these with the topic of this chapter and Richard based on his leadership positions within the Board on Conformity Assessment (BCA) and the Committee on Nuclear Certification (CNC) is the right person to provide this update. A discussion is provided regarding the role of regulators, and the commentary includes accreditation for nuclear construction, Code stamping, the role of the Registered Professional Engineer and Authorized Nuclear Inspector (ANI), and the related Mandatory and Nonmandatory Appendices in the Code. Chapter 1 details two examples of the use of Code reconciliation: repair of steam generator feedwater nozzle cracks at a 1970s nuclear plant and the support material requirements of an Example Nuclear Plant (ENP). Chapter 1 also provides thoughts on Future Developments in the ASME Boiler & Pressure Vessel Code, as well as ASME's emphasis on Globalization of its Codes and Standards. In addition, applicable Code references, description of a typical nuclear survey, and an annotated bibliography are also provided.

In Chapter 2 of this publication which was initially published as Chapter 32 of the "Companion Guide to the ASME" was authored by John D. Stevenson covered in first and second edition the Maintenance Rule. In this edition this has been updated by C. Wesley Rowley. July 10, 1991, a Maintenance Rule titled *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants* was published by the NRC in the Federal Register (56 Fed. Reg. 31324) as 10 CFR 50.65. The rule was developed for the NRC to have an established regulatory framework to provide the means for evaluating the administrative effectiveness of nuclear power plant licensees' maintenance programs. The NRC's overall objective is that structures, systems, and components important to nuclear power plant safety be maintained properly so that plant equipment perform its intended safety functions reliably when required. The Maintenance Rule is performance-based, providing focus on results rather than on programmatic prescriptive requirements.

With his experience in domestic and international nuclear power plants, Wes updates the discussions pertaining to the rudiments of the Maintenance Rule and the criteria on which the Rule is based. Wes also updates historical background, purpose and scope, and expectations of the license holder to abide by the stipulations dictated in the Maintenance Rule. His commentary includes requirements; the methodology to select plant structures, systems, and components (SSCs); the use of existing Standards and programs; establishing risk and performance criteria, goal setting, and monitoring; SSCs subject to effective program maintenance programs; the evaluation of systems to be removed from service; periodic maintenance effectiveness assessments; documentation; and references.

Chapter 37 of "Companion Guide to the ASME Boiler & Pressure Vessel Code" has been renumbered as Chapter 3 for this publication. David E. Olson who authored for the previous publication for the initial, second and third editions has updated this chapter for this publication. David E. Olson discusses industry requirements and methods for pipe vibration testing and qualification. The discussions center on proven methods for measuring and qualifying piping vibration in the power industry. The methods presented for addressing piping vibration are in compliance with the relevant industry codes, standards and regulations, including the 2007 editions of the ASME B&PV Code, the B31.1 Power Piping Code and relevant NRC NUREG's and Regulatory Guides. The chapter addresses the cause and effects of both steady state (e.g. flow induced) and dynamic transient (e.g. water hammer) vibration. The development of testing acceptance criteria is discussed along with data acquisition and reduction procedures. Also discussed are vibration prevention and control techniques along with problem resolution examples. The methods presented in this chapter demonstrate how to meet the requirements of ASME O&M-3 "Vibration Testing of Piping Systems".

This background and requirements for testing, evaluating and qualifying vibration in power plants are addressed. This includes the testing and evaluation methods of the ASME Operating and Maintenance OM-3 "Piping Vibration", the acceptable stress limits included in the ASME Boiler and Pressure Vessel Code and the applicable regulatory requirements for piping vibration. Examples are provided of various types of vibration problems experienced in power plants.

Everett C. Rodabaugh was the initial author of this chapter who authored for the first, second and third editions. For the current publication, Anthony Paulin, President of his consulting company with both national and international consultancy, an acknowledged expert in the subject matter made considerable revisions. These revisions for the current publication include additional equations, figures and numerous paragraphs of textual content which are partial replacements or in totality. B31.3 versions published in 2012 and 2014 contain changes to stress equations and methods that will be discussed in more detail in the next revision.

In Chapter 38, Everett C. Rodabaugh discussed stress intensification factors, stress indices, and flexibility factors with the aid of equations, references, and tables. Everett, a well-recognized authority on the aforementioned topics, notes that piping systems tend to be rather complex structures that include straight pipe and a variety of complex components, such as elbows and tees. A typical piping system might include about 50 components along with many intervening lengths of straight pipe. Each component is subjected to a complex set of loadings. The evaluation of any one component by the detailed analysis methods prescribed in Subsection NB-3200 is an onerous task. The complexity of analyses of piping components and the "standard" aspect of piping components has led to use of stress intensification factors (also called *i*-factors), stress indices, and flexibility factors for evaluations of piping systems. In this chapter, the general concepts behind the development of *i*-factors, stress indices, and flexibility factors are discussed briefly, with references to details of developments.

Everett discusses strain control and stress control as design considerations. Chapter 4 is replete with scholastic discussions and references to substantiate the use of indices. The discussions are provided for the nominal design margin and tests to support these. Stress intensification factors are discussed for girth butt welds; *C* and *K* stress indices are discussed for internal-pressure loading, elbows, and butt-welding tees; moment loading; and thermal-gradient loadings (including branch connections). Fatigue evaluations, ASME Class 2 or 3 piping, and Class 1 Codes for straight pipe, elbows, and seismic analysis are also addressed. Everett provides examples to cover piping systems; moments; Code equations; girth butt welds; elbows; branch connections for Class 2 or 3 piping with branches; best estimates for Class 1 piping; and ASME B31.1 and B31.3 Codes. These examples illustrate how *i*-factors and stress indices are used to check Code compliance and, for a branch connection, to illustrate the quantitative significance of flexibility factors.

Chapter 39 of the third edition of the "Companion Guide" is renumbered as Chapter 5 in the current publication and is once again updated by William J. O'Donnell. As a well-known expert of the field, Dr. O'Donnell was invited to author this chapter

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almost a decade back for the first and initial edition of the "Companion Guide". Ever since then, Dr. O'Donnell articulated immaculately in every subsequent edition updating with fresh insights of the subject matter. Once again in this chapter renumbered as Chapter 5, Dr. O'Donnell provided valuable textual content, references and updated graphics.

In this Chapter, William J. O'Donnell, whose consulting services have covered all aspects of fatigue evaluations, covered Code design and evaluation for cyclic loading in Sections III and VIII. The author notes that fatigue "is recognized as one of the most frequent causes of failure in pressure vessels and piping components ... for fatigue strength is sensitive to design details, such as stress raisers, and to a myriad of material and fabrication factors, including welding imperfections. Fatigue is also sensitive to such unforeseen operating conditions as flow-induced vibrations, high-cycle thermal mixing, thermal striations, and environmental effects. What is somewhat surprising is the number of fatigue failures that are directly related to poorly chosen design and fabrication details." The ASME B&PV Code was one of the first Codes and Standards to treat the design for fatigue explicitly.

Dr. O'Donnell covers the historical background of fatigue failures. He notes that Section III was the first to include fatigue in its 1963 Edition; Section VIII, Division 2 (*Alternate Rules for Pressure Vessels*). Section VIII, Division 1 (*Rules for Construction of Pressure Vessels*) still does not include explicit fatigue design life-evaluation methods. Fatigue in pressure vessels and piping is of considerable importance. They frequently operate in the low-cycle regime where local stresses are far in excess of yield. This chapter covers the use of strain-controlled fatigue data; stress-strain concentration effects; the effects of mean stress; fatigue failure data; the procedure for fatigue evaluation; cumulative damage; exemption from fatigue analyses; experimental verification of design fatigue curves; and fatigue data for pressure vessel alloys.

More than half of this updated Chapter is devoted to Current and Future Code fatigue design evaluation developments. High temperature water environmental effects are shown to be very important, and the available data is presented in numerous plots. New fatigue design curves proposed by the ASME Code Subgroup on Fatigue are included. Environmental fatigue is expected to be a major Code issue for decades.

Fig. 39.18 presents a new fatigue design curve for austenitic stainless steels in air, revised from the 2006 Second Edition of the *Companion Guide to the ASME Boiler and Pressure Vessel Code*. Figure 39.40 is the corresponding fatigue design curves for austenitic stainless steels in reactor water, also revised from the Second Edition of the *Companion Guide.*

The environmental fatigue design curves in the Second Edition of the *Companion Guide* are independent of temperature. The temperature dependence of reactor water environmental effects on fatigue degradation have recently been determined to be quite significant for carbon, low alloy and stainless steels. Their effects decrease with decreasing temperature below 350ºC (662ºF). Methods of taking credit for such temperature effects have been developed and are included in this new Third Edition of the Guidelines. Section 39.15 describes these new temperature corrections and Figs. 39.41 and 39.42 show their comparison with data for austenitic stainless steels and A333-Gr. 6 carbon steels, respectively. The Chapter includes a comprehensive bibliography.

John D. Stevenson initially authored Chapter 34 for the first and second editions of the "Companion Guide to the ASME Boiler & Pressure Vessel Code". This was subsequently updated in the third edition by Michael Porter. For the current publication, this chapter is renumbered as Chapter 6 and is covered by Michael A. Porter.

In the previous editions John Stevenson dealt with perspectives on cyclic, impact, and impulse dynamic loads. John notes that dynamic loads applied to the design of mechanical systems and components are of three basic types: cyclic, impulse, and impact. In addition, there is a fourth potential cyclic-type load in the vibratory motion category. Although vibratory motion is not usually considered in the original design basis, it may be observed during steady-state or transient operations to cause premature fatigue or ratchet failure of metal components. The original Section III definition of a plant's operating life includes design-basis normal, abnormal, emergency, and faulted plant- or system-operating conditions, as defined in the Design Specification. John notes that these operating conditions should not be confused with Service Levels A, B, C, and D currently defined in the Code for design purposes. It is possible to have different Service Level design conditions for the same operating condition, depending on the required response of a component.

John covered in-depth Nonmandatory Appendix N (*Dynamic Analysis Methods*) of Section III. For completeness, he covers other types of dynamic loads not addressed explicitly by Appendix N that the designer of pressure-retaining nuclear components must consider. He also discusses the ASCE Standard used for defining earthquake motions to a building foundation and for supporting the mechanical system or component; these two references deal primarily with earthquake cyclic–type dynamic loads. In addition, commentary is provided on the guidelines used for dynamic impulse and impact loadings provided in the ANS, ASME Appendix B, and B31.1 Code Standards. A discussion is provided about the ASME Operation and Maintenance (O&M) Standard, used for determining the effect of operational vibratory motion independent of the cause of vibration.

In past editions of the handbook, this chapter has primarily addressed issues as they pertained to Section III of the ASME B&PV Code. In particular, it has addressed issues concerning the seismic response of nuclear facilities. Currently, many other facilities covered by the ASME B&PV Code have had to address these same issues, often with little guidance from the appropriate Code section. Modern LNG terminals, for example, have had to undergo extensive seismic reviews. These facilities contain equipment covered by Section VIII and B31.3 of the Code. Neither of these Code section give any guidance to the designer concerning seismic analysis, other than to require that seismic loads be addressed. In this revision of the chapter by Michael A. Porter, some of these issues will be addressed. In addition, a new section discussing the use of computer software for analysis has been included. This section will address some of the issues associated with different computer codes used for different parts of a plant. In addition, the Code references have been revised to reflect the (2007) Code provisions.

Chapter 7 of this publication (Chapter 35 in previous publication) was initially authored by Guy Deboo for the first two editions of the "Companion Guide to the ASME Boiler & Pressure Vessel Code". The third edition was updated by Stephen R. Gosselin. Gosselin incorporated detailed discussion of nuclear industry piping components' service experience and the degradation mechanisms associated with these failures.

In this current publication, Stephen Gosselin and Thomas Esselman, who between them have decades of professional experience and often leadership roles in their consultancy assignments

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in the subject matter, describe methods and criteria to deal with plant systems, structures, or components (SSCs) that are found to be degraded, nonconforming, or subject to an unanalyzed condition during operation. A functionality or operability evaluation may be necessary to demonstrate the capability to continue operating safely. The role of probabilistic analyses in these assessments is introduced.

The authors discuss the methodology and acceptance criteria applicable to this evaluation. Typical systems, structures, and components that may require operability evaluations are described and definitions related to operability are provided. An operability or functionality evaluation requires a consideration of failure modes. The experience gained over years of operation for piping, supports, pumps, and valves is described. The ASME B&PV Code contains requirements for operability in Section III, Section XI, and the ASME O&M Code. The rules provided by the various codes are described.

Analytical methods that can be used for operability are generally extensions of standard design analysis methods. The standard analysis methods and acceptance criteria applicable to piping systems, components, and supports inherently contain conservatisms to compensate for uncertainties in the operation, fabrication, and construction of systems. The evaluation methods used to demonstrate operability first examine the design-basis analysis methods to define and understand the conservatism in the methods used. Performing more realistic analyses can often be used to demonstrate operability. Methods for various components are described.

The use of probabilistic analyses for a variety of topics is being used more in the commercial nuclear industry. This can be valuable for the assessment of operability. The application of probabilistic analyses provides distinct advantages over qualitative likelihood of failure estimates. This chapter introduces the potential to utilize probabilistic analyses to demonstrate operability.

Chapter 8 of this publication was in the "Companion Guide to the ASME Boiler & Pressure Vessel Code" and appeared as Chapter 36, authored by Frederick J. Moody, and covered fluids. Frederick is a recognized authority in the field of fluids; he explains briefly the force predictions from fluid phenomena and behavior, which are significant in the formulations and criteria employed in the ASME B&PV Code. He focuses on the nature of fluid forces imposed on vessels and piping systems from the standpoint of designers, who require guidelines for both the design and operational recommendations of fluid-transport systems. Fluid forces are the result of pressure and shear phenomena and are caused by the energy transfer at pumps or turbines or by disturbances arising from sources such as valve operation, pipe rupture, vapor-void collapse, and the motion of the frame to which the system in question is anchored. A fluid disturbance generally occurs over a predictable time period, and the fluid may respond simultaneously (bulk-flow response) or in a propagation sense (waterhammer response), depending on the system geometry. The nature of bulk-flow and waterhammer responses is significantly different, making it essential to identify the specific fluid response before calculating the resulting forces.

With appropriate equations and references, Frederick covers the basic formulations resulting in fluid forces. He describes the nature of such fluid forces as hydrostatic forces and pressure, as well as shear forces from fluid motion. Predictions made of fluid forces of concern in boiler and piping design are from pressure and shear within internal-flow systems. However, fluid forces are of significant concern in external-flow systems as well, where structures are sub-merged in fluids. Frederick discusses disturbance sources, including motor- or manual-operated valves, safety-relief valves, check-valve closures, pipe ruptures, liquid-column impact at area contractions, liquid-column separation, condensation-induced waterhammer, centrifugal pumps, pipe movements, positive-displacement pumps, gas cushions, and vortex shedding. Frederick also addresses bulk-flow and propagative-flow modeling in pipes, the estimation of fluid-flow forces in pipes, and fluid forces, such as acceleration and standard drag forces, on submerged structures.

William J. Koves one of the authorities on the subject was invited to write about Bolted-Flange Joints and Connections from the initial and first edition of the "Companion Guide to ASME Boiler and Pressure Vessel Codes and Standards" about a decade back. Ever since then William Koves contributed to the second and third editions updating with the 'state of the art' information. Chapter 40 is now renumbered as Chapter 5 in the current publication and William J. Koves is once again providing updates for the subject.

In this Chapter, William J. Koves addresses the design of bolted-flange joints and connections, perhaps one of the crucial safety aspects of the power and petrochemical industries because entire piping systems and components are ultimately held together by connections and welded joints. Addressed in this chapter are flanged joints, which are essential and complex components in nearly all pressurized systems. Many factors determine the successful design and operation of a flange joint in service. William notes that the bolted-flange joint involves the interaction between the bolting, flange, and gasket, with important nonlinear variables such as friction and gasket properties considered. The Code design rules provide a method for sizing the flange and bolts to be structurally adequate for the specified design conditions; however, these rules do not address assembly or special requirements, nor do they guarantee a leak-tight joint for all transient-operating conditions.

The purpose of this Chapter is to provide the background and basis for the bolted-flange joint design rules contained in the ASME Codes in addition to a discussion of how the rules are applied. Considering this topic's interaction with several ASME Code Sections and Piping and related Codes, William, who has 38 years of experience serving in ASME Code Committees, translates his professional and Code experience in the writing of this chapter by providing cross-references to the various Codes and Standards. He discusses Codes that address flange-joint design, including design requirements and applicability, and he discusses flange standards as well as flange design for pressure vessels and piping. He provides an in-depth discussion of flange-stress design methods, including the ASME design methodology; the historical background and technical basis; the scope and design philosophy; and the flange types. He comments on flange designs not addressed by ASME: design for external loads, leak-tightness-based design, and flange joint assembly, including ASME Appendix S, bolting and gasket considerations

In the third and second editions of "Companion Guide to the ASME Boiler and Pressure Vessel Code" Chapter 52 authored by Ronald S. Hafner is now renumbered as Chapter 10 in the current publication and is once again updated by Ronald Hafner. Ronald S. Hafner, covers the historical *Development of U.S. Regulations for the Transportation of Radioactive Materials*. The discussion in this Chapter is a highly condensed version of the information presented previously in Chapter 52 of the Second Edition of the *Companion Guide to the ASME Boiler & Pressure Vessel Code*. This Chapter offers a high-level overview of the information

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presented previously, including all of the appropriate references. Primarily based on the requirements for Type B quantities of radioactive material, the information presented in this chapter includes a number of citations that describe the detailed interactions that have taken place between a variety of U.S. governmental agencies, commissions, and departments, such as, the Department of Transportation and its predecessor, the Interstate Commerce Commission, the Department of Energy and its predecessors, the Energy Resource and Development Agency and the Atomic Energy Commission, and the Nuclear Regulatory Commission, etc. The information presented also includes numerous citations from the interactions that have also taken place between these governmental agencies and the International Atomic Energy Agency.

From a regulatory perspective, the information presented covers the time period from 1965 through 2004, or about 40 years. Starting in 1978, however, the information also begins to look into the interactions that have taken place between the *regulatory requirements* for transportation packages specified in 10 CFR 71 and the *regulatory guidance* for transportation packages provided by the NRC in the form of Reg. Guides, NUREGs, and NUREG/CRs. As is shown throughout the chapter, the regulatory guidance provided by the NRC specifically notes that the regulatory requirements of 10 CFR 71 can be met using the additional requirements defined in specific sections of the ASME's Boiler & Vessel Pressure Code as a metric for the design, fabrication, assembly, testing, use, and maintenance of packagings used for the transport of Type B quantities of radioactive materials.

In the "Companion Guide to the ASME Boiler & Pressure Vessel Codes", Alan Murray, an international authority on the "Pipeline Integrity and Security" was invited to contribute on the subject in the second edition of the publication. Since then in the third edition, Chapter 54 on Pipeline Integrity and Security Pipelines benefited from the additional contribution of a coauthor, Rafael Mora. For the current publication Chapter 54 has been renumbered as Chapter 11 which has now been updated by Alan Murray.

The authors note that pipelines are currently at the forefront of much public debate following several high profile incidents involving loss of life and environmental damage. Notwithstanding these setbacks, pipelines are central to a modern economy and remain by a considerable margin, the most economic and comparatively safe means of transporting hydrocarbons and many other fluids over great distances. Incidents, while relatively rare, can have serious consequences, so protecting the public, and the environment, is paramount. This is achieved through a combination of regulatory oversight, prudent pipeline integrity management and the use of appropriate technology. Regulatory requirements vary greatly throughout the world and are reflective of an underlying safety philosophy, ranging from the prescriptive approach adopted in the United States to the performance-based methods favored in the United Kingdom. These various approaches are compared before addressing how they, and accompanying codes and standards, are used to formulate the essential elements needed in a sound integrity management plan. The finite resources available for maintaining a pipeline means that, a risk-based approach must be followed, so as to prudently allocate expenditures.

Accordingly both qualitative and quantitative methods of assigning risk are described. The four main methods of undertaking integrity assessments are outlined including an expanded section on the steadily improving capabilities of intelligent pigging and a detailed approach to assessing defects is provided including several worked examples.

A number of relatively simple means of protecting a pipeline asset are available, ranging from coatings and cathodic protection to preventing third-party damage. These are described, before addressing a relatively new threat stemming from willful targeting a pipeline operation either through physical or cyber attack.

In the "Companion Guide to the ASME Boiler & Pressure Vessel Code" the initial number of this chapter was 55 and in the current publication this has been renumbered as Chapter 12. For the current publication, updating of Chapter 12 has been provided by Harold E. Adkins.

Chapter 55 was authored for the second edition and completely revised for the third edition by Anibal L. Taboas. The author presents an editorial view of Decommissioning Technology Development within a context that energy, environment, education, and economy are inextricably linked. In this edition, Harold E. Adkins has provided few additions and editorial modifications as this chapter presents a complete and up-to-date sketch of critical factors to consider during the process of decommissioning. The author highlights related approaches by the US Department of Energy and the UK Nuclear Decommissioning Authority. The causes and contributing factors to significantly increased cost estimates are discussed, as well as the cost of delay (missed regulatory opportunities, reluctance to cut back non-productive expenditures, a bias against innovation, and lack of incentives for transition to other significant missions after the completion of environmental remediation).

A compendium of technology challenges and needs is presented, along with an overall program performance rating. The author observes that (1) funding for basic, long, and medium term components, has dwindled as to support primarily paper [or desk] studies, (2) fiduciary responsibility requires demonstrating whether the resources consumed by industry and government in the safe and compliant environmental remediation of radiological and nuclear facilities remains commensurate with the risks averted, and that (3) reverting the funding trend in D&D technology development requires integrated planning, strategic action, and effective communication. The chapter concludes with a call for a plan to (1) develop the business case for investment; (2) invest in high visibility projects of demonstrably high return for investment; (3) meet customer identified expectations; (4) track leading indicators and contractual incentives; (5) resolve key policy issues; and (6) transparent independent peer review.

Chapter 14 on Seismic Protection of Pressure Piping Systems authored by Chakrapani Basavaraju and Mohinder Nayyar is a new chapter added in this publication written by contributors specifically invited in view of the importance of the topic after the devastating seismic related incident at Fukushima, Japan. The authors from the regulatory field and consultancy, with their immense reputation of dealing with the topic, have addressed in the few pages allocated for the coverage the last chapter in this Part of this publication – "Continuing Priorities". The authors include in the coverage several equations and references for an understanding of this subject.

The major highlights include discussion of seismic analysis methods, damping, recent changes and updates on seismic analysis introduced in the ASME Code based on industry tests. The discussion also includes some regulatory perspectives, and ASME Nuclear piping classes 1, 2 and 3.

The objective of the authors is to provide some highlights on the requirements, analysis, and issues related to the seismic protection of piping systems. Title 10 of the Code of Federal Regulations Part

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50 (10 CFR 50) Appendix A [1] contains General Design Criteria for Nuclear Power Plants. General Design Criterion 2, Design Bases for Protection Against Natural Phenomena under Group I of 10 CFR 50, mandates that Structures, systems, and components (SSCs) important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions.

The design bases for these structures, systems, and components shall reflect: (1) Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

10 CFR Part 50 .55a(b)(1)(iii) addresses the codes and standards to be used in seismic design of piping for ASME Section III, Division 1 Code Classes 1, 2, and 3 safety related piping. Therefore, it is essential that the piping systems in nuclear power plants are adequately designed protecting them from seismic events using the appropriate codes and load combinations.

The causes of the damage and failures observed in power plant piping due to earthquakes can be summarized into three main categories 1) Seismic Anchor Motion, SAM, 2) Spatial Interaction, and 3) Corrosion and Erosion. The mechanisms which lead to these damages and failures can also be summarized into three categories as determined by tests 1) seismic stress ratcheting, 2) fatigue and 3) plastic instability or plastic rupture. (NUREG/CR-6240, "Application of Bounding Spectra to Seismic Design of Piping Based on the Performance of Above Ground Piping in Power Plants Subjected to Strong Motion Earthquakes" [2].

This chapter presents (1) an overview on seismic analysis of piping systems, (2) recent changes to the Section III of the ASME Boiler and Pressure vessel Code rules accepted by the United States Nuclear Regulatory Commission (USNRC) with conditions, and (3) GI-199 issue related to seismic input to nuclear plants in the central and eastern United States (CEUS) based on *"Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants"*.

PART 2: CHANGING PRIORITIES OF BOILER & PRESSURE VESSEL CODES AND STANDARDS

In Chapter 57 of the "Companion Guide to the ASME Boiler & Pressure Vessel Code" Generation III+ PWRS has been addressed in three distinct parts: in Part A: AP1000 by John T. Land, in Part B: EPR by Marty Parece and in Part C: U.S. APWR by Masahiko Kaneda. In the current publication, this chapter number has been altered to 15 and the contributors are for Part A by Keith E. Schwab, for Part B, Mary Parece continues and Part C is now by Masanori Onozuka. From the commissioning of the first commercial nuclear reactor more than 50 years ago, the nuclear power industry has been developing and improving reactor technology with particular emphasis on reliability and safety. There are several generations of reactors that have been developed or are being developed. These reactors are generally categorized as Generation I, II, III, III+, and IV reactors. The authors illustrate with the help of schematics the development and the technology distilled from 50 years of successful nuclear operating experience that has led to the Generation III+ pressurized water reactors (PWRs).

Generation I reactors were developed in the 1950s and 1960s, Generation II reactors were developed in the 1970s through the 1990s, and Generation III reactors were developed in the 1990s and 2000s. Generation III reactors are considered to be evolutionary reactors such as the System 80+, and advanced pressurized water reactor (APWR). Generation III+ reactors are based on the nomenclature from the Department of Energy, that is, Generation III reactors with improved economics and safety. Generation IV reactors are new technologies that are being developed for future reactors.

For the current update for Part A which has been updated by E. Keith Schwab has replaced several figures and few tables and textual changes. Part C updated by Masanori Onozuka has incorporated considerable changes addressing the state-of-the-art technology that is constantly undergoing alterations. Thus, coming from the helm of industry outfit the updates reflect information that the readers would very much welcome.

Chapter 58 of "Companion Guide to the ASME Boiler & Pressure Vessel Code" authored by Hardayal Mehta and Daniel Pappone in the third edition has been renumbered as Chapter 16 in the current publication and updated by Hardayal Mehta. The Generation III+ PWR reactors discussed in this chapter have design features with more robust design improvements, higher availability and longer operating life, extended fuel life, and improved and innovative safety features over the currently operating reactors. The Generation III+ Boiling Water Reactors (BWRs) are discussed in Chapter 16.

The scope of this commentary is to describe in some detail the Generation III+ PWR plant design features, technology, safety and reliability features, and the elimination or mitigation of degradation issues associated with Generation I, and II PWR designs. This chapter provides commentary on the following Generation III+ PWRs that have received Design Certification approval or are in the process of receiving certification approval from the U.S. Nuclear Regulatory Commission (NRC): AP1000, EPR and U.S. APWR. Authors have with the help of illustrations, graphs, charts and figures provided in addition to the historical background and futuristic scope covered the current practices covering each of the three topics of the Generation III+ PWRs.

The coverage for each of these three parts are: In Section 57A the coverage of AP1000 included AP1000 Plant Design, AP1000 Operational Technology, Safety Features, Containment Design, Modularization and Construction, Operation and Maintenance, ASME Code Aspects, Future Direction, References and Nomenclature; In Section 57B discussions regarding EPR covered EPR Development, EPR Plant Design, EPR Safety, Containment Design, Construction, Operation and Maintenance, Code Aspects, Building Now and References were addressed; In Section 57C coverage of U.S. APWR included U.S. APWR Plant Design, Operational Technology, Safety Features, Containment Design, Modularization and Construction, operation and Maintenance, ASME Code Aspects, Future Direction on the U.S. APWR, References and Nomenclature.

Chapter 16 was numbered as Chapter 58 in the 3rd edition of the "Companion Guide" and authored by Hardayal Mehta and Daniel Pappone which is now updated by Hardayal Mehta who provides details of the development of boiling water reactor (BWR) based nuclear steam supply system (NSSS) and the role of ASME Code in its design, material selection, fabrication and in-service inspec-

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tions. A general background of the development of the BWR product line is first provided including the current offerings (the Advanced Boiler Water Reactor, ABWR, and the Economic Simplified Boiling Water Reactor, ESBWR). This includes the description of the reactor and reactor system design, safety system design and the containment design. The authors next describe the key features of the ESBWR including the natural circulation design, operating domain and passive safety features. The ESBWR core and containment cooling systems represent a radical departure from those of the earlier BWR product lines in that the cooling systems are passive and do not rely on electrically driven pumps. The ASME Code aspects covered include the ASME Code versions used in the construction, treatment of environmental fatigue issues, material selection, and others. Future directions in terms of fabrications, modularization, and others are lastly discussed.

Chapter 17 of the current publication was Chapter 59 of the third edition of "Companion Guide to the ASME Boiler & Pressure Vessel Code" which was initially authored by William J. O'Donnell and Donald S. Griffin and updated by them for this book, as well. William J. O'Donnell and Donald S. Griffin, describe the structural integrity issues in Section II, VIII, III, and Subsection NH (Class 1 Components in Elevated Temperature Service), and Code Cases that must be covered to support the licensing of High Temperature Generation IV Reactors. It also describe how the Code addresses these issues, and the need for additional criteria to cover unresolved structural issues for very high temperature reactors.

Since the 1980s, the ASME Code has made numerous improvements in elevated temperature structural integrity design criteria. These advances have been incorporated into Subsection NH of Section III of the Code. The current need for designs for very high temperature and for GEN IV systems requires the extension of operating temperature from about 1400ºF (760ºC) to about 1742ºF (950ºF) where creep effects limit structural integrity, safe allowable operating conditions, and design life.

Materials with more creep and corrosion resistance are needed for these higher operating temperatures. Material models are required for cyclic design analyses. Allowable strains, creep fatigue and creep rupture interaction evaluation methods are needed to provide assurance of structural integrity for very high temperature applications. These criteria intended to prevent through-wall cracking and leaking.

The detailed material properties needed for cyclic finite element creep design analyses are generally not provided in the Code. Chapter 17 describes the material models, design criteria and analysis methods which NRC has indicated are remaining needs in the ASME Code to cover Regulatory Issues for Very High Temperature Service:

1. Material cyclic creep behavior, creep-rupture, creep-fatigue interaction and environmental effects.
2. The structural integrity of welds.
3. The development of extended simplified analysis methods (to avoid dependence on "black box" finite element analyses (FEA) for cyclic creep).
4. Test verification of 1, 2 and 3.

Chapter 42 in the "Companion Guide to the ASME Boiler & Pressure Vessel Guide", initially authored by Drs. Kenneth Chang and Pao-Tsin Kuo for the second edition and updated by Robert Kaiwaha Hsu and P.T. Kuo for the third edition is now renumbered as Chapter 18 for the current publication and updated by P.T. Kuo. This provides a detailed description of the NRC's license renewal process and its guidance documents developed for ensuring a uniform format and technical content of a license renewal application and a consistent review of the application by the NRC staff. The authors also provide a clear synopsis of the NRC's technical requirements for license renewal of current operating licenses. In addition, this chapter provides a summary of the emerging issues at the present time and the NRC's interim staff guidance process to capture early any lessons learned from operating experience and/or past license renewal application reviews.

Authors address the License Renewal and Aging Management. The U.S. Nuclear Regulatory Commission (NRC) license renewal process establishes the technical and administrative requirements for renewal of operating nuclear power plant licenses. Reactor operating licenses were originally issued for 40 years and are allowed to be renewed for up to an additional 20 years. The review process for license renewal applications (LRAs) provides continued assurance that the level of safety provided by an applicant's current licensing basis is maintained for the period of extended operation. The license renewal review focuses on passive, long-lived structures and components of the plant that are subject to the effects of aging. The applicant must demonstrate that programs are in place to manage those aging effects. The review also verifies that analyses that are based on the current operating term have been evaluated and shown to be valid for the period of extended operation. As of July 1, 2005, the NRC has renewed the licenses for 33 reactors licenses. Applications to renew the licenses of 15 additional reactors are under review. If the applications currently under review are approved, approximately 50 percent of the licensed operating reactors will have extended their life span by up to 20 years. As license renewal is voluntary, the decision to seek license renewal and the timing of the application is made by the licensee. However, the NRC expects that, over time, essentially all U.S. operating reactors will request license renewal.

Authors recognize the growing interest in License Renewal and mention that to meet this demand, the NRC has established a streamlined process for reviewing applications in a consistent and timely manner. Likewise, the Nuclear Energy Institute (NEI) has developed guidance for the industry on how to prepare an application for renewal. This chapter describes a number of license renewal guidance documents that have been developed to describe interrelated aspects of preparing and reviewing license renewal applications: Standard Review Plan for License Renewal (SRP-LR), Generic Aging Lessons Learned (GALL) Report, Regulatory Guide for License Renewal (RG-LR) which endorses NEI's industry guideline for implementing the requirements of 10 CFR Part 54—The License Renewal Rule (NEI 95-10). The objective of the chapter is to provide back-ground information on the development of these documents and to briefly explain the intended use of the guidance documents singularly and in combination—to facilitate the renewal process from application development to NRC staff review including its audits and inspections of on-site supporting technical documentation. This chapter also provides a brief description of the NEI's environmental review process for license renewal.

Chapter 41 in the second and third editions of the "Companion Guide to the ASME Boiler & Pressure Vessel Code", authored by Hardayal Mehta, is renumbered as Chapter 19 in the current publication, presents a review of the applications of many and sometimes unique ways in which the provisions of Section III and Section XI of the ASME Boiler & Pressure Vessel Code have

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been used in addressing the service induced degradation in the BWR vessels, internals and pressure boundary piping. The vessel internals addressed included steam dryer, shroud and jet pumps. The vessel components considered were feedwater nozzle, stub tube welds, attachment and shroud support welds. Review of pressure boundary piping flaw evaluation methods also included consideration of weld overlay repairs. The service related degradation mechanisms considered were environmental fatigue crack initiation and growth, and stress corrosion cracking. The most form of service-induced cracking in the stainless steel and Ni-Cr-Fe components in the BWR pressure boundary is typically due to intergranular stress corrosion cracking (IGSCC).

Dr. Mehta has included extensive bibliographical references from his own publications, research journals, related EPRI, ASME, and other international publications. Accompanying tables, several figures and examples are used for supporting the detailed discussions regarding several topics he touched upon including BWR Internals, Pressure Vessel, Reactor Pressure Boundary Piping and Crack Initiation & Growth relationships and Plant Monitoring. In the discussions of BWR Internals the inspection, evaluation and repair methods are covered. Dr. Mehta has included in his discussions about BWR Pressure Vessel topics such as the application of probabilistic fracture mechanics for inspection exemption, and low upper shelf energy evaluations. Discussing about Reactor Pressure Boundary Piping, Dr. Mehta expounds the causes of cracking, and remedial/mitigation/repair measures. Fatigue initiation, Relationships for Fatigue and Stress Corrosion Cracking and Crack Growth Monitoring are covered in the last part of this chapter. The updated chapter includes consideration of developments pertaining to the 2007 ASME Code, the NRC actions and EPRI reports.

Chapter 43, in the second and third editions of the Companion Guide to the Boiler & Pressure Vessel Code, authored by Timothy J. Griesbach is renumbered as Chapter 20 for the current publication and updated by Hardayal Mehta and William Server. The authors's objective is to provide an overview of the codes and regulations for prevention of brittle fracture of reactor pressure vessels. The background and bases for the original Section III, Appendix G Code requirements are discussed along with a description of the recent improvements that have been implemented in the Code in Section XI, Appendix G using more up-to-date technology. The changes and improvements are detailed such as the method for determining stress intensity factors, structural factors to account for uncertainties in the analytical methods, and material reference toughness curves. While the Code has incorporated these technical changes, the philosophy of protecting the vessel against brittle fracture has remained the same. The chapter also discusses ongoing efforts to incorporate the Master Curve approach for vessel toughness into the ASME Code, it considers areas for future improvements in the Code method for brittle fracture prevention of PWR reactor vessels, and it summarizes the aging management of PWR reactor vessel internals.

Chapter 21 of the current book was initially published as Chapter 44 in the third volume of the second edition of the "Companion Guide to the ASME Boiler & Pressure Vessel Code." Jeff Gorman, Steve Hunt and Pete Riccardella authored the initial Chapter 44, which was updated in the third edition by Pete Riccardella and Glenn A. White. Glenn A. White revised the chapter, which has been renumbered as Chapter 21, for the current book. They have considerable expertise and experience in handling PWR Reactor Vessel Alloy 600 and related issues confronted by the industry. Considering the extreme importance of this topic the authors have covered concerns pertinent to several ramifications of the problem.

Primary water stress corrosion cracking (PWSCC) of alloy 600 nickel-chromium-iron base metal and related alloy 82/132/182 weld metal has become a principal materials degradation concern to commercial pressurized water nuclear power plants. Cracks and leaks have been discovered in alloys 600/82/182 materials at a number of locations in PWR reactor vessels and other reactor coolant loop components worldwide. These locations include control rod drive mechanism (CRDM) nozzles, bottom head instrument nozzles, reactor vessel outlet nozzle butt welds, and pressurizer nozzle butt welds. The consequences of PWSCC have been significant including numerous leaks, many cracked nozzles and welds, expensive inspections, more than 100 reactor vessel heads replaced, and extensive repair and mitigation activities on reactor coolant loop butt welds. A number of plants experienced months-long outage extensions to repair leaks, and one plant was down for over two years as a result of regulatory action following the detection of extensive corrosion to the vessel head resulting from a leaking CRDM nozzle. This chapter addresses alloy 600/82/182 material locations in reactor vessels, operating experience, causes of PWSCC, inspection methods and findings, safety considerations, degradation predictions, repair methods, remedial measures, and strategic planning to address PWSCC at the lowest possible net present value cost. Recent industry and ASME Code activities to address these concerns are also discussed. These activities include safety assessments and other studies published by the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP), and ASME Section XI code cases defining inspection requirements made mandatory by the U.S. Nuclear Regulatory Commission for U.S. plants.

The original authors of this chapter numbered as Chapter 45 appeared in the "Companion Guide to the Volume 3 ASME Boiler & Pressure Vessel Code, Second Edition" were Sidney A. Bernsen, Fredric A. Simonen, Kenneth R. Balkey. This Chapter 45 had been updated in the subsequent Third Edition by Sidney A. Bernsen, Kenneth R. Balkey, Raymond A. West and Ralph S. Hill III. Thus update is by Ralph S. Hill III, a longtime member of ASME Code Committee and currently an officer of Boiler & Pressure Vessel Codes and Standards traces the development of nuclear power plant probabilistic risk assessment (PRA) from its initial evolution as a means for evaluation of public safety through the recognition of its use to identify important safety concerns. This chapter ultimately addresses the PRA's use in Codes and Standards through the 2007 Edition of the Boiler and Pressure Vessel (BPV) Code and its associated Nuclear Code Cases in helping to determine risk importance and the appropriate allocation of resources, and inservice activities under Section XI of the BPV Code. It discusses the current status of related Codes and Standards that provide rules and guidance for the development of the PRA and the risk analysis needed to support nuclear power plant applications. The chapter also addresses several specific activities in place or underway to risk-inform the Operation and Maintenance (OM) Code requirements for inservice testing and Code design rules being developed under Section III of the BPV Code. The authors were all active participants in the development and implementation of risk-informed methods for ASME Codes and Standards.

This is the last chapter of Part II captioned "Changing Priorities of B&PV Codes and Standards" authored by J. Phillip Ellenberger, a senior member of the ASME Code Committees responsible for ASME B16, B31, B31.3 Design, B31 MDC,

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B31.12, and B31 Fabrication. With several decades of responsibility and expertise covering these topics, Ellenberger was invited to cover the entire set of B16 committees. In this chapter, he describes the history of the standard and describes the way in which separate groups of manufacturers of flanges, fittings and valves began to develop standards so that uniformity, safety and reliability are ensured. His discussions indicate the evolution of these standards posited for the benefit of users of the codes and standards. As in many cases standardization also delivers economic benefits.

These groups evolved into the B16 standards committee and ASME became the single organization that was coordinating and developing the standards. This evolved into the disparate standards being offered under the banner of The American National Standards Institute (ANSI). Some of the original organizations ceded their standards to the B16 set. Many of the original groups still exist and work standards or standard practices in their narrower areas.

The chapter also explains how the B16 group is split into specific categories of the basic flanges, valves and fittings. The coverage also includes how these various groups are divided by type, material or method of manufacture. It addresses the basic procedures of evolving editions of the standards themselves.

One key section outlines the date of the current editions, the expected date of the next edition and a discussion of expected new editions. This chapter is a valuable survey and analysis of this set of ANSI standards.

PART 3: CHANGING PRIORITIES OF CODES AND STANDARDS: PERSPECTIVES OF LESSONS LEARNED

Chapter 24 is the leading chapter of Part III of this book entitled "Changing Priorities of B&PV Codes and Standards: Perspectives of Lessons Learned". The intent of this chapter is to show the importance of Section VIII that includes Part A: Lessons Learned Based on Section VIII, Division 1 by James C. Sowinski; and Part B: Lessons Learned Based on Section VIII, Division 2 by David A. Osage.

Sowinski and Osage had been specifically invited to chronicle their experiences, to learn-first-hand, what we can imbibe about intricacies in Section VIII, Divisions 1 and 2. It is not easy to write, especially having participated in the deliberations, but James Sowinski provided us the benefit of such experience for the users of the code. Similarly David Osage, who heads his own consulting firm is worthy of authoring the text, capturing his rich experience and recording the intent of the chapter – "lessons learned".

The technology for pressure equipment design continues to advance each and every day. The American Society of Mechanical Engineers (ASME) has been keeping pace with these advances over the last 100 years. Specifically, the ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 has become the International benchmark standard for pressure vessel design for a multitude of industries. In response to these ever-growing industries and their unique design requirements the document has grown in scope, technology, and size. Organization, maintenance, and use of a document of such magnitude have become a real challenge, especially with a writing style and format that is not readily adaptable to change. In Chapter 24, Part A, James Sowinski provides commentary into what are generally thought to be the more relevant issues of ASME Section VIII, Division 1 that need attention to better serve its users and to provide recommendations to resolve these issues. In Part B, David A. Osage provides an overview of the ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 published in 2007, and explores the technical concepts included and the new format designed for ease of use. Included are results of test exercises sponsored by ASME giving actual applications of the new Code for design of vessels. In addition, user experience with VIII-2 for new construction is provided along with a discussion of the Common Rules initiative within the ASME B&PV Code.

Ultimately "Utility Experience" and a critique from that perspective is a vital part of "Lessons Learned", especially when we are confronted with aging nuclear reactors. Gary Park was particularly selected and invited to record his assessments based not only because of his decades of participation at the helm of Code Committees, but also due to his association with operating nuclear plants. In Chapter 25, Gary Park records the "Lessons Learned Based on Operating Experience, Section XI".

There is an old saying that if we don't learn from our mistakes and pass those lessons onto our future generations, those same mistakes will be repeated. Mr. Park identifies several areas wherein as the nuclear renaissance continues we can learn from the past construction of the operating nuclear power plants that were built in the 1970s. This chapter is to help understand what we have learned and provide solutions to those issues for the future of nuclear power. The topics addressed in this chapter is 1) development of requirements in the proactive state as opposed to the reactionary state, 2) addressing the new reactor designs and developing requirements to meet those designs, 3) operating experience from those nuclear power plants that have been operating for the past 30 years, 4) new ways of meeting safety issues in the way inspections are implemented, and 5) reducing the number of construction code repairs by using fracture mechanics in evaluating construction type flaws.

In Chapter 26 Part A: Lessons Learned: Industry Experience of Materials by John F. Grubb; Part B: Lessons Learned: Experience with Nonmetallic Materials in Structural/Pressure Boundary Applications by C. Wesley Rowley is perhaps one of the crucial subjects in today's industrial fabric irrespective of the industry. When this editor started his association with nuclear industry, leave alone fossil, locomotive or automobile areas there was a single volume addressing materials in B&PV Codes. Since then this has bulged into four three-inch ring binders, and that was a decade back! Today and more so tomorrow, role of materials in industry will play unbelievable fathomless levels. Therefore it was important an invitation is sent to the icons of the industry who can address dispassionately 'lessons learned'! Dr. Grubb and Professional Engineer Rowley are such individuals who were asked to record their message in a limited number of pages, which they did immaculately.

Chapter 26, Part A, by John Grubb addresses industry experience with metallic materials. The introduction of new materials, especially the introduction of "advanced" alloys into the B&PV code, has prompted the introduction of new rules. Some of the lessons learned in this process are addressed. The ASME BPV Code promotes the introduction of new materials. As materials are produced to more closely fit users' requirements, new issues arise. One example is the introduction of "advanced" alloys into the B&PV Code, which represents a significant change in philosophy regarding materials' use at elevated temperatures. The inevitable acceptance of these alloys has prompted the introduction

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of new rules in the construction codes and new protocols in SC II that are more prescriptive than the rules and protocols adopted to govern the use of the more "traditional" materials. In view of the very significant changes in the power industry that have occurred over the last 30 years, this general trend is likely to continue. Dr. Grubb has addressed some of the lessons learned, in the limited space allocated for him!

In Chapter 26 Part B, Wesley Rowley states that the API, ASME, AWWA, and BS have a number of codes and standards utilizing nonmetallic materials that provide construction and repair requirements. He notes that the term "construction" in ASME pressure technology applications includes design, materials, fabrication, erection, inspection, testing, and quality assurance of components. Many of these construction codes and standards allow the use nonmetallic materials to some extent (sometimes via a Code Case). A note identifies nonmetallic material construction codes and standards. Rowley states that the proper use of these construction codes and standards is performed through the use of the Design Specification. Most application issues are caused by the use of a poorly written Design Specification. Rowley reiterates that the use of nonmetallic piping systems in plant pipework applications can be superior to metallic piping systems, especially in corrosive environments and long service life applications. For properly constructed nonmetallic piping systems, adherence to the requirements of the ASME, API, AWWA, and BS construction codes and standards must be insured. The key requirement is the use of detailed Design Specifications, based on industry codes and standards. Since volumetric and surface NDE/NDT is not always possible, developing and implementing detailed process controls is very important for a successful construction process.

As it was mentioned previously, without any exception this publication has contributors who are icons in their respective fields, utility or regulatory sectors, architect engineers, consultants, ASME Code Committees or even as consultants. This publication has three important parts, each segment being a follow-up of the 'Companion Guide' a "classic" in its own right. Thus, this particular chapter falls in that corridor where authors were selectively invited. For Chapter 27, Douglas A. Scarth whose reputation in the ASME Code Committees is a common knowledge was invited to write about "Section XI: Lessons Learned – Flaws, Degradation and Corrosion Processes".

In Chapter 27, Douglas A. Scarth summarizes developments in flaw Acceptance Standards and analytical evaluation procedures in Section XI of the ASME B&PV Code for nuclear piping degraded by flaws and corrosion processes based on lessons learned. Section XI is involved on an ongoing basis in the development of evaluation procedures and acceptance criteria to evaluate the structural integrity of degraded nuclear pressure boundary components as new industry degradation issues arise. These Section XI activities are in general performed by Working Groups and Task Groups that are under the direction of the Section XI Subgroup on Evaluation Standards.

As described in this chapter, there has been a history of intergranular stress corrosion cracking in Boiling Water Reactor austenitic piping, and primary water stress corrosion cracking in dissimilar metal welds in piping in Pressurized Water Reactors. The author discusses a number of revisions that have been made to the Section XI flaw Acceptance Standards and analytical flaw evaluation procedures to address these cracking mechanisms. Such revisions are published on an ongoing basis. The background to a major revision to the evaluation procedures and acceptance criteria to improve consistency with piping design intent is discussed. Recent developments and work in progress to address stress corrosion cracking in piping items including crack growth rates and weld residual stresses are described. The background to the improved transition temperatures for the onset of upper shelf fracture behavior in ferritic piping to reduce conservatism is also provided.

The author then describes Section XI procedures that were needed to evaluate wall thinning due to flow-accelerated corrosion, as well as wall loss due to other corrosion mechanisms, in nuclear piping systems. Improvements to evaluation procedures and acceptance criteria for wall thinning due to flow-accelerated corrosion, as well as for temporary acceptance of flaws including through-wall flaws in moderate energy Class 2 and 3 piping systems, that are in progress are also described in this chapter. In addition, based on service experience with leakage from buried piping, evaluation procedures and acceptance criteria for evaluation of flaws in buried piping have recently been published.

Changes to the pipe flaw evaluation procedures in Section XI are supported by technical basis documents, and a number of these documents are listed by the author in the references for this chapter.

Lessons Learned from manufacturing oriented subjects could be easy and forthright applicable if it is coming from industry, however if the same has to be written with a code perspective it cannot be as straightforward and doubly challenging to get a credible person to chronicle it. Chip H. Eskrige with multi-disciplinary professional engineering license and Joseph F. Ball at the helm of The National Board of Boiler & Pressure Vessels Inspectors who had been invited to write the Lessons Learned in The Use of Pressure Relief Devices in Chapter 28.

Chapter 28, authored by Chip H. Eskridge and Joseph F. Ball, discuss pressure relief devices (PRDs); their history, the certification process, as well as their application with adhering to the various codes and standards which specify their use. Pressure relieving devices have evolved over the last 100+ years from simple spring/counter weighted devices to more ingenious devices such as bursting disks, buckling pins, and breaking pins. Rules for the use of open vents are also discussed. This chapter discusses lessons learned during this evolution and provides a timeline of when these devices entered the code books as well as how the certification process is performed for PRDs at the National Board of Boiler and Pressure Vessel Inspectors in Columbus, Ohio. Valve repair and "grandfathering" existing installations are also discussed.

The authors discuss the role and authority of the local jurisdictions and the Chief Boiler Inspector as well as how to access local laws including contacting the Chief for enforcement interpretation. In the last 10 years, changes in PRD rules have evolved rapidly, especially with pressure vessels. The omission of PRDs was codified with the addition of UG-140 in order to harmonize the ASME code with international codes. Open vents, which would appear to be an obvious overpressure protection method, are now explicitly addressed in Section VIII with backpressure rules. Piping and tank overpressure protection is also discussed and overpressure margins are provided. The 3% and 10% inlet/outlet pressure drop rules are discussed and summarized. ASME code cases and ASME/API Interpretations are discussed throughout the chapter to provide the reader with alternate rules and clarity to existing code language. These documents are often overlooked by users and designers but can be extremely valuable in the right application.

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This is a distinctive chapter in this part of this book since 'lessons learned' are provided by a Utility Engineer, based on the "Insights from Nuclear Utility Experience with PRA Applications". In Chapter 29, Deepak Rao provides an introduction to the increasingly important field known as Probabilistic Risk Assessment or PRA. He has described in layman's terms, a definition, brief history, summary of nuclear applications as well insights from PRA. These are all provided from a utility PRA practitioner's perspective and gleaned from his experience in the field lasting several decades.

This chapter starts with an explanation of what is PRA, *i.e.*, the risk triplet (What can go wrong? How likely is it to go wrong? What are the consequences?). He then provides a discussion tracing the evolution of how probability and statistics evolved over a timespan involving many hundreds of years into the field that is now called PRA. He shows how these concepts were increasingly needed and had to be invented as the complexity of modern systems increased exponentially and how this need led to the development of PRA methodologies. Next a brief history of early nuclear power plant safety was framed during their licensing is provided. Also provided is information on early nuclear power plant PRAs including the monumental WASH-1400 or Rassmussen Report along with discussions of how decision analysis is intertwined with PRA.

Deepak Rao goes on to enumerate a sample of the various multitude of PRA applications that are being pursued in the nuclear industry. A historical perspective is also provided in explaining how the major nuclear power plant accidents (Three Mile Island and Fukushima) led to an increased appreciation of risk analysis potential and results. The Three Mile Island Accident in fact led to the several major nuclear power plant PRAs in the USA. The use of PRA in the nuclear industry has helped increase capacity factors, improve safety, allowed increased on-line maintenance, and allowed the regulation to be more risk-informed so that each regulatory violation or proposed regulatory violation now has to be evaluated for risk significance using realistic PRA models. PRA has been instrumental in obtaining regulatory approvals for increasing the allowed outage time (AOTs) in nuclear power plant technical specifications of various systems such as emergency diesel generators which have proved crucial to the nuclear utilities in their quest for more optimal and efficient operation. Combined with such technical specification improvements and more on-line maintenance, nuclear capacity factors have increased from 60-odd percent in the 1970's to 90-plus percent today. All of these PRA applications have considerably enhanced the importance and role of PRAs in safe operations of today's nuclear power plants.

Chapter 29 concludes by providing the essence of some insights obtained by Deepak Rao from involvement in three decades of nuclear power plant PRA applications. Some of these are

- Fire risk methods need much improvements in order that fire risk results be aggregated with internal events PRA risk
- US nuclear power plant (particularly the new nuclear designs being currently built) have very low public health risk
- Nuclear power's safety should be quantitatively compared with those of other alternatives. Only by doing this on an "apple-to-apples" basis will there be a fair comparison of these options. Enhancing the use of PRA in all of these alternatives is an imperative if the quality of life of the public is to be optimized.

Lessons learned Part of this book is meant to open a window to fresh insights from experts belonging to various fields and one such perspective is the regulatory aspect. Although these should be considered as an opinion of the individual providing the insights, nevertheless its value rests upon the content covered. In this respect, in Chapter 30, Chakrapani Basavaraju provides value added "Lessons Learned: NRC Experience".

The objective of this chapter is to provide some highlights on the recent issues and lessons learned by the Nuclear Regulatory Commission (NRC) for the safety related and safety significant nuclear power plant components, which utilize the ASME Boiler and Pressure Vessel Codes, Sections III and XI. These include issues related to 2011 Japan Earthquake that directly impacted the Fukushima Nuclear Plant, and also led the regulatory bodies worldwide to take a closer look at the emergency systems for any needed changes for beyond the design basis events. This chapter also provides some information on environmental assisted fatigue of nuclear components exposed to Light Water Reactor (LWR) environments, buried piping leakage and contamination issues, the issues related to High density polyethylene (HDPE) as an alternate piping material for the replacement of buried steel piping, the issues and lessons learned related to BWR steam dryers subjected to flow induced vibration loading associated with extended power uprate (EPU) conditions, the current conclusions related to quasi-laminar indications in reactor pressure vessel ring forgings, steam generator tube leaks and fluid elastic instability, and lessons learned from Operating plants experience for consideration in new nuclear power plant (NPP) construction.

As had been mentioned in the preceding chapter introductions for this part of the book – "lessons learned", Chapter 31 is another exclusive coverage of a topic of interest – namely, 'the "balance of plant" of the nuclear industry. The aspects of the coverage address issues of interest to fossil and petro-chemical industries who use B31.1 and B31.3 Piping. Written by a professional engaged on the topical issues, with several decades of experience and at the helm of Code Committees dealing with this aspect, 'lessons learned' would be helpful to those in the industry as well as utility and regulatory personnel.

Over the past 40 years piping designed to either the ASME B31.1 Power Piping Code or the ASME B31.3 Process Piping Code has proved it will perform well. That being said, why are there still failures in the industry? This chapter will attempt to review some significant failures or more common types of failures and provide some guidance on how they can be avoided. The design rules have proved adequate and have significant margin for safety if all of the design requirements have been identified. This is proving to be no small task and involves the original design as well as operations and maintenance activities.

PART 4: CHANGING PRIORITIES OF CODES AND STANDARDS: FUTURE DIRECTIONS

The challenge of the nuclear industry is not only what is on the platter, but what is 'yet-to-come'. In that light last Part of this book addresses "Changing Priorities of B&PV Codes and Standards: Future Directions".

Chapter 32 covers "New Deliberations in Nuclear – Modular Construction" which is in the forefront of the current industry efforts. Industry leaders had been invited for writing this chapter, and based on the responses two outfits chronicled their efforts in Parts A and B.

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Part A: A Scalable Approach to Commercial Nuclear Power: NUSCALE Power's New Approach to Safety and Deployment of Nuclear Plants by José N. Reyes and Daniel Ingersoll systematically dealt the subject with several impressive graphics including pictures, schematics and a litany of references. NuScale Power's unique, scalable approach to the deployment of commercial nuclear plants provides the financial, schedule, supply chain, and workforce advantages that will broaden the market for commercial nuclear power. NuScale Power also offers a new level of safety that may simplify siting and increase public acceptance of nuclear power. Although novel in its deployment approach, the factory-fabricated NuScale Power Module (NPM) relies on well-known light-water reactor technology, significantly reducing technological and regulatory risks. Most importantly, the NuScale design has achieved the "Triple Crown of Nuclear Safety." That is, a NuScale reactor can safely shutdown and self-cool for an indefinite period of time with no operator action, no AC power or DC power, and no additional water. The design also eliminates the possibility of many accidents from occurring and adds greater defense in depth to protect against even the most severe events such as occurred at the Fukushima Daiich plant in Japan. These remarkable advances in safety are achieved while offering all the financial benefits that come with small modular infrastructure.

NuScale has completed 4 years of active pre-application meetings with the NRC to discuss unique features of a multi-module plant. As a result, the NRC is developing a Design Specific Review Plan (DSRP) that will enable both a comprehensive and efficient review of the NuScale design certification application. Most of the DSRP falls within the existing regulatory framework for light-water reactors. More importantly, by the time that the tests. The result is expected to be a streamlined and expedited review and approval.

The NuScale design combines proven LWR-based technology and innovative engineering to provide a new nuclear plant option with a high level of safety and affordability. The design was built from the ground up with safety as the fundamental goal and continues to support that goal through a design process that is both risk-informed and test-informed. The many innovations within the NuScale plant, including design-specific innovations, operational innovations, and economic innovations, create a new paradigm in nuclear power deployment. The innovations are appropriately balanced by active engagement with the regulator and utility customers to help ensure that the design is convincingly safe and will satisfy the desired market needs.

Part B: New Deliberations in Nuclear Modular Construction – Westinghouse Small Modular Reactor was addressed by Alexander W. Harkness, in which he included material in the chapter that had been published in part previously by ASME, "An Overview of the Westinghouse Small Modular Reactor, by Fetterman, Harkness, Smith, Taylor, Paper Number SMR2011-6597". Author includes impressive graphics including schematics and appropriate references.

The Westinghouse Small Modular Reactor (SMR) incorporates an integral pressurized water reactor (iPWR) design in which all components associated with the nuclear steam supply system (NSSS) are housed within one pressure vessel. The Westinghouse SMR design also utilizes many of the key features developed for the **AP1000®** plant, including passive safety systems. The Westinghouse SMR will be fueled by a derivative of the successful Robust Fuel Assembly (RFA) product. An 89 assembly core with an active height of 8 feet will provide a 24 month operating cycle with a power output of 800 MWt. Derived from the **AP1000** plant and adapted to operate inside the reactor pressure vessel, 37 control rod drive mechanisms provide reactor shutdown and reactivity control capabilities. Eight seal less pumps provide a nominal reactor coolant flow of 100,000 gallons per minute. An innovative evolution of a straight tube steam generator produces a saturated mixture that is delivered to a steam separating drum located outside of the containment vessel. The steam generator along with the integral pressurizer is attached to the reactor vessel with a single closure flange located near the center of gravity of the reactor assembly and is designed to be removed during refueling operations. Like the AP1000 plant, the Westinghouse SMR relies on the natural forces of gravity and natural circulation to provide core and containment cooling, during accident conditions. The passive cooling systems provide sufficient heat removal for seven days without the need for offsite AC power sources. The Westinghouse SMR also includes traditional active components such as diesel generators and pumps; however these components are not required for the safe shutdown of the plant. At a diameter of 32 feet, approximately 25 of the Westinghouse SMR containment vessels can fit within the envelope of the **AP1000** plant containment building. This compact containment will be completely submerged in water during power operation providing a heat sink for postulated accidents. For protection against external threats, the containment vessel and plant safety systems are located below ground level. At approximately one fifth the net electrical output of the AP1000 plant, the Westinghouse SMR is designed to address infrastructure challenges associated with replacing America's aging fossil fuel plants by providing a safe, clean and reliable energy source. The challenges associated with economies of scale are offset with a compact and simplified plant design, rail shippable components and modular construction.

Often it is not easy to rope in the industry leaders to address challenging topics, especially topics which are 'futuristic'. Considerable financial, R&D and manpower resources had been committed for development of "Fusion Reactors. After months of frantic search three experts have been chosen to chronicle this intricate chapter that transcends possibility to probability!

This last chapter of this book dwelling on futuristic domain of nuclear energy has been authored in 3 distinctive parts – Part A by James Mahaffey who provides a scholastic picture of the basics of fusion process; Part B by Brad Nelson who has synthesized what is the public domain pertaining to ITER efforts for 'fusion reactors'; and in Part C Irving Zatz has given his R&D picture of the Fusion Reactors.

Chapter 33, co-authored by James A. Mahaffey, Brad Nelson, and Irving Zatz, provides an introduction to the ground-breaking discipline of power production by hydrogen fusion. Fusion power has been under development for the past six decades, with the efforts strung out across the Western and Eastern Hemispheres in hundreds of experiments toward extracting net energy from a process that is common in the greater Universe. Hydrogen fusion is similar to the fission of uranium, currently used in nuclear power plants worldwide, in that it involves changing the structure and the identity of elements, producing power that is millions of times more efficient than simply combusting burnable materials. It is different in that it occurs at the opposite end of the atomic mass scale, and it has clear advantages over the well established fission reaction.

In Part 33A, Mahaffey gives a brief overview of the theoretical basis for this unique power source, beginning with a description of the process of making four hydrogen atoms fuse into one

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helium atom. This action, which lights the Sun and makes life on Earth possible, gives us a model for releasing energy that works well only in structures of extreme size, such as stars. An alternate, terrestrial-scale scheme of fusion involving heavier isotopes of hydrogen is then described. Although a continuous reaction of this type has yet to be demonstrated, reasons are given for the possible practicality of such a reaction and its use in Earth-based electrical generation.

In Part A the "fusion of light elements" is discussed. Finally, the author of this Part A has provided scholastic references of value to substantiate his expose as well wealth of information he could not include due to the page restrictions imposed on him for this publication.

Chapter 33, Part B describes the ITER project and is a compilation of content from www.ITER.org (ITER Organization, 2013) and attributable to the ITER team. ITER (Latin for "the way") is a major international research project with the goal of demonstrating the scientific and technological feasibility of fusion energy. ITER is designed to be the world's first fusion device large enough to produce a self-heated or "burning" plasma. The project is being designed and built by seven partners: the European Union, India, Japan, the People's Republic of China, the Republic of Korea, the Russian Federation, and the United States. The site for the device is near Saint-Paul-lez-Durance in southeastern France, with the European Union as the host party. Each partner will contribute hardware components, personnel, cash for the central ITER organization, and contingency during the construction phase of the project. ITER will use the magnetic confinement approach to fusion, where ionized fuel, plasma, is confined with a high magnetic field and heated to fusion temperatures. The ITER configuration is a long-pulse tokamak (toroidal-shaped plasma with internal current) designed to operate with a fuel mixture of deuterium and tritium. The ITER tokamak design emphasizes high plasma confinement with a vertically elongated plasma and single-null poloidal divertor. The nominal inductive operation will produce fusion power of 500 MW for a burn duration of 300 to 500 seconds, with 50 MW of injected auxiliary heating power. Extended operation would aim at steady state performance with a 1000 second or longer pulse length.

Irving Zatz wrote Part 33C, Nuclear Fusion, in which he describes the pursuit of nuclear fusion research in the United States and the goals of the Fusion Energy Sciences branch of the U.S. Department of Energy. As Zatz points out, the need for new ASME standards and codes for fusion energy devices is finally impending. The decades of research have moved into power plant development. The effort to develop these essential codes will involve temperatures and pressures over unprecedented ranges in new types of structures and devices. This is just the beginning.

Irving J. Zatz describes the process of nuclear fusion and its importance as part of the U.S. and world's long term energy strategy. The technical challenges are discussed in the context of the U.S. Department of Energy's mission to support the research of nuclear fusion with the goal of practical energy production. As part of this strategy, the ASME has formed a committee tasked with developing a code case for fusion within the Boiler and Pressure Vessel standards.

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CHAPTER

1

HISTORY OF THE CODE RULES FOR ACCREDITATION, CERTIFICATION, AND RELATED ISSUES

Richard Stevenson and Marcus N. Bressler[1]

1.1 INTRODUCTION

This chapter provides an overview of the history of the ASME Boiler and Pressure Vessel (B&PV) Code from its inception through its incorporation of nuclear components and up to the present. Applicable rules for certification and accreditation were developed in parallel with the growth of the Code. From earlier coverage of boilers and pressure vessels, the nuclear initiative required coverage for piping, pumps, valves, storage tanks, vessel internals, and both component and pipe supports.

The earlier Codes not within the scope of the Boiler and Pressure Vessel Code are described, including their part in the development of the rules incorporated into the Nuclear Code in 1971. Code implementers, including the Registered Professional Engineer as well as the Authorized Nuclear Inspector and his or her supervisor, are highlighted, as are the organizations that employ them. Authorized Inspection and Quality Assurance are discussed, as well as Inservice Inspection and its interfaces with the Construction Code. Rules for repairs and replacements of nuclear components and the use of newer codes are referenced, including the need for code reconciliation and commercial grade dedication. Two examples of how Code reconciliation is used are provided.

The development of certification and accreditation are covered, with emphasis on the new requirements for organizations seeking ASME accreditation. The globalization of the ASME certificates and stamps are thoroughly described.

1.2 HISTORICAL BACKGROUND

A detailed article titled "History of the ASME Boiler Code" was written by Dr. Arthur M. Greene, Jr., and was first published in various issues of *Mechanical Engineering Magazine* in 1952 and 1953. Later, it was published as a book by the American Society of Mechanical Engineers (ASME) in 1955. The following paragraphs are excerpted from this publication [1].

> As a result of the many boiler explosions experienced during the nineteenth century, a committee was formed in 1897 under the American Boiler Manufacturers Association (ABMA) to develop uniform specification laws. Due to inability by some members of the association to look beyond the interests of their own companies, the proposed rules were not approved.

On August 30, 1907, the Commonwealth of Massachusetts approved the first set of rules for construction of boilers proposed by a committee headed by John A. Stevens. By 1909, the original rules, consisting of three pages, were expanded to three parts and approved as "An Act for the Operation and Inspection of Steam Boilers." The State of Ohio did likewise on October 24, 1911, approving a code essentially identical to the Massachusetts rules. This code went into effect on January 1, 1912, and Part 3 became mandatory on July 1, 1912.

In June 1911, Col. E. D. Meier, president of the Heine Boiler Company and a past president of the ABMA, became president of the ASME. With the ABMA rejection still in his mind, Col. Meier believed that a set of rules formulated by ASME, with its reputation and broad scientific interests which made it commercially disinterested, might be accepted. In September, 1911, he asked the Council of the ASME to approve appointment of a committee to formulate standard specifications for the construction of steam boilers and other pressure vessels. After four years of hard work and negotiations, better described in the above cited book, the standard, based on the Massachusetts rules, was approved by Council on March 12, 1915, as the "Rules for the Construction of Stationary Boilers and for Allowable Working Presssures."

The first meeting of the Boiler Code Committee was held in Buffalo, NY, on June 23, 1915, and among its first considerations was the question of Code Symbol Stamping. Authorization to use the Code symbol would be referred to the Boiler Code Committee for recommendation and report to the Council. The committee also adopted the statement that the Code Symbol applied to a boiler would indicate that the boiler had been built in full compliance

[1] Late Marcus N. Bressler was the author of the initial write-up of this chapter and subsequently up-dated it in the Second and Third Editions that appeared in the "COMPANION GUIDE TO THE ASME BOILER & PRESSURE VESSEL CODE, VOLUME 2." For this publication the up-date is done by Richard Stevenson. – Editor

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with the Code, and that the stamp should be applied by the manufacturer. It is interesting to note that Code Case No. 10 asked where the Code stamp specified in par. 332 of the Code might be obtained, and the reply was "through ASME at a price of $3 each." These were the rules for certification of boiler manufacturers: compliance with the code rules, and stamping the boiler with a stamp procured from ASME.

Through the years it only required a letter from the jurisdiction (a State of the United States or a Province of Canada) to permit a manufacturer to secure a Code Symbol Stamp. On March 2, 1922, the Boiler Code Committee directed that a new certificate and a consecutive number be issued to each company holding a stamp for the purpose of registration. This registry recorded the issuance of 222 stamps as of April 25, 1924. The minutes of the 1937 to 1940 meetings reported, for the first time, the names of the companies to which the Code Symbol Stamp had been issued or reissued, with an indication of the section or sections for which these would be used. There were 108 in 1938, 109 in 1939, and 124 in 1940. Certification remained an unstructured program for many years.

In 1911, the American Society of Mechanical Engineers established the Boiler and Pressure Vessel Committee to formulate standard rules for the construction of steam boilers and other pressure vessels. In 2009, the Boiler and Pressure Vessel Committee was superseded by the following committees:

(a) Committee on Power Boilers (I)
(b) Committee on Materials (II)
(c) Committee on Construction of Nuclear Facility Components (III)
(d) Committee on Heating Boilers (IV)
(e) Committee on Nondestructive Examination (V)
(f) Committee on Pressure Vessels (VIII)
(g) Committee on Welding, Brazing, and Fusing (IX)
(h) Committee on Fiber-Reinforced Plastic Pressure Vessels (X)
(i) Committee on Nuclear Inservice Inspection (XI)
(j) Committee on Transport Tanks (XII)

Today for Nuclear, the Committee on Construction of Nuclear Facility Components (III) and the Committee on Nuclear Inservice Inspection (XI) serve as the standards committees for Section III and Section XI respectively.

1.3 NUCLEAR ENERGY

Nuclear energy was first harnessed for the production of steam to drive ship turbines in the early 1950s. The first applications were military; specifically, they were for the propulsion of submarines. The standards used for the construction of the required equipment were necessarily developed by the U.S. Navy and also by the contractors involved in designing and manufacturing the nuclear power plants for early prototype submarines. The first commercial operating nuclear power plant, Shippingsport, placed into service a duplicate of a ship's reactor near Pittsburgh, Pennsylvania. In 1958, the ASME B&PV Committee created the Special Committee to Review Code Stress Basis, charging it with the responsibility of developing rules for the safe construction of pressure vessels of superior quality. Admiral Hyman Rickover persuaded the committee to first develop a standard for nuclear vessels to permit the Navy to bid competitively among the nation's pressure vessel manufacturers. That action marked the first time that a nuclear Code would be prepared and become the global Standard for nuclear power plant construction. It became Section III, Nuclear Vessels, described in paragraph 1.5.

1.4 PIPING, VESSELS, PUMPS, AND VALVES IN THE 1950s

When the early commercial nuclear power plants were considered in the late 1950s, the available Codes and Standards were those used for the construction of thermoelectric power plants, refineries, and chemical plants. This in itself was not a problem, as more than 60% of a nuclear power plant is essentially the same as that of any other thermal or chemical plant in terms of its piping, vessels, pumps, valves, and supports.

The late 1950s was a period of quantum leaps. The development of calculating equipment—from hand-cranked and electrified adding machines to gas-tube electronic calculators and gas-tube computing machines—reached a high level of sophistication by the end of the 1950s. Stress analysis techniques and the high-speed calculations permitted by the new computers led to large increases in the formulation of piping and vessel analyses. New standards and revisions to existing standards took advantage of the new tools in time for the needs of nuclear power.

A historical note may help explain the various prefixes to these standards. The American Standards Association (ASA) was reorganized in 1966 as the U.S.A. Standards Institute. Standards approved as American Standards were designated U.S.A. Standards (USAS). In 1969, the Institute was renamed the American National Standards Institute (ANSI); its approved national Standards became ANSI Standards. Throughout those years, the ASME had administrative control of its Standards under procedures accredited by the ANSI. These are now listed as ASME Standards; moreover, the ASME retains the sole responsibility for their interpretation.

In 1955, the B31 committee decided to publish the new piping Code in separate volumes. At the beginning of the 1960s, piping was designed, fabricated, and installed in accordance with ASA B31.1–1955. Vessels were under the scope of the ASME B&PV Code, Section VIII (Unfired Pressure Vessels), 1959 Edition, summer and winter 1959 Addenda.

Pumps and valves were designed and manufactured under manufacturer's standards, with dimensional parts complying with national standards. For example, flanges for bonnet and casing covers as well as for flanged pipe connections were manufactured to the dimensional standard ASA B16.5–1957. (For a history of the development of the flanges and flange fitting standards, as well as rules for nuclear valves, see ref. [2].) The pump and valve bodies and internals were the responsibility of the manufacturer. The only other requirements were hydrostatic tests of the bonnets and bodies performed at 1.50 times the rating pressure at room temperature, as developed in B16.5 or in accordance with the Manufacturers Standardization Society of the Valve and Fittings Industry (MSS) SP-61, Hydrostatic Testing of Steel Valves, and SP-66, Pressure Temperature Ratings for Steel Butt-Welding End Valves. (Note: "SP" denotes "Standard Practice.") The ratings were based on material specifications, and their allowable stresses at temperature. Minimum wall-thickness for valve bodies were listed in the standard, as well as dimensional standards for seven classes of pressure. (For a history of the development of the pump rules, see ref. [3].)

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1.5 ASME SECTION III, NUCLEAR VESSELS, IN THE 1960s

Section III, Nuclear Vessels, was first published in 1963, at which time it was the only National Standard completely dedicated to nuclear applications. The second Edition was published in 1965; the third, in 1968. Code Editions were effective on July 1 of the publication year and were published triennially. Semiannual Addenda were issued between Code Editions and could be used after their publication; they became mandatory six months after issue. The publication dates were on June 30 and December 31 of the publication year; they were referred to as Summer and Winter Addenda, respectively. Each Edition was intended to include the previous Edition as modified by the six Addenda published during the triennial period ending in the next Edition. The 1963 Edition only included two Addenda, because the next Edition was published at the same time as the rest of the 1965 ASME B&PV Code.

The first ASME Section III Code made provisions for the construction of three classes of vessels: Class A, Class B, and Class C. Class A rules were intended for the construction of vessels designed to contain nuclear fuel and reactor coolant within the reactor-coolant pressure boundary, as stated in paragraph N-131(a). Class A vessels were designed by analysis using the maximum shear stress theory of failure (Tresca Criterion). Primary stresses (general membrane, local membrane, and bending) were limited by the stress intensities allowed for design conditions. The summations of primary and secondary stresses were also determined for the operating conditions, the results of which were compared to the allowable design stress intensities. An extensive discussion of stress intensity classification in vessels is beyond the scope of this chapter. Reference [4] provides such a discussion, as it is the commentary that describes the basis for "Design by Analysis" in Section III for Class A vessels. This reference was reissued in 1969, Reference [5], and included the design criteria used in Section VIII, Division 2, which was published in July 1968.

Class B rules covered primarily vessels used for containment, as noted in paragraph N-132. Class B vessels could be designed either to the maximum stress theory used in Section VIII or, alternatively, to the rules of the new Section VIII, Division 2, and were similar to Class A vessel design.

Class C rules were intended for vessels used for the auxiliary systems in the plant not classified as either Class A or Class B (paragraph N-133). Class C vessels could be entirely constructed to the rules of Section VIII, Division 1.

1.6 PIPING, PUMPS, AND VALVES IN THE 1960s

While the ASME B&PV Code Section III was developing, the B31 Standards Committee was reorganizing and, in keeping abreast of current technological improvements, issued a new individual standard—USAS B31.1.0 (in title only)—in 1967 until the revision of B31.1–1955 could be completed. A separate subcommittee, which included many personnel involved in the development of Section III, started the development of a code for nuclear piping and another for nuclear pumps and valves. In 1968, the draft code for pumps and valves was issued for trial use and comment; in 1969, the USAS B31.7 Code for Nuclear Piping was published.

Although the Data Report Form NP-1 referred to the Certificate of Authorization Number for the Fabricator, the text of the B31.7 Code made no reference to requirements for certification of the piping fabricator by the ASME. It was not until the piping code was absorbed by Section III in the 1971 Edition that requirements for certification were included and Code Symbol Stamps were established.

Section III, 1968 Edition with summer 1969 Addenda, introduced paragraph N-153, which stated the following: "Piping that is part of a nuclear energy system and is required to be constructed in accordance with this code, shall meet the requirements for Class I piping of USAS B31.7, Code for Nuclear Piping." Also, the paragraph made the provision that pumps and valves "shall meet the requirements for Class I pumps and valves of the ASME Code for Pumps and Valves for Nuclear Power." In addition to those references, paragraph N-153 specified that piping, pumps, and valves would need the required inspections to be performed by qualified inspectors, in accordance with paragraph N-612, and also that they would need to be stamped, in accordance with paragraphs N-811 and N-815 to N-818 (inclusive).

Section III, winter 1969 Addenda, published a revision to paragraph N-153. This clarified that the requirements for inspection and stamping applied to piping, pumps, and valves when they "were required to be constructed in accordance with this code." In addition, the paragraph clarified that this requirement applied when the piping was classified as Class I, USAS B31.7, and also when pumps and valves were classified as Class I, ASME Code for Pumps and Valves.

As early as 1967, the Atomic Energy Commission (AEC) published criteria for the codes and standards to be used for nuclear plant construction. In January 1975, the AEC was renamed the Nuclear Regulatory Commission (NRC); it continued to be sensitive to national standards as it always had been.

The NRC, defined by the Section III Code as the Regulatory Authority, is responsible for administering the applicable federal laws that are listed in Title 10, *Energy* of the Code of Federal Regulations (CFR), PART 50: *DOMESTIC LICENSING OF PRODUCTION AND UTILIZATION FACILITIES,* Section 50.55, Conditions of Construction Permits, Section a, Codes and Standards.

The AEC stated in 10CFR50.55a that plants licensed before 1967 could use the ASA B31.1–1955 Code, Addenda, and applicable Code Cases for piping within the reactor-coolant pressure boundary. Later revisions of 10CFR50.55a permitted use of the USAS B31.1.0–1967 Code, Addenda, and applicable Code Cases, as well as the Class I section of USAS B31.7–1969.

1.7 CERTIFICATION FOR NUCLEAR CONSTRUCTION

When Section III, Nuclear Vessels, was first published in 1963, the ASME was not ready for a formal approach to certification of manufacturers of nuclear vessels. In a book by Wilbur Cross [6], Melvin R. Green, Managing Director of the ASME Codes and Standards Department, is quoted as follows:

> In 1965, ASME included nuclear vessels in its Certification Program. A certificate was issued based on a favorable report from the authorized inspection agency and the jurisdictional authority.

Section III introduced Mandatory Appendix IX, Quality Control and NDE Methods, in the winter 1967 Addenda. With the revisions presented in the appendix, the ASME was now in position to establish procedures for certification: "On July 1, 1968, the concept of nuclear survey teams became mandatory."

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Prior to 1968, ASME had depended on the jurisdictional bodies or inspection agencies for recommendations to use Code Symbol Stamps. Then, in July 1968, more comprehensive Code requirements were put into effect regarding applicants for nuclear accreditation. These requirements introduced Quality Assurance on a more formal basis and also initiated the use of nuclear survey teams. Since then, requirements for other sections of the Code evolved to require a review team; the revisions have maintained the principle that an authorized inspection agency must have a potential legal or insurance interest in the finished product to be stamped with the ASME Code symbol stamp. The inspector must assure himself that the manufacturer conformed to the Code rules. The National Board of Boiler and Pressure Vessel Inspectors (National Board) acknowledged the value of this organizational procedure for reviewing Code Stamp applicants and began to participate in the survey teams in July 1968.

Audit teams began to visit manufacturers and their reports were reviewed by the Subcommittee on Code Symbol Stamps.

1.8 DEVELOPMENTS OF THE 1970s

In 1971, ASME Code Section III was renamed Nuclear Power Plant Components and incorporated the USAS B31.7–1969 Code for Nuclear Power Piping and its three Addenda: ANSI B31.7a–1971 (February 16, 1971); ANSI B31.7b–1971 (March 10, 1971); and ANSI B31.7c–1971 (October 21, 1971). The draft ASME Code for Pumps and Valves for Nuclear Power (dated November 1968) and its March 1970 Addenda were also included. This Draft Code was never published as a separate ASME standard. The renamed Code provided rules for the construction of pressure vessels, pumps, valves, piping systems, and metal containment vessels. The winter 1971 Addenda added rules for atmospheric storage tanks based on the American Petroleum Institute (API) Standard 650, and 0–15 psig storage tanks based on API Standard 620.

By 1973, 10CFR50.55a, paragraph (c), specified that for "construction permits issued before January 1, 1971, for reactors not licensed for operation, pressure vessels which are part of the reactor-coolant pressure boundary shall meet the requirements for Class A vessels set forth in Section III . . . applicable on the date of order of the vessel." Paragraph (d)(i) equally permitted USAS B31.1.0 or USAS B31.7 Editions, Addenda, and applicable Code Cases in effect on the date of order of the piping; paragraph (d)(ii) specified B31 Code Cases N7, N9, and N10; and paragraph (f) permitted valves to meet the requirements of B31.1.0 or Class I rules of the draft ASME Code for Pumps and Valves for Nuclear Power.

Federal law limited the early codes of the 1960s to plants with construction permits that had been issued before January 1, 1971. The permitted codes were as follows: For piping, the rules of ASA B31 and USAS B31.1.0 were permitted, of which the earliest code of record was the one in effect 6 months before the issuance of the construction permit. For pumps and valves, the rules of ASA B31 and USAS B31.1.0 could be used, as could those of the draft ASME Code for Pumps and Valves for Nuclear Power and Addenda in effect on the date of order; the earliest permitted code of record was the one in effect 12 months before the issuance of the construction permit. For vessels that were part of the reactor-coolant pressure boundary, the requirements that applied were those for Class A vessels set forth in the Section III and applicable Code Cases and Addenda in effect on the date of order of the vessels. The earliest permitted code of record was the one in effect 18 months before the issuance of the construction permit. No guidance was given for Classes 2 and 3 construction until Safety Guide 26 (later Regulatory Guide 1.26) was published with such rules.

For construction permits issued on or after January 1, 1971, but before July 1, 1974, 10CFR50.55a specified that the foregoing rules still applied; however, reference was made to ASME Section III because it now covered all the foregoing components. For construction permits issued on or after July 1, 1974, the requirements were revised to specify that Codes applied to the components needed to be of an Edition no earlier than the 1971 Edition, Section III, winter 1972 Addenda. This revision required materials for Class 1 construction to meet the new fracture toughness requirements introduced in the summer 1972 Addenda.

Since March 15, 1984, the federal rules require nuclear components to be certified and stamped in accordance with the ASME B&PV Code, as exemplified by most utilities specifying ASME components for their plants while they were under construction, as well as for replacement equipment and parts for operating plants. These requirements are described in paragraphs (c), (d), and (e) of 10CFR50.55a.

In 1973, the B31.7 committee issued B31 Case 115, which stipulated that piping designed and constructed in accordance with ASME Section III of the B&PV Code, including Addenda and applicable Code Cases, may be accepted as complying with the requirements of USAS B31.7–1969 and applicable Addenda for the particular class of construction. ASME Section III, winter 1973 Addenda, added rules for component supports (Subsection NF), for core-support structures (Subsection NG), and for materials (Subarticle NA-3700).

To make the requirements for the different classes of components more easily understood, Section III, Division 1, was split into seven separate volumes in the 1974 Edition. Each volume was called a subsection, and Division 1 included all the rules for the metal components of the nuclear system. Section III, Division 2, Code for Concrete Reactor Vessels and Containments, was published in 1975 as a separate volume. It contained the rules of construction for concrete reactors and containment vessels as well as the requirements for containment metallic liners; it referenced Division 1 and its appendices as required. Note that Division 2 includes its own appendices, so one must be careful in using this Code. A referenced Division 1 appendix will state that it is part of Division 1; otherwise, a referenced appendix will be to the Division 2 volume.

In the 1977 Edition, the General Requirements for Division 2 (identified as "CA") were put into the same volume as the General Requirements for Division 1 (identified as "NA"). In the summer 1977 Addenda, the two sets of General Requirements were combined into one set identified as "NCA," and NA-3700 was renumbered as NCA-3800. The purpose of this change was to consolidate the Code and, more important, to show the close relationship between various parties in the construction of Code components for a nuclear plant. Every plant with concrete reactor vessels or concrete containments has other components that are made of steel. In fact, all Division 2 concrete reactors and containments have steel parts that must meet some of the requirements of Division 1.

By 1976, the Code Cases that were referenced as applicable to Sections III or XI numbered well over 175. The Nuclear Code Cases were removed from the B&PV Code Cases, and both were published in separate volumes in 1977. The Nuclear Code Cases were listed with both the 4-digit number from the 1974 Edition

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(in parentheses), as well as the new N-XXX number, but only during the three years of the 1977 Edition. *Code Cases remain available for use until annulled by the applicable Standards Committee.*

In 1977, the ASME B&PV Main Committee authorized the publication of Interpretations in separate volumes. These books were published every six months and included all of the Interpretations issued for each section of the Code. Initially, they were sold separately from the Code (eleven volumes were issued altogether), but sales were dis-appointing. To ensure that all users of the Code had access to these Interpretations, they were published with each Addenda beginning with volume 12 in the summer 1983 Addenda. The 1986 Edition was the first in which the entire Code had Addenda published only once every year. It was decided to continue publishing the Interpretations every six months. (Although many organizations involved in Code activities consult the Interpretations to resolve problems, they cannot be used to change the Code: inquiries to do so generally result in a Code revision or a new Code Case.) Volume 57 was published in December 2004; it includes three indexes: a subject index for the new volume proper; a key word-type subject index for volumes 12 through 57; and a cumulative numerical index. The Interpretations of Section III, Divisions 1 and 2, are included with the update service to Subsection NCA and as of January 2012 are also posted on the ASME Codes and Standards web page. ASME B&PV Code Interpretations including those for Section III, Division 1 and 2 are posted in January and July at http://cstools.asme.org/interpretations.cfm.

Appendices to Section III were included from its inception as a Vessel Code. In the 1971 Edition, all sections and appendices of the Nuclear Code were included in one volume, and in the 1974 Edition, Subsection NA and Appendices were printed in the same book. Because of their significant size increase, the Appendices were published in the 1977 Edition in a volume separate from NCA.

Appendices are classified as either Mandatory or Non-Mandatory. Mandatory Appendices are titled by Roman numerals and include topics such as allowable design stress intensities, allowable stresses, material properties, and design charts for external pressure (these were moved in the 1992 Edition to Section II, Part D), as well as stress analysis techniques; design rules for bolted flange connections and flat heads with large openings; and other Code design and administrative rules. Non-Mandatory Appendices are titled by capital letters and include stress analysis and dynamic analysis methods; rules for such specific design details as flat-face flanges, bolt cross-sectional area, and clamp connections); guidelines for the preparation of Design Specifications and Reports; lowest service temperature determination and protection against nonductile failure; evaluation of service loadings in the faulted condition; and guidelines to fabrication controls. When they are specified in the Design Specifications, Non-Mandatory Appendices become mandatory.

1.9 THE REGISTERED PROFESSIONAL ENGINEER

The Registered Professional Engineer (RPE) who certifies a Design Report as accurate and complete is responsible for reconciling the design drawings and any changes thereto with his or her Design Report. The Design Report must be provided to the Authorized Nuclear Inspector (ANI), although the Inspector is not responsible for its accuracy or even for reviewing it. The RPE who certifies an Owner's Design Specification is probably the person best qualified to perform the required Owner's Review of the Design Report (NCA-3260); however, he or she is not required to certify the performance of the review. Revisions to Design Specifications and Reports must be recertified. The RPE certifying either document does not need to be from a different design organization, but he or she must be independent from the specific activity.

Initially, the Code did not address how competency in a field of design could be verified. The Board on Nuclear Codes and Standards organized the Main Committee on Qualifications and Duties for Authorized Nuclear Inspection and Specialized Professional Engineers (N626). The first standard covering qualification of RPEs was issued in 1978; in the 1980 Edition, summer 1980 Addenda, Section III adopted N626.3–1979, requiring review by Owners or N-Certificate Holders of the credentials of RPEs as well as the maintenance of his or her expertise once every three years. Survey teams expect to see an RPE's self-evaluation of qualification at least once annually.

Section III, 1995 Edition with A95 Addenda, refers to N626.3–1993. It provides guidance to the RPE by listing the paragraph numbers of each subsection for which he or she should have working, hands-on knowledge and those for which he or she should have general knowledge. This Standard became Appendix XXIII in the 1996 Addenda and N626.3 has since been annulled.

1.10 AUTHORIZED INSPECTION

The ASME system uses an independent third party to inspect work performed to ascertain that nuclear parts, appurtenances, and components meet the requirements of the ASME B&PV Code. This independent third party is represented by the Authorized Nuclear Inspector (ANI), who is the key to success of the ASME Code. He or she is truly independent because he or she cannot be an employee of the two parties most interested in the construction of the component: the Owner and the Certificate Holder. He or she works for an Authorized Inspection Agency (AIA) designated by or acceptable to the appropriate Enforcement Authority.

The ANI has experience and background in the inspection of nuclear components and, in addition, is knowledgeable of both the Nuclear Code and Quality Assurance. The duties and responsibilities of the ANI are detailed in NCA-5220. The qualification requirements for the ANI and the Authorized Nuclear Inspector Supervisor (ANIS) were originally listed in ANSI N626.0–1974 for Division 1 and ANSI N626.2–1976 for Division 2. The three Standards, including N626.1–1975 for Inservice Inspection, were combined in 1985 into one Standard: N626 Qualifications and Duties for Authorized Nuclear Inspection Agencies and Personnel which was later replaced by QAI-1 in 1995. The ANI and the ANIS are tested and commissioned by the National Board and must be qualified according to ASME QAI-1 Part 1 for Section III, Division 1, "Rules for Construction of Nuclear Power Plant Components," and for Section III, Division 3, "Containment System and transport Packagings for Spent Fuel and High Level Radioactive Waste" and QAI-1 Part 2 for Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." For Division 2, the ANI and ANIS must meet the requirements of QAI-1 Part 3 and have experience in the activities required for

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the placement of structural concrete. The AIA is required to be Accredited in accordance with Part 4 of the QAI Standard.

The ANI monitors the Quality Assurance Program and verifies compliance with the Code by the Certificate Holder. He or she verifies that the Certificate Holder has the necessary and up-to-date Codes and Addenda, that the Design Specifications and the Design Report are available and properly certified, and that the Owner's Review of the Design Report has been received by the manufacturer. He or she verifies that the materials used comply with the Code requirements, that proper welding procedures are used, and that welders are properly qualified. Another requirement is to ensure that Non-Destructive Examination (NDE) procedures are acceptable and that the NDE personnel are qualified. He or she verifies that design calculations have been prepared, that Design Reports are provided and, in addition, verifies and certifies that (to the best of his or her knowledge) the component or part is in full compliance with the Code. The integrity of the ASME program using Authorized Inspectors has been demonstrated for over 85 years.

If any questions regarding Code compliance are encountered, they can be answered by the ANI. A Code decision by an ANI must be accepted; otherwise, the same question must be asked of his or her supervisor (the ANIS) or of his or her employer (the AIA). The question may also be posed to the ASME; it should follow the provisions of Appendix XX for Edition earlier than the 2013 Edition and the provisions of the Forward Section in the 2013 Editon and Later. Appendix XX was deleted and the information moved to the Forward Section in the 2013 Edition. Interpretations cannot be obtained from individual committee members or from any other party; only the B&PV standards Committee can issue official Interpretations.

Before the initial application, and during the three years between ASME surveys, the ANIS is responsible to review and accept all changes to the Quality Assurance Manual. No changes to the program are to be implemented until acceptance by the ANIS. For N type (i.e., N, NA, NPT, and NS) certificates having a scope that includes the manufacture and supply of material, the ANIS is required to audit this portion of the program annually. Also, he or she is required to perform semiannual audits of both the ANI performance and the status of the Certificate Holder's Quality Assurance Program. The A92 Addenda to ASME Section III approved the N626a–1991 Addenda to ASME N626–1990. This revision introduced N626.4, requiring nuclear AIAs to be accredited by the ASME (NCA-5121); this requirement became mandatory on July 1, 1993, and nuclear AIAs are currently accredited.

This Standard was replaced by QAI-1–1995, Qualifications for Authorized Inspection. This document introduced Part 5, which requires accreditation of AIAs who provide boiler and pressure vessel insurance and inspection services. An Addenda was issued in April 30, 1996, QAI-1-1a–1996. It was followed by another Addenda, QAI-1-1b–1999, issued on April 10, 2000. The "N626 Committee" was also renamed the "QAI Main Committee," which now serves under the supervisory Board on Conformity Assessment. Since the 1995 Edition, Editions of QAI-1 were published in 2003, 2005, and in 2010. The 2010 Edition is the latest Edition and was published on May 28, 2010.

1.11 QUALITY ASSURANCE

The rules of Section III are very comprehensive regarding the duties and responsibilities of all parties involved in the construction of each component. Once the component has been classified, it is the duty of all parties involved to ensure that all of the Code rules for design and construction have been met.

These parties are the following:

- The Owner (generally the licensing utility).
- The N-Type Certificate Holders: N, N3, NV, NA, NPT and NS.
- The Quality System Certificate (Materials) Organizations: MOs.
- The AIA and its employees: the ANI's and ANIS's.
- The Enforcement Authority: municipality, U.S. State, or Canadian Province.
- The Regulatory Authority: NRC.

The Quality Assurance (QA) Program is an integral part of the Nuclear Code. All parties are required to have such a system, for it is used for verification of Code compliance. In addition, it is extremely helpful in the manufacturing process because it constitutes a detailed program for doing work properly. Thus a good Quality Assurance Program saves both time and money; it enables the Certificate Holder to do the work correctly.

Section III introduced Mandatory Appendix IX, Quality Control and NDE Methods, in the winter 1967 Addenda. On April 17, 1969, the AEC published a proposed amendment to 10CFR50 that would add an Appendix B, Quality Assurance Requirements for Nuclear Power Plants. Appendix B was issued officially on June 27, 1970.

In May 1969, the N45 Committee, Reactor Plants and Their Maintenance, established an ad hoc Committee on Quality Assurance Program Requirements, composed of AEC representatives and key segments of the nuclear industry. In 1970, a new N45-2 Subcommittee on Nuclear Quality Assurance Standards was formed to provide for the preparation, coordination, and approval of the N45.2 series Standards, which resulted in the initial issue of ANSI N45.2–1971.

In the 1971 Edition of ASME Section III, the Quality Assurance Program requirements were included in NA-4000. The N45.2 Committee indicated in its Foreword that these requirements were consistent with the requirements of their Standard. There were many problems in interpreting the coverage, for the criteria were not as numerous as the 18 criteria of 10CFR50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. Finally, in the 1977 Edition, the winter 1978 Addenda revised NCA-4000 to match the 18 criteria of 10CFR50 Appendix B. During that time, another Main Committee under the Board on Nuclear Codes and Standards—the Committee on Nuclear Quality Assurance—completed review of the ANSI N45.2 series of documents and issued the first Edition of ANSI/ASME NQA-1–1979, Quality Assurance Program Requirements for Nuclear Power Plants.

NQA-1 incorporated some of the ANSI/ASME N45.2–1977 daughter Standards:

- N45.2.6, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.
- N45.2.9, Requirements for the Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants.
- N45.2.10, Quality Assurance Terms and Definitions.
- N45.2.11, Quality Assurance Requirements for the Design of Nuclear Power Plants.
- N45.2.12, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants.

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- N45.2.13, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants.
- N45.2.23, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants.

NQA-1 was reviewed by Section III for some time. After three years, the 1979 Edition of NQA-1 was adopted in the winter 1982 Addenda—with many exclusions, primarily Supplement 2S-2, and instead retained NX-5500 for qualification of NDE personnel. Several Editions of NQA-1 have been adopted by Section III.

The A91 Addenda approved ASME NQA-1–1989 Edition and 1a–1989 Addenda, Quality Assurance Program Requirements for Nuclear Facilities, and the A92 Addenda added the 1b–1991 Addenda, as modified and supplemented in NCA-4134. The 2006 Addenda approved NQA-1–1994, which has also been accepted by the NRC.

NQA-1–2008 Edition with the 2009a Addenda has been reviewed and accepted by both ASME and NRC, and is referenced by the 2010 Edition of ASME III Subsection NCA.

1.12 INSERVICE INSPECTION

Lawrence Sage provided a history of the development of Section XI in ref. [7]. He recounted that there were no inservice inspection requirements for nuclear equipment beyond that mandated by state boiler and pressure vessel laws and insurance requirements. In 1967, the ANSI and ASME established the American Standards Committee N45, Reactor Plants and Their Maintenance, to develop these rules. In 1969, the AEC announced its intention to require inservice inspection at all new nuclear power plants.

The results of this work were first published in 1970 as ASME B&PV Code Section XI, Inservice Inspection of Nuclear Reactor Cooling Systems. Section XI includes rules for inservice inspection, examinations, repairs, alterations, and replacements for those nuclear components until the nuclear power system is taken out of service. It began as the nuclear equivalent of Sections VI and VII and the National Board Inspection Code for boilers and pressure vessels.

In June 1971, the AEC made the requirements of Section XI mandatory for all nuclear power plants with construction permits issued on or after January 1, 1971. In February 1976, the NRC made Section XI mandatory for all nuclear power plants. Sage's article provides a good summary of the changes that have occurred in this Code from 1970 to 1992.

Section XI now provides inspection rules for three different nuclear cooling systems in three divisions. Rules for inservice testing of pumps and valves have been moved to the Operations and Maintenance (O&M) Standards; they are no longer contained in Section XI. In service testing of snubbers has also been moved.

The rules of Section III are applicable during the construction of components by their Manufacturers, including their installation at the nuclear plant site. Section XI rules are applicable after the completion and stamping of the component or after its installation at the nuclear plant site. Under the traditional 10CFR Part 50 licensing process, the two Codes operate in parallel during the later years of the construction cycle (as partial and completed systems are turned over to the start-up organizations at the construction site for calibration of instruments), to provide water-coolant flow for pumps and rotating machinery, and also to familiarize the operating personnel with the equipment. Under the new 10CFR Part 52 combined licensing process, Section XI does not apply until after the NRC authorizes the fuel loading via the 10CFR Part 52.103g finding. Until then, ASME Section III compliance must be maintained.

There are no accreditation requirements for organizations working under the provisions of Section XI. However, when the ISI work plan calls for replacement of components with Code Symbol–Stamped components or the addition of a complete new system, the rules for Section III and its accreditation requirements apply. The work plan can specify the original Construction Code or any other Code of record.

1.13 CONSTRUCTION CODE–SECTION XI INTERFACES

Owen F. Hedden described ASME Section XI as providing the rules for examinations, test, analyses, and repairs to ensure that structural integrity of the primary coolant pressure boundary is maintained [8]. Whereas all other sections of the Code are directed toward the activities of equipment manufacturers, Section XI is the only mandatory section of the Code that is directed toward the postconstruction activities of the power plant Owner/Operator.

Deardorff et al. state the following about Section XI [9]:

> [It] contains rules and requirements for inservice inspection, testing, evaluation, and repairs to operating nuclear plants. Section XI defines the inspection interval and inspection locations such that fatigue cracking (or other material degradation mechanisms) would be detected in a timely manner. If cracking is detected, then evaluation criteria are provided for determining if continued operation is acceptable, or if repairs/replacements are required.

1.14 REPAIRS AND REPLACEMENTS

Metrow, in ref. [10], describes the development of the Enforcement Authority's involvement in Section XI activities, including review of repair plans. The 1970 Edition contained requirements for a repair program, but details on content were missing, and the summer 1973 Addenda introduced repair pro-grams for reactor vessels only. Section XI combined replacements with repairs until well into the 1974 Edition. The summer 1976 Addenda separated replacements into a separate article: IWA-7000.

The winter 1985 Addenda established the requirement for a documented replacement program. Repair programs were described in the various articles, but it was not until the 1989 Addenda that details of the content, scope, and other aspects intended for inclusion into the repair program were written into one central location.

The A91 Addenda consolidated the replacement requirements from IWA-7000 into IWA-4000. The rules for repair and replacement are located in Section XI, IWA-4000, 1992 Edition. This was done as a result of a feasibility study begun in 1986. Gimple provided an excellent description of the current changes and plans for future revisions in ref. [11].

Significant changes were introduced in the 1992 Addenda that provided alternative requirements in paragraph IWA-4122 for NPS 1 Class 1 piping, tubing (except heat-exchanger tubing, sleeves, and welded plugs), valves, fittings, and associated supports and other criteria described in IWA-4121.

The alternative requirements include exclusions from NCA-3800, Certificate of Authorizations (and, obviously, Code Symbol Stamping), and agreements with AIAs. The Owner's QA Program provides measures for assurance that material is furnished in

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accordance with the Material Specifications and applicable requirements of Section III.

Pressure testing, AIA participation, and completion of the NIS-2 Data Report Forms are not required for the installation of these items.

1.15 BACKFITTING OF NEW CODE REQUIREMENTS ON OPERATING PLANTS

As a result of the "lessons learned" from the Three Mile Island (Middletown, Pennsylvania) accident, many items have been added to operating plants to prevent recurrence of similar events. Unless specified by the NRC, retrofitting is not a code requirement. In fact, many codes and standards clearly state that "this standard is not retroactive." It also should be understood that a plant license is "pegged" to an effective Code, and changes introduced in later Codes are not required by the Construction Code or the plant operating license.

As described in the preceding paragraph, the NRC permits the use of older Codes and Standards. Even today, the Regulatory Authority accepts repair and replacement plans that refer to the original Construction Code. It is therefore imperative that the Code specified for the repairs, replacements, and mandatory backfits be carefully reviewed for acceptability and for impact on the fabrication and installation schedules.

1.16 CAREFUL PREPARATION OF WORK PLANS

It must by now be self-evident that knowledge of the operating plant's effective Codes is of paramount importance in properly selecting original Codes for repair or replacements. Availability of replacement items (material, parts, or components) depends on the continued presence of the original manufacturer or fabricator.

The brief summations of original Codes in this chapter do not provide enough information on specific requirements that would permit the use of reduced requirements on organization certification, material quality assurance, or procedure qualification. Doing so can be achieved only through careful review of the original Construction Codes or by general knowledge of the requirements of current Codes to permit use of later Editions and Addenda.

The two examples shown in Sections 1.18 and 1.19 involve a plant representative for most of the operating plants with construction permits awarded before January 1, 1971. The requirements of the Construction Code were used to justify questions and findings raised by Inspectors during review of the work progress against the work plans.

1.17 CODE RECONCILIATION

In maintaining the operating status of a power plant, it is often necessary to procure material, parts, and components as part of plant repairs and replacements. If like-for-like replacement material, parts, and components can be procured, reconciliation may not be required. However, because nuclear power plants encompass a period of over 30 years, it may no longer be possible to find like-for-like replacements. Both Sections III and XI make provisions for the use of later Editions and Addenda of the Codes because the Codes are revised every year (before the 1986 Edition for Section III and the 1983 Edition for Section XI, they were revised twice each year). Owners are often forced to buy replacement items to the Code currently in effect.

Section III, Divisions 1 and 2, Subsubarticle NCA-1140, permits the use of specific provisions of later Editions and Addenda if all related requirements are met. It also permits the use of existing material procured before the Code effective date for the component with certain provisos. These provisos are: the mutual consent of the Owner or Owner's designee and the N-Certificate Holder, and acceptance of their use must be made by the Enforcement and Regulatory Authorities having jurisdiction at the site. NCA-3554 also requires that the Owner reconcile the Design Report when any modification of a document affects the design.

Since the summer 1976 Addenda, Section XI, IWA-7210(c), requires reconciliation by the Owner of the use of any provisions of later Editions or Addenda not specified in the Design Specifications for design, fabrication, and examination of a replacement. Mechanical interfaces, fits, and tolerances that provide satisfactory performance are not to be changed; moreover, new materials must be compatible with the installation and system requirements. These requirements are now in IWA-4170 beginning with the 1992 Edition. Future revisions to this subsubarticle will clarify the requirements for reconciliation.

Reconciliation has frequently consisted of a detailed and onerous comparison of every revision, however minor, that has occurred between the Code of Record and the Code being reconciled. Each utility is compelled to repeat the reconciliation process for each item. Commercial programs are available to simplify this process.

To the best of this author's knowledge, no U.S. state or any Canadian province has yet objected to the use of any Code Edition or Addenda. Except for the time in which the NRC did not accept the ASME Section XI flaw size, all Editions and Addenda through the 2010 Edition have been accepted by the NRC. NRC staff is completing the technical bases for the amendment to 10 CFR 50.55a to endorse the 2011 Addenda and the 2013 Edition. The proposed rule is scheduled to be finalized and issued in the last quarter of 2014.

1.18 EXAMPLE A: REPAIR OF STEAM-GENERATOR FEEDWATER-NOZZLE CRACKS AT A NUCLEAR PLANT IN THE 1970s[2]

1.18.1 Statement of the Problem

Feedwater nozzles in Westinghouse steam generators were examined under the Southeastern Electric Cooperative (SEC) Section XI program and were determined to have sustained severe cracking that required weld repairs. An IWA-4000 program was written and submitted to the Authorized Nuclear Inservice Inspector (ANII) for approval; preparations for weld repairs were then initiated. A foreign repair organization, not holding any ASME accreditation, was engaged to do the repairs. The weld filler metal was not procured to the requirements of NCA-3800, nor had it been qualified in accordance to Section IX. The ANII, reviewing the progress of the repairs, took the position that the work package did not meet SEC commitments and that the welding did not meet Code. He indicated that a nonconformance should be identified and resolved before he would sign off on the NIS-2 Data Report Form.

[2]In these examples, both the name of the utility and the affected nuclear power plant have been disguised, as well as the names of personnel listed.

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1.18.2 Background

Example Nuclear Plant (ENP) is a Codes and Standards–transition plant because of its licensing chronology. Criteria for material procurement at ENP are dependent on whether the material is intended for components procured by the SEC or intended for components supplied by the Nuclear Steam Supply System (NSSS) vendor under his scope. This position paper will establish the basis for material procurement at ENP for NSSS-supplied components by using the Westinghouse steam generators to represent typical ASME Section III components. The bid specification for ENP was completed in late 1967; the NSSS contract was awarded to Westinghouse on April 18, 1968. Most of the nuclear equipment procured by Westinghouse had a Code of Record of ASME Section III Nuclear Vessels, 1968 Edition.

The construction permit for ENP was granted on October 1, 1969. At that time of nuclear plant construction, the AEC was forced to accept a commercial Code such as USAS B31.1.0–1967 as the Construction Code for power piping. In addition, it accepted B31 Code Cases specifically intended for nuclear applications. The various Code requirements were specified in the Federal Regulations.

The component contracts that Westinghouse awarded resulted in the ordering of items for Westinghouse's scope of supply in mid-1968. This established the 1968 Edition, ASME Section III, Nuclear Vessels as the Code of record for the reactor pressure vessels, pressurizers, and steam generators. The certification sheet of the steam generator stress report states "the 1968 Edition of Section III," which verifies the foregoing assumption.

As for piping, pumps, and valves, the SEC continued its established practice of placing a contract with a piping fabricator. It expanded this contract to cover the procurement of pumps, valves, component and piping supports, and loose material for field fabrication.

The principal piping systems and appurtenances contract at ENP was awarded to National Valve & Manufacturing Company (NAVCO) on August 26, 1970 (SEC Reference No. 71C-37-92615). The USAS B31.7 Code had been approved on August 24, 1969. For main steam piping, the SEC selected B31.1.0–1967 and labeled it as non-QA but specified B31.7 for fabrication and testing for all other piping.

The rest of this discussion will consider the Code of Record for the steam generator as ASME Section III, 1968 Edition. For piping, it will consider USAS B31.7–1969 without Addenda because all B31.7 Addenda were issued after August 26, 1970.

1.18.2.1 Steam Generators: Code Requirements Paragraph N-141, Design Specification only covered functions, loadings, environmental conditions, and classification; no material requirements were addressed. Paragraph N-142, Stress Report also failed to address materials. The Authorized Inspector duties listed in paragraph N-143 included ascertaining that the vessel or part was "constructed in accordance with approved drawings and the Design Specification, using materials complying with the relevant Material Specifications." In paragraph N-144, the manufacturer's responsibility included "that related to the identification of correct materials and valid material certification."

Paragraph N-151 established that the jurisdiction of Section III terminated at the limit of reinforcement given by N-454(b) but not closer to the main shell than the first circumferential joint, exclusive of the connecting weld in welded connections. A further requirement stated that "where connected piping differs from the vessel in nominal thickness or coefficient of thermal expansion, the joint was to be analyzed as a vessel joint."

The connecting weld at the feedwater nozzle bridges a very large difference in nominal thickness between the nozzle and the piping because of the difference in material specified tensile and yield strengths. The nozzle is made of quenched and tempered SA-508 Class 2 material, with an allowable design stress intensity of 26.7 ksi at the design temperature of 600°F. The pipe material is made of SA-333 Grade 6, ASTM A 333 Grade 6, or ASTM A 106 Grade B material, all of which have an allowable design stress intensity of 17.3 ksi. The inverse ratio of stresses results in a calculated pipe thickness 1.5 times the nozzle thickness at the design pressure of 1,085 psig.

The joint needed a transition "dutchman" or a special compound-bore nozzle, wherein the vesselside ID narrowed to the pipe ID using a tapered transition to reduce discontinuity stresses. The SEC chose to transition using an intermediate piece of SA-508 Class 2 material that was shop-welded to the first pipe spool by means of a qualified P3-to-P1 weld procedure specification. The field weld then became an essentially uniform wall-thickness P3-to-P3 weld. If the field weld was within the reinforcement limit, then the weld had to meet Section III requirements. If it was located outside of the reinforcement limits, it was a piping weld and had to meet either B31.7 or B31.1.0 requirements–based on the Code Class listed in the NAVCO contract.

The material requirements in ASME Section III, 1968 Edition, are listed in Article 3, Materials. Paragraph N-310 required that pressure-boundary material or material welded thereto "used under the rules of Subsection A shall conform to the requirements of one of the specifications for materials in Tables N-421, N-422, and N-423. . ." All special requirements of Article 3 applicable to the product form (plate, forging, tube, pipe, etc.) had to be met.

The Material Manufacturer was required to satisfy all the requirements of the Material Specifications and those of Article 3 in addition to certifying the completion of all activities that were performed. The Manufacturer had to include certified reports of any required tests, inspections, and repairs made on the materials (paragraph N-312). Paragraph N-511 required that the vessel manufacturer certify compliance with the special requirements of Article 3 for any activity that was performed, and to certify reports of all tests and examinations that were made on the material.

The requirements for welding material were described in paragraph N-511.3, which specified that tests shall be conducted for each lot of covered or flux-cored electrodes, for each heat of bare electrode and for each combination of heat of bare electrode and batch of flux mix to be used for vessel welding. The tests were required to be made in accordance with paragraph N-511.4 or N-511.5; the results had to conform to the minimum requirements of those paragraphs. Paragraph N-512 (Material Identification) required that pressure-part material carry identification markings until the vessel was completed; therefore, an as-built sketch or a tabulation of materials had to be prepared to identify each piece of material with the mill test report (MTR) or coded marking (if such was used).

Although Section III, paragraph N-512, did not specifically address weld metal identification, paragraph N-523(b) specified that the "manufacturer is responsible for control of the welding electrodes . . . suitable identification, storage, and handling of electrodes, flux, and other welding materials shall be maintained." It was not until the summer 1970 Addenda that any quality programs for materials were specified. The requirements of the new paragraph N-335 were later incorporated in NX-2600 in the 1971 Edition, where they remained until NA-3700 was introduced in the winter 1973 Addenda.

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To summarize, it can be stated that for Section III (Nuclear Vessels), Material Manufacturers did not have to be accredited, material did not have to be manufactured to a written QA program, and the only requirements were provision of the MTR (certifying that the material complied with the requirements of the Material Specifications) and also certification by the material and/or vessel manufacturer that all the special requirements of Article 3 for pressure-boundary material and Article 5 for welding material had been met. Another provision was providing identification of base metal and welding material traceable to the MTR or other test results.

1.18.2.2 Piping Systems: Code Requirements If the first circumferential weld was a piping weld, the applicable Code was USAS B31.7–1969. The requirements for piping were very similar to those of Section III, 1968 Edition, for vessels. Paragraph 700 required a Design Specification; 700(d) required the manufacturer, fabricator, and erector to provide materials complying with the requirements of this Code and Design Specification. Paragraph 700(e) required MTRs to be retained by the Owner for the life of the plant, and paragraph 700.1.4 included the first circumferential weld joint external to the vessel under B31.7's jurisdiction.

Chapter 1-III, B31.7–1969, listed all the requirements for materials for this Code. Paragraph 1-723.1.1 stated that material "shall conform to the requirements of Table 1-724 and Division 1-724 that apply to the material product form." Paragraph 1-723.1.2 required a certification from the material manufacturer that all the requirements of the Material Specifications were complied with and all special requirements of the chapter fulfilled. Certifying that the material met these requirements had to be done, and a certified report of the results of all required tests, examinations, and repairs performed on the materials and their identification had to be included.

Paragraph 1-723.1.3 required each piece of pipe, each fitting, and any component part to be clearly identified, as described in (a), (b), or (c) of the paragraph. Paragraph 1-725.5 described the identification requirements for welding material.

The only references to brittle fracture in B31.7–1969 were found in paragraph 1-723.2.3, which warned about low temperatures, and in paragraph 1-737.3(g), where the standard indicated a warning that hydrostatic pressure tests should be conducted at a fluid temperature of 60°F and higher for material whose resistance to brittle fracture at low temperature had not been enhanced. This requirement was similar to what was traditionally listed in Section I, Power Boilers, and Section VIII, Unfired Pressure Vessels–70°F and 60°F, respectively—for minimum hydrostatic test temperature.

The fabricator and erector were required to certify that the materials used complied with all the requirements of Chapter 1-III, as shown in paragraph 1-727.2. Paragraph 1-727.2 permitted filler metal not incorporated in Section IX to be used if a procedure qualification test was first successfully made in accordance with Section IX.

It was not until the ANSI B31.7b–1971 Addenda, dated April 1, 1971, that Appendix I was introduced. Paragraph I-104.4 described the requirements for C_v-Notch impact testing of welds. It was also in the B31.7b–1971 Addenda that a paragraph was added: 1-727.5.7, which required additional welding qualifications for weld procedure qualification tests for materials with impact test requirements.

USAS B31.7–1969 did not have any requirements for qualification of Material Manufacturers, nor did it have any for written quality control programs. To summarize, the material requirements for USAS B31.7–1969 were less stringent than those for Section III, Nuclear Vessels, 1968 Edition. They required certified MTRs to certify compliance with the requirements of the Material Specifications, and certification by the fabricator or erector that the materials comply with all requirements of Chapter 1-III and of Section IX.

1.18.3 Conclusions

The filler metal used in the connection welds to the steam-generator feedwater nozzle is acceptable under the provisions of Section XI, which permit the use of the original Construction Code for repairs.

The filler metal should be procured in identified containers or spools; the weld deposit should be tested as required by Section III, 1968 Edition, and/or by Section IX; and a welding procedure qualification test should be performed to show successful compliance with Code requirements.

The filler Material Manufacturer's MTR, the certification by the repair organization of the results of the chemical and mechanical tests of the deposited weld metal as meeting the requirements of the Code, and the records of the weld procedure qualification test and welder performance tests for the welders making the feedwater-nozzle welds, should all be presented to the ANII for review before the NIS-2 Data Report Form is accepted and certified.

If the steam generator is not to be subjected to another full-pressure test, the hydrostatic pressure test requirements of Section XI may be used in lieu of the 1.25 times design pressure of paragraph 1-737.4. Alternatively, the helium mass spectrometer test or halide leak test of paragraph 1-737.1(b) (more fully described in paragraph 1-737.1.3) may be used if it is acceptable to the ANII. It would then be followed by a Section XI system leak test.

1.19 EXAMPLE B: ENP-SUPPORT MATERIAL REQUIREMENTS

1.19.1 Statement of the Problem

In reviewing material documentation at the ENP, the ANII identified a problem with piping supports material documentation.

His interpretation of the SEC's material procurement commitments was that material for "load-bearing" supports should be procured with at least the Material Manufacturer's ASME Section III Certificate of Compliance (COC). With the plant attempting to return on line after an extended outage, any delay in establishing a material verification program would have resulted in an unacceptable time delay in the return schedule. This investigation is intended to identify the Code requirements and the applicable SEC commitments, as well as to justify the use of commercial grade material if it is permitted for pipe supports.

1.19.2 Background

Before addressing the resolution of the problems presented by various ENP Problem Evaluation Reports (PERs) on component support materials, it is important to establish the requirements of the Codes and Standards involved, as well as list the commitments made by the SEC's Division of Engineering Design (DED) during the early years of the ENP's construction.

The Codes and Standards first employed in the design and construction of the ENP were ASME Section III, Nuclear Vessels, 1968 Edition, for vessels and pumps, and also USAS B31.1.0–1967 (B31.1.0) for piping and valves. With the publication of USAS B31.7–1969, Nuclear Power Piping, the ENP piping design continued in accordance with B31.1.0. Fabrication and testing in accordance with B31.7 were selected for systems associated with

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the reactor-coolant pressure boundary. Supports for piping and components were not covered in a separate standard as they are today in ASME Section III, Division 1, Subsection NF, Component Supports. Vessel supports were covered by the vessel Design Specification and were constructed with the same rules used for the pressure-retaining component. Large pumps and valves were individually supported, using the design rules associated with vessel supports. Valves and pumps installed in the piping system transferred their weight to the piping and its supports; thus they were included in the design of the piping.

Piping was described in paragraph 100.1.1 as also including hangers, supports, and other equipment items considered necessary to prevent overstressing the pressure-containing parts. Pipe-supporting elements, such as hangers, supports, and structural attachments, were defined in paragraph 100.2 in B31.1.0 and in greater detail in paragraph 120.1. Design rules for pipe-supporting elements were discussed in paragraph 121; this wording was used for the rules of piping supports in B31.7 and was included in ASME Section III, Subsection NF, 1971 Edition, winter 1973 Addenda. The definition of piping moved to paragraph 700.2 in B31.7, which also included the definition for pipe-supporting elements. These definitions are very important to the requirements for material certification and identification (which vary significantly in these two Piping Codes).

In the early years of piping design, the loadings to be considered did not vary significantly and were related to sustained loads from pressure and temperature; from impact forces caused by external and internal causes, such as the effects of water and steam hammer; from natural events such as wind, earthquakes, and vibration; and weight effects from piping, fittings, insulation, snow, ice, and the transported fluid. Unexpected conditions—operator error, equipment malfunction, and limited variations from normal operation (e.g., transients in pressure and temperature)—were evaluated and accounted for by allowances on stresses for various operating periods that experience indicated would not cause damage to the piping requiring repair or replacement.

Because these loadings did not cause major changes of the magnitude of loads, items covered by MSS SP-58 (which were load capacity–rated by the Standard) and mass-produced catalog items (which were load capacity–rated by their manufacturers) were employed to design a load-carrying string or path. These standards and catalogs specified what today are referred to as commercial grade materials; they relied on the integrity of Material Manufacturers and suppliers to guarantee that materials met the minimum properties specified in the Material Specifications. Reporting the results of specified tests to verify the compliance of the material with the Specifications was not required unless it was requested by the purchaser.

Most specifications did not require material identification with the ladle-analysis of the heat from which the product was manufactured. At best, some specifications required marking the material with the specification number and the material type or grade, or else a specific symbol that accomplished the same result as today's COC. The material manufacturer's COC was introduced in the ANSI B31.7c–1971 Addenda, paragraph 1-723.1.2, and the ASME Section III, winter 1973 Addenda, paragraph NA-3767.4(a).

As nuclear plant design became subjected to failure-prevention considerations, many postulated events of low and intermediate probability were added to piping design by the AEC/NRC staff positions (later to the Standard Review Plans). These events required design consideration of loadings of a magnitude never before envisioned by piping analysts: single- and double-ended pipe-guillotine failures, jet-impingement loads, pipe-whip, cold-leg breaks, and so forth. The resulting loads were so large that the "Standard" supports of MSS SP-58 were no longer adequate for use in piping supports, so new, "engineered" support assemblies were designed using large, thick, structural shapes and, with increasing frequency, cold-drawn ASTM A 500 Grade B material and hot-rolled ASTM A 501 square and rectangular pipes. Material requirements changed from medium carbon steels to quenched and tempered low-alloy steels in the 110–160 ksi specified minimum tensile strength levels. Eventually the ASME Code published Code Case 1644, which was divided into two cases in the 1977 Edition and reissued as Nuclear Code Cases N-71 (for welded construction) and N-249 (for nonwelded construction). These Code Cases provided many more high-strength, quenched, and tempered materials than were listed in Tables I-11.1, I-12.1, I-13.1, and I-13.3, all of which are now listed in Section II, Part D, Subpart 1, Tables 1A, 1B, 2A, 2B, 3, and 4.

Much of the change in design philosophy was introduced into B31.7, which adopted the ASME maximum shear-stress design criteria for Class A Nuclear Vessels and Section VIII, Division 2 Nuclear Vessels (Class B) Pressure Vessels for Class I Nuclear Piping. In addition, it adopted more restrictive requirements for materials. In B31.7, paragraph 1-723.1.2, Certification of Materials by Manufacturer and 1-723.1.3, Identification of Materials, no distinction was made between pressure-boundary and structural material, which resulted in significant constraints on support manufacturers. The ANSI B31.7c–1971 Addenda solved the problem by defining a new term—"pressure-retaining material"—in paragraph 1-723.1.1(b), as well as by addressing non–pressure-retaining material in paragraph 1-723.1.1(c), which were both published in a completely rewritten Chapter 1-III. Paragraph 1-723.1.2 defined the COC as the Material Manufacturer's certification that the material complies with the applicable material certification. It also stated that COCs may be supplied in lieu of Certified Material Test Reports (CMTRs) for pipes, tubes, and fittings of $\frac{3}{4}$ in. nominal size and less, as well as for all material to be used as attachments, hangers, supports, and fasteners. Paragraph 1-723.1.3 required identification for pressure-retaining material, but did not address component standard supports or support material. Paragraph 1-723.1.4 provided specific requirements for materials of support and hangers, and exempted other materials from CMTRs and COCs. No such requirements were specified for materials used for piping in USAS B31.1.0, thereby deferring material certification and identification to whatever requirements were listed in the applicable Material Specifications or standards.

1.19.3 SEC Commitments

The first recorded SEC commitment for design and installation of piping systems is in the ENP Preliminary Safety Analysis Report (PSAR), Table 3.2.2-2, and later revisions in the Final Safety Analysis Report (FSAR). This table makes no reference to pipe-supporting elements; therefore, the requirements of the referenced Codes for the piping systems become the initial SEC commitment for the design of, installation of, and materials used for piping supports.

The National Valve and Manufacturing Company's (NAVCO) principal piping contract incorporated the SEC Specification 9923 for principal piping systems and appurtenances for the ENP. Paragraph 2(a) required NAVCO to furnish, fabricate, test, and deliver hangers required for the work. Paragraphs 4(a) and 4(b) listed the piping systems that would be fabricated and tested to B31.1.0 and B31.7, respectively.

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Paragraph 6(a) makes reference to the SEC Standard Hanger Drawings—prefixed G-M-4 in Drawing Series 30W615-1 through -5 (Pipe Supports and Anchors)—whereas paragraph 6(d) describes their purpose. Paragraph 7(c)(2)C addresses "other materials" and appears to indicate that heat traceability and MTRs are required; however, it does not clearly specify that the term "other" includes materials for component supports and component standard supports. The General Notes section of Table 3.2.2-2 (Sheet 1, second paragraph) does identify the reference to B31.7 as including Addenda (a), (b), and (c), so therefore the certification requirements of paragraph 1-723, Addenda (c) for hangers and supports permit the use of COCs when certification is required.

Further clarification on SEC commitments was provided by the DED in a series of memorandums (or letters) issued in 1975 and 1976. One memorandum from D. R. Punter to R. M. Kicker, dated September 5, 1975, addressed certification requirements for integral attachments and component standard supports for ENP Classes A, B, C, and D piping. In this memorandum, the Mechanical Engineering Branch indicated that integral attachments to Class A pipe and Classes B, C, and D impact-tested pipe would require CMTRs and heat-code traceability. On the other hand, for Classes B, C, and D pipe with no specified impact testing, only COCs would be required. Component standard supports would require COCs to MSS SP-58 and the SEC specification. Items excluded by paragraph NF-2121 would not require any Material Manufacturer's COCs.

A memorandum from R. G. Center to R. H. Passer, dated April 20, 1976, established requirements for traceability of material and examination requirements for later nuclear plants. The provisions of the September 5, 1975, letter were repeated; for all other raw support material, traceability in accordance with the Material Specifications was required from the project-segregated warehouse to the mill heat number, but traceability from the warehouse to the installed location was not required. The April 20, 1976, letter also made provision for testing support material not meeting these requirements in accordance with the material's relation to nuclear safety. The ENP was specifically excluded from the provisions of this memorandum.

A later memorandum from R. G. Center to R. H. Passer, dated August 17, 1976, and of the same subject, permitted the use of the provisions of the April 20, 1976, memorandum at ENP. Therefore, the requirements of the original Code of Record still apply.

Finally, the PERs mention "load-bearing" members. This term has been used in documents of the SEC (and possibly that of other licensees) documents. The earliest reference available to the author is a copy of the NRC Information Notice No. 88–95, "Inadequate Procurement Requirements Imposed by Licensees on Vendors." A reference to a manufacturer's QA manual addresses the requirements for "load-bearing" parts of a snubber. However, this term does not exist as a defined term in ASME Section III, Subsection NF, nor is it by itself a basis for review or lack of compliance.

There are many "load-bearing" parts of component and piping support load paths for which no code requirements have been specified. As described in the aforementioned NRC notice, many of these parts are listed in paragraph NF-2121 and are excluded from the requirements of Article NF-2000; as such, they do not require COCs pursuant to the provisions of NF-2130. These parts are and have always been exempted from the requirements of ASME NCA-3800. The exemptions clearly indicate that these parts can be procured as commercial grade items. Component and piping support materials not exempted by NF-2121 may be exempted from NCA-3800, Metallic Material Manufacturer's and Material Supplier's Quality System Program, as permitted by NF-2610 for small products and materials that NF-2130 permits to be supplied with COCs. All these considerations are for information only, for ENP is not required to meet the requirements of Subsection NF.

1.19.4 Section XI Requirements

The requirements of IWA-7220 must also be considered in the replacement of material in existing supports or for installation of new supports. The reason for the installation becomes an important issue in this evaluation.

Although components, parts, and appurtenances are called items in ASME Sections III and XI, so are material and component supports (IWA-9000). Therefore, the provision of IWA-7220 that before authorizing the installation of an item to be used for replacement, the Owner shall conduct an evaluation to determine the suitability of that item. By addressing "failure of an item" that necessitates replacement, the cause of the "failure" must be considered.

When the replacement item is like-for-like and caused only by routine maintenance (such as replacing a fastener during the disassembly and reassembly of a pipe clamp), the evaluation for suitability would only consist of Material Specifications' year-date reconciliation.

When the need for like-for-like replacement is caused by erosion, corrosion, or fatigue failure, for example, replacement without eliminating the cause of failure or making appropriate corrective provisions will only result in a need for future replacement. The corrective action must be consistent with the original Construction Code or the Section III Code in effect at the time of specification revision. The evaluation report becomes part of the Form NIS-2 Data Report.

Supports for piping systems NPS 1 and smaller are exempt from the foregoing requirements.

1.19.5 Compliance with Original Construction Code Requirements

The following position is based on the assumption that the Section XI replacement program work package specifies the original Construction Code and Code Cases as applicable.

(1) For ENP, the certification requirements for replacement material for piping system supports that NAVCO was permitted to fabricate and test to B31.1.0 only need to meet the requirements of the item's Material Specifications. Since the original Construction Code permitted ASTM material, commercial grade material is acceptable as-is if it is ordered to the Material Specifications' year-date originally used. The only evaluation required is a reconciliation to ensure that material manufactured and supplied to later Editions of Codes and Standards meets or exceeds the requirements of the original Material Specifications.

(2) The certification requirements for replacement material of component supports for piping systems that NAVCO was required to fabricate and test to B31.7 are, as a minimum, a COC with the Material Specifications. However, this is not the same COC defined in NA-3767.4(a), for B31.7 only required a statement of compliance with the Material Specifications. Because qualification of Material Suppliers and Manufacturers was not a B31.7 Code requirement, qualification and QA procedures for approved vendor lists only apply if ENP committed to them in their QA Program. If the material is ordered to the same specifications usedas the original Material Specifications, the only evaluation required is a reconciliation to ensure that material manufactured to later Codes and Standards meets or exceeds the requirements of the base Material Specifications. This

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Example Nuclear Plant

CERTIFICATE OF COMPLIANCE

I,_____certify that the material supplied with Purchase
(Name of SEC Engineer)
Order_____Item_____has been dedicated in accordance with SSP 10.5
(Number) (Number)
and we have determined that this material was manufactured in accordance with and meets the requirements of ASTM Material Specification_____
(A or B) (Number) (Year) (Type or Grade)
The material was heat treated in accordance with the requirements of the specified material specification.

_____
(SEC Engineer) (Date)

FIG. 1.1 EXAMPLE OF A PROPOSED SEC CERTIFICATE OF COMPLIANCE

reconciliation can be accomplished by the provision of a vendor-supplied COC or by performing a commercial grade dedication process and, if the material is determined to be acceptable, issuing a SEC COC. A proposed example of such a SEC COC is shown in Fig. 1.1.

1.19.6 Commercial Grade Dedication (CGD)

CGD evaluates the critical characteristics and specifies the required inspection and acceptance criteria to ensure that items dedicated after receipt are acceptable for use as replacement parts. It provides more assurance of the capabilities of the material than what was required by the original Construction Code. For ENP, in which the material could have been originally procured as what is today called "commercial grade," in addition to being supplied to B31.7 with a simplistic COC for meeting the requirements of Material Specifications, the testing and inspection of the CGD clearly can be considered equal to or better than the specified COC.

In any of the preceding cases, if replacement material is procured to different Material Specifications than those of the original support material, a more thorough evaluation is required. This evaluation must prove the functional adequacy of the material, including equal or higher specified tensile requirements, ductility, weldability, and fracture toughness (if specified). To do this task, the SEC evaluation program must include material testing to establish actual mechanical properties. For attachment material, chemical testing is required to establish the chemical composition of the replacement material.

1.19.7 Recommended Disposition of PERs

Procurement of new supports required for a modification will necessitate design, materials, fabrication, and testing commensurate with the original Construction Code or a specified later Code, as permitted by ASME Section XI. Certification requirements for materials shall be specified in accordance with the requirements of that Code.

Procurement of replacement material for existing supports should, as a minimum, meet the requirements of the original Construction Code, the SEC commitments, and the Section XI requirements as described previously.

1.20 MATERIALS PROCUREMENT

Material can be procured to the current Code. Contrary to the perception of many Quality Assurance organizations, it has never been the intent of the NRC to limit material certification to only those specifications listed in Section II, Parts A, B, and C of the Edition and Addenda accepted in 10CFR50.55a. That particular Edition (currently the 2007 Edition with the 2008 Addenda) includes NCA-1140(b), (e), and (f). This inclusion permits the use of later Editions and Addenda as well as earlier Code material. Reconciliation is the key.

Earlier or existing material must be certified to the same specification, grade, type, or class as the material it will replace. In addition, it must meet the minimum specified tensile and yield strengths of the material described in the component's Construction Code. Although ductility (evidenced by reduction of area and elongation properties) does not affect design, it does affect toughness, so it merits evaluation. Changes in chemical composition should be reviewed and evaluated as well.

Material procured to certification year-dates later than those specified in the component's Construction Code must also be reconciled. Technical changes made to subsequent revisions to the specifications should be documented and evaluated.

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On some occasions, Material Specifications are annulled; for example, SA-155, welded-with-filler-metal carbon and alloy steel pipe, was replaced by SA-671, SA-672, and SA-691. Due care must be exercised in procuring this material to ensure that the correct grade and class have been specified.

Material initially used on the basis of a Code Case can be replaced by material listed in a later Edition or Addenda by the use of the Code Case index and documentation of the date in which the Case was incorporated into the Code. Material whose specified strengths have been changed in the Material Specifications can still be used. In the case of a reduction in strength, documentation of the mechanical property test results can be shown to meet the effective Code's specified strength levels. If the specified tensile and yield strengths have increased, the new material is inherently qualified.

1.21 MATERIALS DOCUMENTATION

Before the winter 1973 Addenda, the terms CMTR and COC were not used in the Code. Material Specifications required, or else provided, that when requested by the purchaser, the results of all tests and examinations would be supplied with the material. This record was (and still is) referred to as the MTR.

There are two basic documents specified by the Code for materials: the CMTR and the COC ("materials" include pipe made from sheet or strip rolled and welded without the addition of filler metal, as in autogenous welding). The contents of a typical CMTR are described in Section III, Division 1, Appendix P. Welded-with-filler metal-type pipe requires fabrication under an NCA-4134 QA Program for an N-Type Certificate Holder; the application of an NPT-Code Symbol Stamp; and the completion, certification, and submission of the NM-1 Data Report Form. Nameplates, however, are not required.

Not all Material Specifications require heat traceability. For replacement items and for upgrading "stock material," this author believes that traceability is necessary to prevent material-identification problems later. The Owner's QA Program assumes the responsibility for acceptability. Without traceability, a significant cost will be incurred in qualifying unidentified material.

1.22 COMPONENT PROCUREMENT FOR REPLACEMENTS

Anyone can order a component. The reason is that a component is a stand-alone item. Its data package must include the following:

- The Owner's Certified Design Specification.
- The Manufacturer's Certified (if required) Design Report.
- The documentation of the Owner's Review of the Design Report (if applicable).
- The appropriate Data Report Forms.
- All required permanent and nonpermanent records.
- Certifications specified in NCA-4134.17.

The component can be ordered to any Code, as described in NCA-1140 and IWA-4140. Because of the rapidly diminishing manufacturers still retaining their Certificates of Authorization, the NRC has issued guidelines for use of commercial grade dedication items, or CGD. CGD programs are becoming increasingly important to operating utilities, but discussion is beyond the scope of this chapter. Some aspects of a CGD program are included in Example B (Section 1.19).

1.23 USE OF SPECIFIC PROVISIONS OF LATER EDITIONS AND ADDENDA

The nature of the rules and the definitions of nuclear power items are included in subsubarticles NCA-1110 and NCA-1120. NCA-1130(a) limits the scope of the rules to *new construction*. It requires consideration of mechanical and thermal stresses caused by cyclic operation. NCA-1130(b) lists one of the important sets of exclusions from the rules of Section III. Exempted are valve operators, controllers, position indicators, pump impellers, pump drivers, and other accessories and devices that are not pressure-retaining. Also exempted are intervening elements used as component or piping supports; instruments and permanently sealed fluid-filled tubing systems furnished with instruments; and instrument, control, and sampling piping unless they are specified as Code items in the Design Specifications.

Before the winter 1977 Addenda, the Code of Record for a component was the Code in effect on its order date. The summer 1977 Addenda made provisions for Division 2 Components. The winter 1977 revision permitted the Owner to specify one Edition and Addenda of the Code to be used for all components at a plant site. The date that the Owner chooses for his or her plant cannot be any earlier than three years before the docket date of the construction permit application. The change allows duplicate nuclear plants at the same site (or replicate plants at different sites—even with different Owners) to be built to the same Code within a three-year umbrella period between nuclear plant PSAR filings. The NRC has increased the umbrella to five years, but the Code has not. NCA-1140 still allows updating by means of Code Cases or the use of specific provisions from later Editions and Addenda. It recommends discussing these uses with the Enforcement and Regulatory Authorities having jurisdiction at the nuclear plant or shop site.

NCA-1140 was revised in the winter 1981 Addenda to make provisions for the use of existing material previously produced according to Code Editions and Addenda earlier than the one specified for construction of an item.

1.24 NUCLEAR CERTIFICATION PROGRAMS

The ASME provides a service for any organization applying to it for nuclear certification to perform activities in compliance with the rules of the ASME B&PV Code Section III, Divisions 1 and 2.

By 1971, Section III of the B&PV Code had been expanded to cover piping, pumps, valves, and storage tanks. In 1972, procedures were in place, and three-year certificates were being issued by the Subcommittee on Nuclear Certification, which was formed to review the reports of the nuclear survey teams. In the winter 1973 Addenda, Section III was expanded further to include core-support structures and component supports, as well as to provide for Code coverage of Material Manufacturers and Suppliers.

Around 1973, the nuclear approach spread into the non-nuclear certification program; by 1974, the Subcommittee on Code Symbol Stamps began reviewing reports by jurisdictional authorities or the National Board of Boiler and Pressure Vessel

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Inspectors accompanied by representatives of the Authorized Inspection Agencies.

By 1982, the Subcommittee on Nuclear Certification was renamed the Subcommittee on Nuclear Accreditation (SCNA) and then by 2009 was renamed the Committe on Nuclear Certification (CNC); the Subcommitteee on Code Symbol Stamps was renamed Boiler and Pressure Vessel Accreditation (SCBPVA) and by 2009 was renamed the Committee on Boiler and Pressure Vessel Conformity Assessment (CBPVCA). Both committees reported originally to the Boiler and Pressure Vessel Main Committee; they were supervised, respectively, by the Board on Nuclear Codes and Standards and the Board on Pressure Technology Codes and Standards. Since 1996, both subcommittees have been supervised by the Board on Accreditation, Registration and Certification that, in March 1999, was renamed the Board on Conformity Assessment (BCA).

The requirements that must be followed by organizations seeking nuclear certification are detailed in NCA-8100. The evaluation of these organizations' QA Programs is performed by survey teams who report the survey and audit results to the CNC, and results of reviews to the CBPVCA for approval action, and issuance of Certificates.

1.24.1 Types of Nuclear Certificates

Prior to the 2010 Edition, there were four types of Certificates available: the Certificate of Accreditation, the Quality System Certificate, the Certificate of Authorization, and the Interim Letter. The Interim Letter was terminated in the 1998 Edition and replaced by a Certificate of Accreditation. In the 2010 Edition, a change in terminology took place throughout Section III eliminating the term "Accreditation" in reference to ASME Certificates. All ASME N-Type Certificates (N, N3, NV, NA, NPT, and NS) are now issued as "Authorizations" (with or without stamps), the Owners Certificate is issued as an "OWN Authorization" and a new Quality Assurance Program Certificate was established to replace the Certificate of Accreditation where the survey involved only the review and acceptance of the Quality Assurance Program and there was no Quality Assurance Program demonstration (old Interim Letter). All certificates are issued for a period of three years.

1.24.1.1 Owners Certificate of Authorization (OWN) As indicated in NCA-3230, this Certificate is available to a utility after they receive notification from the regulatory authority that their application for a construction permit or combined license for a specific plant site has been docketed. The Owners Certificate is required to be obtained prior to beginning field installation and a written agreement with an Authorized Inspection Agency (NCA-8130) is required prior to application. In lieu of a survey, the Owner is interviewed to verify the Owner's understanding of Code responsibilities (NCA-3220) and to obtain the Owner's agreement to meet those requirements. The Owner's Certificate is issued for a three year period and is renewed based on ASME review of the results of AIA audits of the Owner's Quality Assurance Program. The Owner's Certificate expires when all N-3 Data Reports for the units listed on the Owners certificate have been completed. As of August 2013, four (4) utilities had Owners Certificates, which permit control of one or more subcontractors holding the appropriate Certificates of Authorization that are required for the activities they perform. In addition, the Owners Certificate permits certification and filing of the Owner's Data Report Form N-3 after completion of Code Construction.

1.24.1.2 Quality System Certificate (QSC) The next type of certificate is the Quality System Certificate (QSC). It is awarded to the Material Organization who manufactures material and to the Material Organization who supplies material.

In 1975, these certificates were called the Material Manufacturer (MM) and Material Supplier (MS) certificates. They were intended for Material Manufacturers and supply ware-houses and, moreover, did not permit welded ASME III fabrication. The scopes also provided for suppliers who were capable of performing some of the activities usually associated with Material Manufacturers. The rules in NCA-3800 were completely revised in the 1994 Addenda. On July 1, 1995, these certificates began to be phased out, as provided in Code Case N-540, and after July 1, 1998, the only QSCs issued by the ASME are for Material Organizations. There were 114 Quality System Certificates issued as of June 2013. 74 were located outside of the United States and 40 were located in the United States.

1.24.1.3 N-Type Certificates of Authorization (N, N3, NV, NA, NPT, and NS) The next category is the N-Type Certificate of Authorization. There are six N-Type Certificates in this category, each providing ASME Authorization to perform a specific scope of work and to either certify with Code Symbol Stamping signifying compliance with the ASME III Code rules for construction or to certify without Code Symbol Stamping signifying compliance with the ASME III Code rules for construction. They are the N-Certificate Holder, the NA-Certificate Holder, the NPT-Certificate Holder, the NV-Certificate Holder, the NS-Certificate Holder, and the N3-Certificate Holder. The ASME Nuclear Component Certification program covers the following equipment and activities under Section III of the ASME Boiler and Pressure Vessel Code:

N	Nuclear vessels, pumps, valves, piping systems, storage tanks, core support structures, concrete containments, and transport packaging
NA	Field installation and shop assembly
NPT	Fabrication, with or without design responsibility, for nuclear appurtenances and supports
NS	Nuclear supports
NV	Pressure relief valves
N3	Containment for spent fuel and radioactive waste

Before the 1977 Edition, the N-Certificate Holder was called the Manufacturer; the NA-Certificate Holder was called the Installer, and the NPT-Certificate Holder was called the Fabricator. Additionally, there were Corporate Certificates of Accreditation, which are now issued as Certificates of Authorization (Corporate), for corporate type QA Programs where a corporate office would perform code activities such as engineering, procurement, and/or QA under the Corporate Certificate (N-xxxx) and a shop or field site would complete the balance of code activities, typically hardware activities, under an extended certificate issued as a Certificates of Authorization with a dash number (N-xxxx-1, etc) off of the Corporate Certificates of Accreditation.

A new certificate, the Nuclear Support (NS) Certificate, was authorized in the 1998 Edition, 1999 Addenda, by the Subcommittee on Nuclear Power (SCIII). This certificate is intended to resolve the problem created when the Code introduced Subsection NF (Component Supports) in the winter 1973 Addenda. The winter 1975 Addenda established the requirement

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for NPT-stamping of any welded support, but it made no provisions for manufacturers who supplied standard supports as material under the provisions of paragraph NF-1214. These companies still have design responsibility; however, the only certificate available was the Material Supplier and (now) the Material Organization (MO). This certificate had no requirements for Design Control. Many stop-gap actions were required to permit Material Organizations to supply standard supports such as mechanical snubbers which ultimately led to the establishment of the NS Certificate. The new NS certificate requires an agreement with an AIA and is limited to the construction of supports intended to be in compliance with the requirements of ASME Section III including piping and standard supports (both welded and non-welded). Additionally, the NS Certificate Holder may provide a Design Specification for standard supports in accordance with NCA-3256(b) and, when required, prepare design output documents for standard supports in accordance with NCA-3550. Nameplates and stamping of welded supports are no longer required.

All ASME N-Type Certificates (N, N3, NV, NA, NPT, and NS) are now issued as "Authorizations" (with or without stamps). ASME began issuing these new certificates in August 2010 after the 2010 Code Edition was published. The N-Type Certificate scope can describe activities performed in other locations. An organization can hold an N, N3, NA, NPT, NS and/or NV Certificates of Authorization (Corporate) at its headquarters office and, in addition, the certificates can be extended as Certificates of Authorization to other locations such as a nuclear plant site, including the headquarters address if hardware activities are performed there. They can also be issued individually to a nuclear plant site or plant location. The scopes of N-Type certificates can permit the holder to perform Material Organization activities and supply or manufacture and supply material [NCA-3820(c)]. Code Symbol Stamps are not provided with Certificates Authorization where a full QA Program demonstration was not provided to an ASME survey team such as Certificates of Authorization (Corporate) or Quality Assurance Program Certificates. A contract with an AIA for the services of an ANI and an ANSI is required for all ASME N-Type Certificates (N, N3, NV, NA, NPT, and NS) except the services of an ANI are not required for the NS Certificate.

As of August 2013, there were 877 N-Type certificates issued, 502 of which were outside the United States in 24 countries and 375 were in the United States. There were 231 Total N certificates; 141 total NA certificates; 315 total NPT certificates; 10 total NV certificates; 159 NS certificates; and 21 N3 certificates.

1.24.1.4 Interim Letter The last category of certificate was the Interim Letter. Now phased out, this certificate permitted an organization with an approved QA Program to apply to the ASME for a survey, even though the organization might not be able to demonstrate the proven capability to implement the program. An agreement with an AIA was required.

The Interim Letter was usually applied for by a company wishing to advertise their desire to secure nuclear business, but not having any work in progress, was unable to run a commercial order for an item as if it were a nuclear order or to put together a hardware demonstration under their QA Program. All the requirements of the QA Program had to be implemented for a Certificate of Authorization. Interim Letters required application to ASME and a Survey Team review of the QA Program for initial issuance. They were issued for one year, and could be renewed annually by mail by request to the ASME. This process was limited to two renewals; a third required another Survey Team review of the QA Program. Renewal applications had to be submitted at least 90 days before each annual renewal and not less than 6 months before to the third renewal expiration date. Deposit fees for renewal surveys were required. Those companies holding Interim Letters were issued Certificates of Accreditation which have now been replaced by the Quality Assurance Program Certificates. They must apply for renewal of their Certificate when their certificate expires. The Interim Letter (NCA-8162) was eliminated in the 1998 Edition and replaced by the Certificate of Accreditation and the Certificate of Accreditation for this purpose was eliminated in the 2010 Edition and replaced with the Quality Assurance Program Certificates. Interim Letters have not been issued since the 1998 Edition came into effect. They were issued for one year. The replacement Certificate of Accreditation and now the Quality Assurance Program Certificate, however, is issued for a three-year period.

1.24.2 Issuance and Renewal of Certificates

A construction permit or docket date issued by the NRC is a prerequisite for the initial issuance of an Owner's Certificates of Authorization. These certificates are renewed based on ASME review of the results of AIA audits of the Owner's Quality Assurance Program. Renewal application should be submitted at least 90 days before expiration. An administrative fee is required for each certificate.

All other certificates require an application to the ASME for initial issuance. For renewal, the application must be made at least 6 months before their date of expiration. A minimum specified deposit is required also subject to receipt by the application deadline.

1.24.3 Certification Process

The process of certification is the same for initial issuance as it is for renewal of an existing certificate, with the exception that the initial application is made after the ANIS (or a Quality System Certificate Holder's staff or subcontracted consultant) is satisfied that the organization is ready. Applications for renewal must be made as described in the preceding paragraphs. The process is somewhat different for the various certificates.

Application for initial issuance of the Owner's Certificate results in the applicant being interviewed by an ASME Interview Team, which typically consists of an ASME Team Leader the AIA's Repsentative and the Jurisdictional Authority. In a case in which there is no jurisdictional authority, the jurisdictional authority elects not to participate, or the jurisdictional authority is also the AIA, a National Board representative is used for the Interview Team. The jurisdictional authority is not included on surveys located outside the United States and Canada. Renewal may be made as described previously.

Applicants for QSCs generally supply and manufacture materials; until the 1999 Addenda, they were able to supply and manufacture standard supports. Application for initial issuance or renewal results in a scheduled survey by an ASME Survey Team consisting of an ASME Team Leader and an ASME team member. A minimum of two annual unannounced audits are performed by a Team Leader who can be either of the original team members. A number of random unannounced audits are also assigned by staff.

Application for initial issuance or renewal of Certificates of Authorization result in the applicant being surveyed by an ASME Survey Team typically consisting of an ASME Team Leader, an

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ASME team member, a National Board representative, the AIA personnel (ANIS and ANI), and the Jurisdictional Authority.

On resurveys, the Team Leader may be a member of the original ASME team. The National Board member should preferably be the original team member.

Application for initial issuance or renewal resulted in the applicant being surveyed by an ASME Survey Team typically consisting of an ASME Team Leader, a National Board representative, and the AIA personnel.

The jurisdictional authority is generally invited by the ASME. On resurveys, the Team Leader may be any ASME member of the original team. The National Board member should preferably be the original team member, and a utility representative may be assigned by staff.

1.24.4 Scope of the Survey

Issuance or renewal of Certificates is accomplished by completing a successful survey performed by an ASME team that includes the following:

(1) review for approval of the QA Manual describing the program;
(2) review for acceptance of a demonstration for implementation of the program;
(3) receiving a favorable recommendation from the ASME Survey Team to the CNC for renewal of the certificates;
(4) successful completion of the CNC ballot process;
(5) notification by ASME Conformity Assessment staff of the ballot process results and submittal of all invoices;
(6) payment of all outstanding invoices, including costs of N-symbol stamps, where applicable; and
(7) receipt of certificates.

Failure of the renewal survey would require a resurvey, with potential loss of certificates during the process unless all required steps are met.

1.24.5 Contractual Requirements with an AIA

All certificates other than the QSCs require an agreement with an AIA to provide third party inspection using one or more ANIs, as required, supervised by an ANIS. QSCs are not subject to third party inspection, and the duties for review and acceptance of changes to the QA Manual are assumed by the ASME.

The applicant's or Certificate Holder's ANIS and ANI (for an N-Type Certificate) participate with the ASME Survey Team in the review of the QA Program. Observers will frequently be part of the team, as it is necessary to provide training to prospective ASME survey team consultants and nuclear inspectors. New members of the CNC must participate in one nuclear survey during the first two years of their appointment. Inspection personnel must also meet the minimum number of surveys required for commission.

1.24.6 Manual Revisions and Audits of QSCs

Manual revisions for QSC Holders must be submitted to the ASME for review and acceptance by a member of the Survey Team. Changes to the program should not be implemented before ASME acceptance of the changes. QSC organizations are subject to at least two unannounced audits by the ASME during the intervening three years between surveys. During the audits, all changes to the manual are subject to verification and implementation.

1.24.7 References to Applicable Codes

(a) Certification requirements:
  (1) QSC Certification: NCA-3800.
  (2) Other Certificate Holders: NCA-8000 and IWA-8000.
(b) QA Program requirements:
  (1) QSC Holders: NCA-3800.
  (2) Other Certificate Holders: NCA-4000, IWA-4000, and ASME QAI-1.
(c) Duties and responsibilities:
  (1) Certificate Holders: NCA-3000.
  (2) Authorized Inspection: NCA-5000 and ASME QAI-1.

1.24.8 Typical Nuclear Survey

The applicant notifies the ASME of his or her intent to seek Certification. The ASME staff then sends the applicant an application packet that includes a questionnaire and information on required fees. The applicant completes the forms and submits them with a check for the appropriate dollar amount to the ASME. The ASME staff reviews the availability of survey personnel and provides the company with a proposed date for the survey. The applicant has the option to accept the date or ask for a later date. The applicant also recommends to staff the hotel facilities most appropriate to the plant location. The ASME staff then submits an information letter announcing the designated team membership, the dates for the survey, and the time that the QA Manual submitted for approval and the completed survey checklist (and the number of copies needed for the team) should be available at the team's hotel. The application packet also includes a letter that describes the confidentiality of the survey.

The team meets at the hotel, reviews the QA Manual for compliance with ASME Section III requirements, makes notations where deficiencies are observed, and makes recommendations for revision. Particular attention is paid to the organization chart, the references to the listed personnel in later sections of the QA Manual, and the presence of controls for the activities included in the QA Program. The Team Leader assigns areas for implementation review to the other members of the team, including observers if any are present. He or she also reserves areas of implementation review for him- or herself and the ANIS. At the conclusion of the Manual review by the team, he or she contacts the applicant and arranges for an entry meeting.

It is recommended that senior managers of the applicant's organization attend the meeting with the Survey Team. Doing so shows interest in the viability of the QA Program and helps educate the management on the involvement of the ASME in its Certification programs.

At the entry meeting, the Team Leader introduces the team, then describes the scope of the Survey. The requested scopes of the certificates are discussed with the applicant to ensure that they represent the activities for which the company seeks accreditation. The Team Leader also spends time on the confidentiality ramifications of the process and recommends that questions be asked whenever the applicant's personnel finds a situation confusing. A list of the areas for which personnel are assigned for implementation review is presented; the applicant is requested to provide guides to take the team members to the locations where the activities are being performed. The team then requests a tour of the facility to become oriented with it. After the tour, the Team Leader and the ANIS meet with the QA Manager and his or her staff to review any deficiencies

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in the QA Manual and to accept any of the applicant's recommended dispositions, as well as to ask any questions that were raised by the team during the Manual review. The other team members and their guides depart to perform the implementation review. The Team Leader annotates the agreements in his or her copy of the Manual, then requests that the QA Manager have a corrected version of the Manual ready for his or her and the ANIS's review the next day. The Team Leader and the ANIS then join the implementation teams and audit their assigned areas of responsibility.

At the end of the day, the team members caucus in a room reserved for their use by the company to discuss the results of their audits, including any findings. If further changes are required in the QA Manual, they are brought to the attention of the QA Manager. The following morning, the Team Leader and the ANIS review the revised QA Manual and compare it with the Team Leader's copy. If it is found acceptable, the ANIS signs off on the cover sheet, and the revision level and date of the Manual are recorded. The Team Leader and the ANIS again join the rest of the team personnel in the implementation review. At a designated time, the team members meet to determine if the reviews have been completed and to complete QD forms for detected quality deficiencies, if required (including corrective actions taken to close out deficiencies), and personnel training, if also required.

Occasionally, the team finds a company inadequately prepared and subject to failing the survey. The Team Leader will offer the company the opportunity to abort the survey. If the company agrees, the ASME staff is consulted and must concur with the action before the survey is aborted.

The team votes on whether to recommend a certificate for issuance; if the team decides not to recommend issuance, it recommends a resurvey. The Team Leader notifies the QA Manager of the time for an exit meeting. Generally, most personnel in attendance at the entry meeting participate in the exit meeting. At this meeting, the Team Leader discusses the results of the survey and reports the team's recommendation. He or she again discusses confidentiality, then asks for any questions. When the meeting is concluded, the team members depart for their residences or possibly to other surveys.

In foreign countries, the team expects to see a translation into English of the QA Manual and any procedures required for the implementation review. If translators are required, the applicant provides them at his or her expense. The final copy of the Manual is translated from the applicant's native language into English, and the team must be satisfied that the English translation and the original are compatible. Foreign surveys frequently take longer because of the language barrier.

1.24.9 New Developments in ASME Accreditation

One of the more important changes to the Code is the required accreditation of Authorized Inspection Agencies. The nuclear AIAs were accredited under ANSI/ASME N626, Part 4, during 1993. Its replacement, QAI-1–1995 (Qualification for Authorized Inspection) included Part 5 and was issued July 1, 1995. It requires accreditation of AIAs who provide inspection services to nonnuclear organizations when the applicable Codes adopt QAI-1. The Main Committee of the N626 Committee on Qualifications and Duties for Authorized Nuclear Inspection and Specialized Professional Engineers took the action to have SCNA (predecessor to CNC) handle the review and acceptance of Survey Team Reports during an interim period. This activity is now handled by the QAI Subcommittee on AIA Accreditation.

In June 1993, the Council on Codes and Standards changed the Board on Accreditation and Certification (BAC) from an Advisory Board to a Supervisory Board, renaming it the Board on Accreditation, Registration, and Certification (BARC) when it was given responsibility over the ISO Registration Program. In 1999, the name was again changed; it became the Board on Conformity Assessment (BCA). In June 1994, the Council also stipulated that the N626 Committee move from under the Board on Nuclear Codes and Standards to the BARC. The N626 Committee changed its name to the Committee on Qualification for Authorized Inspection (QAI). The QAI Committee now reports to the BCA. At present, the CNC and CBPVCA report to the BCA, as do many other Code accreditation committees. The Standard N626.3–1993 was assigned to Section III and was published as Appendix XXIII in the 1996 Addenda.

Further problems in certification have been caused by an NRC position that holds the ASME Survey Teams responsible for performing programmatic audits, and its position that the ASME survey system is not adequate to properly evaluate implementation. The NRC Staff letter requires utilities to audit their suppliers even though they may be Certified by the ASME. This resulted in a new organization formed in 1989, the Nuclear Utilities Procurement Issues Committee (NUPIC), which has established qualified auditors to perform cooperative audits on behalf of member utilities to meet this additional NRC auditing requirement. It is believed that this is also a fallout from the many problems encountered in the past 20 years with some organizations that hold ASME accreditation who have supplied false and substandard material. NUPIC audits are not acceptable to ASME as a means of meeting the audit requirements of NCA-4134.18.

A recent development was the passing of Code Case N-549 (Stamping and Flow Certification of Rupture Disk Devices, Classes 2 and 3). The Code Case included provisions for the accreditation of manufacturers of these items and also proposed the use of an "ND" stamp and Data Report Form similar to the existing NV Certificate of Authorization. The BCA had no rules prepared for this action, so the implementation of this Code Case has been suspended. (The requirements will be available in the near future.) The BCA has ruled, however, that only changes to a Code or a new Code (but not to Code Cases) can start a new accreditation program.

In the 2010 Edition, a change in terminology took place throughout Section III eliminating the term "Accreditation" in reference to ASME Certificates. All ASME N-Type Certificates (N, N3, NV, NA, NPT, and NS) are now issued as "Authorizations" (with or without stamps), the Owners Certificate is issued as an "OWN Authorization" and a new Quality Assurance Program Certificate was established to replace the Certificate of Accreditation where the survey involved only the review and acceptance of the Quality Assurance Program and there was no Quality Assurance Program demonstration (old Interim Letter). All certificates are issued for a period of three years. ASME's product certification programs have grown dramatically. Starting with just two countries in the years prior to 1972, there are now 74 countries in which companies have been certified. ASME is proud that the value of these certification programs has been so widely acknowledged, and that ASME is playing this increasingly vital role in fostering product safety and international commerce.

The growth of these programs has presented many new opportunities, but also some challenges, especially regarding how to maintain the trademark registrations of ASME's 28 separate product certification marks across the more than 100 nations in which these marks are currently used on products.

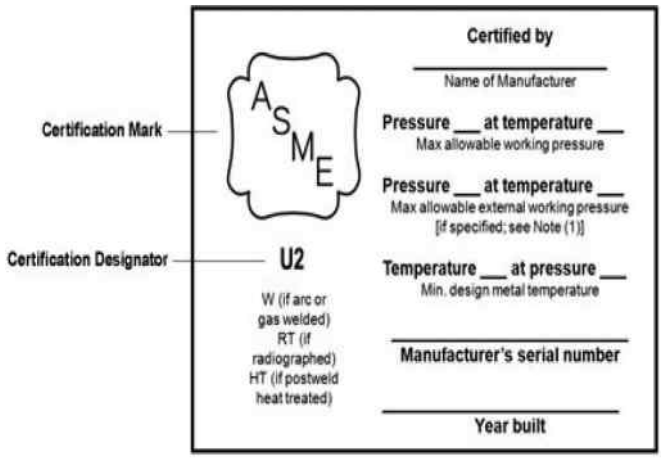
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In order to streamline ASME's multiple marking processes and more effectively manage ASME's numerous global relationships; ASME announced the introduction of a new single product certification mark in the 2011 Addenda to the 2010 Edition of the B&PV Code:



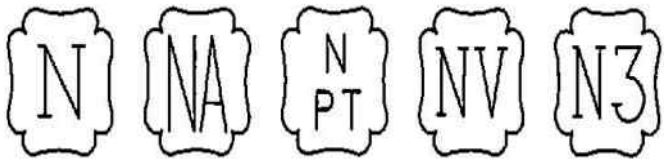
New ASME Product Certification Mark

Instead of 28 separate ASME product certification marks, there will now be this single comprehensive mark. To maintain a link to the current marks, the new mark will be used in conjunction with a "certification designator" to indicate the applicability of the certification. The following is an example of how the new mark would be used on a nameplate (in this case for a vessel constructed to Section VIII, Division 2):



Sample ASME Product Certification Nameplate

For Section III work, the new single ASME Certification Mark, accompanied by the appropriate Nuclear Designator required by NCA-8000 or WA-8000, replaces the ASME Code Symbols shown below:



To facilitate the introduction of the new single ASME Certification Mark for ASME III work, Code Case N-822-1 was issued documenting ASME's position that the ASME Certification Mark with the appropriate Nuclear Designator is equivalent to the corresponding N, NA, NPT, NV, and N3 Code Symbols; that the ASME Certification Mark with the appropriate Nuclear Designator as required in the 2011 Addenda or the 2013 Edition may be used for construction to Section III Editions and Addenda prior to the 2011 Addenda; and that the N, NA, NPT, NV, and N3 Code Symbols may be used only through December 31, 2014. The December 31, 2014 date was chosen in anticipation that the NRC would complete their 10CFR50.55a rule making to accept the 2011 Addenda and the 2013 Edition by that date.

With the publication of Section III, Division 3 (Containment Systems for Transport Packaging) in 1997, a new accreditation program has been initiated providing for the N– and NPT–Class TP (now TC) Certificate of Authorization for manufacturers of these casks. As of August 2013, there were 20 companies holding N-Type–Class TC Certificates of Authorization.

In the 2001 Edition, Division 3 eliminated the "Design Owner" and the "Packaging Owner," established the "N-3 Certificate Holder," changed Class TP to TC, and made provisions for a new Class SC, for storage containments. A new subsection, WC, providing rules for these containments, has been approved as Code Case N-717, and was published in Supplement 1 to the Nuclear Code Case Volume in late 2004 for use and experience. Subsection WC was published in the 2005 Addenda to the 2004 Edition of Section III, Division 3, and is now in effect.

1.25 GLOBALIZATION

As mentioned previously in this chapter, ASME accreditation has been available outside the United States since the 1960s. Nuclear activity in the form of new construction of nuclear power plants is now limited to countries in the Pacific rim and Finland. Figures 1.2 and 1.3, prepared by the ASME Conformity Assessment Department, detail the numbers of companies and certificates (including nuclear certificates) in the United States and Canada. Figures 1.3 through 1.10 do likewise for North America as a whole, as well as countries in South America, Europe, the Middle East, Eastern Asia, Australia and Africa. Countries that currently have companies with one or more nuclear certificates are listed alphabetically in Figure 1.11. Figure 1.12 reviews the distribution of certificate holders and the number of current certificates in the U. S. A., Canada, and International. Finally, Figure 1.13 is a summary of Code Symbol Stamps by Code sections in the U. S. A., Canada, and International. All these figures and statistics are effective as of August 2013.

Currently, ASME is actively engaged in establishing relationships on an international basis to permit the use of the ASME Certification process throughout the entire world. This effort is already underway with the metrication of many ASME Standards, and in de-nationalizing the requirements of the ASME Codes. The Council on Codes and Standards has established a Task Group to study the question to permit the Board on Conformity Assessment and the QAI Committee to develop rules. These rules will define Authorized Inspection Agencies beyond the current limitation to a jurisdiction (State of the United States and Province of Canada) that has adopted and administered one or more sections of the code as legal requirements within its territorial jurisdiction, and was qualified to be represented on the ASME B&PV Code Conference Committee, or an insurance company that had been authorized by the government of a state or province to write boiler and pressure vessel insurance within its territorial jurisdiction. This work is

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progressing and we are seeing results immediately, with the requirements for qualification of Registered Professional Engineers moving from the ASME N626.3-1993 Standard to Appendix XXIII in Section III, and the requirements for the ANII moving to an Appendix of Section XI. International Material Specifications are being approved and published in Section II and the Stress Tables, and more projects will be completed in the near future.

The Board on Nuclear Codes and Standards has been engaged actively in meetings with delegations from other countries who are interested in adopting the ASME Boiler and Pressure Vessel Code, at least for its technical requirements. The administrative requirements that currently prevent this from occurring are being defined, so that they can be separated from the technical requirements. The adopting country will then be able to replace the administrative requirements with their own rules. Members of the BNCS have met with representatives from Canada, China, Finland, France, India, Korea, South Africa and Sweden. Finland is in the process of building a new nuclear plant. Spain has 6 BWRs and PWRs; UK has Sizewell B; Japan has a large number of BWRs and PWRs; South Korea a large number of PWRs; Taiwan has 8 BWRs and PWRs; China has a Pebble-bed Research Reactor; Slovenia has the Krsko BWR; Brazil has Angra 1; India has the Tarapur plant; and South Africa is building the PBMR Demonstration Plant.

In a further effort to globalize the ASME Boiler and Pressure Vessel Code, the 2004 Edition has been published in Hard Metric format, and the Stress Tables of Section II, Part D, have been published as a separate, metric volume. In addition, the QME Standard is being converted to Soft Metric, and the O&M standard has been converted to Hard Metric. International membership on Codes and Standards Committees has increased. We now have Canadian, French, and Japanese participants in Boiler and Pressure Vessel committees; Canadian, Japanese, Russian, Korean and UK members in Section III; Canadian and Japanese in Section XI; Japanese and Spanish in O&M; Canadian and Japanese in the QME; UK in the CNRM; French, UK, and South African in the Project Team for Graphite Core Supports; and Japanese participants in the System Code Project Team.

On October 13, 2004, the US DOC (Department of Commerce) formally announced that the Consortium on Standards and Conformity Assessment has been awarded an MDCP grant to

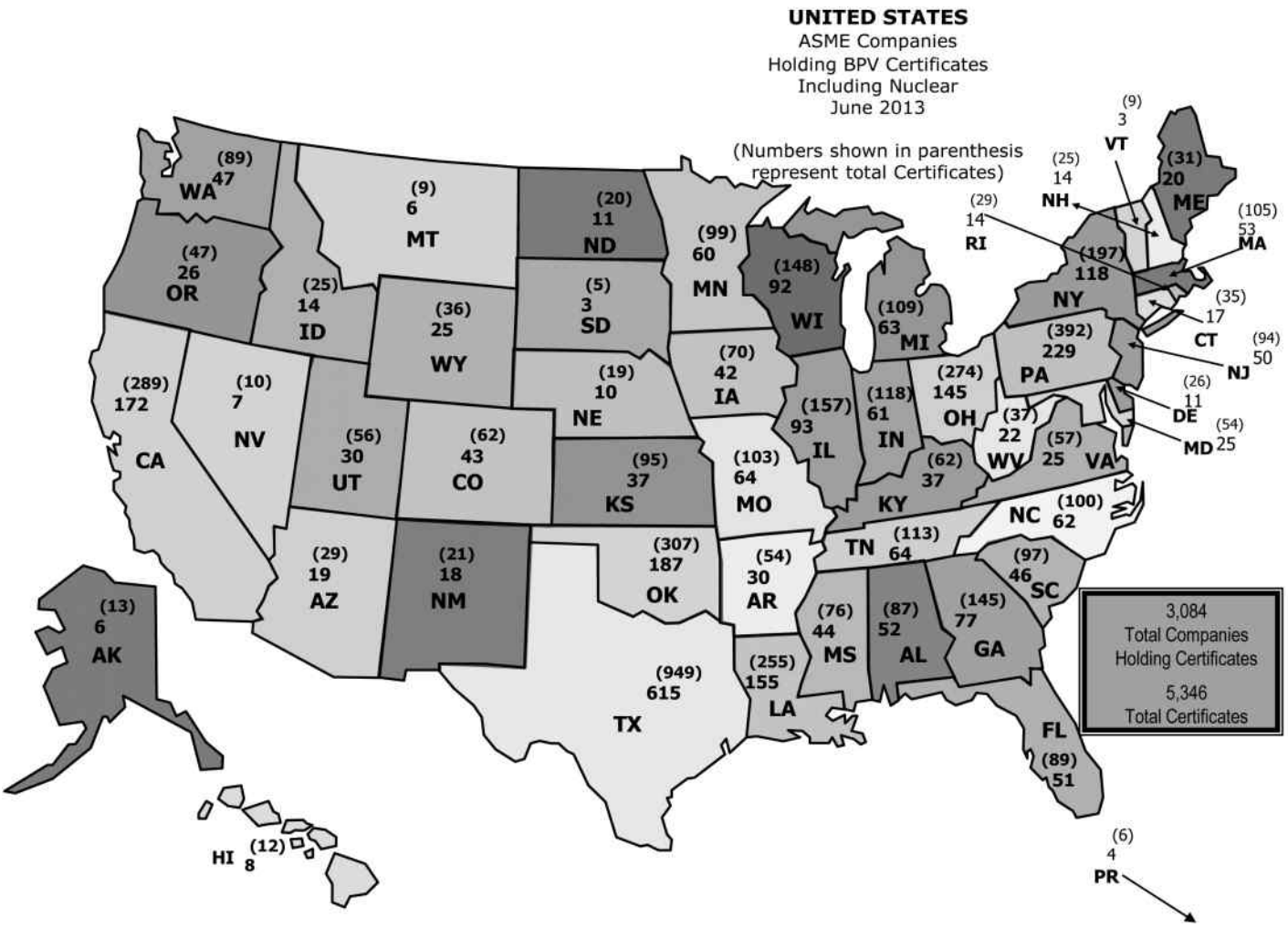


FIG. 1.2 THE UNITED STATES: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

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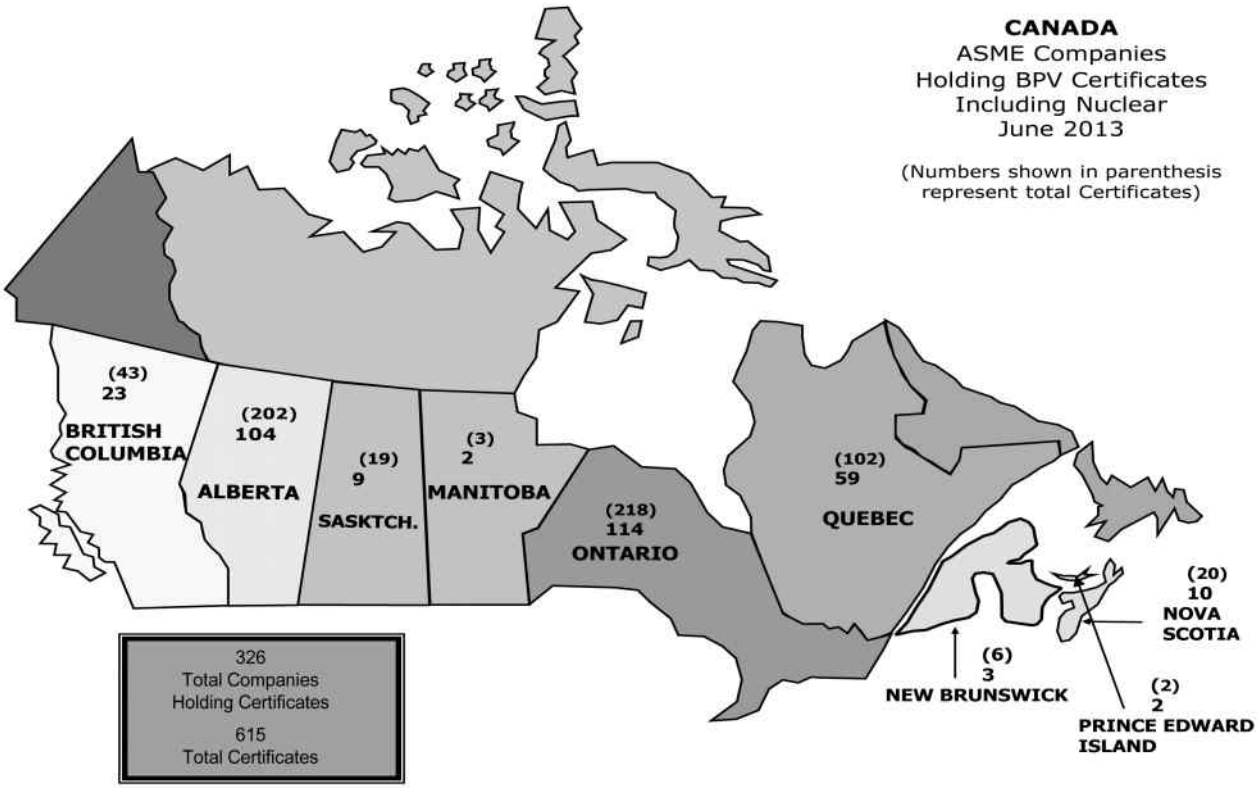


FIG. 1.3 CANADA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)



FIG. 1.4 NORTH AMERICA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

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FIG. 1.5 SOUTH AMERICA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

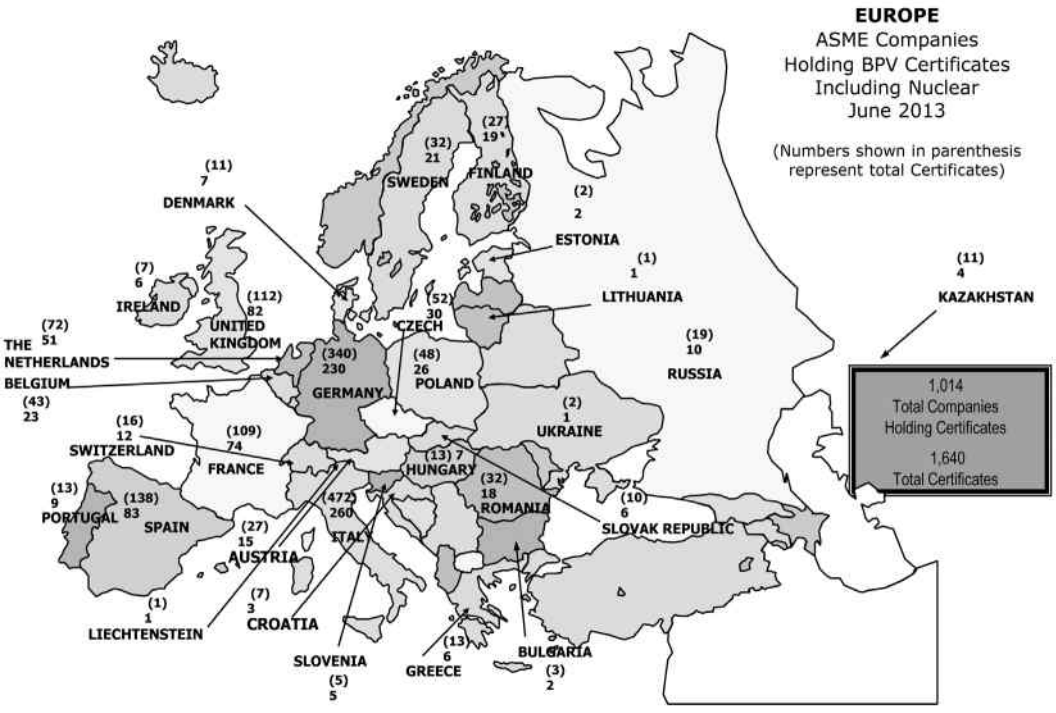


FIG. 1.6 EUROPE: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

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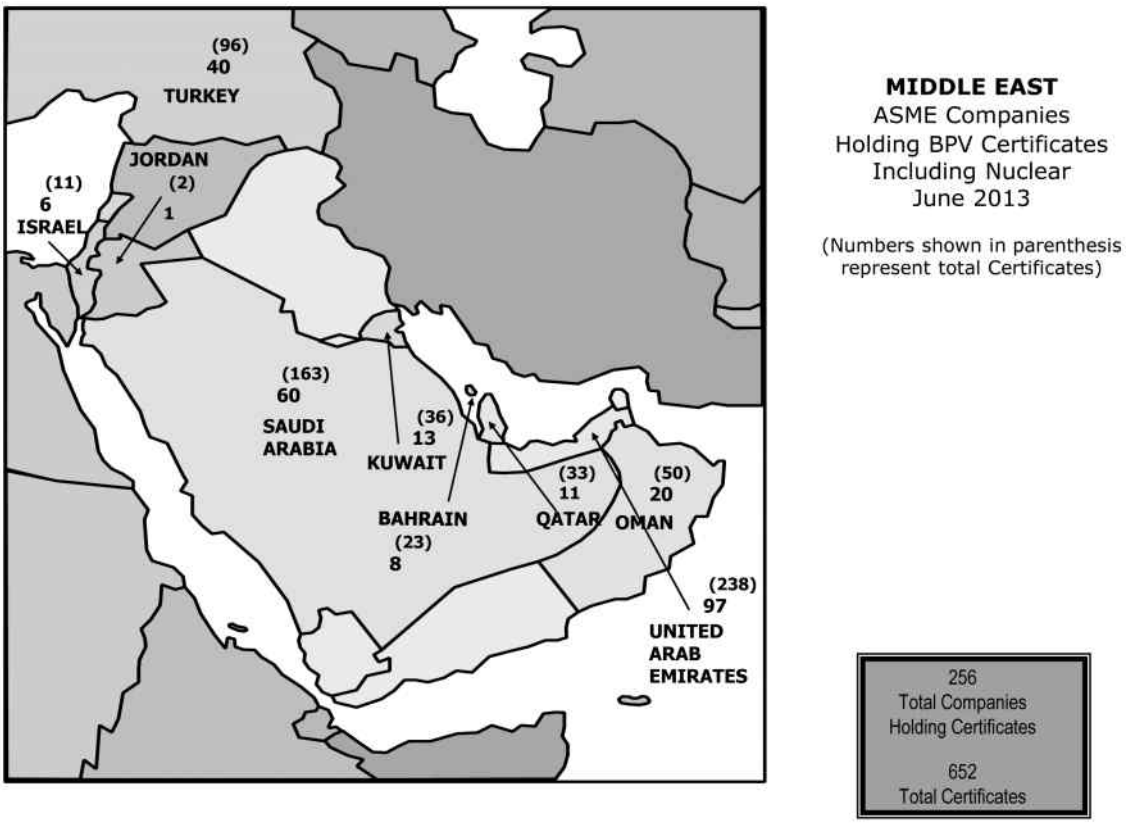


FIG. 1.7 THE MIDDLE EAST: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

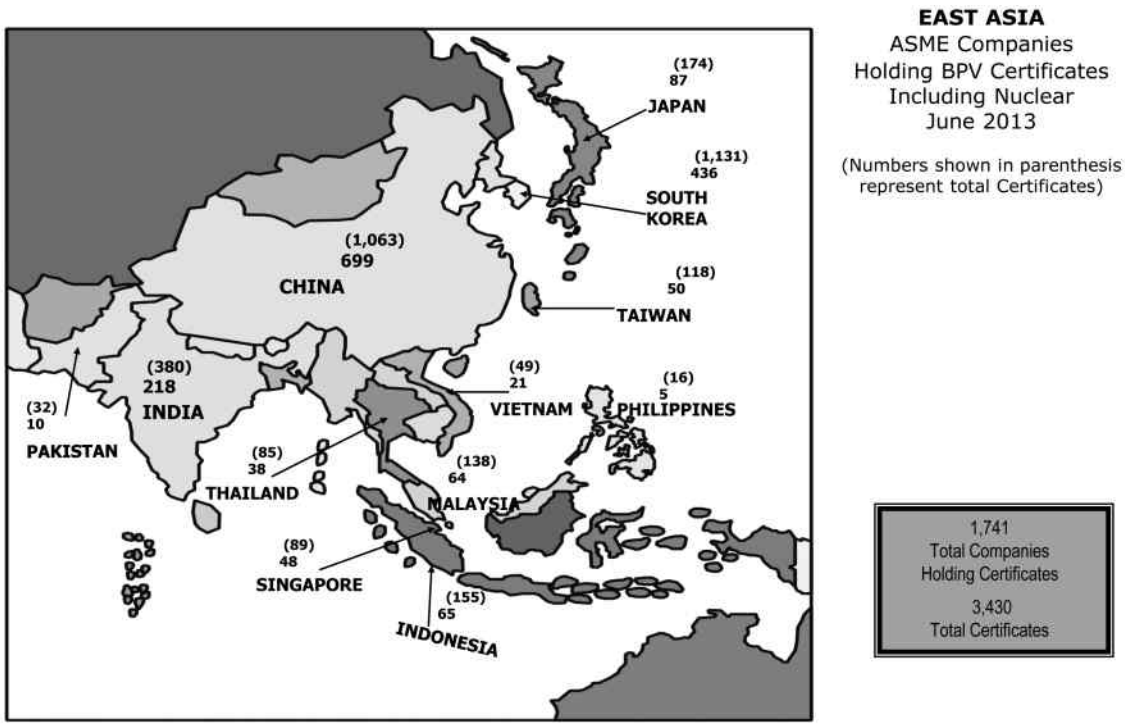


FIG. 1.8 EASTERN ASIA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

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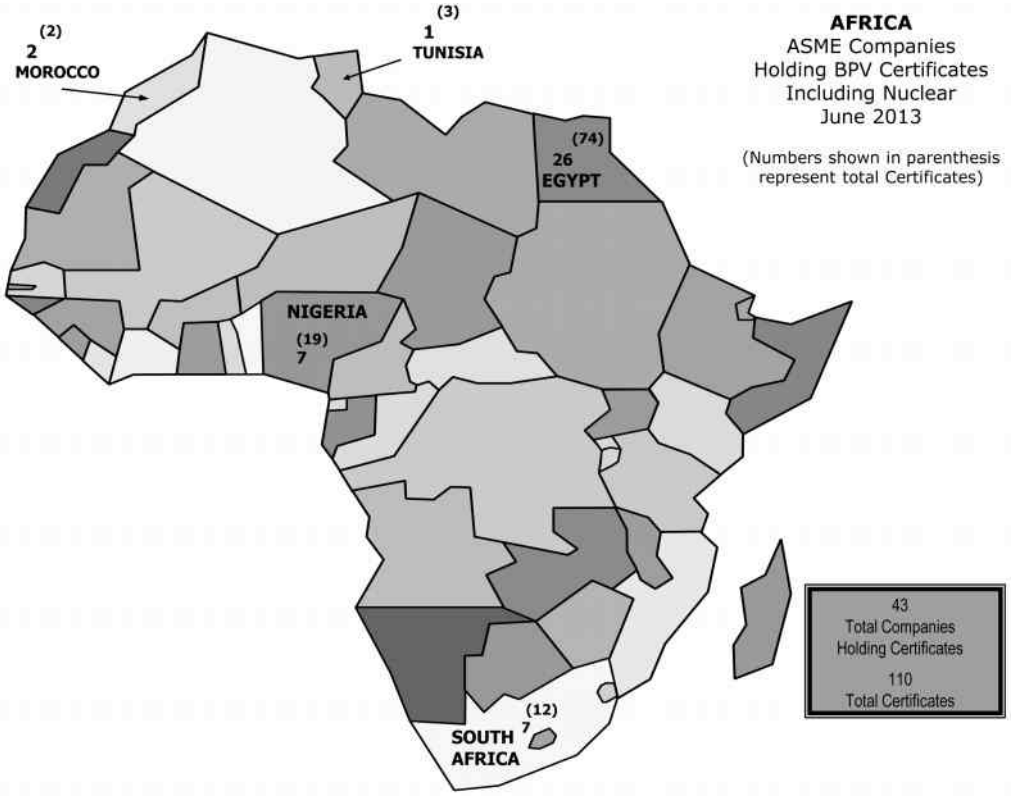


FIG. 1.9 AFRICA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

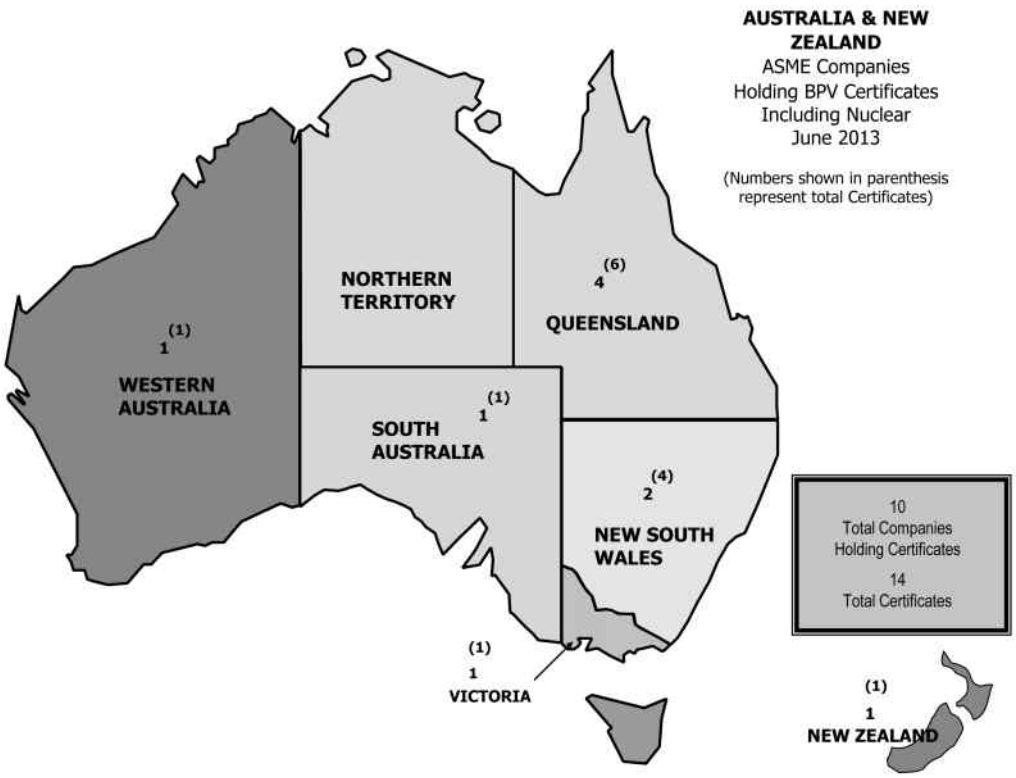


FIG. 1.10 AUSTRALIA: ASME COMPANIES HOLDING B&PV CERTIFICATES (INCLUDING NUCLEAR) AS OF JUNE 2013 (NUMBERS IN PARENTHESES REPRESENT TOTAL CERTIFICATES)

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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR INTERNATIONAL COUNTRIES BY COUNTRY

(Nuclear)

Country Code	Country Name	Company Count	Certificate Totals
ARE	United Arab Emirates	1	1
ARG	Argentina	2	8
AUT	Austria	3	5
BEL	Belgium	1	1
BRA	Brazil	1	3
CHE	Switzerland	1	4
CHN	People's Republic of China	39	79
CZE	Czech Republic	1	3
DEU	Germany	13	34
ESP	Spain	7	16
FRA	France	13	22
GBR	United Kingdom	6	11
IND	India	6	17
ITA	Italy	26	41
JPN	Japan	22	62
KOR	Republic of Korea	73	189
MEX	Mexico	1	1
SCO	Scotland	2	4
SWE	Sweden	4	7
THA	Thailand	1	1
TUR	Turkey	1	3
TWN	Taiwan	5	16
ZAF	South Africa	1	3
	Totals:	230	531

FIG. 1.11 SUMMARY OF INTERNATIONAL NUCLEAR COMPANIES AND CERTIFICATES, JUNE 2013

establish a CSCA office in Beijing, China. The consortium consists of ASME, ASTM International, API and CSA America. The Beijing office will assist in monitoring developments in China that impact on the use of US standards and conformity assessment programs in China, and will serve as an entry point for various programs aimed at educating Chinese industry and government on the benefits of using US standards, particularly those that are international standards.

Utilization of the ASME Mark is a means of complying with the laws and regulations in all states in the U.S., and all of the provinces of Canada. In addition, according to ONE/TÜV/BV Technische Inspektions GmbH, over 113 countries accept the ASME Boiler and Pressure Vessel Code as a means of meeting their government safety regulations. This link, *http://www.fmtuevbv.de/asme_code_countries.htm*, takes you to a web page listing these countries. Figure 1.14 paraphrases the list of countries shown on this web page.

Through its certification activities, ASME has achieved a truly global stature.

1.26 FUTURE DEVELOPMENTS IN THE ASME B & PV CODE

Since the first Edition of this Companion Guide, many activities have taken place, and more are in course of preparation. Some of these developments are summarized below:

At the request of the US Department of Transportation, ASME undertook to prepare rules for transport equipment to replace Federal standards. This project has resulted in the publication of Section XII, Rules for Construction and Continued Service of Transport Tanks, and has become international. To permit other alternatives for inspection, the BCA, through its QAI Committee, developed rules for the Qualification and were Duties for Certified Individuals. These rules were published as Part 8 of ASME QAI-1 2010 Edition, Qualifications for Authorized Inspection. Unlike the AI and the ANI, the CI will be an employee of a certificate holder authorized for the application of the ASME Mark. The CI shall provide oversight to assure that each use of the Mark with applicable designator is in accordance with

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A.S.M.E

REVIEW OF CERTIFICATE HOLDERS & CERTIFICATES

July End 2013

BOILER AND PRESSURE VESSEL ACCREDITATION

1. NO. OF CURRENT CERTIFICATE HOLDERS

USA	2,970
CANADA	318
INTERNT.	3,155
***	6,443

2. NO. OF CURRENT CERTIFICATES

USA	4,942
CANADA	590
INTERNT.	5,901
***	11,433

NUCLEAR COMPONENTS

1. NO. OF CURRENT CERTIFICATE HOLDERS

USA	119
CANADA	10
INTERNT.	163
***	292

2. NO. OF CURRENT CERTIFICATES

USA	373
CANADA	29
INTERNT.	453
***	855

NUCLEAR MATERIALS

1. NO. OF CURRENT CERTIFICATE HOLDERS

USA	35
CANADA	0
INTERNT.	66
***	101

2. NO. OF CURRENT CERTIFICATES

USA	40
CANADA	0
INTERNT.	76
***	116

AUTHORIZED INSPECTION AGENCY

1. NO. OF CURRENT CERTIFICATE HOLDERS

USA	14
CANADA	10
INTERNT.	5
***	29

FIG. 1.12 DISTRIBUTION OF CERTIFICATE HOLDERS AND CERTIFICATES BY REGIONS

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2. NO. OF CURRENT CERTIFICATES	
USA	14
CANADA	10
INTERNT.	5
***	29
REINFORCED THERMAL PLASTICS	
---	
1. NO. OF CURRENT CERTIFICATE HOLDERS	
USA	11
CANADA	1
INTERNT.	0
***	12
2. NO. OF CURRENT CERTIFICATES	
USA	11
CANADA	1
INTERNT.	0
***	12
QUALITY ELEVATOR INSPECTOR	
---	
1. NO. OF CURRENT CERTIFICATE HOLDERS	
USA	3
CANADA	0
INTERNT.	0
***	3
2. NO. OF CURRENT CERTIFICATES	
USA	3
CANADA	0
INTERNT.	0
***	3
GRAND TOTALS	
---	
1. NO. OF CURRENT CERTIFICATE HOLDERS	
USA	3,165
CANADA	338
INTERNT.	3,392
***	6,895
2. NO. OF CURRENT CERTIFICATES	
USA	5,431
CANADA	630
INTERNT.	6,441
***	12,502

FIG. 1.12 DISTRIBUTION OF CERTIFICATE HOLDERS AND CERTIFICATES BY REGIONS (CONT.)

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	USA	CANADA	INTERNT.	TOTAL
POWER BOILERS (SECT. I)				
A	92	21	88	201
E	4	0	1	5
M	17	0	5	22
PP	446	43	472	961
S	1122	105	1350	2577
V	85	11	11	107
HEATING BOILERS (SECT. IV)				
H1	22	1	19	42
H2	144	34	67	245
HLW	28	7	13	48
HV	6	0	0	6
PRESSURE VESSELS (SECT. VIII, DIV. 1)				
U	2477	279	2903	5659
UM	175	43	92	310
UV	139	17	50	206
UD	8	2	10	20
PRESSURE VESSELS (SECT. VIII, DIV. 2)				
U2	139	27	759	925
PRESSURE VESSELS (SECT. VIII, DIV. 3)				
U3	19	1	23	43
UV3	1	0	0	1
PRESSURE VESSELS (SECT. X)				
REINFORCED PLASTIC				
RP	7	0	16	23
TRANSPORT TANKS (SECT. XII)				
T	11	0	22	
TV	0	0	0	0
TD	0	0	0	0
NUCLEAR CERTIFICATES (SECT. III)				
MO	40	0	76	116
N	100	10	114	224
NA	70	3	62	135
NPT	126	11	169	306
NS	63	4	89	156
NV	3	1	6	10
N3	7	0	13	20
OWN	4	0	0	4
Grand Totals	5355	620	6430	12405

FIG. 1.13 NUMBER OF CODE SYMBOL STAMPS BY SECTIONS IN THE USA, CANADA AND INTERNATIONAL, JUNE 2013

the requirements of the applicable Code Section. When so referenced by the respective Code Section (I; IV; VIII Divisions 1, 2, and 3; X; and XII), a CI may be used in the same manner as an Authorized Inspector. Section XII has already adopted this initiative for Class 3 vessels in the 2004 Edition. Section IV has also incorporated the use of the CI for the inspection of Heating Boilers manufactured of cast iron in this Edition.

ASME Conformity Assessment used to publish two books listing all Boiler and Pressure Vessel Certificates in one annual volume, and Nuclear Certificates in the other, six times per year. The publication of these books has been discontinued. The nuclear certificate lists are now accessible through the ASME web site. If a code user wishes to download the entire list of companies holding nuclear certificates, he can do so by accessing the following URL *http://reports.asme.org/reports/Nuclear-/Nuclear Certificates List 01.rpt.* Because of the very large size of the Boiler and Pressure Vessel Certificates list, it has not been made available for downloading. However, if a user wishes to search for a specific company, type of certificate, state, province or country, either boiler and pressure vessel or nuclear, it can be done by accessing this URL: *http://cstools.asme.org/holder-search/.*

Section III's subgroup on Nuclear Packaging (NUPACK) is beginning development of a new subsection WD. This effort will bring rules for the construction of internal structures for transport and storage containments into the Division 3 standard. Currently, all items involving design and construction are brought to the NRC for approval and licensing, and only a few Code Cases on materials, and one on construction (N-595-5) have been approved by the Committee.

For many years, BNCS has supported a Committee on Nuclear Risk Management, whose charter is "To develop, revise and maintain standards and guides on risk management techniques, including Probabilistic Risk Assessment for nuclear power plants and other facilities." The actions of this committee resulted in the publication of a new ASME standard in April 2002, ASME RA-S-2002, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications, and its first Addendum, ASME-RA-Sa-2003, which became available in October 2003. A second Addendum is in course of preparation. Section XI has taken the lead in applying this new approach and has published several Code Cases implementing the procedure.

As new designs are being brought forward for new generations of Advanced Boiling Water, Pressurized Water and Gas Cooled Reactors, the BNCS has established a New Reactors Task Group. This committee has undertaken the mission to "ensure, on a worldwide basis, that ASME Nuclear Codes and Standards protect public health and safety and meet the needs of users." These Codes and Standards are developed with an approved consensus process. To achieve this goal, Section XI is in the process of reviving Division 2, Rules for the Inspection and Testing of Components of Gas-Cooled Plants. This Division became silent in the mid 90s, and the current Edition is the 1992 Edition with the 1993 Addenda, pages 485 through 653. Rules are being proposed to only include IGA, and not to have subsections IGB, IGC or IGD. The entire process will be risk based. Systems will not be classified as before, they will be "risk categorized." The initial examinations will be deterministic, but will be selected via risk based methods, in a manner similar to Code Case N-660.

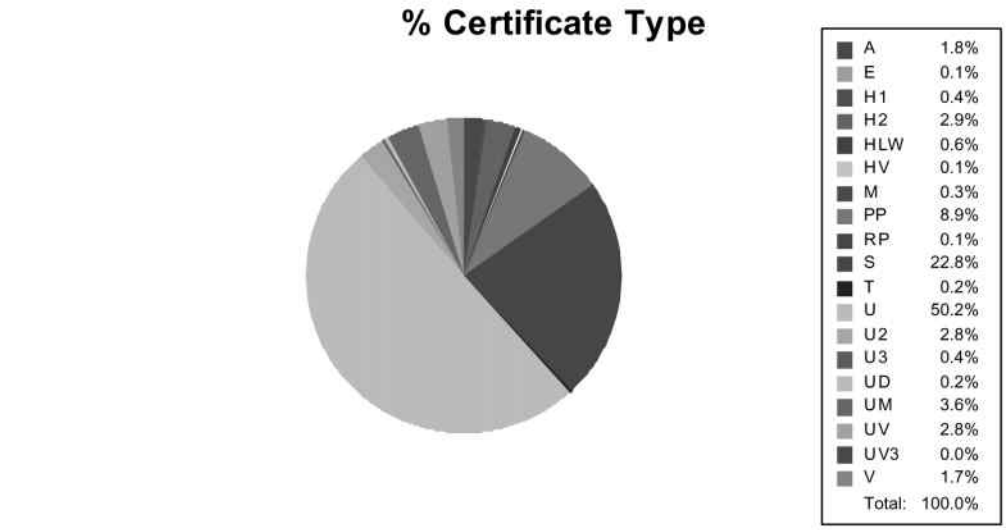
For a number of years, a project team consisting of scientists and engineers from China, Europe, Japan, Korea, Russia, and the United States have been working in an unprecedented *international collaboration* on the next major step for the development of

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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR USA BY CERTIFICATE TYPE

(Boiler)



Certificate Type	Company Count	Certificate Totals
A	90	90
E	4	4
H1	22	22
H2	144	144
HLW	28	28
HV	6	6
M	17	17
PP	439	439
RP	7	7
S	1120	1,120
T	11	11
U	2467	2,467
U2	137	137
U3	18	18
UD	8	8
UM	175	175
UV	139	139
UV3	1	1
V	86	86
**********		4919

FIG. 1.14 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR USA BY CERTIFICATE TYPE (BOILER)

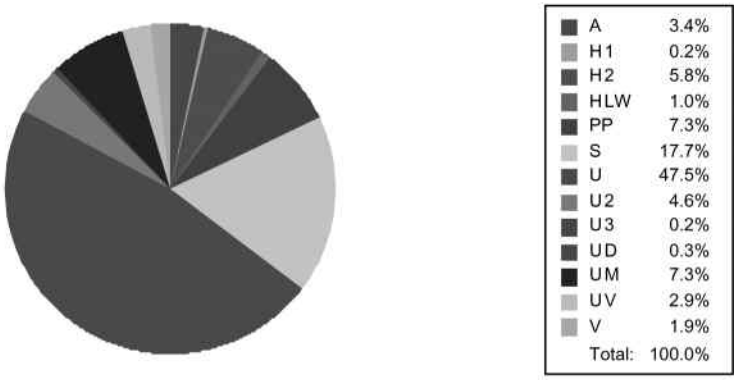
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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR CANADA BY CERTIFICATE TYPE

(Boiler)

% Certificate Type



Certificate Type	Company Count	Certificate Totals
A	20	20
H1	1	1
H2	34	34
HLW	6	6
PP	43	43
S	104	104
U	280	280
U2	27	27
U3	1	1
UD	2	2
UM	43	43
UV	17	17
V	11	11
	**********	589

FIG. 1.15 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR CANADA BY CERTIFICATE TYPE (BOILER)

fusion-ITER (which means "the way" in Latin). The acronym also stands for International Thermonuclear Experimental Reactor.

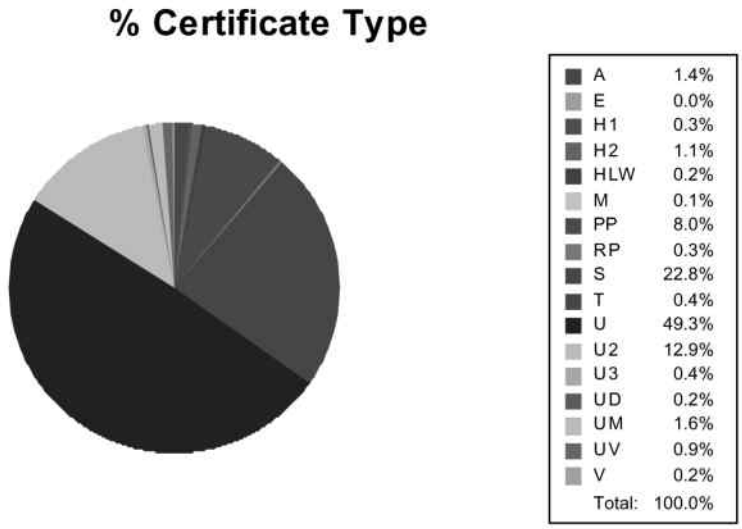
ITER's mission is to demonstrate the scientific and technological feasibility of fusion energy for peaceful purposes. To do this, ITER will demonstrate moderate power multiplication, demonstrate essential fusion energy technologies in a system integrating the appropriate physics and technology, and test key elements required to use fusion as a practical energy source. ITER will be the first fusion

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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR INTERNATIONAL COUNTRIES BY CERTIFICATE TYPE

(Boiler)



Certificate Type	Company Count	Certificate Totals
A	84	84
E	1	1
H1	19	19
H2	65	65
HLW	13	13
M	5	5
PP	466	466
RP	15	15
S	1338	1,338
T	22	22
U	2885	2,886
U2	756	757
U3	23	23
UD	10	10
UM	91	91
UV	50	50
V	11	11
	**********	5856

FIG. 1.16 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR INTERNATIONAL COUNTRIES BY CERTIFICATE TYPE (BOILER)

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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR USA BY CERTIFICATE TYPE

(Nuclear)

% Certificate Type



Certificate Type	Company Count	Certificate Totals
MO	36	41
N	78	99
N3	5	6
NA	50	70
NPT	105	126
NS	53	63
NV	3	3
OWN	4	4
**********		412

FIG. 1.17 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR USA BY CERTIFICATE TYPE (NUCLEAR)

device to produce thermal energy at the level of an electricity-producing power station. It will provide the next major step for the advancement of fusion science and technology, and is the key element in the strategy to reach the following demonstration electricity-generating power plant (DEMO) in a single experimental step.

ITER is an experimental fusion reactor based on the "tokamak" concept—a toroidal (doughnut-shaped) magnetic configuration in which to create and maintain the conditions for controlled fusion reactions. The overall ITER plant comprises the tokamak, its auxiliaries, and supporting plant facilities. In ITER, superconducting magnet coils around a toroidal vessel confine and control a mix of charged particles - the "plasma" - and induce an electrical current through it. Fusion reactions take place when the plasma is hot enough, dense enough, and contained for long enough for the atomic nuclei in the plasma to start fusing together. The tokamak concept was first developed in Russia and has since been brought to a high level of development in all the major fusion programs of the world.

To meet its objectives, ITER will be much bigger (twice linear dimensions) than the largest existing tokamak and its expected fusion performance will be many times greater. These extrapolations in size and *physics* performance provide the major challenges to the *design* of ITER. Section III has received permission to incorporate the rules that will be forthcoming from this multinational project team into a new Section III, Division 4.

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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR CANADA BY CERTIFICATE TYPE

(Nuclear)

% Certificate Type



Certificate Type	Company Count	Certificate Totals
N	8	10
NA	3	3
NPT	9	11
NS	4	4
NV	1	1
**********		29

FIG. 1.18 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR CANADA BY CERTIFICATE TYPE (NUCLEAR)

The International Thermonuclear Experimental Reactor (ITER) will be located in Cadarache, France. This announcement, made in Moscow on June 28th, 2005, reflects the agreement of representatives from the U.S., European Union, Japan, the Russian Federation, China, India and Korea. This agreement resolves a major difficulty for U.S. participation in the project. In 1998, the U.S. withdrew from ITER participation due to concerns over the management and cost of the project. In 2003, that position was reversed. However, Senate appropriators have been skeptical about the project, earlier this month reducing ITER funding to $28,000,000 due in large part to the delay in agreeing on a location for ITER. This siting decision clears the way for House and Senate appropriators to work with the Department of Energy (DOE) to provide additional ITER funding. DOE's Office of Science Director, Ray Orbach, noted that the U.S. looks forward to ITER construction in the near future. However, he cautioned that ITER negotiators still must resolve key management and oversight arrangements. "The U.S. will continue to strive for a robust management structure and an oversight program based on the principles of equality, accountability and transparency to ensure both the success of the project and the best use of American taxpayer dollars." It is possible that the agreement could be ready by the end of the year, followed by a three to four month review period. If the agreement is signed early in 2006, construction could start soon after. ITER construction is anticipated to take eight years. Further information on this project is available online by accessing this URL: *www.iter.org*.

One of the most active projects is the Pebble Bed Modular Reactor, which uses nuclear fuel embedded in graphite spheres and is cooled by helium. A demonstration plant is currently being constructed in South Africa, and the proponents are seeking assistance from the ASME to insure that the reactor system meets the ASME Code.

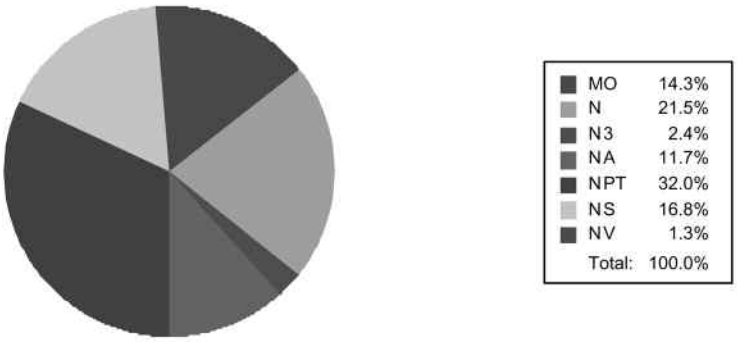
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CERTIFICATE HOLDERS SUMMARY

COUNT LISTING FOR INTERNATIONAL COUNTRIES BY CERTIFICATE TYPE

(Nuclear)

% Certificate Type



Certificate Type	Company Count	Certificate Totals
MO	66	76
N	111	114
N3	12	13
NA	55	62
NPT	157	170
NS	82	89
NV	7	7
**********		531

FIG. 1.19 CERTIFICATE HOLDERS SUMMARY COUNT LISTING FOR INTERNATIONAL COUNTRIES BY CERTIFICATE TYPE (NUCLEAR)

One of the activities to support this concept is the proposed inclusion in Section III of Design Requirements for Graphite Core Supports. A Section III Special working group on Graphite Core Structures has been formed. The committee charter is "to establish rules for materials selection and qualification, design, fabrication, testing, installation, examination, inspection, certification, and the preparation of reports for manufacture and installation of non-metallic internal components for fission reactors, where non-metallic internal components are defined as components, including control rods and assemblies, contained within a fission reactor pressure vessel and manufactured from graphite, carbon, carbon/carbon composites, ceramics, or certain matrix composites. The rules shall apply to non-metallic components as defined above. The rules shall not apply to graphite fuel elements or assemblies, bushings, bearings, seals, blanket materials, instrumentation, or components internal to the reactor other than those defined above." It is assumed that these rules will eventually be published as Section III, Division 5.

Section III has also established a Special Working Group on Code Consolidation. This committee is considering ways to simplify Section III, Division 1. Some of the proposals include eliminating NC-3200, Class 2 vessels Designed by Analysis; deleting Subsection ND, Class 3 components, and combining it with Subsection NC; combining Subsection NE with either NB or NC; and simplifying Subsection NF by letting it cover only Plate and Shell Type supports, which require

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Albania *
Algeria
Argentina
Australia*
Austria *

Bahamas
Bahrain
Bangladesh
Barbados
Belarus *
Belgium *
Bermuda
Bolivia
Bosnia and Herzegovina *
Brazil
Burma (Myanmar) *

Canada
Chile
China *
Colombia
Costa Rica
Croatia *
Cuba
Cyprus

Denmark *
Djibouti
Dominican Republic

Ecuador
Egypt *
Estonia *
Ethiopia

Finland *
Fiji
France *

Gambia
Georgia *
Germany *
Ghana
Greece *

Hong Kong *
Hungary*

Iceland *
India *
Indonesia
Iraq *
Ireland *
Israel
Italy *
Ivory Coast

Jamaica
Japan *
Jordan

Kazakhstan *
Kenya
Korea *
Kuwait

Latvia *
Lebanon
Libya
Lithuania *
Luxembourg *

Malawi
Malaysia
Malta *
Mauritius *
Mexico
Moldowa *
Morocco
Mozambique

Netherlands *
New Zealand
Nicaragua *
Nigeria
Norway *

Oman

Pakistan
Paraguay
Peru
Philippines
Poland *
Portugal *
Puerto Rico

Quatar

Romania *

Saint Lucia
Saudi Arabia *
Serbia *
Singapore
South Africa
Spain *
Sri Lanka
Sudan
Swaziland
Sweden *
Switzerland *
Syria

Taiwan
Tanzania
Thailand
The Russian Federation *
Trinidad and Tobago *
Tunisia
Turkey *

United Arab Emirates
United Kingdom *
Uganda
Uruguay *
USA

Venezuela

Yemen
Yugoslavia *

Zambia
Zimbabwe

* subject to approval of local authority
Source: Technical help to Exporter, British Standard Inst.

FIG. 1.20 COUNTRIES ACCEPTING THE ASME CODE

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analysis, replacing Linear Type supports with the AISC specification N-690; and removing Standard supports and replacing those rules with MSS SP-54, as currently permitted by Code Case N-500. These proposals are still under consideration, and progress is slow.

It is evident that nuclear power is not yet ready to reach its nadir, and may really be approaching its zenith.

1.27 SUMMARY

This chapter has attempted to provide a summary of the early Codes to which a majority of today's operating plants have been committed. Throughout the chapter, the message for the reader to bear in mind is not to overlook the original Construction Code. Even when it is not used for procurement, the original Code establishes the requirements that must be met, and can be used to justify use-as-is dispositions.

Another message is that the user can utilize later Editions and Addenda in part, or in their entirety. When the later is the case, all related requirements must still be met, and the Enforcement and Regulatory Authorities must accept the selection for this change prior to its implementation.

Globalization is an intense activity in the ASME Codes and Standards, and the Codes and Standards team is busily engaged in meeting the present and future needs of their users.

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CHAPTER

2

THE MAINTENANCE RULE

C. Wesley Rowley[1]

2.1 INTRODUCTION

On July 10, 1991, a Maintenance Rule, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, was published by the U.S. Nuclear Regulatory Commission (the USNRC, or simply the NRC) in the Federal Register (56FR31324) as 10CFR50.65. This Maintenance Rule was developed to provide a regulatory framework for the NRC for mechanisms used to evaluate the administrative effectiveness of maintenance programs applied by nuclear power plant licensees. The NRC's overall objective is to ensure that the structure, systems, and components important to the safety of nuclear power plants are maintained properly so that plant equipment will reliably perform its intended safety functions. The Maintenance Rule is characterized as performance-based, for it provides focus on results rather than on programmatic adequacy.

The importance of proper maintenance to safe and reliable nuclear plant operation has long been recognized by the nuclear utility industry as well as the NRC. Since 1963, the industry has had inservice inspection standards (from ASME Section XI) applicable to nuclear safety–related pressure vessels. In the early 1970s, this requirement was extended to nuclear safety–related pumps, valves, and piping, but no other standards generally applicable to the maintenance of other nuclear power plant structures, systems, or components were in existence. Consequently, the Maintenance Rule was created to provide such standards.

The information presented in this chapter is based on the criteria developed by the Nuclear Energy Institute [1] to assist the nuclear utility industry (hereafter referred to as simply *the industry*) in implementing the Maintenance Rule, building on the programs, facilities, and significant progress made in general to improve maintenance performance. These criteria are used for determining which of the many structures, systems, and components (SSCs) that constitute a commercial nuclear power plant are within the scope of the Maintenance Rule and also comply with the NRC regulatory guidance [2]. This chapter describes the processes of establishing plant-specific risk-significant and performance criteria to be used for deciding if goals need to be established for specific SSCs covered by the Maintenance Rule. See Section 2.2 for a discussion regarding the establishment of performance criteria.

Both the industry and the NRC recognize that effective maintenance reasonably ensures that key structures, systems, and components are capable of performing their intended safety functions and also minimizes any age-related degradation of safety performance. The guideline provides focus on maintenance activities and personnel use to ensure the performance of safety functions by maximizing the use of proven existing industry and Owner's plant maintenance programs while minimizing the dilution of critical resources to modify maintenance programs when established performance criteria are being met.

2.2 PURPOSE AND SCOPE

Noteworthy to the purpose and scope of performance criteria are the following elements:

(1) selecting the SSCs[2] within the scope of the Maintenance Rule;
(2) establishing and applying risk-significant criteria;
(3) establishing and applying performance criteria;
(4) setting goals and monitoring applicable SSCs to ensure that plant and system functions are maintained reliably and also to demonstrate the effectiveness of maintenance activities;
(5) considering the effects on overall plant safety that result from taking SSCs out of service to perform monitoring or preventative maintenance;
(6) performing the periodic assessment of performance; and
(7) providing documentation needed to support implementation of the Maintenance Rule.

As stated previously, this guideline, based on the Nuclear Energy Institute criteria, provides processes for determining which of the many SSCs constituting a commercial nuclear power plant are included within and outside the scope of the Maintenance Rule, and also describes the processes involved in establishing plant-specific risk-significant and performance criteria used for deciding if goals need to be established for specific SSCs covered by the Maintenance Rule. It should be noted that the task of establishing performance criteria is tied in to the task of establishing

[1]John D. Stevenson was the author of this chapter for the first and second editions. This chapter was updated by C. Wesley Rowley as Chapter 32 for the third edition of the "Companion Guide to the ASME BPVC." C. Wesley Rowley, author of this chapter has stated that there are no revisions for this edition. – Editor

[2]As the term is used in this guideline, SSCs can mean "structures, systems, and components," or "structures, systems, *or* components," depending on use. Where the guideline discusses the need to establish goals and monitoring, the meaning of SSCs will include, as applicable, "structures, systems, subsystems, trains, components, parts, appurtenances, and/or devices".

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goals. The approach is to first establish an acceptable set of performance criteria and then monitor that set's performance. If performance criteria are not met, goals are established to institute the necessary improvements in performance. The term *goal*, as it is used in these guidelines, only pertains to performance criteria if they are not being met. By restricting the term's use in that manner, the necessary focus is provided at all levels within the utility that needs the additional attention. In most situations, the goals are identical to the performance criteria for which the past performance of the SSCs does not meet. Although goals are created and monitored as part of paragraph (a)(1) of the NRC's Maintenance Rule, the preventative maintenance and performance-monitoring activities are actually part of paragraph (a)(2) and pertain to SSCs that are within the scope of the Maintenance Rule.

2.3 RESPONSIBILITY

Each maintenance organization shall implement a plant-specific program (composed of criteria) to comply with the Maintenance Rule. These criteria assist one in developing and implementing plant-specific programs. This guideline provides flexibility for individual plant implementation.

2.4 APPLICABILITY

These criteria are applicable to maintenance organizations belonging to a utility with a nuclear power plant license issued in accordance with 10CFR50.21(b) and 10CFR50.22.

Periodically, modifications to the plant occur that may affect the maintenance program. Such modifications should be reviewed to ensure that the maintenance program is appropriately adjusted in such areas as risk significance, goal setting, and performance monitoring.

2.5 TERMS AND DEFINITIONS

The following definitions to terms associated with the Maintenance Rule are provided to promote its consistent interpretation. The terms are, as much as possible, defined in accordance with their current existing industry usage. For some terms, a description is provided for clarification.

2.5.1 Availability

The time that SSCs are capable of performing their intended function as a fraction of the total time that the intended function may be demanded. Stated simply, it is the numerical complement of unavailability.

2.5.2 Cut Sets

Cut sets refer to combinations of accident sequence failure.

2.5.3 Function

As used in this guideline, the scoped function is an attribute (e.g., safety-related, accident-mitigating, or scram-causing) that includes an SSC within the scope of the Maintenance Rule. For instance, some units scope the condenser vacuum system under the Maintenance Rule because its total failure causes a scram rather than using the design function of pulling a vacuum on the condenser.

2.5.4 Industrywide Operating Experience

Through the sharing of operating experiences, the NRC, the vendor equipment used in the nuclear utility industry, and industry personnel in general all disseminate valuable information that helps minimize hazardous or otherwise adverse plant conditions.

2.5.5 Maintenance

Maintenance actions are for the aggregate of those functions required to preserve or restore safety, reliability, and availability of plant structures, systems, and components. Maintenance includes not only activities traditionally associated with identifying and correcting actual or potential degraded conditions—namely repair, surveillance, diagnostic examinations, and preventive measures—but also includes all supporting functions for the conduct of these activities [3].

2.5.5.1 Programmed Maintenance This pertains to predictive, sometimes periodic, and planned maintenance actions taken before SSC failure to maintain the SSC within design-operating conditions by controlling degradation or failure.

2.5.6 Initial and Repetitive Maintenance-Preventable Functional Failure

A maintenance-preventable functional failure (MPFF) is the failure of an SSC or train within the scope of the Maintenance Rule to perform its intended safety function (i.e., the function performed by the SSC requiring its inclusion within the scope of the rule) in which the cause of the failure is attributable to a maintenance-related activity. (This maintenance-related activity is regarded in the broad sense of maintenance as defined in Section 2.5.5.) The failure of function can be either direct (i.e., the SSC fails to perform its intended function) or indirect (i.e., the SSC fails to perform its intended function because of another SSC's failure—either safety-related or non–safety-related).

An *initial* MPFF is the first occurrence of failure in a particular SSC for which the loss of function is attributed to a maintenance-related cause. An initial MPFF is a failure that would have been avoided had a maintenance activity evaluated the SSC as giving acceptable results (i.e., if allowed to reach failure because of an acceptable risk).

A *repetitive* MPFF follows an initial MPFF; it is the subsequent loss of function attributable to the same maintenance-related cause that occurred previously. For example, an MOV fails to close because of an improperly installed spring pack (initial MPFF); any subsequent failure to close would also be from an improperly installed spring pack, indicating that the MPFF is repetitive and that the previous corrective action did not preclude recurrence. A second or subsequent loss of function that results from a different maintenance-related cause, however, is not considered a repetitive MPFF. For example, an MOV initially fails to close because of an improperly installed spring pack; any subsequent failure to close would be caused by another mechanism—say, an improperly installed set screw—for the MPFF to be considered repetitive.

During initial implementation of the Maintenance Rule, repetitive failures that occurred in the previous two operating and refueling cycles should be considered. After that rule implementation, utilities should establish an appropriate review cycle for

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repetitive MPFFs (i.e., during the periodic review or during the next maintenance or test of the same function).

2.5.7 Performance Monitoring

Performance monitoring pertains to continuous or periodic tests, inspections, and measurement or trending of the performance or physical characteristics of an SSC to indicate current performance and the potential for failure. Performance monitoring is frequently conducted on a nonintrusive basis. Examples of preventive maintenance actions may include operator rounds, engineering walkdowns, and management inspections.

2.5.8 Operating System

An operating system is one that is required to perform its intended function continuously to sustain power operation or shutdown conditions. The system function may be achieved through the use of redundant trains (i.e., two redundant independent trains, each with a motor-driven pump capable of delivering 100% capacity to each train). In this case, either train using either pump will be capable of performing the system function.

Normal operation is with one operating train and one standby (not operating) train. The standby train is normally capable of starting and providing the system function if the operating train failed. In such a case, if the function of the operating train is lost, and if the standby train starts and maintains the system function with no perturbation of plant operation, there will not be any loss of system function. The performance criteria for this type of system should include both the operating and standby trains' performance characteristics as applicable.

In the case of a system having redundant trains with a diverse system (i.e., steam-driven pumps and piping, valves, and so forth) that will perform the same function, it is possible to lose both trains of the redundant system and still maintain system function with the diverse system. Performance criteria should be established for the diverse system based on its individual performance, taking into consideration its diverse method of performing the required function, its unique configuration, and any other functions that it performs as they are related to the Maintenance Rule.

2.5.9 Performance

When used in the context for criteria and monitoring, performance includes availability, reliability, and/or condition as appropriate. Both availability and reliability should be used to the greatest extent possible because they provide the most ensurance that performance is being monitored. There are instances, however, when availability does not provide a meaningful measure of performance and therefore should not be captured. The condition of structures is more appropriate to monitor than the reliability or availability. The monitoring of individual components (e.g., unacceptable performance) when goals are being set may include the monitoring of condition. (Condition typically includes vibration, flow, temperature, and other similar parameters.)

2.5.10 Reliability

Reliability pertains to a measure of the expectation (assuming that the SSC is available) that the SSC will perform its function instantaneously upon demand. The monitoring of performance and any resulting MPFFs is an indicator of reliability.

2.5.11 Risk

Risk encompasses what can happen (the scenario), its likelihood (the probability), and its level of damage (the consequences).

2.5.12 Risk-Significant SSCs

Risk-significant SSCs are those SSCs that are significant contributors to risk as determined by PRA or other methods.

2.5.13 Standby System or Train

A standby system or train is one that is not operating, performing its intended function only when initiated by either an automatic or manual demand signal.

Some standby systems perform a function that may be required intermittently during power operations (e.g., a process system used to adjust or correct water chemistry). Because the system or train is in the standby mode, it will most frequently be determined as operable/inoperable during operability (surveillance) testing, but if it is designed to actuate automatically, it could fail as the best way to measure the performance of the standby system as based on the results of performance on demand (both an automatic response to a valid signal and as a result of surveillance testing). Examples of standby systems of this type are the hydrogen recombiner system and the containment spray system.

Other systems and their associated trains may be configured in a standby mode during power operation, but normally operate during an outage (e.g., RHR). Performance monitoring should consider the system function during all plant modes.

2.5.14 System

A collection of equipment that is configured and operated to serve specific plant functions (e.g., providing water to steam generators, spraying water into the containment, and injecting water into the primary system), as defined by the terminology of each utility (e.g., auxiliary feedwater system, containment spray system, and high-pressure-coolant injection system). The system definition should generally be consistent with the system definition in the FSAR or PRA analysis.

2.5.15 Train

A collection of equipment or components and operated to serve a specific plant safety function, may be a subset of a system. The utility can cause the Final Safety Analysis Report (FSAR) or PRA analysis to better define the intended configuration and functions.

2.5.16 SSC Unavailability for the Purpose of Availability or Reliability Calculation

These calculations are the numerical complement of availability. An SSC that cannot perform its intended safety function and that is required to be available for automatic operation must respond without human interaction.

2.5.17 Unplanned Automatic Scrams per 7,000 Critical Hours

This indicator tracks the average scram rate per 7,000 hours of reactor criticality (approximately 1 yr. of operation) for units operating with more than 1,000 critical hours during the year. Unplanned automatic scrams result in thermal or hydraulic transients in plant systems.

2.5.18 Unplanned Capability Loss Factor

Unplanned capability loss factor is the percentage of maximum energy generation that a plant is not capable of supplying to the electrical grid because of unplanned energy losses (e.g., unplanned shutdowns, forced outages, outage extensions, and

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load reductions). Energy losses are considered unplanned if they are not planned at least 4 wk. in advance.

2.5.19 Unplanned Safety System Actuations

Unplanned safety system actuations include unplanned emergency core-cooling system actuations and also emergency AC power system actuations caused by loss of power to a safeguards bus bar.

2.6 GENERAL REQUIREMENTS

The Maintenance Rule requires that licensees "monitor the performance or condition of structures, systems, or components against licensee-established goals, in a manner sufficient to provide reasonable assurance that structures, systems, and components, as defined in paragraph (b), are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industrywide operating experience. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken."

Monitoring, as specified in paragraph (a)(1) of the Maintenance Rule, is not required if it is demonstrated that the performance or condition of an SSC is effectively controlled through the performance of appropriate preventative maintenance. This SSC remains capable of performing its intended safety function.

Performance and condition monitoring activities and their associated goals and programmed maintenance shall be evaluated at least every refueling cycle if the interval between evaluations does not exceed 24 mo.

The evaluation shall be conducted by taking into consideration (where practical) industrywide operating experience. Adjustments shall be made where necessary to ensure that the objective of preventing SSC failure through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs by way of monitoring or preventative maintenance. In performing monitoring and preventative maintenance activities, an assessment of the total plant equipment that is out of service should be considered to determine the overall effect on performance safety functions.

2.7 USE OF EXISTING STANDARDS AND PROGRAMS

These criteria are intended to maximize the use of existing industry standards, programs, studies, initiatives, and bases. Key among the existing industry standards are the requirements for components addressed by the ASME BPV Code Section XI, Inservice Inspection and ASME OM Code Section IST, Inservice Testing.

2.8 METHODOLOGY OF SELECTING PLANT STRUCTURES, SYSTEMS, AND COMPONENTS

2.8.1 10CFR50.65

The scope of the specified monitoring program shall include safety-related and non–safety-related SSCs as follows:

(a) Safety-related SSCs are relied upon to remain functional during and following design-basis events to ensure the integrity of the reactor-coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, as well as the capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposure comparable to the 10CFR Part 100 guidelines,

(b) Non–safety-related SSCs
  (1) are relied upon to mitigate accidents or transients;
  (2) are used in plant emergency operating procedures (EOPs);
  (3) whose failure could prevent safety-related SSCs from fulfilling their safety-related function; or
  (4) whose failure could cause a reactor scram or actuation of a safety-related system.

2.8.2 Guidance

2.8.2.1 Selection of Plant SSCs The licensee must first determine which SSCs are within the scope of the Maintenance Rule by applying the screening criteria described herein. (For the purpose of these criteria, a system is any collection of equipment that is configured and operated to serve specific plant functions, as defined in Section 2.5.14.)

The scope of the Maintenance Rule, as it is defined in 10CFR50.65(b), is limited to SSCs that directly affect plant operations, regardless of which organization actually performs the maintenance activities. For example, electrical distribution equipment out to the first intertie with the off-site distribution system should be considered for comparison with 10CFR50.65(b) and, thereafter, considered for inclusion under the scope of the Maintenance Rule. Thus, equipment in the switchyard (regardless of its geographical location) is potentially within the scope of the Maintenance Rule.

Safety systems may perform not only safety functions but other functions that lack safety significance. For example, a system may be used to transfer water from one part of a plant to another and also provide additional safety functions. (The safety functions of SSCs are addressed by the Maintenance Rule.)

It is necessary to identify and document the functions for both safety-related and non–safety-related SSCs that allow the SSCs to fall within the scope of the Maintenance Rule. There are two fundamental reasons why this information is needed. First, the function that the system or structure provides is needed for all failures to be evaluated against those functional aspects. Not all failures that cause loss of some function are considered functional failures by the Maintenance Rule, for the lost functions may not be within the scope of the Maintenance Rule. Second, when removing SSCs from service, one needs to know which function is being lost to determine the impact of removing multiple equipment from service.

2.8.2.2 Safety-Related SSCs Are the safety-related SSCs relied upon to remain functional during and following design-basis events ensure any of the following conditions:

(1) The integrity of the reactor-coolant pressure boundary?
(2) The capability to shut down the reactor and maintain it in a safety shutdown condition?
(3) The capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposure comparable to 10CFR Part 100 guidelines?

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A "yes" answer to any item in the preceding list identifies that the SSCs are within the scope of the Maintenance Rule.

2.8.2.3 Non–safety-Related SSCs that Mitigate Accidents or Transients Are the non–safety-related SSCs relied upon to mitigate accidents or transients? This step requires licensees to determine which non–safety-related SSCs are needed to mitigate accidents or transients as described in the plant's FSAR.

A "yes" answer identifies that the SSCs are within the scope of the Maintenance Rule.

2.8.2.4 Non-Safety-Related SSCs that Are Used in Emergency Procedures Are the non–safety-related SSCs used in plant EOPs?

This step requires an evaluation to be performed to identify important related SSCs under utility control that are used in EOPs. For an SSC to be considered important, it must add significant value to the EOP's function.

Some examples of non–safety-related SSCs used in EOPs are the following:

(1) Instrumentation providing information but not controlling function.
(2) Fire hose supplying only a small amount of the water required to mitigate the fire event.
(3) Portable emergency equipment that is available from off-site vendors but remains within utility control. (Conversely, if the fire hose provides a large amount of the water required to mitigate an accident, it should be within the scope of the Maintenance Rule.)

2.8.2.5 Non–Safety-Related SSCs with a Procedure Preventing Safety-Related SSCs from Fulfilling Their Safety-Related Functions Will the failure of non–safety-related SSCs prevent safety-related SSCs from fulfilling their safety-related functions? This step requires that each plant investigate the systems and their interdependencies to determine failure modes of non–safety-related SSCs that directly affect safety-related functions.

Does the term *directly* apply to non–safety-related SSCs with failure that:

(1) prevent a safety function from being fulfilled, or
(2) (as a support SSC) prevent a safety function from being fulfilled?

A "yes" answer to either of the listed items identifies that non–safety-related SSCs are within the scope of the Maintenance Rule. A plant should rely on actual plant-specific, industrywide operating experience before engineering evaluations such as PRA environmental qualification (EQ), and 10CFR50 Appendix R analyses. Industrywide operating experience is reviewed for plant-specific applicability and, where appropriate, is included in specific utility programs and procedures. This information should be used to the greatest extent practical to preclude repeat occurrences of unacceptable performance. An event that occurs at a similarly configured plant should be considered applicable to the reviewing utility.

The determination of hypothetical failures that could result from system interdependency but that have not been previously experienced is not required. Failures subsequent to implementation of the Maintenance Rule shall be addressed in the determination of cause, corrective action, and performance monitoring as described herein.

2.8.2.6 Non–safety-Related SSCs Whose Failure Causes Scram or Actuates Safety Systems Will failure of the non–safety-related SSCs cause a reactor scram or actuation of safety-related systems? This step requires plants to determine, on the basis of plant-specific and industrywide operating experience, those non–safety-related SSCs whose failure causes a reactor scram or actuation of a safety-related system.

A "yes" answer identifies that the SSCs are within the scope of the Maintenance Rule.

A licensee should rely on actual plant-specific and industrywide operating experience, previous engineering evaluations (such as PRA), the EQ, and 10CFR50 Appendix R analysis. Industrywide operating experience is reviewed for plant-specific applicability and, where appropriate, is included in maintenance organization specific programs and procedures [2]. This information should be used to the greatest extent practical to preclude repeat occurrences of unacceptable performance. An event that occurs at a similarly configured plant should be considered applicable to the reviewing utility.

The determination of hypothetical failures that could result from system interdependency but that have not been previously experienced is not required. Failures subsequent to implementation of the Maintenance Rule shall be addressed in the determination of cause, corrective action, and performance monitoring as described in Sections 10.5.8, 10.5.9, and 10.5.10 of the Maintenance Rule.

2.8.2.7 SSCs Outside the Scope of the Maintenance Rule Any SSCs that do not meet the above criteria are outside the scope of the Maintenance Rule. These SSCs will continue to have appropriate maintenance activities performed on them as a function of plant requirements and component vendor recommendations. The degree of maintenance attention for these SSCs is dependent on such factors as the consequence of SSC failure on power production as well as economic importance.

2.9 ESTABLISHING RISK AND PERFORMANCE CRITERIA (GOAL SETTING) AND MONITORING

2.9.1 CFR50.65(a)(1)

Each holder of an operating license under 50.21(b) or 50.22 shall monitor the performance or condition of SSCs against licensee established goals to reasonably ensure that such SSCs, as defined in paragraph (b), are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety, and they also take into consideration industrywide operating experience where practical. When the performance or condition, or SSC, fails to meet established goals, appropriate corrective action shall be taken.

2.9.2 Guidance

Once the selection is completed of those SSCs determined to be within the scope of the Maintenance Rule (Section 8.0), it is then necessary as a minimum act of precaution to establish risk-significant performance criteria to initially determine which SSCs must have goals established and monitoring activities performed in accordance with paragraph (a)(1). For SSCs not meeting performance criteria, a determination of cause is performed and, if appropriate, goals are established commensurate with the safety significance and performance of the SSCs. Monitoring the

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performance of the SSCs against goals is intended to reasonably ensure that the performance of the SSCs is acceptable.

All SSCs determined to be within the scope of the Maintenance Rule are subject to an effective programmed maintenance (PM) program as indicated by paragraph (a)(2) (see Section 10.5.10 of the Maintenance Rule). SSCs that are within scope of this paragraph could be included in the formal PM program; otherwise, they can be considered inherently reliable (e.g., by having a visual inspection during walkdowns to meet licensee requirements that already exist), or they can be allowed to run to failure, thereby providing little or no contribution to system safety function. When SSCs in paragraph (a)(2) do not perform acceptably, they are evaluated to determine the needs of goal setting and monitoring under the requirements of paragraph (a)(1).

2.9.3 Performance Criteria for Evaluating SSCs

Performance criteria for evaluating SSCs are necessary to identify the standard against which performance is to be measured. The criteria of availability, reliability, or condition are established to provide a basis for determining satisfactory performance criteria to be used.

The performance criteria can be quantified to a single value or range of values. For example, if a plant Owner wants to maintain an availability of 95% for a particular system because that percentage was the assumption used in the PRA, the 95% value would therefore be considered the performance criteria. If the performance criteria are not met, however, a goal could therefore be set at a value equal to or greater than 95%. Additionally, an example of a performance criteria condition is a case in which a plant wants to maintain the wall-thickness of a piping system to comply with the ASME Code requirements. The plant would establish some acceptable value for wall-thickness and then monitor the thickness by radiography, ultrasonic testing, or through other means.

If performance criteria are not met, the basis for the criteria should be reviewed to determine if goal setting is required and to establish the appropriate goal value. It should be recognized that although goals and performance criteria may have the same value and units, goals are established only by using paragraph (a)(1) if the performance criteria are not met and the goals are meant to reasonably ensure that the performance of the SSCs is acceptable.

Specific performance criteria are established for all risk-significant and non-risk-significant SSCs that are in a standby (not normally operating) mode. Standby systems—risk-significant or non–risk-significant, safety-related or non–safety-related—may only affect plant-level criteria if they fail to perform in response to an actual demand signal, which means that these systems could be failed but their inability to perform their intended safety functions will not be known until performance is required in response to a demand signal or during testing (e.g., a surveillance test to determine operability). The mode in which most standby system failures are observed is during testing. Because plant transients occur less frequently, failure on demand provides minimal information and, for this reason, plant-level criteria are not good indicators or measurements of performance.

The set of performance criteria for a standby system can be qualitatively stated as "initiates upon demand and performs its intended function." The reliability of a standby system to satisfy both criteria can be quantitatively established as calculated in PRA methodology.

Plant-level performance criteria are established for all remaining non–risk-significant, normally operating SSCs. However, there may be some non–risk-significant SSCs whose performance cannot be monitored practically by plant-level criteria, in which case other performance criteria should be established, as appropriate (e.g., repetitions of safety function failures attributable to the same maintenance-related cause).

All risk-significant SSCs determined to have acceptable performance are addressed under paragraph (a)(2) guidelines and monitored against performance criteria established for risk-significant SSCs. An example of the process is as follows:

(1) The SSC is determined to be in scope of Maintenance Rule;
(2) The SSC is determined to be risk-significant;
(3) The SSC performance criteria are established (e.g., the criteria could have an acceptable level of reliability and availability or unavailability as appropriate);
(4) The SSC performance is determined to meet the established criteria; and
(5) The SSC performance is monitored under paragraph (a)(2) guidelines against performance criteria established for risk-significant SSCs.

Those non–risk-significant SSCs in standby and having acceptable performance are also addressed under paragraph (a)(2) guidelines and may be monitored by evaluating surveillance performance. Risk-significant SSCs and non–risk-significant SSCs in standby that are determined to have unacceptable performance are addressed under paragraph (a)(1) guidelines, have goals established, and have their performance monitored to those goals. The remaining non–risk-significant SSCs (those normally operating) are addressed under paragraph (a)(2) guide-lines and their performance is monitored against plant-level criteria. In the event that plant-level performance criteria are not met, a determination of cause will be conducted to determine if the failure of the SSC within the scope of the Maintenance Rule was responsible and, if so determined, whether this failure is considered an MPFF. If it is considered as such, the utility may address the SSC under paragraph (a)(1) guidelines, establish a goal, and monitor performance to that goal; otherwise, it may continue to address performance under paragraph (a)(2) guide-lines after taking corrective action. The performance criteria selected should monitor what included it in the scope of the Maintenance Rule. For example, automatic reactor scrams may be established as the performance criteria to be monitored for demonstrating the effectiveness of preventative maintenance for a given system.

If the function of the scoped system is lost, causing a scram to occur, the determination of cause needs to be ascertained to determine if it is from an MPFF. If an MPFF is indeed the cause, it must be tracked. If a second scram occurs that is caused by the same failure (i.e., repetitive) or if the plant-level performance criteria are not met, a goal must be established at the train or component level. However, failures not causing a scram or actuation of a safety system do not need to be tracked.

For example, Plant A has two 50% capacity circulating water pumps providing cooling to the condenser, and Plant B has three 50% capacity circulating water pumps. If one assumes that loss of circulating water caused both reactors to scram, the system is within the scope of the Maintenance Rule for both Plants A and B. If Plant A loses one pump, that loss causes the plant to scram; however, if Plant B experiences the loss of one pump, it does not cause a scram. Plant A is required to do a determination of cause for any MPFF involvement in the loss. If an MPFF was involved, it must be tracked. Plant B may elect to do a determination of cause but is not required to do so because a scram did not occur;

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moreover, if it experiences a second failure of the same type several weeks later—and the unit does not scram—that failure is not considered repetitive. Neither failure on Plant B needs to be addressed under the Maintenance Rule for two reasons:

(1) the failure that occurred did not cause a loss of the function—that is, the total loss of cooling water that caused the scram conforming it to the Maintenance Rule; and
(2) the plant-level performance criteria—that is, unplanned automatic reactor scrams per 7,000 critical hours—were not affected.

Overall plant-level performance critera are broad-based and supported by many SSCs that could be either safety- or non–safety-related. Because equipment performance is a major contributor to meeting plant-level performance criteria, it can be useful in determining maintenance program effectiveness.

Plant-level performance criteria should include any of the following conditions:

(1) unplanned automatic reactor scrams per 7,000 critical hours;
(2) unplanned safety system actuations; or
(3) unplanned capability loss factor.

Other performance criteria may include indicators similar to those recognized by the NRC and industry organizations, or those established by the plant to monitor SSCs that cannot be monitored practically by plant-level performance criteria.

Each plant Owner should evaluate the plant's own status when determining the quantitative value for its individual plant-level performance criteria. The determination of the quantitative value is influenced by various factors including design, operating history, plant age, and previous plant performance. Plant Owners should also use specific risk-significant SSC performance criteria to consider plant-specific performance and, where practical, industrywide operating experience. Performance criteria for risk-significant SSCs should be established to ensure that reliability and availability assumptions used in the plant-specific PRA or other risk-determining analysis are maintained or adjusted whenever determined necessary by the utility. When Owners establish performance criteria for non–risk-significant standby systems, they should review surveillance and actual system demands. Any failures that result from surveillance and a valid system actuation should be evaluated as well.

2.9.4 Goal Setting and Monitoring

Goals are established to initiate the necessary improvements in performance. When establishing goals, a plant Owner should consider various goal-setting criteria such as existing industry indicators, industry Codes and Standards, failure rates, duty cycles, and performance-related data. In addition to the assumptions made in, and the results of, reliability approaches to maintenance, the assumptions made in, or the results of PRAs should also be considered when establishing goals. In addition, analytical techniques (e.g., system unavailability modeling) may be considered for developing goals. As a goal is selected, the data should be collected over a sufficient time period to minimize the effects of a random event.

Monitoring should consist of periodically gathering, trending, and evaluating information pertinent to the performance and/or to the availability of the SSCs and comparing the results with the established goals and performance criteria to verify that the goals are being met. Results of monitoring, including paragraphs (a)(1) and (a)(2) activities, should be analyzed in a timely manner to ensure that appropriate action is taken.

Regulations and utility commitments (e.g., Emergency Diesel Generator docketed reliability targets in response to the Station Blackout Rule—see 10CFR50.63) provide a baseline for testing and surveillance activities of some SSCs under the scope of the Maintenance Rule. Additional testing and surveillance activities might be necessary if SSC performance is unacceptable, although the Maintenance Rule results might also provide the basis for reduced testing and surveillance. The basis for Technical Specifications, licensing commitments, and other regulations, typical examples of which follow, may be used appropriately for goal setting.

(1) Surveillance test and inspections performed in accordance with ASME OM Code, Section IST and ASME BPV Code, Section XI as required by 10CFR50.55a.
(2) Reactor pressure vessel material surveillance tests conducted in accordance with Appendix H of 10CFR Part 50.
(3) Containment leakage tests performed in accordance with Appendix J of 10CFR Part 50.
(4) Component surveillance or testing required by plant Technical Specifications.
(5) Fire protection equipment tested and maintained in accordance with Appendix R of 10CFR Part 50.
(6) Tests and inspections performed in response to NRC bulletins, generic letters, or other information notices.

2.9.4.1 Determining Whether an SSC-Level Goal is Required If any of the following conditions exist, a goal should be established at the appropriate level (i.e., structure, system, train, or component):

(1) An MPFF altogether caused plant performance criteria to be exceeded;
(2) an MPFF caused a risk-significant or non–risk-significant SSC performance criteria to not be met; or
(3) A second MPFF (of the same cause) occurs following the initial MPFF and implementation of corrective action.

2.9.4.2 Goal Setting Goals can be set at the structure, system, train, or component level, and also for aggregates of these where appropriate. In some cases the utility may elect to establish thresholds that provide an indication of improved performance toward the ultimate goal. A quantitative value for a goal or threshold may be established on the basis of judgment resulting from an appropriately documented review of performance criteria (see Section 9.3.1 of the Maintenance Rule). As a goal is set, the utility should take into consideration (where practical) industrywide operating experience.

2.9.4.3 System Level For those SSCs requiring goal setting, it is expected that many these goals will be established at the system level, in which case the system availability could be used as the monitored parameter. Unavailability times for systems (e.g., service water and HVAC) supporting many other systems can be accounted for by charging the time to the support system that failed rather than the individual systems. Conversely, the unavailability times could be charged to both the support system (i.e., service water) and the supported system (i.e., diesel generator). It is important to ensure that the determination of cause and the corrective action are effective and respond properly to correcting the problem regardless of how the unavailability times are counted. A consistent approach is needed so that the performance criteria can be monitored and tracked. Because

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of plant-specified redundancy and diversity, an SSC failure does not necessarily cause a loss of safety function, but it could result in unacceptable system or train performance.

2.9.4.4 Train Level Risk-significant systems and standby systems with redundant trains should have goals established for the individual trains. The goal could be based on the availability desired or to that assumed in the PRA analysis. Train-level goals provide a method to address degraded performance of a single train even though the system function is still available, and the train-level goal should be set consistent with PRA or other methods of risk-determining assumptions. Alternative goal settings might consider the possibility that the best performing train will be unavailable and that the safety function reliability might be potentially reduced.

2.9.4.5 Component Part Appurtenance and Device Level If these lower level goals are determined to be necessary, they should be established based upon their contribution to a component or system not meeting its performance criteria or a system-level goal. Candidates for component or system goals include classes of items with unacceptable performance, items that caused trips, items directly associated with the causes of safety system challenges, and those items that, because of their failure, cause the performance level to be missed. Careful review and analysis should be per-formed before establishing individual item goals to ensure that the number of item goals is manageable and not overly complex.

2.9.4.6 Structure Level It is expected that most structures will be addressed as required by paragraph (a)(2) of the Maintenance Rule. In those cases in which a structure requires a goal established, that goal might be based on the limits of cracking, corrosion, erosion, settlement, and deflection, for example, or to another condition criteria.

2.9.4.7 Monitoring Monitoring will be performed to determine if maintenance results are in acceptable performance. If one allows the plant-specific updated final safety analysis (UFSAR) or PRA used for addressing a regulatory issue (e.g., NRC Generic Letter 96-05) to be credited for any existing components in the system or train, those components supporting that function should therefore be monitored by use of the Maintenance Rule; otherwise, they could be considered installed spare components not requiring monitoring by use of the Maintenance Rule.

Monitoring SSCs against specific established goals should be conducted in a manner that provides a means of recognizing performance trends. If functional failures result in the inability to meet performance criteria, possibly resulting in the loss of an intended Maintenance Rule function, monitoring should be predictive (when appropriate) to provide a timely warning, and it should also provide a means for determining the effectiveness of previous corrective actions.

Monitoring should appropriately consider the following factors:

(1) existing plant-specific or industry performance monitoring such as Technical Specification surveillance, plant operator daily tours, and plant predictive maintenance.
(2) establishing a practical monitoring process (i.e., it should not require extensive analytical modeling or excessive data collection) capable of detecting changes in SSC performance; and
(3) establishing a baseline to which the goals are monitored.

The monitoring frequency to meet established goals varies, but it may be initially established as the one currently required by existing surveillance requirements or other surveillance-type monitoring being performed. Frequency of monitoring is also dependent upon the goal established and the availability of plant-specific or industry data; it may be either time-directed or based on performance. If necessary, the frequency of monitoring should be adjusted to allow for the early detection and timely correction of negative trends.

Data can be collected from existing sources (e.g., from Technical Specification surveillance, work order tracking, and post-maintenance testing) that are relevant to the goal being monitored. The type and quality of the data being collected and trended is so important that it will ultimately determine if goals are being met. The analysis and evaluation of the collected data should be timely so that, where necessary, corrective action can be taken.

2.9.4.7.1 Monitoring System Level Goals The object of monitoring at the system level is to evaluate the performance of the system against established goals to proceed from the present status of not meeting performance criteria toward a level of acceptable performance. Some examples of parameters monitored at the system level include availability, reliability, and failure rate. Systems should be monitored by use of existing surveillance procedures as long as the data collected by these procedures addresses the specific system goal or goals.

2.9.4.7.2 Monitoring Train-Level Goals Monitoring train-level performance against established goals should consist of gathering availability or failure data and evaluating their results. The review and analysis of this data provide a basis on which improvements are needed and also confirm the effectiveness of corrective actions. Individual train performance should be compared to other such performances or against the average train performance.

2.9.4.7.3 Monitoring Components, Parts, Appurtenances, as well as Devising the Level of Goals Should it be determined that an item requires goal setting, monitoring would include performance-characteristic data (e.g., the flow, pressure, pump, head, temperatures, vibration, current, and hysteresis) that can be used to determine the component performance. Monitoring can also be done using some type of predictive maintenance and nondestructive examination (NDE) analysis (e.g., by means of using oil or grease, vibration, acoustics, and electric continuity, as well as ultrasonic, infrared, thermographic, and eddycurrent examinations). Information might include surveillance test results that the utility had already performed or industry failure rate data.

2.9.4.7.4 Monitoring Structure Level Goals Should it be determined that a structure requires goal setting, that goal should be monitored to ensure that it will be met. Such structures include the reactor containment, the foundations for important components such as turbines, pumps, and heat exchangers, as well as the structures having degradation or failure that could significantly compromise the function of other SSCs covered by the Maintenance Rule. Examples of monitoring include NDE, visual inspection, vibration, deflection, thickness, corrosion, and other appropriate monitoring methods.

2.9.4.8 Dispositioning of SSCs from Paragraphs (a)(1) to (a)(2) After a goal is determined to have been met, the monitoring

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of SSC performance against that goal may be discontinued if any of the following criteria are satisfied:

(1) performance is acceptable for three surveillance periods in which the surveillance periodicity is equal to or less than a 6 mo. interval;
(2) performance is acceptable for two successive surveillance periods in which the surveillance periodicity is greater than 6 mo. but not greater than two fuel cycles; or
(3) an approved and documented technical assessment ensures the cause is known and corrected, thus making monitoring against goals unnecessary.

If any of these conditions are met, the SSC may be returned to the provisions of paragraph (a)(2).

2.9.4.9 Unacceptable Performance or Failure Cause Determination and Dispositioning SSCs from (a)(2) to (a)(1) A determination of cause of appropriate magnitude is required for the following conditions:

(1) a goal not being met, and
(2) a performance criteria are not being met.

The results of the determination of cause may make that establishing a goal a requirement for the following two conditions:

(1) a functional failure of a risk-significant SSC, even if the goal or performance criteria are met, and
(2) a repetitive MPFF of any SSC within the scope of the Maintenance Rule, even if the goal or performance criteria are met.

During the Maintenance Rule's initial implementation, repetitive failures that occurred during the previous two operating and refueling cycles should be considered. After the initial rule implementation, utilities should establish an appropriate review cycle for repetitive MPFFs (e.g., a periodic review—during the next maintenance or test of the same function.

The determination of cause should identify the cause of the failure or unacceptable performance and if the failure was an MPFF, it should also identify any corrective action to preclude recurrence and determine if the SSC requires the use of paragraph (a)(1) for goal setting and monitoring. Numerous techniques are available to the nuclear utility industry that could be used for determining if the failure is indeed an MPFF. In some cases this determination is a simple assessment of an obvious cause; in other cases, however, the determination requires a rigorous and formal root cause analysis in accordance with the methodology that exists in the industry. The use of any of these procedures is satisfactory provided it results in the identification and correction of the problem.

The determination of cause and the corrective action should reinforce achieving the performance criteria or goals that are monitored and may also determine whether the goal or performance criteria themselves should be modified. Deciding whether SSCs should have performance or goals monitored should be done. The decision to allow failure may be an acceptable one; for example, deciding to replace a failed component providing little or no contribution to safety function rather than performing a preventative maintenance activity may reduce exposure, contamination, and cost without impacting safety. Once the determination of cause and the corrective actions are completed, monitoring and periodically evaluating the performance should continue until the goal or performance criteria are achieved.

The determination of cause should address failure significance, the circumstances surrounding the failure, the characteristics of the failure, and whether the failure is isolated or has a generic or common cause [4]. The circumstances surrounding the failure may indicate that the SSC failed because of adverse operating conditions (e.g., operating a valve dry and overpressurization of the system) or because of failure of another component. The results of the determination of cause should be documented for failures of SSCs under the scope of the Maintenance Rule.

2.9.5 MPFFs

An MPFF is an unintended event or condition in which an SSC within the scope of the Maintenance Rule is not capable of performing its intended function and that should have been prevented by performing appropriate maintenance actions. Under certain conditions, an SSC may be considered incapable of performing its intended function if it is out of its specified adjustment or not within its specified tolerances.

The determination of cause should establish if the failure is an MPFF, after which it will be necessary to determine if a goal should be established on any SSC experiencing the MPFF. If the SSC failure is not an MPFF, the utility should continue performing the appropriate maintenance on the SSC.

If a plant determines that a modification is not cost-effective and decides not to make a change, any subsequent failure may not be an MPFF. The decision to not make a design modification includes an evaluation of the consequences of future failures and also consideration of whether run-to-failure or degraded performance (i.e., performs corrective maintenance rather than preventative maintenance) is an acceptable condition (see NUMARC 93-01, Section 9.3.3). Additional preventive maintenance or inspection activities may be necessary to compensate for the deficient design. If the utility augments the preventive maintenance program to compensate for a design deficiency, this activity is within the scope of the Maintenance Rule, and future failures could be MPFFs. An MPFF failure would occur if the utility did not maintain the SSC in its original state (i.e., its design condition).

2.10 SSCS SUBJECT TO EFFECTIVE PROGRAM MAINTENANCE PROGRAMS

2.10.1 CFR 50.65(a)(2)

Monitoring as specified in paragraph (a)(1) of the Maintenance Rule is not required if the performance or condition of an SSC is demonstrated as being effectively controlled through the performance of appropriate program maintenance. This activity permits the SSC to remain capable of performing its intended function.

2.10.2 Guidance

Although goals are set and monitored as specified in paragraph (a)(1), the programmed maintenance (PM) and performance monitoring activities are part of paragraph (a)(2) and apply to all SSCs that are within the scope of the Maintenance Rule. Any SSCs that are within the scope of paragraph (a)(2) could be included in the formal PM program, be inherently reliable (e.g., by having a visual inspection during walkdowns to meet licensee requirements that already exist), or they can be allowed to run to failure, thereby providing little or no contribution to system safety function.

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An effective programmed maintenance program is one that will achieve the desired results of minimizing component failures and increasing or maintaining SSC performance. The individual maintenance program elements (training, procedures, cause determination, and so forth) are directed toward achieving effective maintenance through the appropriate use of resources.

If the performance of an SSC being effectively controlled through a PM program cannot be demonstrated, establishing a goal and monitoring the performance of the SSC against that goal becomes necessary. If the SSC is determined to be inherently reliable, placing the SSC in the scope of paragraph (a)(1) and establishing a goal is therfore unnecessary. An inherently reliable SSC is one that can maintain a high level of reliability without preventative maintenance. SSCs that provide little or no contribution to system safety function can therefore be allowed to run to failure (i.e., they would perform *corrective* rather than *preventative* maintenace) and be addressed by paragraph (a)(2).

2.10.2.1 Performance of Applicable Program Maintenance Activities Several methods are available to the nuclear utility industry for determining applicable and effective preventative maintenance activities to ensure satisfactory performance of SSCs. It is not the intention of this guideline to identify these programmatic methods of determining applicable maintenance activities. Sound preventative maintenance activities include, but are not limited to, elements in the following list and are discussed in the forthcoming paragraphs.

(1) periodic maintenance, inspection, and testing;
(2) predictive maintenance, inspection, and testing; and
(3) trending of appropriate failures.

2.10.2.2 Periodic Maintenance, Inspection, and Testing Periodic maintenance, inspection and testing activities are accomplished on a routine basis—typically based on operating hours or calendar time—and include external inspections, alignments or calibrations, internal inspections, overhauls and component or equipment replacement. Lubrication, filter change, and equipment overhaul are some examples of activities included in periodic maintenance.

2.10.2.3 Predictive Maintenance, Inspection, and Testing Predictive maintenance activities, including performance monitoring, are generally nonintrusive and normally can be performed with the equipment operating. Vibration analysis (which includes spectral analysis), bearing temperature monitoring, lube oil analysis (ferrography), infrared surveys (thermography), and motor voltage and current checks are some examples of preventative maintenance activities. The data obtained from predictive maintenance activities are used to trend and monitor equipment performance so that planned maintenance can be performed before equipment failure.

2.10.2.4 Performance Trending Performance should be trended against established performance criteria to identify adverse trends, for which appropriate corrective action should be promptly initiated. The utility's historical data, combined with industry operating experience, operating logs and records, and station performance monitoring data, can be useful in analyzing trends and failures in equipment performance and also for making adjustments to the preventive maintenance program.

2.10.2.5 Ongoing Maintenance Effectiveness Evaluation Ensuring satisfactory performance of risk-significant and standby SSCs requires an ongoing assessment of the SSCs against the utility's performance criteria. The results of this assessment should provide feedback and adjustment of maintenance activities so that MPFFs are addressed. Those MPFFs that are repetitive or risk-significant must be investigated and have their cause determined. When performance is determined to require improvement, the utility should promptly implement the appropriate corrective actions.

It should be noted that the objective of monitoring plant-level performance criteria is to focus attention on the aggregate performance of many of the operating, non–risk-significant SSCs within the scope of the Maintenance Rule.

There are no individual SSC performance criteria included in the plant-level performance criteria, for the SSCs that support plant-level performance criteria are included in the preventative maintenance program addressed by paragraph (a)(2) of the Maintenance Rule. An individual SSC's failure may not result in unacceptable performance and thus may not affect the plant-level performance criteria; the utility may establish a goal for that failed SSC. If plant-level performance criteria are not met because of an MPFF, the SSC should therefore be considered for disposition to paragraph (a)(1) provisions.

(For monitoring maintenance effectiveness, this section is not intended to exclude a periodic review of preventative maintenance activities in addition to the ongoing review.)

2.10.2.6 Monitoring the Condition of Structures Structures can be monitored by using performance criteria under paragraph (a)(2) provisions or goals under paragraph (a)(1) provisions of the Maintenance Rule. These performance criteria or goals can be established to monitor either performance or condition. For example, certain structures such as the primary containment can be monitored through the performance of established testing requirements, such as those contained in Appendix J of 10CFR50, whereas other structures, such as reactor buildings, auxiliary buildings, and cooling towers, may be more amenable to visual inspection similar to that performed as part of the inservice inspection (ISI) activities required by the ASME Codes. Other visual inspection activities may include such activities as monitoring of corrosion, settlement, roof leakage, and concrete cracking. Monitoring of structures should be given the same priority as mechanical and electrical systems and their components.

Utilities should establish performance criteria and goals within the scope of the Maintenance Rule for which the existing monitoring activities are credited or on which they are based.

Monitoring of structures, like systems and components, should be predictive and provide an early warning of degradation. The baseline condition of plant structures should be established to facilitate condition monitoring activities—a subject that, although not required by regulations, is addressed in NUREG 1522, "Assessment of Safety-Related Structures in Nuclear Power Plants."

2.11 EVALUATION OF SYSTEMS TO BE REMOVED FROM SERVICE

2.11.1 10CFR50.65(a)(3)

In performing monitoring and preventative maintenance activities, an assessment of the total out-of-service plant equipment

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should be considered when determining the overall effect on performance of safety functions.

2.11.2 Guidance

This section guides the development of an approach used for assessing the impact on overall plant safety functions when the SSCs are removed from service. The method used is intended to ensure that overall plant safety function capabilities are maintained, and this guidance is intended to cover all modes of plant operation.

The assessment does not require the performance of a quantitative assessment of probabilistic risk. However, a capable utility can use the quantitative assessment option in varying forms of guidelines for removing the SSCs from service. Some examples of these guidelines are the use of a matrix approach, a checklist, and a list of preanalyzed configurations. In those cases where a matrix, preanalyzed configuration, or another approach fails to address which configuration the plant would need to be in to support the maintenance activity, additional considerations or evaluations should be performed. (Additional guidelines for the removal of systems from service during plant shutdown are included in NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management.")

The development of an approach used for assessing the impact on overall plant safety functions after the SSCs are removed from service consists of following three steps:

(1) identifying key plant safety functions to be maintained;
(2) identifying the SSCs that support key plant safety functions; and
(3) considering the overall effect on key plant safety functions by removing the identified SSCs from service.

Steps (1) and (2) of the preceding list were discussed in a general context in previous sections of this chapter and established a framework for Step (3)—assessing the removal of SSCs from service.

2.11.3 Identifying Key Plant Safety Functions Applicable to the Plant Design

Key plant safety functions are those that ensure the integrity of the reactor-coolant pressure boundary, ensure the capability to shut down and maintain the reactor in a safe shutdown condition, and ensure the capability of preventing or mitigating the consequences of accidents that could result in potential offsite exposure comparable to 10CFR Part 100.

Some examples of these key plant safety functions are the following:

(1) containment integrity (containment isolation, containment pressure, and temperature control);
(2) reactivity control;
(3) reactor-coolant heat removal; and
(4) reactor-coolant inventory control.

These functions are achieved by using systems or combinations of systems that may include redundant subsystems or trains.

2.11.4 Identifying SSCs that Support Key Plant Safety Functions

Once the required key plant safety functions are identified, the SSCs that support them also must be identified. The ability of a system to perform its intended function in support of identified plant safety functions is crucial to determining the overall effect of taking SSCs out of service.

Work done to date on symptom-based emergency operating procedures as well as PRA vulnerability assessments can be used to establish risk-significant criteria for identifying SSCs and selecting those for which the fulfillment of the key safety function is required.

2.11.5 Assessing and Controlling the Effect of SSC Removal from Service on Key Plant Safety Functions

During the planning and scheduling phase, and before authorizing the removal of SSCs from service, each planned maintenance activity that results in the removal of a Maintenance Rule–Scoped SSC from service should be assessed for its impact on key plant safety functions. This assessment applies during all modes of plant operation, and one should consider the current plant configuration as well as the expected changes to plant configuration. For example, scheduling maintenance requiring out-of-service auxiliary feedwater pumps should consider the plant mode or condition, an assessment of when auxiliary feedwater would be needed the least, scheduled availability of other feedwater sources, and the time that auxiliary feedwater would be unavailable. Additionally, before actually removing the system from service to begin maintenance, the condition of the plant should be reviewed to verify the acceptability of conditions to take the system out of service.

On-line maintenance is a planned, scheduled activity used for performing preventative or corrective maintenance—with the reactor at power—while properly controlling out-of-service time of systems or equipment. The benefits of well-managed maintenance conducted during power operations include the following:

(1) increased system and unit availability;
(2) reduction of equipment and system deficiencies that could impact operations;
(3) more focused attention during periods when few activities are competing for specialized resources; and
(4) reduction of the scope of work during outages.

On-line maintenance should be carefully managed to achieve a balance between the benefits and the potential impacts on safety, reliability and availability. For example, the margin of safety could be adversely impacted if maintenance is performed simultaneously on multiple equipment or systems without proper consideration of risk, or if operators are not fully cognizant of the limitations placed on the plant because of out-of-service equipment. Online maintenance should be carefully evaluated, planned, and executed to avoid transients or other undesirable conditions, thereby ensuring a conservative margin of core safety.

Insights gained from available operating experience and analytical tools (i.e., probabilistic safety assessments) can be incorporated into the on-line maintenance process. Such insights can be used for identifying the systems or equipment that can be removed from service while considering assessments of when the system would be needed the least, and can also be used (where appropriate) to establish specific criteria for making decisions about planned equipment removal, frequency, and duration. Generally, actions to manage risk are directed at properly controlling out-of-service time and maintaining configuration control to ensure in-depth defense whenever certain systems or equipment are made unavailable.

It is important to note that the decision to take equipment out of service for maintenance during power operation should consider the likelihood—and possible consequences—of an event occurring while the equipment is out of service.

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At each plant, a number of systems or trains are identified as risk-significant and have performance criteria established for allowable unavailability and reliability. For these systems, the performance criteria is periodically evaluated to ensure that maintenance activities are effective and result in high levels of system availability and reliability. The total time that a risk-significant system or train is out of service for all causes (the total unavailability) is monitored against the performance criteria and controlled to avoid an inadvertent increase in the risk of a significant event occurring.

2.12 PERIODIC MAINTENANCE EFFECTIVENESS ASSESSMENTS

2.12.1 10CFR50.65(a)(3)

Performance and condition monitoring activities as well as associated goals and preventative maintenance activities shall be evaluated at least every refueling cycle if the interval between evaluations does not exceed 24 mo. The evaluation shall consider (where practical) industrywide operating experience. An adjustment shall be made where necessary to ensure that the objective of preventing structure, system, and component failures through maintenance is appropriately balanced against the objective of minimizing structure, system, and component unavailability from monitoring or preventative maintenance.

2.12.2 Guidance

Periodic assessments shall be performed to establish the effectiveness of maintenance actions. These assessments shall consider (where practical) industrywide operating experience. The assessment consists of several activities to ensure an effective maintenance program and to identify necessary adjustments that should be made to the program. The periodic assessments, determination of cause, monitoring, and other activities associated with the Maintenance Rule provide an opportunity to feedback and learning. The following paragraphs describe some activities that should be performed.

2.12.2.1 Review of Goals: Paragraph (a)(1) Periodically, goals established under paragraph (a)(1) provisions of the Maintenance Rule shall be reviewed. This review should include an evaluation of the performance of the applicable SSCs against their respective goals and, in addition, evaluate each goal for its continued applicability.

2.12.2.2 Review of SSC Performance: Paragraph (a)(2) Periodically, SSC performance related to plant-level criteria should be assessed to determine maintenance effectiveness. This assessment should determine if performance is acceptable. If it is found unacceptable, the cause should be determined and corrective action implemented.

For SSCs that are monitored under paragraph (a)(2) provisions, the periodic assessment should include a review of the performance against the established criteria. To redisposition SSCs from paragraph (a)(2) to paragraph (a)(1), see Section 9.4.4 of the Maintenance Rule. Where appropriate, industrywide operating experience should be reviewed to identify potential problems that are applicable to the plant. Applicable industry problems should be evaluated and compared with the existing maintenance and monitoring activities; where appropriate, adjustments should be made to the existing programs.

2.12.2.3 Review of Effectiveness of Corrective Actions As part of the periodic review, corrective actions taken as a result of ongoing maintenance activities or goal setting should be evaluated to ensure that action was taken when appropriate and its result was an improvement of the SSC's performance. Corrective actions that should be reviewed include the following:

(1) actions to ensure that SSC performance meets goals established by the paragraph (a)(a) requirements;
(2) actions taken because of determination; and
(3) status of problem resolution (if any) identified during the previous periodic assessment.

2.12.2.4 Optimizing Availability and Reliability for SSCs For risk-significant SSCs, adjustments shall be made (where necessary) to maintenance activities for ensuring that the objective of preventing failure is appropriately balanced against the objective of ensuring acceptable SSC availability. For operating non risk-significant SSCs, measuring SSC performance against overall plant performance criteria is acceptable, whereas for standby systems, measuring performance against specific criteria is acceptable.

The intent is to optimize availability and reliability of the safety functions by properly managing SSCs when they are out of service for preventative maintenance activities. This optimization could be achieved by any one of the following:

(1) ensuring that appropriate preventative maintenance is performed to meet availability objectives as stated in plant-risk analysis, UFSAR, and other reliability approaches to maintenance;
(2) allocating preventative maintenance to applicable tasks commensurate with anticipated performance improvement (e.g., pump vibration analysis instead of teardown);
(3) reviewing to determine that availability of SSCs has been acceptable;
(4) focusing maintenance resources on preventing those failure modes that affect a safety function; or
(5) scheduling the amount, type, or frequency of preventative maintenance as necessary to appropriately limit the time spent out of service.

The emergency diesel generator can be used as an example of optimizing reliability and availability, (a)(3) and as an example of transitioning between the rule requirements specified in paragraphs (a)(1) and (a)(2), as described in the paragraphs that follow.

If an emergency diesel generator fails to meet its established performance criteria, a determination of cause would be made. Examples of performance criteria include the target reliability value (i.e., 0.95 or 0.975) at a level established in the utility's documented commitment from the Station Blackout Rule (SBO), and also unavailability that, if adopted as performance criteria, would not alter the conclusions reached in the utility PRA.

If the need for goal setting is indicated, an appropriate goal should be established and monitored as indicated in paragraph (a)(1) until the goal is achieved and monitoring can be resumed under the paragraph (a)(2) provisions. Monitoring under the paragraph (a)(1) provisions could be achieved by the use of exceedance trigger values, as described in Appendix D of NUMARC 87-00, excluding those values indicated in paragraph D.2.4.4 (Problem EDG) [5].

The periodic assessment can be performed more frequently than the refueling cycle (e.g., on an annual basis), nor does it need to be

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performed at any specific time during the refueling cycle as long as it is performed at least once and the interval between assessments does not exceed 24 mo. This allows utilities at multiple unit sites to perform the assessment concurrent with the refueling cycle, even though these cycles for the units are staggered. The requirements for performing the periodic assessment can be satisfied by using an ongoing assessment combined with a higher-level summary assessment performed at least once every refueling cycle not exceeding 24 mo. between evaluations.

The periodic assessment is intended to evaluate the effectiveness of paragraphs (a)(1) and (a)(2) activities, including goals that have been established, the monitoring of those established goals, determinations of cause, corrective actions, and the effectiveness of preventative maintenance (including performance criteria). The periodic assessment may, at the option of the utility, include the balancing of availability and reliability, the effectiveness of the removal of equipment from service, and any other Maintenance Rule–type procedures demonstrating the effectiveness of maintenance.

2.13 DOCUMENTATION

2.13.1 General

Documentation developed for implementation of the Maintenance Rule is not subject to the utility Quality Assurance (QA) Program unless the documentation was defined previously as being within the scope of the QA Program. This documentation should be available for internal and external review, but it does not require submittal to the NRC.

2.13.2 Documentation of the SSC Section Process

The SSCs that are identified for consideration under the provisions of the Maintenance Rule and the criteria for inclusion shall be documented. SSC listings, functional descriptions, piping and instrument diagrams (P&IDs), flow diagrams, or other appropriate documents may be used for this process.

2.13.3 Maintenance Rule Scoping

The following items from the initial scoping effort should be documented:

(1) the SSCs in scope and their function;
(2) performance criteria;
(3) the SSCs placed under paragraph (a)(1) provisions and the basis for placement, as well as the goals established and the basis for those goals; and
(4) the SSCs placed under paragraph (a)(2) provisions and the basis for paragraph (a)(2) placement.

Periodically, because of design changes, modifications to the plant occur that may affect maintenance programs. These design changes should be reviewed to ensure that the maintenance program is adjusted appropriately in such areas as risk significance, goal setting, and performance monitoring.

2.13.4 Documentation of Paragraph (a)(1) Activities

Performance against established goals and determination of cause results should be documented. Changes to goals—including instances when goals are effective that the performance of the SSC is so important that the SSC can be moved to the provisions of paragraph (a)(2)—should be documented. Monitoring and trending activities, as well as any action taken as a result of these activities, should also be documented.

2.13.5 Documentation of Paragraph (a)(2) Activities

Activities associated with the preventative maintenance program should be documented consistent with appropriate utility administrative procedures—for example, results of repairs, tests, inspections, and other maintenance activities should be documented in accordance with plant-specific procedures. The results of the determination of cause for repetitive or other types of SSC failures resulting from MPFFs should be documented.

Documentation of SSCs subject to the ASME OM Code Section IST inservice testing should be maintained. Evaluation of performance against plant-level performance criteria (see Section 12.2.2 of the Maintenance Rule) shall be documented. Adverse trends shall be identified, with those SSCs affecting the trend investigated and (where appropriate) corrected.

2.13.6 Documentation of the Periodic Assessment

The aforementioned periodic assessment should have documentation, the appropriate details or summaries of which should consider the following:

(1) the results of monitoring activities for SSCs considered under paragraph (a)(1) provisions (the documentation should include the results of the goals that were met);
(2) the evaluation of performance criteria or goals that were not met, along with the determination of cause and the associated corrective actions;
(3) corrective actions for paragraphs (a)(1) and (a)(2) that were ineffective;
(4) a summary of SSCs redispositioned from paragraphs (a)(2) to (a)(1)—and vice versa—and the basis; and
(5) identifying changes to maintenance activities that result in improving the relationship availability and preventative maintenance.

2.14 REFERENCES

1. NEI 96-03, “Guidelines for Monitoring the Condition of Structures at Nuclear Power Plants”; The Nuclear Energy Institute.
2. USNRC RG1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Rev. 3; The U.S. Nuclear Regulatory Commission.
3. Federal Register: Rules and Regulations, Vol. 53, No. 56, p. 9340.
4. NUREG/CR 4780, “Procedures for Treating Common Cause Failures in Safety and Reliability Studies.”
5. NUMARC 87-00, Appendix D, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light-Water Reactors,” Rev. 1, Aug. 1991.

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CHAPTER

3

PIPE VIBRATION TESTING AND ANALYSIS

David E. Olson

In this chapter, background and requirements for testing, evaluating and qualifying vibration in power plants are addressed. This includes the testing and evaluation methods included in the ASME Operating and Maintenance OM-3 "Vibration Testing of Piping Systems", the acceptable stress limits included in the ASME Boiler and Pressure Vessel Code and the applicable regulatory requirements for piping vibration. Examples are provided of various types of vibration problems experienced in power plants.

3.1 PIPING VIBRATION CHARACTERISTICS

For the purposes of piping design and monitoring, vibration is typically divided into two types: steady-state and dynamic transient vibrations. Each type has its own potential causes and effects that necessitate individualized treatment for prediction, analysis, control, and monitoring [1].

3.1.1 Steady-State Vibration

Piping steady-state vibration can be defined as a repetitive vibration that occurs for a relatively long time period. It is caused by a time-varying force acting on the piping. Such a force may be generated by rotating or reciprocating equipment by means of vibration of the equipment itself or as a result of fluid pressure pulses. Vibrational forces may also result from cavitation or flashing that can occur at pressure reducing valves, control valves, and flash tanks. Flow-induced vibrations such as vortex shedding can cause steady-state vibrations in piping, and wind loadings can cause significant vibrations for exposed piping similar to that typically found at outdoor boilers. Steady-state vibrations exist in a range from periodic to random.

The primary effect of steady-state vibration is material fatigue from the large number of associated stress cycles. This failure may occur in the piping itself, most likely at areas with stress risers such as branch connections, elbows, threaded connections, or valves. However, this failure can also occur in various piping system components and supports. Fatigue damage to wall penetrations can occur because of vibration in the attached piping, snubbers, and supports; premature failures of machine bearings are another potential consequence.

3.1.2 Dynamic-Transient Vibration

The dynamic transient is the second, perhaps more dramatic form of piping vibration, differing from the steady-state vibration in that it occurs for relatively short time periods and is usually generated by much larger forces. In piping, the primary cause of dynamic transients is a high- or low-pressure pulse traveling through the fluid. Such a pulse can result in large forces acting in the axial direction of the piping, the magnitude of which is normally proportional to the length of pipe leg—that is, the longer the pipe leg, the larger the dynamic transient force the piping will experience (*pipe leg* is defined as the run of straight pipe between bends). A common transient is water- or steamhammer. The usual causes are rapid pump starts and trips, and also the quick closing or opening of valves such as turbine-stop valves and various types of control valves. Dynamic transients also occur as a result of rapid safety/relief valve (SRV) opening or as a result of unexpected events, such as water accumulating at a low point in steam piping during a plant outage. When the steam is returned to the line, a slug of water will be pushed through the piping, resulting in large axial loads at each elbow.

Effects of transient vibrations are usually obvious; large pipe deflections usually occur that damage the support system and insulation as well as cause possible yielding of the piping. Of course, damage can also be sustained by the associated equipment, valve operators, drain lines, and so forth. An example illustrating the striking nature of dynamic transients occurred in a fossil fuel plant cold-reheat line. There, the low-point drains had not been properly maintained, and water accumulated in the line after a turbine trip. When the turbine-stop valves were opened, a water slug was forced through the piping, resulting in a transient so severe that the 80 ft., 18 in. diameter pipe riser was lifted over $1\frac{1}{2}$ ft. in the air. When the piping came down, most of the hangers were broken, and the piping had large deformations.

3.2 VIBRATION EXPERIENCE WITH U.S. NUCLEAR POWER PLANTS

Piping vibration problems have been well documented for nuclear power plants. Fossil fuel power plants experience many of the same problems, but documentation of their problems is sparse.

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Problems in nuclear power plants are documented by Licensee Event Reports (LERs). An LER is a generic term for a reportable occurrence—an unscheduled incident or event that the U.S. Nuclear Regulatory Commission (USNRC) determines is significant from the standpoint of public health or safety.

Kustu and Scholl performed a survey to identify the causes and consequences of significant problems experienced with light-water reactor (LWR) piping systems [2]. The authors ranked the need for pipe vibration research as highest priority. Pipe cracking was identified as the most frequently recurring problem, the most significant cause of which was determined to be piping vibration. Mechanical vibration was the cause of 22.3% of all reportable occurrences involving pipes and fittings. Problems with pipe and pipe fittings were found to be responsible for approximately 10% of all safety-related events and 7% of all outage time at LWRs.

A separate summary of LERs through Oct. 1979 documented 81 cracks in pipes less than 4 in. that were directly attributable to vibration [3]. A more detailed review of the LERs found that cracks in tap lines (e.g., vents, drains, and pressure-tap connections) were a prevalent mode of pipe failure. The frequency of small tap-line failures has also been verified by personnel familiar with start-up testing and operation of LWR plants. In addition, a Sept. 1983 Institute of Nuclear Power Plant Operations (INPO) Significant Event Report (SER 64-83) noted that from April 1970 to Sept. 1983, 234 reported failures of small-diameter safety-related pipes have been caused by vibration-induced fatigue. The Operations and Maintenance (O&M) Reminder 424 ("Small-Bore Piping Connection Failures," Jan. 7, 1998), another INPO report, stated that failures of small-bore piping connections continue to occur frequently and result in degraded plant systems and unit capability factor losses from unscheduled shutdowns. This INPO report also stated that of the 11 small-bore piping connection failures reported in 1997, 8 required plant shutdowns for repairs.

Another study was completed by Bush to establish trends and predict failure mechanisms in piping [4]. This study was primarily based on LERs and their precursors: Abnormal Occurrence Reports (AORs). Although this study dismissed failure in smaller pipe sizes as not having any major safety significance, it did note that there was substantial failure data for small pipe sizes (diameter less than 4 in. and usually less than 2 in.). Such failures were attributed primarily to vibrational fatigue.

Bush's study noted the large numbers of reported waterhammer and water-slugging events. Waterhammer is defined as a multicycle load induced by transient pressure pulsation in the fluid, whereas water slugging is defined as a single load induced by accelerating a slug of water through the piping. Over 200 such events have been documented, ranging from the trivial to some that caused breakage of piping and significant damage to the piping system.

What can be concluded from this experience is that piping vibration has been a significant source of problems in power plants. Not surprisingly, most pipe failures have been experienced in small piping; there is, after all, much more small-diameter piping than large-diameter piping in a power plant. In addition, small piping is often weaker than its support system; moreover, it is typically the weakest link that fails in the system. The structural vibrational modes of small-branch piping are often excited by the structural vibrations of the header piping. Frequently, pressure pulsations in the header piping or vortex shedding at the branch connection also excite acoustic resonances in the branch piping.

Failure of large-bore piping has been less frequent. This is not surprising, for large-bore piping is often stronger than other components in the piping system. Although vibration of large-bore piping has resulted in pipe failures, failures of other weaker components are far more common. Snubbers—both mechanical and hydraulic—have a history of failure when they are subjected to continuous piping vibration [5]. Small-tap lines have failed because of vibration of large-bore header piping; leaks have developed in flanges and valves; and rotating equipment is adversely affected by piping vibration. Sudden failures can happen as a result of waterhammer or water slugs.

Large-bore piping vibration can also create other problems, one example of which is a steam-bypass line in which steady-state pipe vibration caused failure of the piping weight supports. These failures went unnoticed until a 300 deg. circumferential crack formed in the line at the nozzle weld. The failed hangers resulted in a low point in the piping where water accumulated when the line was not used. The water slugging that resulted when the line was returned to operation contributed to the weld failure.

3.3 ALLOWABLE PIPING RESPONSE FOR VIBRATION

Nearly all piping in a power plant will experience some amount of vibration, and piping vibration problems in operating plants have resulted in costly unscheduled outages and backfits. Vibration effects can be manifested in the gradual fatigue failure of the piping and its appurtenances, or in the more dramatic motions caused by dynamic-transient vibrations. The power industry has addressed these problems by using various Codes and regulations. The discussion that follows reviews the requirements of these documents, the allowable stress limits for piping vibration, and the effect of vibration on piping response.

3.3.1 Industry Codes and Standards

The governing Power Piping Codes—the ASME Boiler and Pressure Vessel (B&PV) Code Section III for Class 1, 2, and 3 Piping [6] and ASME B31.1 (*Power Piping*) [7] both contain requirements regarding piping vibration. The ASME B&P Code Section III uses the following wording to address steady-state vibration:

> Piping shall be arranged and supported so that vibration will be minimized. The designer shall be responsible by design and by observation under start-up or initial operating conditions, for ensuring that vibration of piping systems is within acceptable levels.

Section III contains the following additional requirements for outdoor piping:

> Exposed Piping—Exposed piping shall be designed to withstand wind loadings, using meteorological data to determine wind forces. . . .
>
> Requirements for dynamic transient vibration include the following:
>
> Impact—Impact forces caused by either external or internal loads shall be considered in the piping design.

ASME B31.1-2012 includes the following requirements regarding vibration:

> Vibration. Piping shall be arranged and supported with consideration of vibration

B31.1 Nonmandatory Appendix V Recommended Practice For Operation, Maintenance, And Modification of Power Piping Systems of ASME B31.1 also has the following recommended practice:

V-7.2 Visual Survey

The CPS (covered piping systems) should be observed visually, as frequently as deemed necessary. Any unusual conditions should be brought to the attention of plant management personnel as prescribed in the procedures of para. V-3.1. Observations should include determination of interferences with or from other piping or equipment, vibrations, and general condition of the piping system and supports, including but not limited to hangers, guides, restraints, anchors, supplementary steel, and attachments.

As the foregoing Code excerpts illustrate, the designer must be concerned with piping vibration effects in both the design and testing stages of power plant development.

These Codes also require that piping systems be designed for the effects of earthquakes. However, the fact that a system is designed to withstand earthquake effects does not necessarily mean that the design is satisfactory from a vibration standpoint. For this reason, vibration and seismic effects are typically considered separately in the piping design.

3.3.2 Additional Requirements for Nuclear Plants

Further requirements for nuclear power plants are delineated in USNRC Regulatory Guide 1.68 (*Initial Test Programs for Water-Cooled Nuclear Power Plants*) [8] and NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 3.9.2 "Dynamic Testing And Analysis Of Systems, Structures, and Components", [9]. The relevant portions of these documents are reproduced in the following paragraphs; their significance is that they require most of the plant piping to be tested for both steady-state and dynamic-transient vibrations.

The requirements reviewed above emphasize the importance that this area of piping design has received. The designer is obligated to minimize potential vibration effects to not only prevent costly downtime and backfits, but also to be in compliance with the various requirements concerning piping vibration.

To address these code and regulatory requirements for pipe vibration an ASME Standard, ASME OM-S/G-2003, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 3: "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems," (or OM-3 for short), was developed [10]. OM-3 provides test methods and acceptance criteria for assessing the severity of piping vibration. Steady-state and transient-vibration testing are addressed along with applicable instrumentation and measurement techniques, recommendations for corrective action, and discussions of potential vibration sources. The acceptance criteria from this Standard are discussed later in this chapter.

3.3.2.1 Excerpts from USNRC NUREG-0800 and Reg. Guide 1.68. Standard Review Plan (SRP) NUREG-0800 provides guidance to USNRC staff in performing safety reviews of construction permit or operating license applications under 10 CFR Part 50 and early site permit, design certification, combined license, standard design approval, or manufacturing license applications under 10 CFR Part 52.

The following excerpt from Section 3.9.2 Dynamic Testing And Analysis Of Systems, Structures, And Components relates to piping vibration testing, including related parameters and applicable piping systems.

I. AREAS OF REVIEW

This Standard Review Plan (SRP) section addresses the criteria, testing procedures, and dynamic analyses employed to ensure the structural and functional integrity of piping systems, mechanical equipment, reactor internals, and their supports (including supports for conduit and cable trays, and ventilation ducts) under vibratory loadings, including those due to fluid flow (and especially loading caused by adverse flow conditions, such as flow instabilities over standoff pipes and branch lines in the steam system) and postulated seismic events. Compliance with the specific criteria guidance in subsection II of this SRP section will provide reasonable assurance of appropriate dynamic testing and analysis of systems, components, and equipment within the scope of this SRP section in conformance with 10 CFR 50.55a; 10 CFR Part 50 Appendix A, General Design Criteria (GDCs) 1, 2, 4, 14, and 15; 10 CFR Part 50 Appendix B; and 10 CFR 52.47(b) and 10 CFR 52.80 (a).

The specific areas of review are as follow:

(1) Piping vibration, safety relief valve vibration, thermal expansion, and dynamic effect testing should be conducted during startup testing. The systems to be monitored should include:
   A. all American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code) Class 1, 2, and 3 systems,
   B. other high-energy piping systems inside Seismic Category I structures (the term, "Seismic Category I," is defined in Regulatory Guide (RG) 1.29),
   C. high-energy portions of systems whose failure could reduce the functioning of any Seismic Category I plant feature to an unacceptable safety level, and
   D. Seismic Category I portions of moderate-energy piping systems located outside containment.

The supports and restraints necessary for operation during the life of the plant are considered to be parts of the piping system.

The purpose of these tests is to confirm that these piping systems, restraints, components, and supports have been adequately designed to withstand flow-induced dynamic loadings under the steady-state and operational transient conditions anticipated during service and to confirm that normal thermal motion is not restrained. The test program description should include a list of different flow modes, a list of selected locations for visual inspections and other measurements, the acceptance criteria, and possible corrective actions if excessive vibration or indications of thermal motion restraint occur.

The USNRC Regulatory Guide 1.68, Rev. 3, March. 2007. *Initial Test Programs for Water-Cooled Nuclear Power Plants*, describes the general scope and depth of initial test programs acceptable to the USNRC staff for light-water-cooled nuclear power plants. The following excerpt related to piping vibration testing is from Appendix A, "Initial Test Program," under paragraph 1, "Preoperational testing".

This testing should include verification by observations and measurements, as appropriate, that piping and component movements, vibrations, and expansions are acceptable for (1) ASME Code Class 1, 2, and 3 systems, (2) other high-energy piping

systems inside Seismic Category 1 structures, (3) high-energy portions of systems whose failure could reduce the functioning of any Seismic Category 1 plant feature to an unacceptable level, and (4) Seismic Category 1 portions of moderate-energy piping systems located outside containment.

3.3.3 Vibration Acceptance Criteria

Because piping in a power plant will experience some amount of vibration, acceptable limits of vibration must be established to determine if a particular vibrating pipe is a potential problem. Various criteria are considered when evaluating the vibrations, including pipe stresses and fatigue limits as well as pipe deflections and reactions on (and behavior of) piping system components. For example, a certain degree of piping vibration may be acceptable to the extent that it causes no failure of the piping itself, but it may be unacceptable because it is severe enough to cause premature failure of pipe supports or sensitive equipment such as high-speed pumps. Piping vibration, especially of large-diameter piping, can be the source of worker concern; therefore, corrective actions are often needed to reduce the vibrations to levels that alleviate the concerns. For new applications, test specifications should be in accordance with ASME OM-S/G-1990, "Standards and Guides For Operation of Nuclear Power Plants," Part 3, "Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems," and Part 7, "Requirements for Thermal Expansion Testing of Nuclear Power Plant Piping Systems."

The testing and evaluation techniques discussed herein are based on the requirements of ASME OM-Part 3.

3.3.3.1 Steady-State Vibrations Steady-state vibrations of piping are usually evaluated for their effects on the fatigue life of the piping metal. For steady-state vibration to be tolerable, the resulting stresses must be held below a level that would cause failure during the life of the plant. Because of the large number of stress cycles encountered in steady-state vibration, the allowable stress values must be determined from fatigue curves. Environmental effects, such as erosion–corrosion, can significantly reduce the fatigue life of affected piping and components.

The criterion used for steady-state vibration is to limit the vibrational stresses to a value below the "endurance" limit of the piping material. Endurance limit, as used here, is defined as a stress limit that the piping can vibrate within and not experience a fatigue failure. A 40 Hz vibration occurring continuously over a 40 year plant design life will result in 5×10^{10} stress cycles. Note that a 40 Hz vibration frequency higher than most piping vibration. Therefore, the ASME O&M Part 3 Standard [10] uses the allowable alternating stress that corresponds to 10^{11} stress cycles as an endurance limit for power plants. As shown in Fig. 3.1 conservatively assuming that a 40 Hz vibration occurs continuously for 60 years, the number of stress cycles never reaches 10^{11} cycles.

Other criteria, such as stress and deflection limits, may also need to be specified for piping components, supports, or in-line equipment. For example, pipe supports, such as hydraulic and mechanical snubbers, can experience excessive wear when subjected to continuous steady-state vibration.

3.3.3.2 Dynamic-Transient Vibrations Dynamic-transient vibrations are most often evaluated on the basis of pipe deflections and reactions. Fatigue is a less important concern because of an expected low number of dynamic transient events; however, fatigue must be considered if the number of stress cycles becomes significant. The large pipe deflections associated with transient vibration may result in high pipe stresses and damage to the support system; an inadequately supported piping system may result in catastrophic failure. Failed supports are the most frequently experienced damage, although small branch lines may also be damaged and overloading of attached equipment may occur. The qualification of a piping system for dynamic-transient effects is therefore based primarily on controlling pipe movements and ensuring that the support system and equipment have the capacity to absorb the transient reactions. Piping stresses must also be demonstrated to be within applicable Code limits.

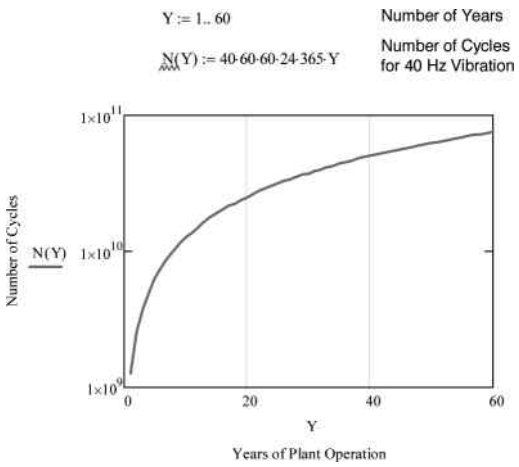


FIG. 3.1 CUMULATIVE NUMBER OF STRESS CYCLES VS. YEARS OF PLANT OPERATION

For dynamic-transient vibration, Piping Codes clearly define piping stress limits, and piping response must be kept within these limits. Typically, however, piping components receive the brunt of the damage from a severe dynamic transient. Therefore, considerations in addition to pipe stress usually form the basis for dynamic-transient acceptance criteria. For example, the magnitude of an acceptable transient may be limited by the load-carrying capabilities of the piping support system or by the effects of the transient on in-line equipment.

3.4 REVIEW OF ASME/ANSI O&M STANDARD ON PIPING VIBRATION

The ASME published the following standard: The ASME/ANSI OM-S/G 2003, *Operation and Maintenance of Nuclear Power Plants.* Part 3 of this Standard, titled "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems," specifically addresses piping vibration and was published to address the vibration requirements included in the piping Codes and USNRC Regulatory Guides. Part 3 was written to address start-up testing and vibration encountered in operating plants.

The O&M Part 3 Standard addresses testing requirements and acceptance criteria for piping vibration. For pipe vibration monitoring and testing, it includes a visual inspection method, a simplified method for qualifying piping systems, and a rigorous qualification method for steady-state and transient vibration. Instrumentation and measurement techniques are included, and corrective action is discussed along with potential vibration sources.

This Standard divides piping vibrations into steady-state and dynamic-transient vibrations. For each type of vibration, a piping system is classified into one of three vibration monitoring groups (VMGs). For each VMG, the Standard specifies a corresponding qualification method to determine the extent of monitoring to be done for each system. VMG-1 involves a rigorous qualification method, requiring that the vibration stresses be determined with a high degree of accuracy, and it may also involve a detailed correlation between analysis and experimental results or instrumentation of the piping with a sufficient number of strain gauges to determine the magnitude of the highest stresses.

VMG-2 is a simplified qualification method intended to conservatively estimate piping vibration stresses. This method is based on modeling the vibration portion of the piping using a simple beam analogy and determining vibration limits in terms of displacement or velocity.

The final method, VMG-3, involves visual inspection. Systems classified as VMG-3 are qualified on the basis of prior experience and judgment.

The Standard leaves with the Owners the responsibility of determining what systems are to be monitored, what type(s) of vibration (steady-state and/or dynamic-transient) to be monitored, and what vibration-monitoring group the system is to be classified in. These commitments would most likely be made in the plant Safety Analysis Reports (SARs) or other design documents.

3.4.1 Stress Allowables

The allowable stresses in the Standard are based on the fatigue curves given in Section III of the ASME B&PV Code. For dynamic transients, an equivalent number of full-range stress cycles is calculated from the recorded time-history traces, and the equivalent cycles are used in conjunction with the fatigue curves to assess the effect of transients on the fatigue life of the piping. These transient stress cycles are considered with other cycling stresses (e.g., seismic) accounted for in the design-basis report. Steady-state vibrations will most likely result in a large number of stress cycles; the Standard therefore sets a steady-state vibration stress allowable equal to the "endurance limit" of the piping material, where the endurance limit is defined as a stress at which the piping can cycle for the life of the plant and not fail as a result of fatigue. If a lower number of cycles can be computed for steady-state vibrations, then the allowable stress can be increased accordingly.

The OM-3 standard uses the alternating peak stress value at 10^{11} cycles as the endurance limit, i.e., the allowable stress for steady state vibration. In Appendix I of the ASME B&PV Code [6], there are fatigue curves for both stainless and carbon steels. The high cycle portion of the curve for stainless steel is shown in Fig. 3.2. Note how the curve significantly flattens out after 10^7 cycles.

The allowable stress value is taken directly from this curve. From the curves the endurance limit for stainless steel equals 13,600 psi. Similar curves are available for carbon steel that indicate the corresponding endurance limit for carbon steel equals 7,000 psi (see Appendix I "Design Fatigue Curves" of the ASME B&PV Code Section III for notes applicable to the use of the fatigue curves).

3.5 CAUSES OF PIPING VIBRATION

3.5.1 Pump-Induced Pressure Pulsations and Flow Turbulence

All piping with flow will vibrate to some degree. Pump-induced pressure pulsations and flow turbulence are two potential sources of piping steady-state vibration.

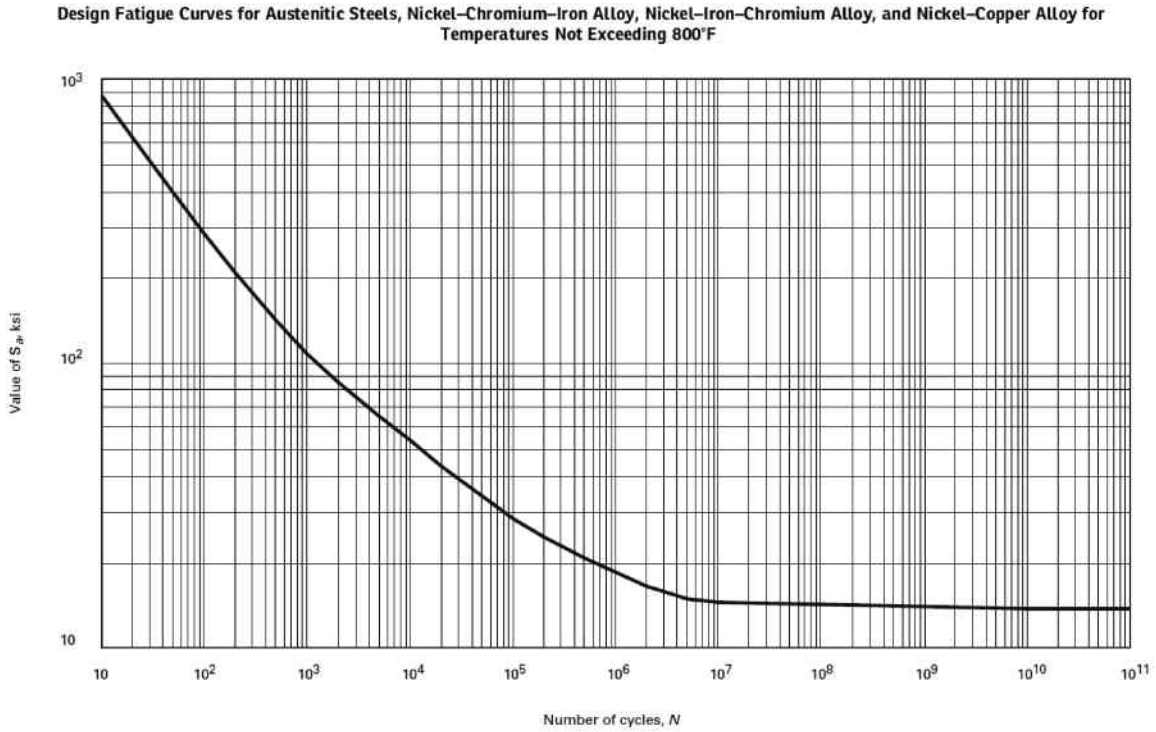


FIG. 3.2 ALLOWABLE PEAK STRESS VS. NUMBER OF CYCLES FOR STAINLESS STEEL [6]

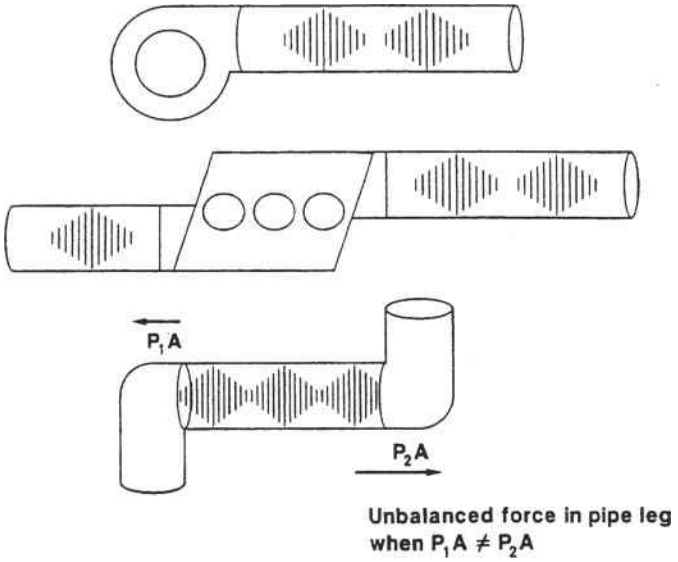


FIG. 3.3 PUMP-INDUCED PRESSURE PULSATIONS

Pump-induced pressure pulsations occur at distinct frequencies, which are multiples of the pump speed. Pulsations originate at the pump and travel throughout the entire discharge piping. In some instances, especially with reciprocating pumps, pulsations may also be induced in suction piping.

The effects of pressure pulsations can be more severe when they coincide with an acoustical and/or structural frequency of the piping. Eliminating the pulsations may involve modifying the pump or changing the piping acoustical frequency. For example, piping acoustical properties can be changed through the addition of a pulsation damper and suction stabilizer.

Pump-induced pressure pulsations affect piping by causing unbalanced forces in pipe legs, as shown schematically in Fig. 3.3. In the absence of pressure pulsations, the pressure acting on each elbow produces opposite and equal forces equal to the pressure (P) times the piping cross-sectional area (A).

These pressure loadings cause longitudinal pressure (and hoop) stress in the piping but do not result in unbalanced pressure loads. When pressure pulsations travel through the piping at any instant in time, the pressure on one elbow may not equal the pressure on the other elbow of the piping leg, resulting in an unbalanced force in the pipe leg. The pressure acts on the projected cross-sectional area of the elbow, resulting in a loading on the elbow to the load shown in Fig. 3.4.

These forces act at each elbow and the resultant loading on a particular pipe segment or straight length of piping is equal to the vector addition of these loadings. The resultant unbalanced loading on a straight leg of piping can be considered to act along the axial direction of the piping.

Pumps may induce pressure pulsations over a wide range of possible frequencies. Pump-induced pressure pulsations may be produced at multiples of the pump-operating speed and multiples of the number of pump plungers, blades, volutes, or diffuser vanes. The potential pulsation frequencies are defined by the following equation [11]:

$$F = \frac{nX}{60} \quad \text{or} \quad \frac{nXY}{60} \tag{3.1}$$

where

F = frequency of pressure pulsation, cycles/sec. (Hz)
n = 1, 2, 3, and so on
X = pump rotating speed, rpm
Y = dependent on pump type: number of pump plungers, blades, volutes, or diffuser vanes

A field problem experienced at one plant helps to illustrate the effects of pump-induced vibration and also demonstrates potential fixes. The charging system in PWR plants often use reciprocating pumps to meet the requirements of high head at low flows. In this case, three reciprocating pumps were used for the charging system, and all of the discharge piping experienced excessive steady-state vibration that resulted in several support failures. Also experienced were vibration failures of attached instrumentation and other small-branch piping, as well as excessive vibrations in the suction piping. This particular plant's three reciprocating pumps in the system all experienced cavitation and loss of prime. There were instances of pump case cracking, and pump maintenance intervals were as short as 2–3 wk. The temporary resolution to these problems was to operate the pumps at flow rates reduced by 25% from their normal operating conditions.

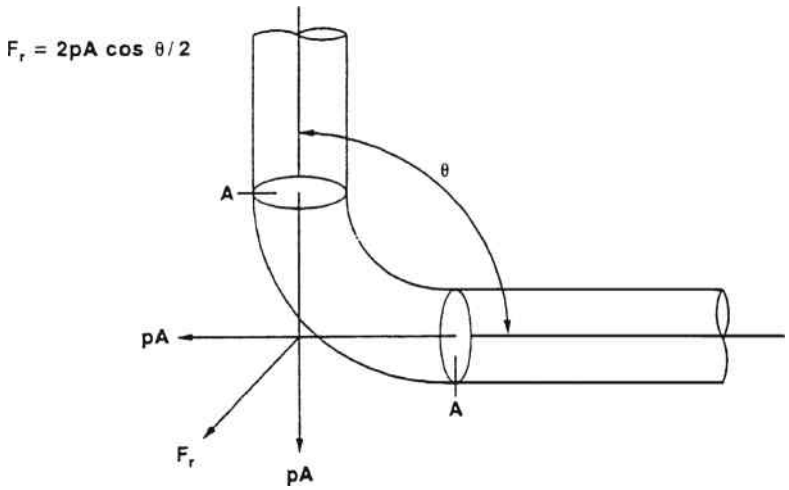


FIG. 3.4 DYNAMIC FORCES AT AN ELBOW

Problems are attributed to two characteristics of reciprocating pumps [12]. At the beginning of each plunger-suction stroke, an instantaneous demand for liquid is created by the plunger acceleration. This demand, or required acceleration head, will accelerate the fluid and lower its pressure, possibly resulting in cavitation and stripping of gases from the fluid. This problem is more prevalent in boron-charging systems because of the hydrogen-saturated water used in these systems. The result can be the loss of pump prime, cavitation, and larger pressure pulsations in both the suction and discharge piping. The solution is to provide, as close to the pump inlet as possible, an ample supply of liquid, which is meant to satisfy the need of the instantaneous acceleration head. A suction stabilizer installed close to the inlet has, for an instant, the same effect as a tank close to the pump.

Another source of problems with reciprocating pumps is the pressure pulsation caused by the reciprocating pistons. These pulsations can be mitigated through the use of discharge dampeners. The two basic types of discharge used are energy-absorbing dampeners, which use a gas envelope to cushion and reduce pressure peaks, and reaction-type dampeners, which act on the principle of a volumetric-resistance acoustic filter. Either type of device can be used to dramatically reduce pressure fluctuations in the discharge piping, thereby avoiding excessive piping vibration. Note that an acoustic analysis of the system should be performed to properly locate and size both the suction stabilizer and discharge dampener. Acoustic analyses performed for various system operating conditions will help ensure smooth operation during all flow conditions.

3.5.2 Flow Turbulence

Flow turbulence will generally have a broadband of frequencies ranging from 0 to 30 Hz, and the turbulence magnitude will generally increase as the flow rate is increased. Significant structural frequencies of most piping systems also range from 0 to 30 Hz. Turbulence will therefore cause all piping to vibrate to some degree; however, piping vibration problems usually do not result unless a structural frequency is excited. Vibration resulting from flow turbulence will also affect piping components and equipment; for example, snubbers have proven susceptible to wear and failure when exposed to continuous steady-state vibration.

Typically, the most cost-effective fix for flow turbulence-excited vibration is to add a rigid support to the section of piping experiencing the excessive vibration. A rigid support will increase piping thermal expansion stresses, but a more detailed piping thermal expansion analysis can usually demonstrate pipe stresses as acceptable. If necessary, the rigid support can be made sufficiently flexible to provide some allowance for thermal expansion but still be sufficiently rigid to control vibration. The addition of a rigid support will change the piping structural frequencies, so the piping response should be inspected again after the addition of the support. Doing so ensures that a different piping structural frequency has not been excited.

3.5.3 Cavitation and Flashing

Cavitation and flashing can result in a wide range of pressure fluctuations and therefore can excite a wide range of piping structural frequencies. Both cavitation and flashing are caused by too large a pressure drop at such flow restrictions such as a flow orifice or a control valve; the flow restriction increases the fluid velocity and as a result decreases its pressure. Cavitation and flashing result when the fluid's static pressure reaches its vapor pressure and the fluid vaporizes. Cavitation occurs when the downstream pressure is greater than vapor pressure and the vapor bubbles implode, causing noise, vibration and high pressure microjets of water that can impinge on, pit and erode the inner walls of pipe and components. Flashing occurs when the downstream pressure is less than vapor pressure and the vapor (steam) does not collapse and two-phase flow develops in the downstream piping. This results in high velocity downstream flow, due to the volumetric expansion of the fluid, and possible slug or plug flows. When cavitation or flashing becomes severe, pipe and component pitting, erosion, and wear will be experienced, as will, in all likelihood, excessive vibration of downstream piping. Also present will be objectionable or excessive noise.

Adding supports to control vibration caused by cavitation or flashing is typically not the best solution. Vibration is likely to be widespread and require many supports to control it; additionally, wear, erosion, and noise would continue. Although some amount of cavitation and flashing can be tolerated and will likely exist at pressure drops, their effects can be mitigated through altering pressure changes. For example, cavitation at a valve can be reduced by the installation of a downstream flow orifice. Anti-cavitation valve trim can be used to reduce cavitation. Gradual or staged pressure drops can be obtained through the use of several consecutive flow orifices. Lower flow velocities, obtained through the use of larger pipe diameters, will also lessen effects of cavitation.

Cavitation or flashing commonly result from overthrottling of control valves as illustrated in Fig. 3.5. Cavitation occurs when fluid pressure approaches its vapor pressure, with vapor pockets forming and collapsing in the downstream piping. These activities result in broadband-pressure pulsations, which can cause severe vibration at

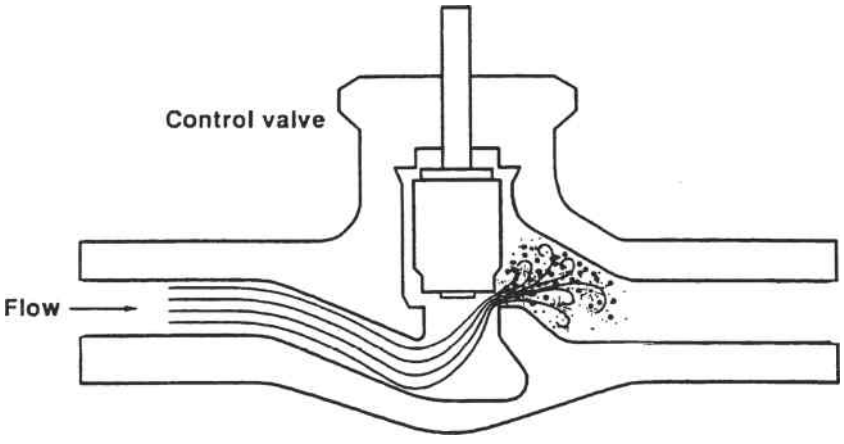


FIG. 3.5 CAVITATION AT A CONTROL VALVE

the cavitating component and the piping downstream of the component. Cavitation will also wear and erode piping and components; it typically is categorized by a loud crackling noise. Other examples of when cavitation can occur are using block valves for flow control, too-rapid pressure reductions at flow orifices or pressure-reducing valves, and sudden flow termination from a pump trip. Flashing also occurs when hot water is discharged into atmospheric environments or below them, such as into a condenser.

The following paragraphs discuss the four categories into which cavitation can be classified, depending on its severity [13]. One is known as incipient cavitation, representing the onset of cavitation and characterized by light, intermittent popping sounds. No damage or vibration is likely to occur.

Critical cavitation is characterized by a light, steady noise similar to frying bacon. Typically, vibrations are negligible, noise is not objectionable, and only very minor damage will occur over long time periods.

Incipient damage cavitation represents the onset of pitting. This stage of cavitation may produce objectionable noise with some vibration, but damage should be minor.

Choking cavitation occurs near choking, where cavitation reaches its maximum intensity, characterized by excessive noise and vibration, with heavy damage likely. Additional increases in upstream pressure result in supercavitation where the flow is fully choked. Vapor pressure will exist for some distance in the down-stream piping, and vapor pockets or cavities will collapse farther downstream where damage, intense noise, and vibration may take place.

3.5.4 Vortex Shedding

Pressure pulsations resulting from vortex shedding occur at distinct frequency bands. Pulsation frequency is proportional to flow velocity; therefore, the frequency will vary with the system flow. Vortex shedding becomes significant when the pulsation frequency coincides with the piping acoustical and/or structural frequency. Eliminating or reducing vortex shedding pulsations is accomplished by modifying the flow restriction or changing the piping acoustical frequency.

Blevins describes vortex-induced vibration and provides the following description of vortex formation [14]. As a fluid particle flows toward the leading edge of a bluff cylinder, the pressure in the fluid particle rises from the free-stream pressure to the stagnation pressure. The high fluid pressure near the leading edge impels the developing boundary layers about both sides of the cylinder; however, the pressure forces are not sufficient to force the boundary layers around the backside of bluff cylinders at high Reynolds numbers. Near the widest section of the cylinder, the boundary layers separate from each cylinder surface side and form two free-shear layers that trail behind the flow. These two free-shear layers bind the wake. Since the innermost portion of these layers moves much more slowly than the outermost portion of the layers that are in contact with the free stream, the free-shear layers tend to form into discrete, swirling vortices. A regular pattern of vortices is formed in the wake that interacts with the cylinder motion and is a source of effects known as vortex-induced vibration.

Any structure with a sufficiently bluff trailing edge sheds vortices in a subsonic flow. The vortex streets tend to be very similar regardless of the tripping structure. Periodic forces on the structure are generated as vortices that are alternatively shed from each side of the structure. The oscillating pressure fields cause oscillating forces on the bluff or cylinder, which can cause elastically mounted cylinders to vibrate. Large-amplitude vibrations can be induced in elastic structures by vortex shedding; their destructive effects are commonly experienced on bridges, antennas, cables, and heat exchangers. Vortex shedding in piping systems is also an important potential source of piping steady-state vibration.

The frequency of vortex shedding can be approximated by the following formula:

$$F = S\frac{V}{D} \tag{3.2}$$

where

S = Strouhal Number = 0.2–0.5 for flow through restrictions or across obstructions
V = flow velocity, fps
D = restriction diameter, ft.

When vibrations are experienced in the field, the foregoing formula can be used to determine if vortex shedding is a potential source of pipe vibration. Note, however, that the wide range of Strouhal numbers makes exact prediction of vortex shedding frequencies difficult.

The Strouhal number is a proportionality constant between the predominant frequency of vortex shedding (F) and the free-stream velocity (V) divided by the flow obstruction width (D). The Strouhal number is a function of geometry and Reynolds number (RE) for low Mach number flows. The Mach number is equal to the fluid velocity divided by the speed of sound in the fluid, and is also a meassure of the tendency of the fluid to compress as it encounters a structure. The Strouhal number for circular cylinders is shown in Fig. 3.6 [14]. At the

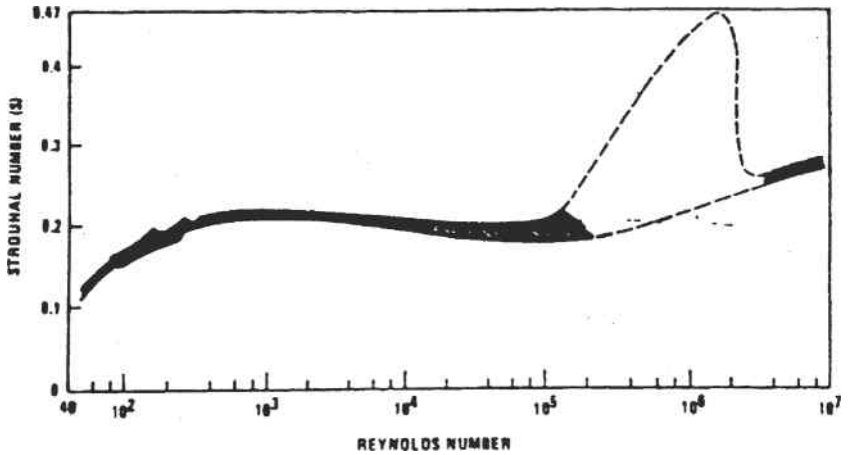


FIG. 3.6 RELATIONSHIP FOR STROUHAL NUMBER VERSUS REYNOLDS NUMBER FOR CIRCULAR CYLINDERS [14]

transition Reynolds numbers, the shedding frequency is defined in terms of the dominant frequency of a broad-band of shedding frequencies. Also, vortex shedding tends to lock into the natural frequency of the vibrating structure or the structure's acoustic natural frequency. Vibration at or near the shedding frequency has a strong organizing effect on the wake. The shedding frequency synchronizes with the vibration frequency.

Vortex shedding normally results in low-amplitude pressure pulsations, and no problem occurs unless these pulsations coincide with a piping acoustical resonance. The vortex shedding tends to lock into a close piping acoustical frequency, and the pressure pulsations can then be greatly amplified. The following equation indicates the steady-state amplification in a single degree of freedom system excited in resonance [15].

$$P = \frac{p}{2d} \tag{3.3}$$

where

P = the amplified pressure
p = the exciting (e.g., vortex-shedding) pressure
d = % of critical damping: by 100

Because fluid damping is typically low, large amplification can be expected when an acoustical system is excited in resonance. For example, 0.5% of critical damping would result in an amplification of 100.

This type of resonance has been encountered frequently in steam-relief and safety-relief valve installations, such as those shown in Fig. 3.7. Vortex shedding in resonance with a quarter-wave frequency of the relief valve branch stub have resulted in large-pressure fluctuations and have been responsible for valve chatter and wear, valve leakage and premature opening, and valves that fail to operate. For example, in one case chatter caused the disk to wear a groove in the valve wall, where the disk subsequently became lodged and caused the valve to become fixed in a closed state. This type of failure is dangerous in that it negates overpressure protection of the system. The symptoms of this type of resonance are excessive vibration and noise near the relief valve.

Note that the quarter-wave frequency of the valve branch stub can be calculated by the following equation:

$$F = \frac{c}{4L} \tag{3.4}$$

where

F = frequency (Hz)
c = speed of sound in steam (acoustic velocity)
L = branch stub length

A solution to the safety-relief valve problem is to separate the vortex shedding and acoustic frequencies to avoid resonance. The use of large-diameter branch openings reduces the vortex-shedding frequencies and has proven successful in resolving these problems. A reducer or conical nozzle is used to taper the branch stub back to the size of the valve inlet connection. Conical nozzles also tend to increase the acoustic frequency of the stub, thereby further separating the two frequencies [16]–[17]. In addition, rounding the inside edges of the branch opening also reduces vortex shedding.

3.5.5 Water- and Steamhammer

Dynamic-transient vibration, such as water- and steamhammer, are short-duration events—typically occurring in less than 1 sec. but with dramatic effects. Large, unbalanced forces can be exerted onto the piping; damage typically occurs to piping supports and restraints, and in severe cases, the piping itself may also be dam-

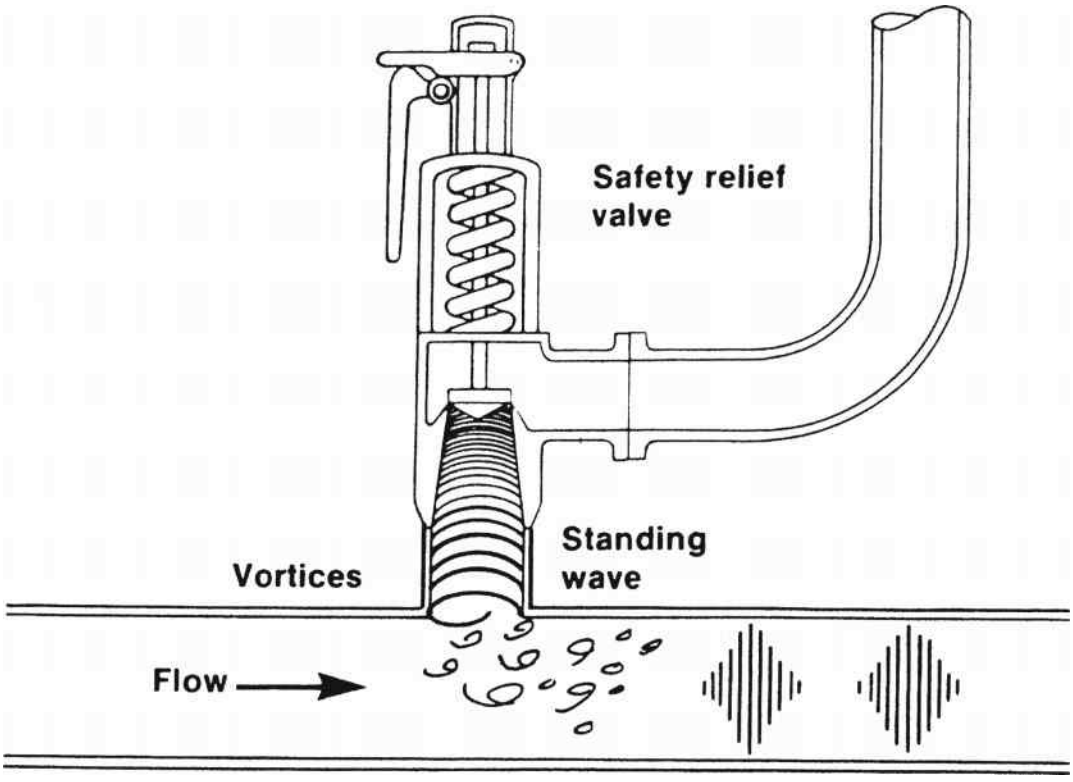


FIG. 3.7 VORTEX SHEDDING AT A RELIEF VALVE

aged. A large number of dynamic transients occurring in nuclear power plants have been reported during commercial operation. A study by the USNRC documented 120 such events [18]. How waterhammer (or steamhammer) affects piping is illustrated in Figs. 3.8 and 3.9. Shown in Fig. 3.8 is a pressure pulse traveling through the piping reaching elbow *A* first and at a time (Δt), later reaching elbow *B*. The pressure wave travels through the fluid at acoustic velocity, *c* (roughly 4,000 fps in water). The time for the pressure wave to travel from *A* to *B* equals the length (*l*) divided by *c*. The pressure at each elbow exerts a force in the axial direction of the piping equal to the pressure times the piping cross-sectional area. Thus, different pressures at elbows *A* and *B* will result in correspondingly different axial forces. The difference between these two forces equals the unbalanced force in the pipe leg. It is the unbalanced force that deflects the piping and loads the restraint system. As can be seen from Fig. 3.9, a longer time (ΔT) resulting from a longer leg length would result in a larger unbalanced force.

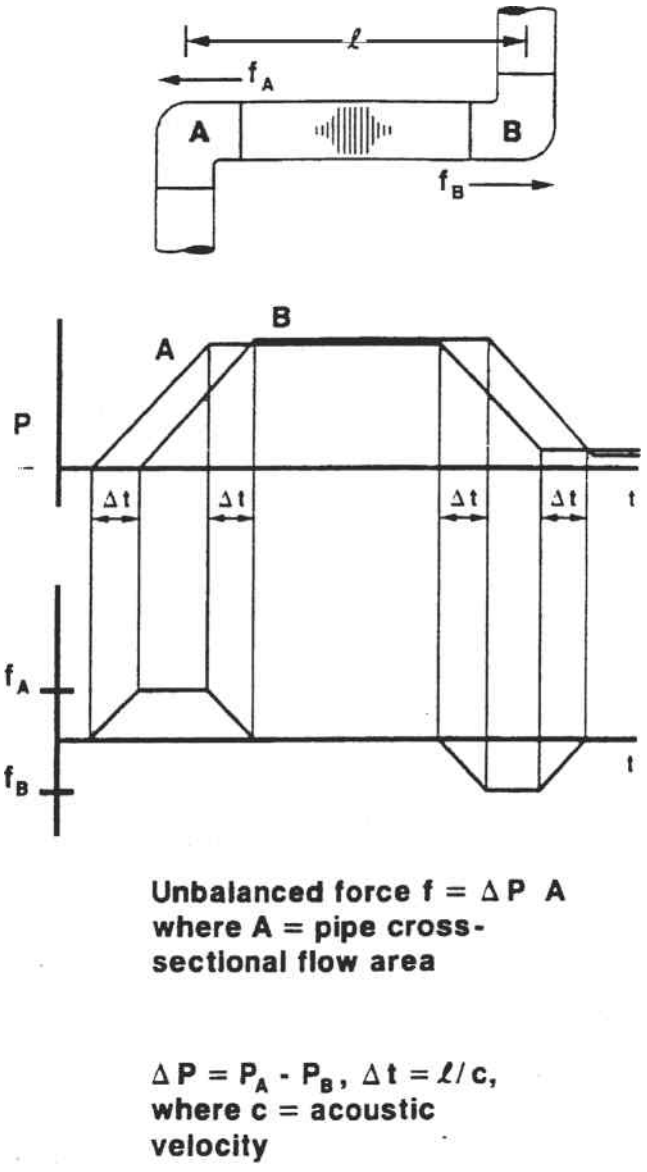


FIG. 3.8 UNBALANCED FORCE FROM A PRESSURE TRANSIENT

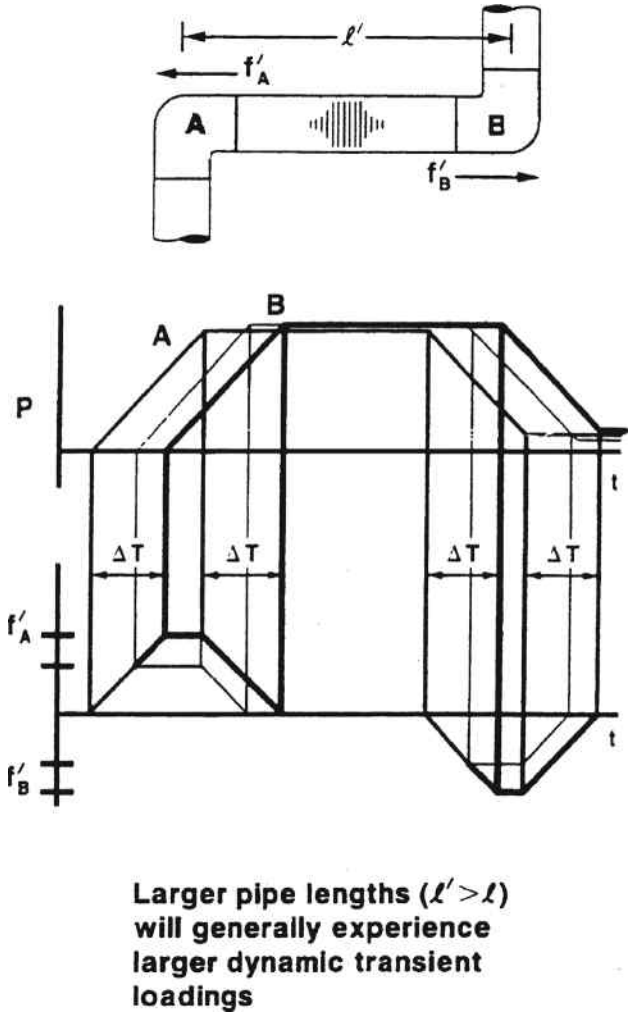


FIG. 3.9 UNBALANCED FORCE FROM A PRESSURE TRANSIENT

Therefore, characteristics of waterhammer are as follows:

- Unbalanced forces act in the axial direction of the piping.
- The unbalanced force is, up to a limit, proportional to the length of pipe leg.
- Unbalanced forces act at elbows, reducers, tees, and other locations of changes in flow direction or flow area.

Fast valve closure is one source of pressure transitents in piping. Fast valve closure is defined as a closure time less than or equal to one round trip of the pressure wave from valve to reservoir and back, ($2L/c$), where L equals the equivalent length of pipe between valve and reservoir, and c is the acoustic velocity.

Examples of events causing fast valve closures are the following:

- Flow reversal at check valves.
- Main steam-stop valve closures.
- Intermittent operation of feedwater control valves.

The magnitude of a pressure transient caused by a fast valve closure can be conservatively approximated by the following equation:

$$\Delta P = \rho c V \tag{3.5}$$

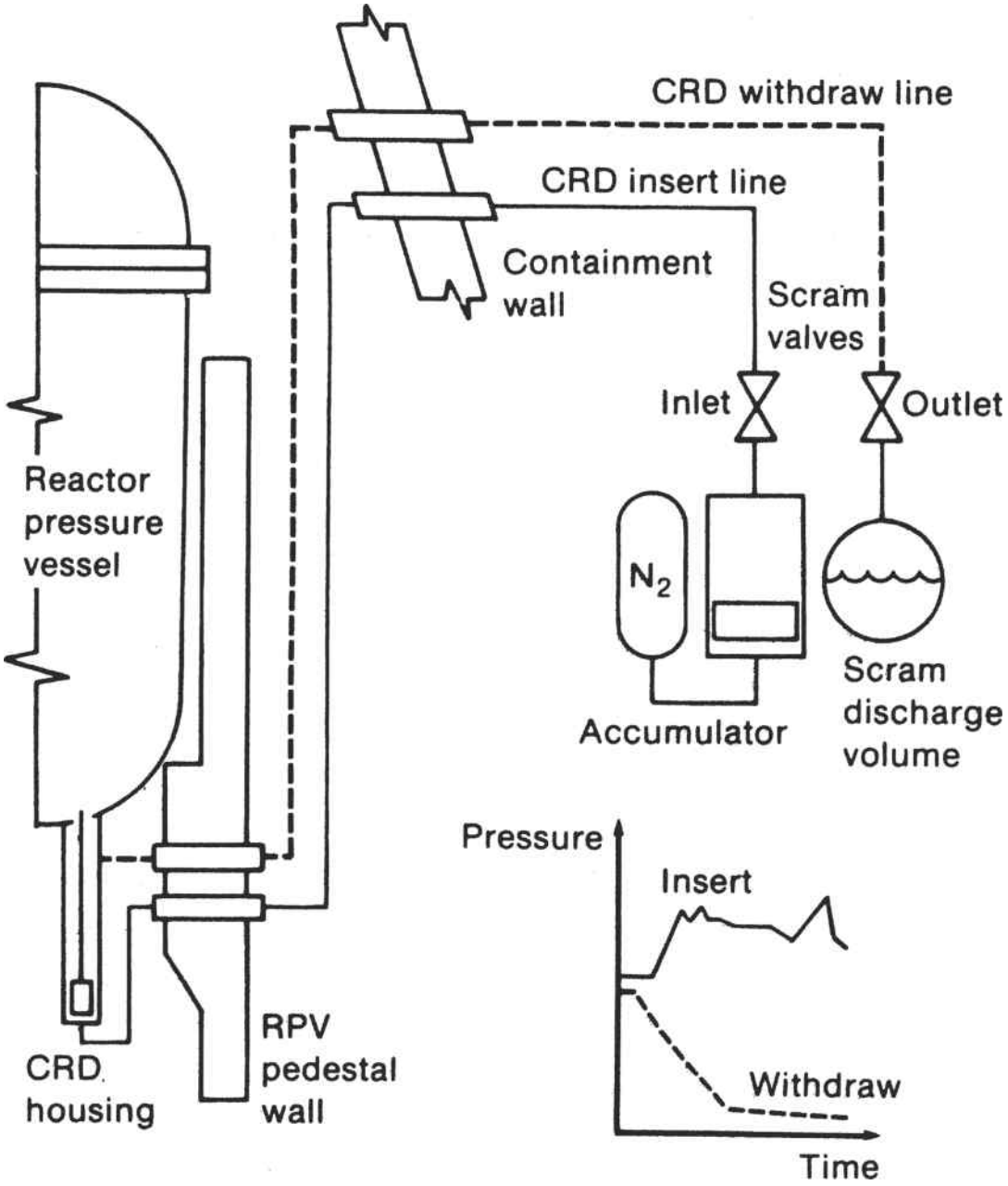


FIG. 3.10 HYDRAULIC TRANSIENT MODEL OF BWR CONTROL ROD–DRIVE SYSTEM

where

ΔP = the magnitude of the pressure transient
ρ = the fluid mass density
V = the initial fluid velocity

A fast valve closure in a line with water flowing at 12 fps could theoretically result in a maximum 642 psi pressure spike. For a 12 in. diameter pipe with approximately Targe lines have been inadvertently voided. In these cases a water slug will be accelerated through the piping, causing pipe loads where the slug momentum is changed at flow discontinuities and elbows. In addition, if the slug impacts a stationary column of water, a pressure transient will be generated in the water. Inadvertent voiding of the discharge lines can occur in open-ended systems such as circulating water because of the draining after a pump trip. In addition, voiding may occur from water column separation when the flow is terminated and also from cavitation or flashing. Jockey or keep-fill pumps have been used to keep discharge piping filled, and vacuum breakers have been used in open-ended systems to prevent vacuums from forming in the discharge piping. The air inlet by a vacuum breaker will act as a cushion and help mitigate the water slugging [20].

Water slugging also occurs as a result of water accumulating in a steamline. Poorly maintained steam trap and drain systems will contribute to this problem. One example is a case in which every hanger on a cold-reheat line in a fossil fuel power plant was broken as a result of a water slug being accelerated by the

steam. An attemperator spray valve leaked while the unit was taken out of operation, an inoperable steam trap allowed water to accumulate, and water slugging occurred when the unit was brought back on line.

Water slugging may also be a result of design, such as in the case of piping with water loop seals. The pressurizer-relief piping in a PWR has a low point in the piping filled with water to form a seal. When the relief valve operates, this water seal is accelerated through the piping, resulting in water-slugging loads.

3.6 DESIGN CONSIDERATIONS AND GUIDELINES FOR PIPING

3.6.1 Single-Degree-of-Freedom Response

Review of the relationships derived for a single-degree-of-freedom (SDF) system is a helpful way of understanding complex piping vibration. Single-degree-of-freedom relationships will be briefly reviewed here because of their importance in the understanding of piping vibration. These relationships were mentioned earlier in the discussions regarding how pressure pulsations are amplified in resonance.

Figure 3.11 illustrates an SDF system with viscous damping and a harmonic forcing function applied to it [15]. In this figure, k represents the system stiffness, c is the viscous damping, m is the system mass, x is the displacement of the mass, and $F_0 \sin \omega t$ is the applied forcing function.

The differential equation of motion for this system can be written as follows:

$$m\ddot{x} + c\dot{x} + kx = F_0 \sin \omega t \tag{3.6a}$$

In words, this equation can be expressed as follows:

Inertia force + damping force + spring force = impressed force (3.6b)

Solutions to the preceding equation provide relationships that are helpful for understanding piping vibration. The following relationships hold true for low damping (damping less than 10% of critical), which is applicable for piping vibration.

$$\omega_n = \sqrt{\frac{k}{m}} \equiv \text{natural frequency in radians/sec.} \tag{3.7}$$

$$f_n = \frac{\omega_n}{2\pi} \equiv \text{natural frequency in cycles/sec.} \tag{3.8}$$

These relationships shown in the preceding equations demonstrate the effect of stiffness and mass on piping vibration. For example, a loosely supported piping system will have a low stiffness (k) and therefore will have a low fundamental vibration frequency. Loosely supported piping systems may vibrate at 1 or 2 Hz or below. Adding supports to a system will increase its stiffness and therefore its vibrational frequencies; it is also one way of shifting the piping frequencies out of resonance and reducing response. Also, the equations demonstrate how a large mass (m) in a system will lower its natural frequency. (A large mass may be a valve or it may be the effect that a long run of piping has on a span perpendicular to it.) In other words, the long run of piping will act as a lumped mass to the perpendicular pipe run. Increasing or decreasing a system's mass also has been used to avoid resonances. The effect of exciting a system in resonance is demonstrated by the following equation:

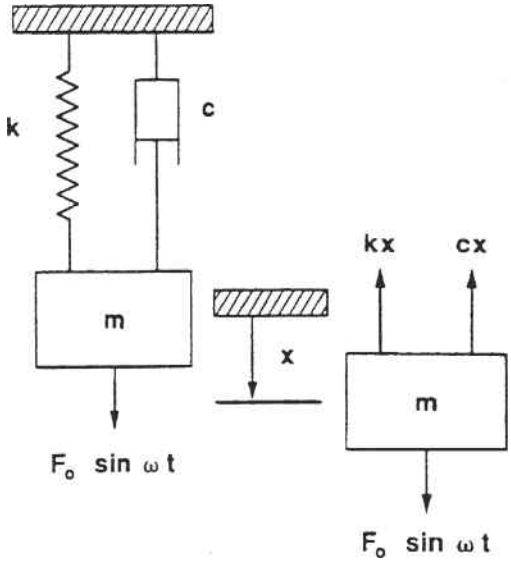


FIG. 3.11 SDF SYSTEM

$$\frac{1}{2z} = \text{dynamic amplification} \tag{3.9}$$

in which $z = C/C_c$ is the fraction of critical damping: C is system damping and C_c is critical damping.

This relationship demonstrates the large amplification that can occur when a system is excited in resonance. For example, 2% of critical damping is common for piping vibration; this would result in an amplification of 25. If a piping system were excited in resonance by a 100 lb. load, the piping maximum response would be as if a 2,500 lb. loading were applied to it statically.

Velocity (V) and acceleration (A) can be expressed in terms of the system vibration frequency (ω) and displacement in the following way:

$$V = \omega x \tag{3.9}$$
$$A = \omega^2 x \tag{3.10}$$

These relationships are important in understanding the relationships between velocity, acceleration, and displacement. The preceding equations show that for a given displacement, velocity increases as a direct function of the vibration frequency (ω) and acceleration increases as the square of the increase in vibration frequency (ω^2)—demonstrating that at low frequencies the vibration velocity and acceleration can be expected to be very low, whereas at high frequencies the velocity and especially the acceleration can be large and the vibration displacements likely to be small. This is why displacement transducers, for example, are typically used to measure vibration of low speed–rotating equipment, velocity transducers are used to measure intermediate speed–rotating equipment, and accelerometers provide the best measurements for high–speed equipment and gear boxes.

3.6.2 Low- and High-Tuning and Damping

Low- and high-tuning and damping are effective means of minimizing vibration response. High-tuning involves designing a structure or system so that its fundamental frequency is higher than that of the forcing function frequency. This design results in a rigid or highly tuned structure. Conversely, low-tuning involves designing the fundamental vibration frequency of the structure to be lower than that of the forcing function. This design involves making a flexible structure so that it is low-tuned to the forcing function.

The intent of these two methods is to avoid resonance where the frequency of the excitation is at or near the natural frequency of the structure. As was discussed previously, resonance results in very large amplifications. Note that high- or low-tuning can also be accomplished by shifting the frequency of the forcing function, which is especially true with piping vibration in which a system modification can be used to shift the forcing function frequency or modify the acoustical frequency of the system.

Damping is a means of dissipating energy; it is effective in reducing vibrational response, especially at or near resonance. The use of damping for piping systems was not extensive in the past, although recently it has received increased attention from the industry. Only a small amount of damping can be expected from the piping material itself. Additional damping results from piping insulation and significant damping may be provided through friction at supports (although designing for friction at supports may not be the best approach, for it could cause excessive wear of the piping and/or support). Commercially available damping devices for piping are available and are proven useful in reducing steady-state vibrational response. In addition, piping snubbers add damping to the system. It is important for any system that does provide damping to withstand the continuous vibration to which it will be subjected. Many devices designed for earthquake loadings have a low number of cycles. If these earthquake devices are to be used on a vibrating pipeline where the vibration is flow induced, then these devices must be capable of withstanding an essentially infinite number of cycles.

The effects of low- and high-tuning and damping are illustrated in Fig. 3.12, which plots the response of an SDF system to a sinusoidal loading. Plotted are dynamic amplifications for various damping values as a function of frequency ratio, in which the frequency ratio equals the frequency of excitation (ω) divided by the natural frequency of the structure (ωn). As this figure shows, high amplifications are experienced in the frequency ratios between approximately 0.7 and 1.4; this is considered to be the range of resonance. For ratios less than 0.7, the structure is rigid compared to the forcing function frequency; thus it experiences low amplifications. For very rigid structures, the dynamic loading has essentially the same effect as a static load, that is, there is no amplification. For frequency ratios above approximately 1.4, the structure is flexible in comparison with the forcing function frequency and is considered to be low tuned. Low-tuned structures have very small amplification factors, and the effect of the loading is less than the effect of an equivalent statically applied load because the applied force is acting against the inertia of the system. In a low-tuned system, the system only partially begins to respond to the applied load; then, because of the oscillations of the applied load, the loading direction is reversed and tends to act against the inertia of the system, resulting in small amplifications.

Figure 3.12 also demonstrates how increased damping values can dramatically reduce a system's response when it is excited in resonance. The effect of damping was demonstrated earlier by equation (3.9).

An example of high-tuning is when supports are added to a piping system to stiffen it and lessen the vibration. It is also used for equipment foundations if they are constructed of massive concrete pedestals, for these pedestals have a high frequency designed to be greater that of the rotational speed of the pump and driver. Another example of high-tuning is the solution to the safety-relief

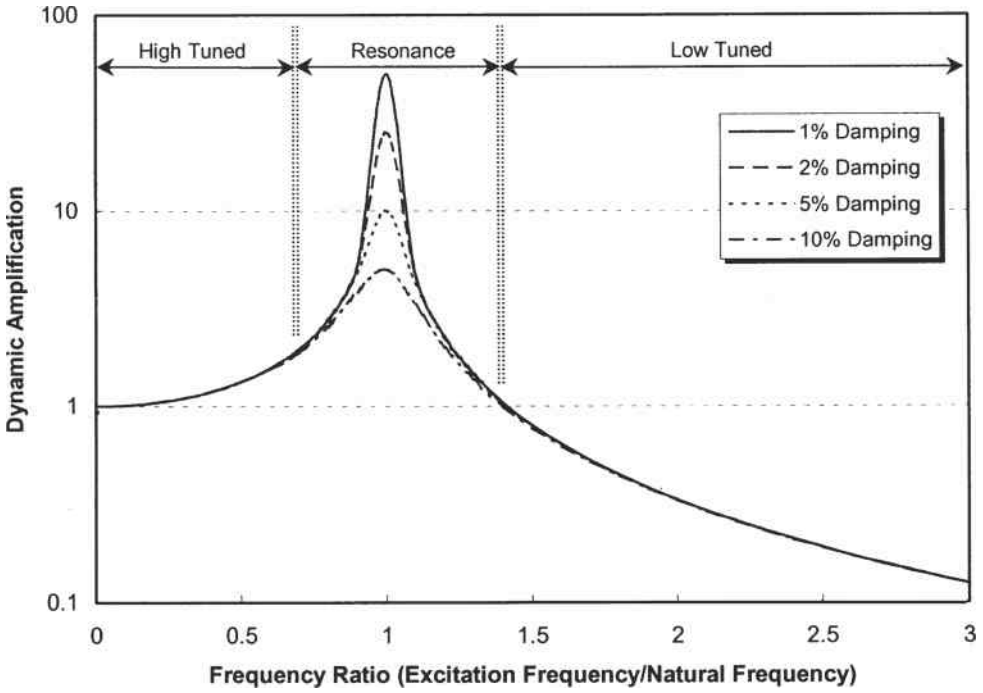


FIG. 3.12 STRUCTURAL RESPONSE TO SINUSODIAL LOADING

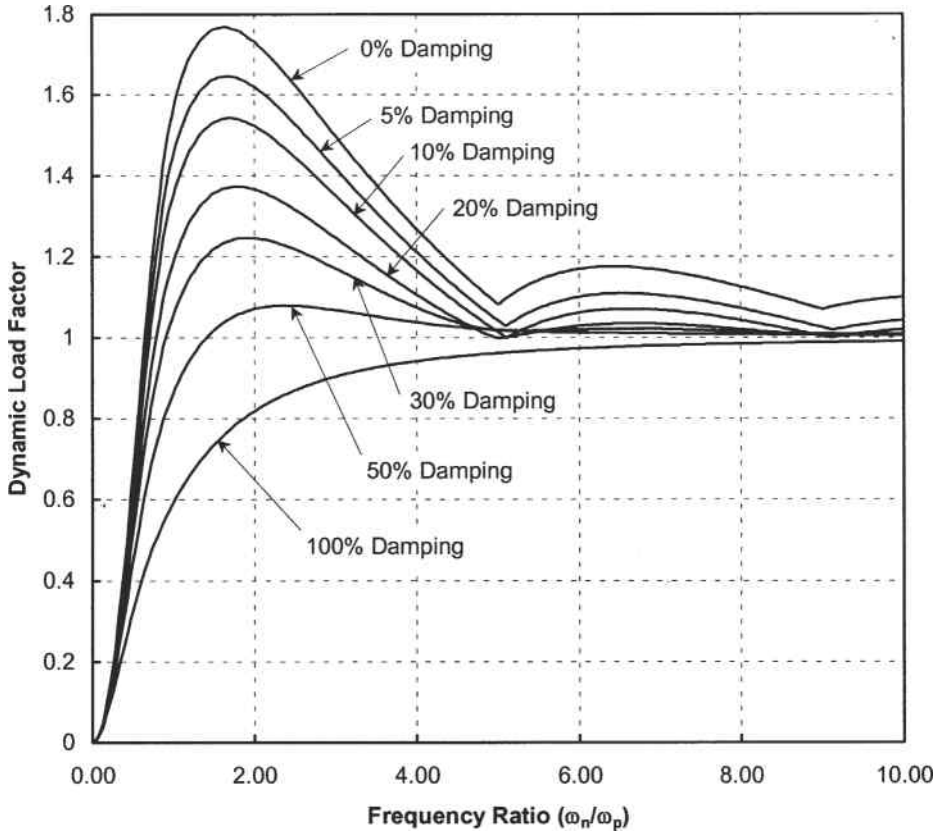


FIG. 3.13 DYNAMIC LOAD FACTOR FOR HALF-SINUSODIAL PULSE

valve vibration problems discussed previously in this chapter. Valve chatter and wear were solved by shortening the branch piping, which increased the acoustical frequency of the branch piping so that it was greater than the vortex-shedding frequency, effectively high-tuning the acoustic response.

An example of low-tuning is the use of vibration isolators for equipment foundations. The use of vibration isolators such as springs and elastomers is a common method of reducing foundation vibrations resulting from pumps and other rotating equipment. A spring or other flexible material is placed between the equipment pads and foundation to obtain low-tuning and transmit only a fraction of the vibrations through the foundation. In some instances, piping response, too, can be reduced through the removal of restraints, thereby low-tuning the piping to the flow-induced vibration. Note that low-tuning avoids resonance with the fundamental or lowest vibrational modes of a structure. Higher vibrational modes may still be excited, but these higher modes are typically harder to excite; moreover, they result in smaller responses than the fundamental or lowest frequency modes of vibration.

Low- and high-tuning and damping are also effective in minimizing piping response to dynamic-transient loadings. However, these methods are less effective, for the amplification factors resulting from dynamic-transient loadings are smaller, with the maximum dynamic load factor being equal to 2.0 for a single-pulse transient load. Transient loads could, for example, result from waterhammer, safety-relief valve openings, or pipe-whip loadings. Some of these loadings may have amplifications larger —than 2.0 because they effectively result in more than one impulse that is, these loads may oscillate for a number of cycles, increasing the energy that is input to the system. Figure 3.13 shows the effect of low- and high-tuning for a dynamic-transient load in the shape of a half-sinusoidal pulse load. As this figure illustrates, a low-tuned system will have the smallest response to a transient loading, whereas a system close to resonance will have the largest response and a high-tuned system will behave as if the loading were applied statically (in terms of maximum response). Figure 3.13 also shows the effect of low- and high-tuning and damping for a transient load; increased damping reduces the response, especially near resonance, and low-tuned structures can have small dynamic load factors—in some cases, much less than 1.0.

3.6.3 Design Guidelines

3.6.3.1 Prevention and Control Prevention and control of piping vibrations is best accomplished in two stages. The first stage is to consider potential vibration problems in the design stage of the plant; the second, to monitor vibration effects in the plant-testing stage. This two-stage philosophy has a twofold benefit. First, the adequacy of vibration-mitigating efforts expended in the design stage can be validated in the testing stage. Second, it can be cost-effective to avoid consideration of vibration for certain systems in the design stage and also to qualify the piping during the testing stage. For example, designing for hypothesized steady-state or transient vibrations will demand a sizeable analysis effort and may require extensive modifications to the pipe routing and/or the pipe support system. However, in the testing stage actual vibrations can

be observed and qualified if they meet applicable acceptance criteria. If the vibrations prove serious, the solution may involve only a change in operating procedure or a minor support modification.

3.6.3.2 Plant Design Stage Prediction of vibrations, their exact magnitudes, and their effect on the piping system is a formidable task - especially when the source mechanism for the vibrations cannot be adequately defined or the nature of the vibrations is such that analytical or experimental models cannot predict vibration magnitudes to the required accuracy. Under these conditions, past experience, intuition, and good layout and design practices become the most effective means of controlling vibrations. Various vibrations can be adequately predicted, for which measures can be taken to moderate their effects. Previous operating experience is a valuable for determining where problems might be expected. For example, small-branch-line piping has suffered the largest number of vibration-related failures. Therefore, routing and support techniques have been developed for small tap lines that minimize vibration failures.

3.6.3.3 Design Practice Some of the design practices used for addressing vibration are given in the following list.

- In the initial layout of the piping, the number of pipe bends should be minimized. The fluid forces tend to couple into and excite the structural vibration modes of the piping at bend locations. In addition, the use of back-to-back fittings, such as an elbow immediately downstream of a valve, can increase flow turbulence and vibration. Minimizing bends will help avoid vibration problems. If possible, rigid restraints should also be placed close to bends.
- Pulsation dampers on the discharge piping and suction stabilizers on the suction piping may be used for pumps that produce large-pressure pulses, such as reciprocating charging pumps. A fluid dynamic analysis is necessary to properly locate these devices in the piping system.
- Small-branch lines should be supported to obtain vibration-resistant designs. Reinforced welded–branch connections should also be used, and threaded connections should be avoided. A fix proven to be effective for small-tap lines (e.g., vents, pressure taps, and drains) is to support them from the header piping—an arrangement that allows tap-line routing to be kept short and rigid, giving it a high structural frequency. The header piping and tap line will then vibrate as a rigid body with little or no relative motion between the tap line and header. This design, an example of which is presented in Fig. 3.14, uses a flexible plate as a support to allow for differential expansion between the header and tap-line piping. The plate stiffness is sufficient to control the tap-line vibration [12].
- Large lumped masses such as valves should be rigidly supported, for the masses lower the piping natural frequency and tend to make it more susceptible to vibration. Cavitation or flashing may also occur at valve locations.

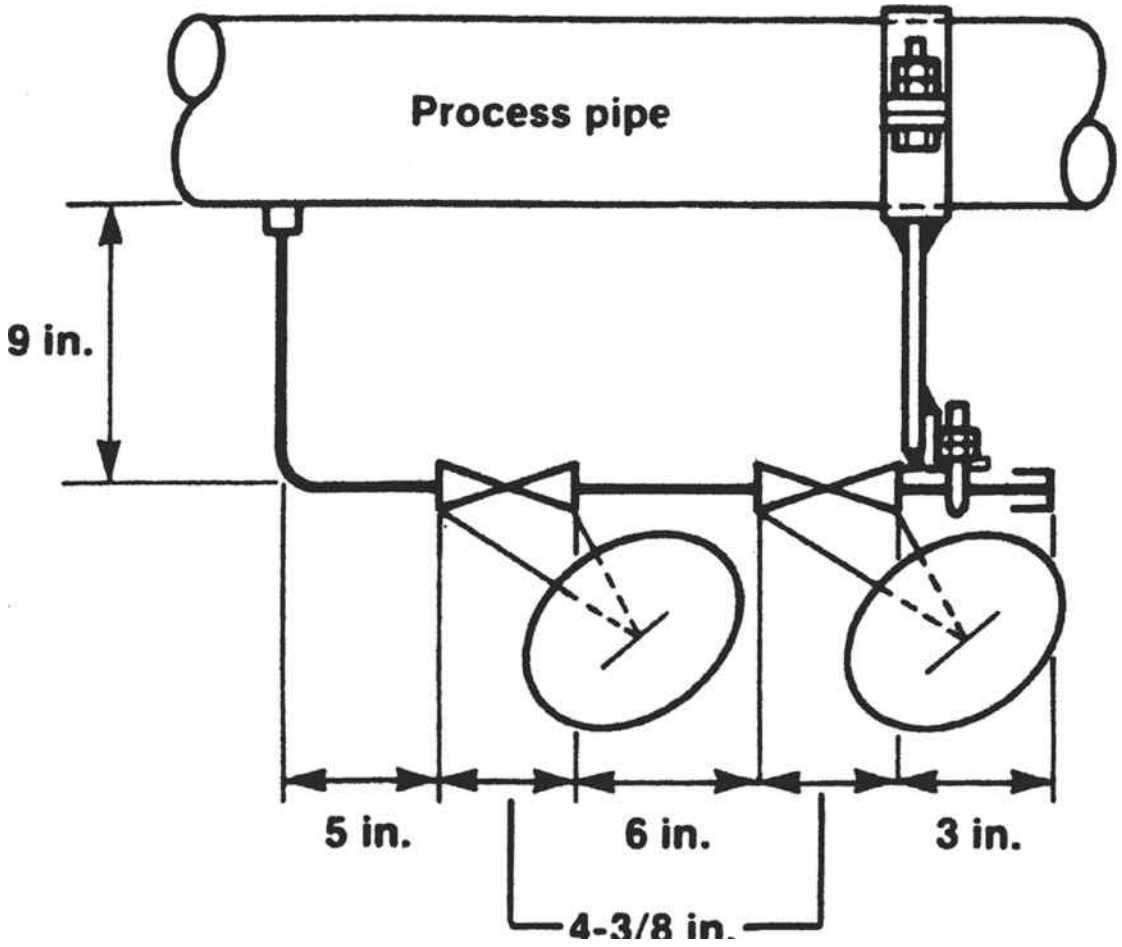


FIG. 3.14 SAMPLE SMALL-TAP-LINE ROUTING AND SUPPORT CONFIGURATION

- The use of fast-closing valves should be minimized. Valves should be specified that are designed to minimize transient or waterhammer effects. Some check valves, for example, are designed to slow at the end of their travel when closing, thus greatly reducing transient effects.
- Control system logic should be developed to avoid unnecessarily fast opening and closing of valves or tripping and start-up of equipment. Effective use of control logic can be used to avoid many system transients.
- A balanced number of spring- or constant-support hangers and rigid supports should be used in the system design. For example, rigid struts will stiffen the system and can also be used to control thermal expansion.
- Restraints designed with close tolerances should be used for restraining vibration. Snubbers may prove useful for dynamic-transient vibrations when thermal expansion is a problem, but some models are known to fail in a relatively short time when subjected to continuous steady-state vibration. For low-frequency steady-state vibration, a snubber may not be active at all. Rigid restraints acting in the axial direction on long pipe legs will best control the system transient response.
- Operating procedures should be written to avoid unnecessary pump trips or rapid opening and closing of control valves.
- Maintenance procedures should strive to avoid allowing air in water lines or water in gas lines. A case was described earlier in which water was allowed to accumulate in a steam line because of a dirty steam trap, causing the damaging dynamic transient experienced by the cold-reheat line.
- A log of vibration problems experienced in operating plants should be kept to aid in the analysis and resolution of the problems so that the recurrence of similar problems can be avoided in new designs.

3.7 VIBRATION TESTING AND ANALYSIS

Vibration monitoring and testing of piping systems involves assessing the operating vibration of in situ piping systems. The goal of monitoring is to qualify a piping system for the vibration it actually experiences, that is, to determine with sufficient accuracy that the magnitude of the vibration-related stresses are not large enough to cause a failure over the 40 yr. design life of the power plant. Monitoring is performed to determine the response of the piping to forcing resulting from the operation of the system. The cause of the vibration (i.e., the forcing function) becomes important when one attempts to control and reduce excessive vibrations and also when one correlates analytical and experimental results. Vibration testing can be performed to quantify system parameters such as modal frequencies, damping, and mode shapes. Experimental parameters obtained by means of testing can then be used to improve and verify analytical models.

3.7.1 Vibration Measurements

3.7.1.1 Instrumentation Requirements The characteristics of piping vibration require instrumentation that may be different from that normally found in a power plant. A good deal of the piping response will be at frequencies lower than 10 Hz; therefore, instrumentation capable of low-frequency measurements is required. In addition, most piping vibration will not be sinusoidal or harmonic; it would be better described as quasi-random—a distinction that becomes important because much of the available instrumentation measures the root mean square (rms) of a vibration signal, which is a time average of the waveform magnitude. The rms reading for a purely sinusoidal vibration can be converted to a peak amplitude by multiplying rms by 1.414. For any vibration that is not composed of a purely sinusoidal motion, this simple relationship is not applicable. As illustrated in Fig. 3.15, a significant error would result from using the sinusoidal relationship between rms and peak to convert the rms measurement of a complex waveform to a peak amplitude. For piping vibration, peak values need to be measured because fatigue allowables are in terms of peak stress. Therefore, a method of obtaining true peak vibration levels is needed, which can be obtained either by using instrumentation that senses true peak values or by statistically converting rms measurements to peak values [22].

Vibration can be defined in terms of displacement, velocity, and acceleration. Therefore, the parameter to be measured must be determined before testing, and the instrumentation chosen must be appropriate for the measured parameter. Each of these parameters has certain advantages and disadvantages. Vibrational piping displacement is the cause of piping-bending stress, so therefore measurements of displacement provide a direct relationship between the measured parameter and acceptance criteria, namely, pipe stress. Test personnel can also more readily estimate displacement amplitude; however, doing so for the amplitude of velocity and acceleration would be more difficult.

Velocity does inherently consider both displacement and frequency, so it is directly related to fatigue and wear. However, accurately predicting piping vibrational frequencies can be difficult—a fact that can complicate the development of velocity acceptance criteria. Acceleration is useful because it provides a measurement directly proportional to the inertial forces resulting from vibration. However, at low piping frequencies accelerations are likely to be small and difficult to accurately measure. In addition, because acceleration increases with the square of frequency, the difficulty encountered with velocity criteria of accurately accounting for piping vibrational frequencies is compounded with the use of acceleration criteria. The best overall parameter is therefore displacement for determining piping vibrational response [23].

3.7.1.2 Vibration-Monitoring Systems A vibration-monitoring system uses hardware transducers to measure the vibrational parameter(s) of interest. These transducers are attached to the piping, structure, or equipment to be monitored and are powered by signal conditioning that transmits signals to data acquisition and reduction instrumentation. Such a system may have alarms and various means for data storage and display. Developments with digital electronics have greatly expanded the capabilities of monitoring systems and have at the same time dramatically reduced their cost. Monitoring systems have become an effective means of assessing vibration severity, discovering the causes of vibration, and accurately determining vibration effects. These systems can be used to resolve a wide range of vibration problems, thereby improving plant reliability.

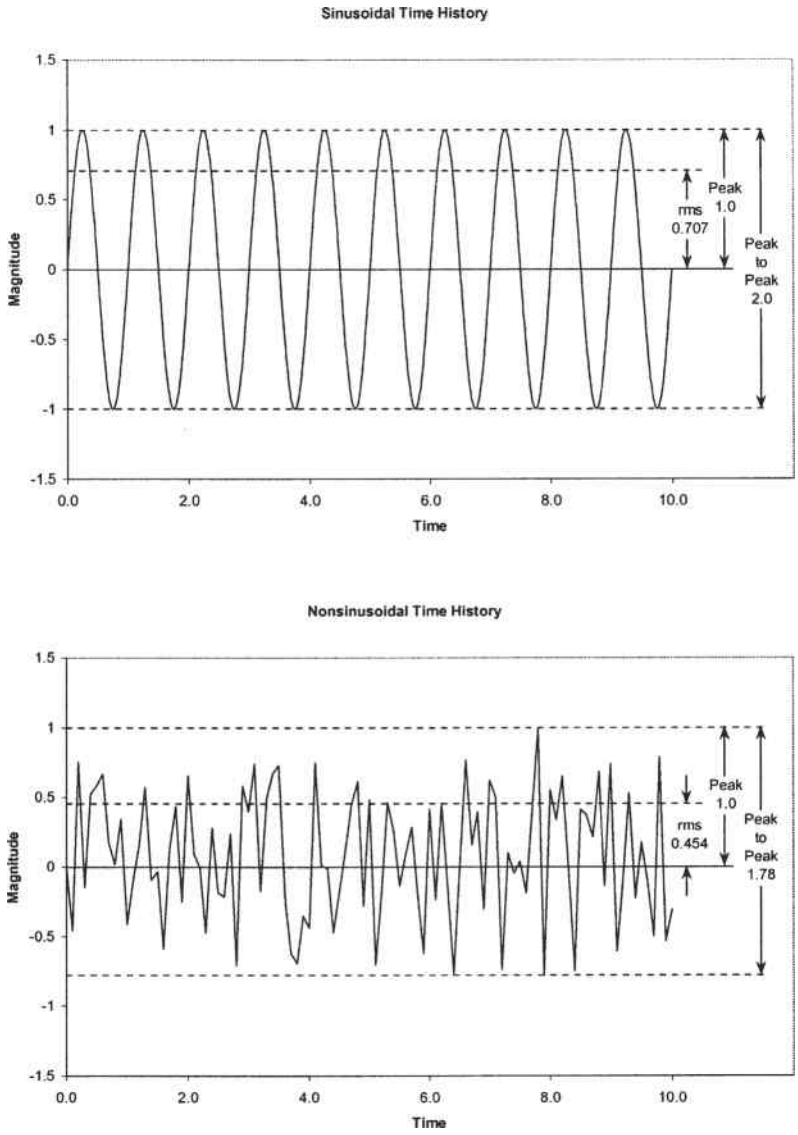


FIG. 3.15 RMS VERSUS PEAK-TO-PEAK MEASUREMENTS

Monitoring systems may be used either for snapshot recording or for continuous monitoring. Snapshot recording involves obtaining test data during a specific short time period. For example, a snapshot system may consist of strain gauges attached to piping, the necessary signal conditioning, and a tape recorder and/or strip-chart recorder. This type of system is practical; for example, it may be used to monitor possible waterhammer caused by pump start-up. A snapshot of the response would be recorded for a short time period, immediately before, during, and after pump start-up.

Instrumentation systems can be also set up for continuous monitoring of the response of the system over a long time period. For example, piping response can be monitored 24 hr. a day, 7 days/wk., for many months at a time. With these types of systems, data would only be recorded if vibrational responses exceeded predetermined trip levels. This type of system will continuously monitor the vibrational response, but if it is less than a given trip limit, no data will be recorded, whereas if it exceeds a certain limit, the system will record data for a predetermined amount of time. Data can be recorded for time periods both before and after exceeding the trip level. These types of systems have been made possible through the use of intelligent data acquisition systems. Stated another way, these are systems that can be programmed to perform such functions as comparing data to trip limits.

Continuous-monitoring systems are extremely useful for situations in which all operating conditions and modes of a system are to be evaluated during normal plant-operating conditions. Doing so avoids the need for special tests that duplicate all these conditions and also allows for the monitoring of potentially unknown events that may occur during operation.

Transducers are available to monitor nearly every possible parameter relating to piping vibrational response and vibration sources. Displacement transducers, such as a linear-variable

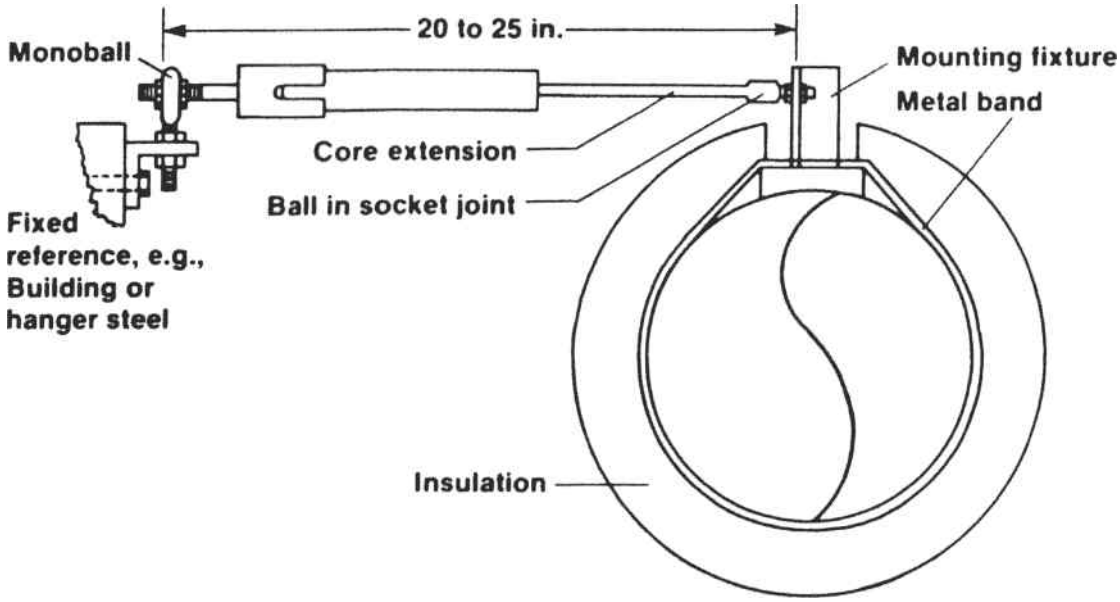


FIG. 3.16 AN LVDT INSTALLATION

differential transformer (LVDT) or lanyard potentiometers, provide good indications of piping vibrational response. An LVDT, shown in Fig. 3.16, has for piping vibration measurements a good frequency range: static and direct current (dc), for example, as well as greater than 200 Hz. The drawback of displacement transducers is that one end of the transducer must be attached to a building structure; they measure relative displacement between the piping or component and a fixed reference.

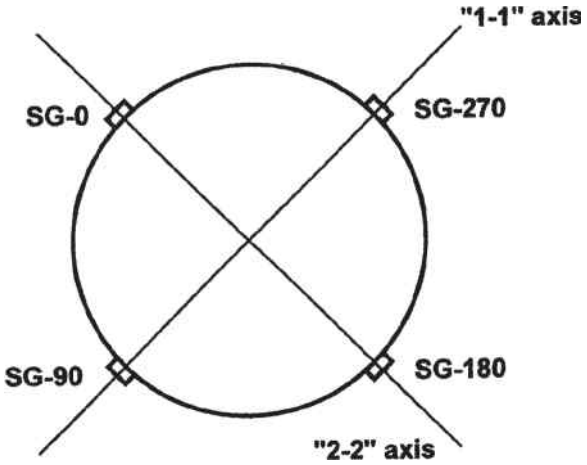
Acceleration, velocity, and displacement can be measured with the use of accelerometers. Velocity and displacement readings are obtained through single and double integration, respectively. The advantage of accelerometers is that they measure absolute acceleration and therefore do not need to be tied back or attached to any plant structure. Accelerometers are, however, subject to noise caused by high accelerations at high frequencies, such as from sudden shocks caused by looseness in the accelerometer bracket; integration of these signals, moreover, can distort the results at low frequencies.

Temperature information can be obtained through the use of thermocouples or resistive temperature devices (RTDs). Temperature readings are important for evaluating the following:

- Thermal expansion response of piping.
- Thermal transients.
- The effects of temperature on fluid conditions.
- The influence of temperature on transducer output.

Acoustic emissions or sound levels can be monitored through the use of microphones. The frequency content of the sound measurements can be analyzed, which is helpful in determining sources of vibration. Sound level measured in decibels also can be used as qualitative evaluations of the vibration severity. Acoustic emissions or noise levels measured before and after vibration fixes are used as qualitative measures of the vibration fix's effectiveness. Acoustic emissions are also important for determining the habitability of various locations within the plant.

Strain measurements are very useful for determining the effect of vibrations. A piping acceptance criterion is given in terms of stress, so strain measurements produce data directly applicable them. Strain readings can also be used to determine the frequency and approximate magnitudes of pressure fluctuations inside the piping, and strain in system supports can be used to calculate vibrational loads on supports. [34] Care must be taken in the placement, orientation and bridging of the strain gauges to ensure that meaningful data, related to the vibrational strains, is obtained. For example, dynamic bending strains due to vibration can be obtained with the strain gauge orientation shown below. In the plane of the moment, bending



STRAIN GAUGE ORIENTATION FOR MEASURING BENDING FROM VIBRATION

results in an axial tension strain and an axial compression strain 180° apart. Therefore, bending strains are measured by subtracting the output of two axial gauges orientated 180° apart. This has the advantage of subtracting out other axial strains existing at that location.

Pressure data can best obtained through the use of dynamic-pressure transducers. The use of pressure transducers requires tapping into the piping, which often creates a system modification. Pressure data are useful in determining the source of the vibration, for pressure fluctuations are the forcing function for piping vibration.

Force measurements can be obtained through the use of force transducers or by applying strain gauges directly on piping supports. Force transducers, which incorporate the use of internally mounted strain gauges, provide the most accurate force information. Transducers are specifically tailored for power plant applications. For instance, transducers are available in the form of clevis pins, in which an existing clevis pin is replaced with a clevis pin having internally mounted strain gauges calibrated in terms of force.

As the foregoing discussion illustrates, because many differential possible parameters can be monitored, a monitoring system is therefore tailored to each application based on what is known about the vibrating piping system, budgetary constraints, and potential vibration sources.

Monitoring systems are required for quantitative information on such short-duration events as waterhammer, and also for monitoring responses in areas inaccessible to personnel during operation. Monitoring systems are used to record vibrations of piping inside containment that can only operate with the use of nuclear-generated steam; such piping is therefore inaccessible to personnel during operation. Monitoring systems are also used for continuously monitoring piping when the source of a transient is unknown, allowing the transient to be recorded whenever it occurs.

A continuous-monitoring data-acquisition system is used to determine the source and quantify the effect of transients that repeatedly fail snubbers at operating nuclear plants. Such a system continuously monitors the piping and supports, and records the transient when it occurrs. A recorded support load resulting from a transient is shown in Fig. 3.17, which demonstrates that the entire event occurred in approximately 1 sec. From the data, the transient source could be determined by correlating the time of the event to how the system was being operated at that time. In this case, the transient was the result of not venting the line before conducting the system surveillance testing. The recorded data also allowed the transient effects to be quantified.

Data obtained and recorded with a monitoring system can be further evaluated through data reduction and evaluation

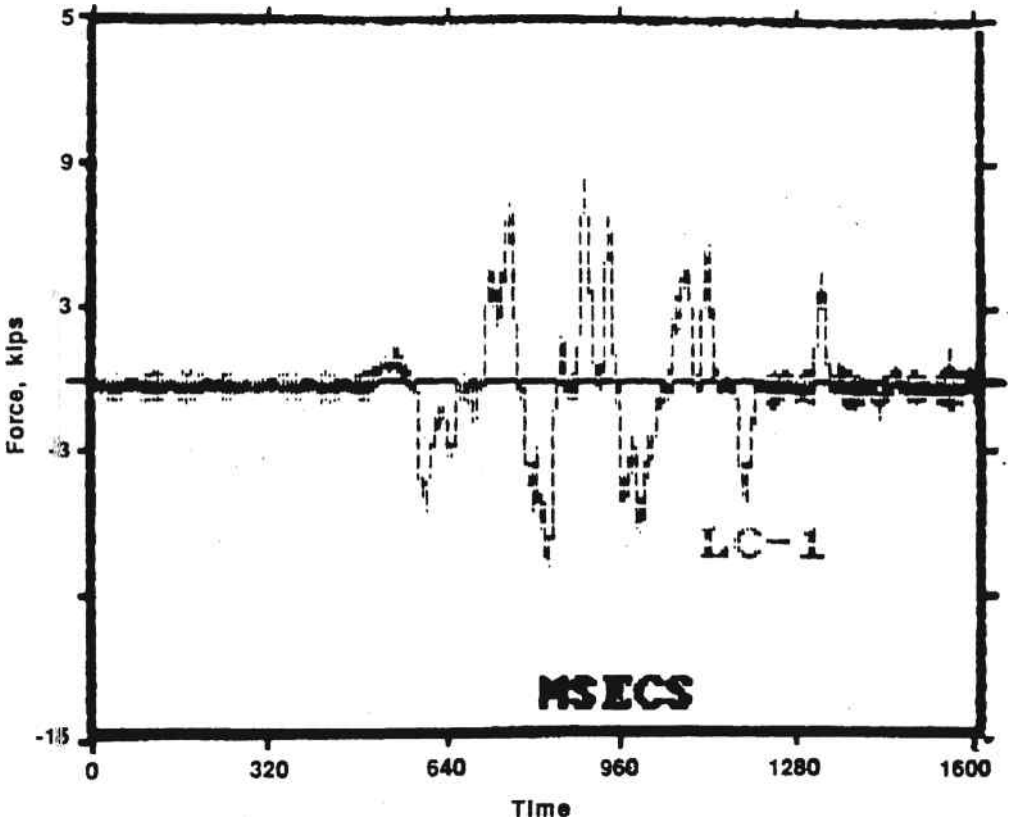


FIG. 3.17 SAMPLE WATERHAMMER CAPTURED BY CONTINUOUS MONITORING

software. Responses from various transducers can be directly correlated and compared to each other and to plant process and control recordings for given instances of time, and frequency analyses of the time history trace can also be completed.

As shown in Fig. 3.18, frequency analysis reveals the frequency and magnitude of each component that comprises a given time history trace. These components in turn provide clues to the source of the transients and to the response of the piping. For instance, a given frequency may correspond to a pump blade-passing frequency, indicating that the pump could be a source of the vibration. Other frequencies may correspond to piping acoustic frequencies, which might mean that an acoustic resonance may be present. Frequency contents may also be related to piping structural frequencies. Monitoring systems offer a powerful investigative and analytical tool for quantifying the effects of vibration, discovering the sources, and developing effective vibration resolutions. Continual advances in digital electronics both reduce the costs of data acquisition systems and transducers and improves

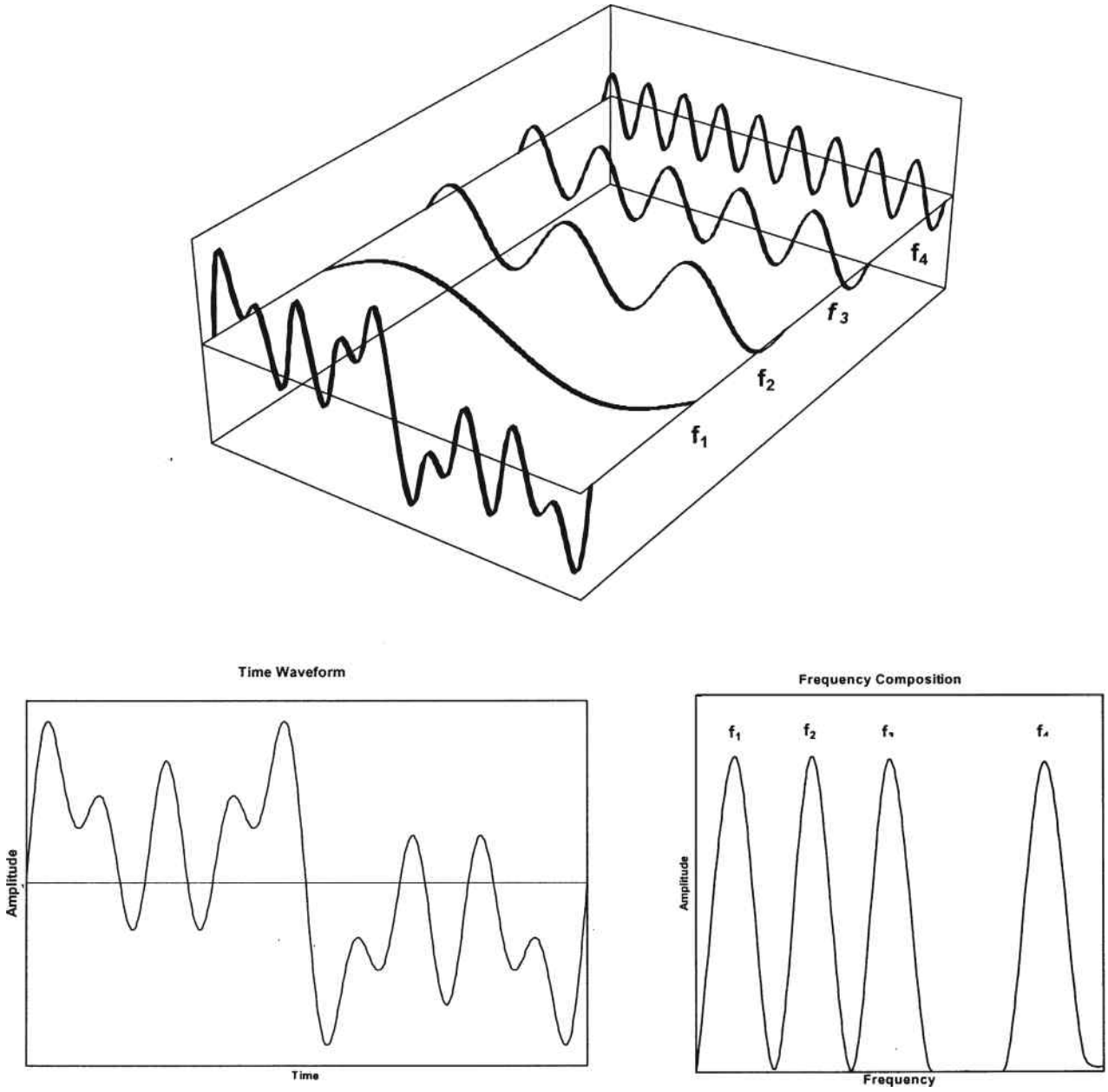


FIG. 3.18 FREQUENCY COMPOSITION OF A TIME HISTORY TRACE

their capabilities. This in turn makes monitoring systems more practical, effective and practical for use with a wider range of applications.

3.7.2 System Walkdown Procedures

Walkdown procedures are effective methods of assessing piping vibration. Walkdowns can be used for both dynamic-transient and steady-state piping vibration. Walkdowns allow for a quick, efficient assessment of the vibration severity, so the effort expended is proportional to the vibration severity. If observed vibrations are small, then in accordance with the walkdown procedure little effort is needed to qualify the piping. If vibrations are more severe, however, additional attention is given to better quantify the piping response and, if required, develop fixes.

Walkdown procedures rely heavily on the judgment and experience of the engineers who complete the walkdowns. Therefore, to ensure that the walkdowns are effective, those completing them should be experienced in a variety of areas related to piping vibration, including experience with the system and its operation, and should be familiar with the potential causes and effects of vibration, the capabilities and limitations of the instrumentation used to obtain vibration measurements, piping structural and stress analyses and Code requirements, and the bases and assumptions applicable to the acceptance criteria used to qualify piping vibration. In fact, these requirements dictate a high level of experience for the engineers completing this work. A team approach may be used for completing the walkdowns, such as by using a test engineer teamed with a piping engineer; the collective experience of the team includes experience in all of the required areas.

3.7.2.1 Dynamic-Transient Vibration A visual walkdown procedure can be an effective method of assessing dynamic transients in piping (see Fig. 3.19). The main objective of visual transient monitoring is to determine whether a system experiences a significant transient (e.g., waterhammer). A transient typically occurs in less than a second, so a quantitative measurement is not possible by purely visual means; nonetheless,

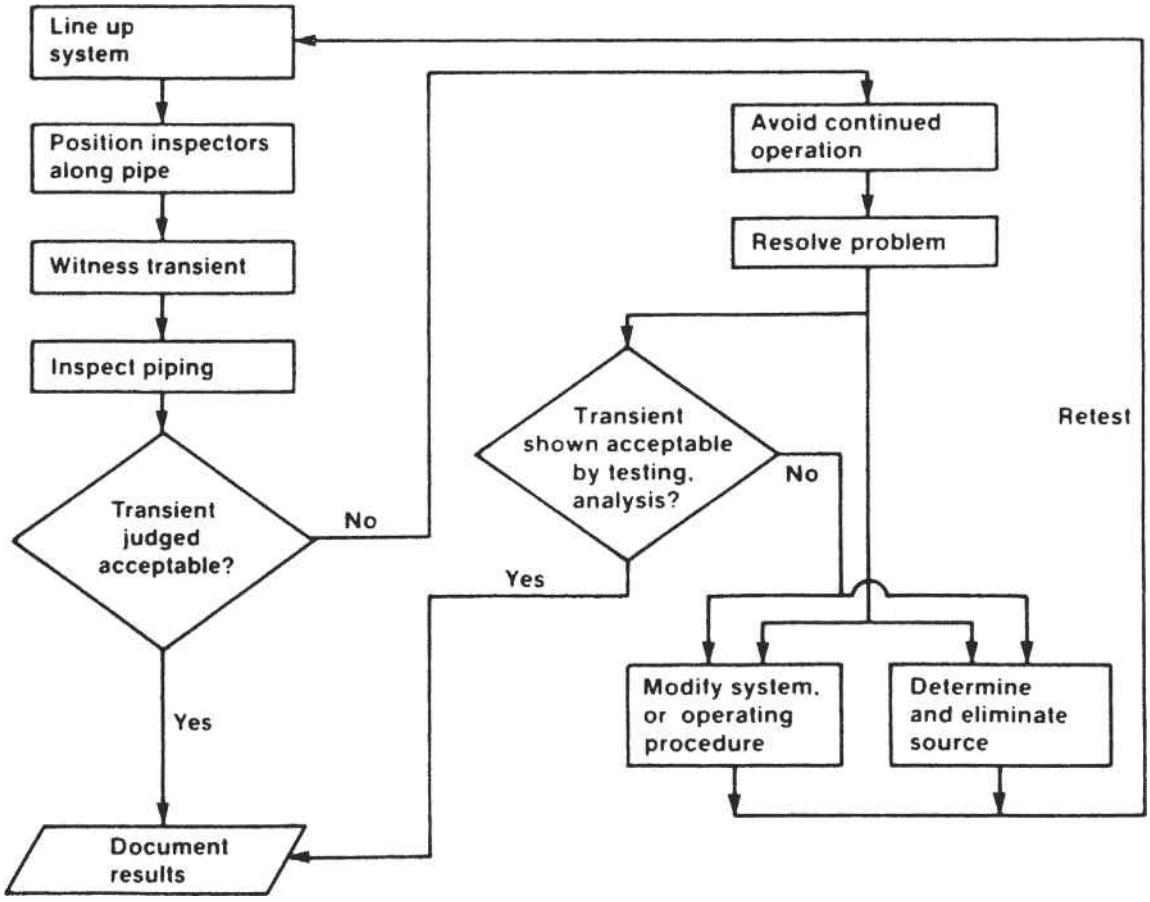


FIG. 3.19 VISUAL MONITORING PROCEDURE FOR TRANSIENTS

a visual inspection is effective in eliminating from consideration systems that experience no problems. Analytical and test efforts can therefore be concentrated on systems exhibiting a potential for experiencing excessive transient vibrations.

3.7.2.2 Steady-State Vibration A flowchart depicting the steps involved in completing a walkdown for qualifying steady-state piping vibration is shown in Fig. 3.20. The first step is to align the piping system in the flow mode(s) expected to result in the most severe vibration. Then, the piping is walked down and its vibration response is witnessed during all modes of operation to result in significant piping vibration.

A piping walkdown allows the entire piping system response to be witnessed and is a very effective method of detecting vibration problems, for most piping vibration problems result in readily detectable symptoms (e.g., significant displacements or excessive noise). During the walkdown, an Inspector decides the quantity and location of vibration measurements to be taken. Doing so allows vibration measurements and locations to be based on actual piping response rather than analytically determined responses, which depend on a host of assumptions.

An example of a common assumption used in piping analysis is that snubbers are locked-up during all levels of vibration. However, snubbers are seismic devices designed to restrain low-frequency, high-amplitude dynamic motion. Although they are effective in restraining seismic motion, they are less effective at restraining flow-induced vibration and in some cases (especially for low-frequency vibration) snubbers may follow the motion of the piping, thereby not providing any restraint. Of course, an analysis that assumes these snubbers to be locked-up would be inaccurate.

Vibration-limiting effects of snubbers are influenced both by their internal mechanical looseness and their inherent design. A

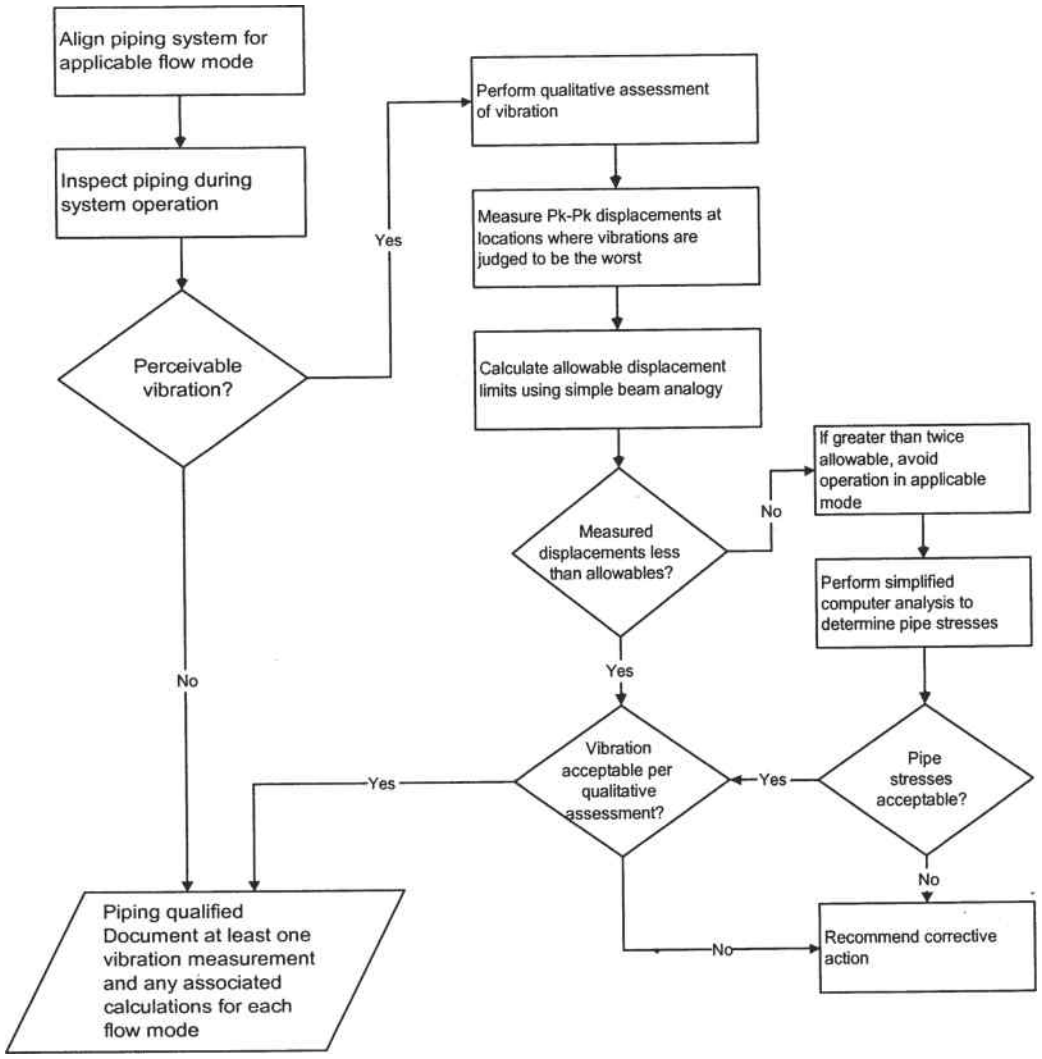


FIG. 3.20 VISUAL MONITORING AND QUALIFICATION PROCEDURE FOR PIPING STEADY-STATE VIBRATION

snubber may have over 32 mils of dead space because of internal tolerances. A steady-state vibration magnitude of 32 mils can be significant for piping. Inherent design determines the threshold of vibration to which a snubber will limit the piping. A commonly used mechanical snubber is designed to limit vibration to 0.02 g; and a commonly used hydraulic snubber is designed to limit vibration to 0.2 in./sec. [24]—[25]. Figure 3.21 plots these limits on a graph that indicates the harmonic relationship between displacement, velocity, and acceleration. As seen from the figure, at a frequency of 1 Hz, both types of snubbers would allow at least 60 mils (peak-to-peak) of vibration exclusive of mechanical dead space considerations. Because most power plant piping vibrations are low frequency, vibration is largely permitted by even perfectly operating snubbers. From this figure, it can also be seen that, at low frequencies, this type of mechanical snubber allows more vibration than the hydraulic snubber. Although the mechanical snubber appears to be better at high frequencies, its dead space of 32 mils or greater partially negates this design advantage.

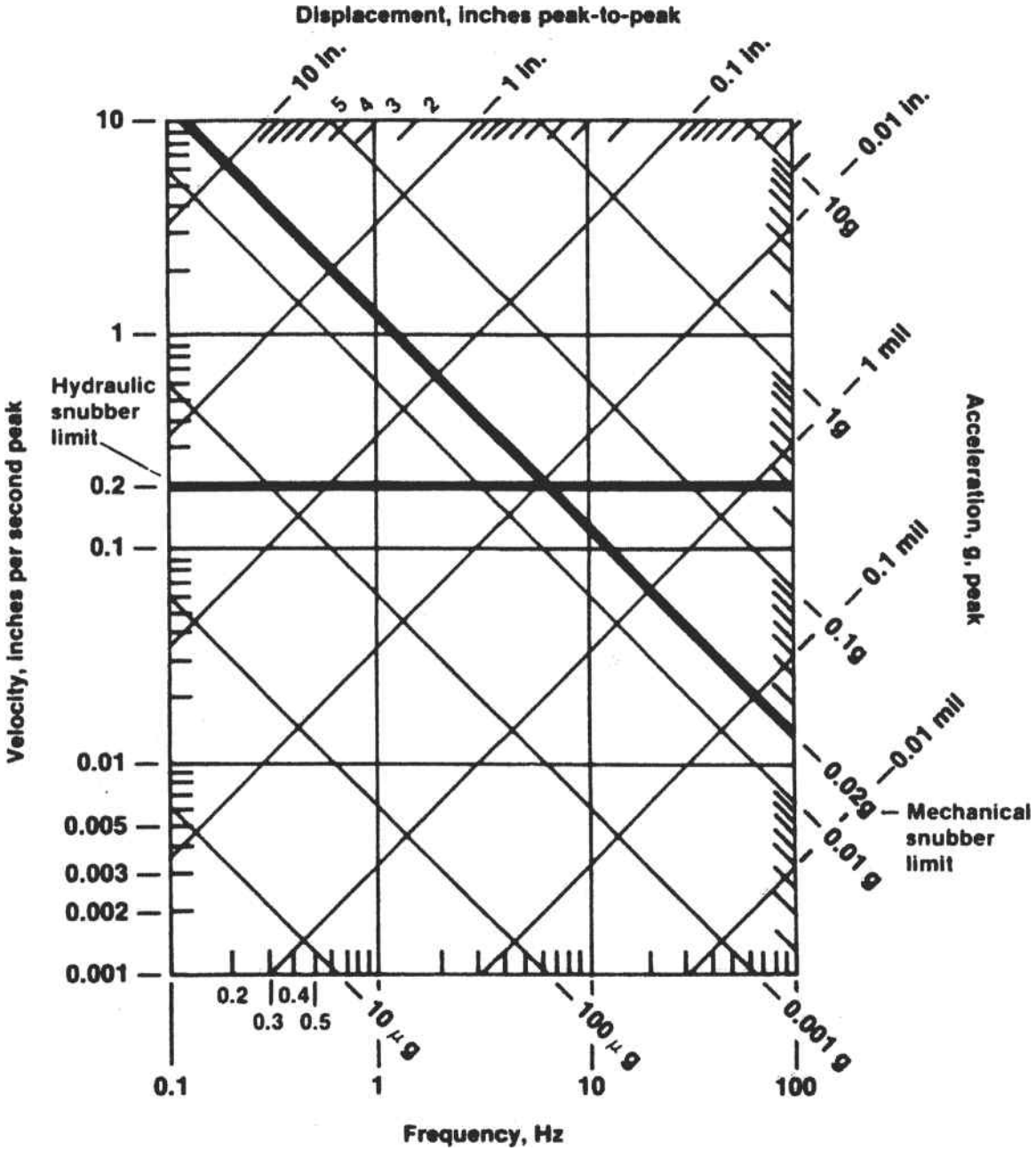
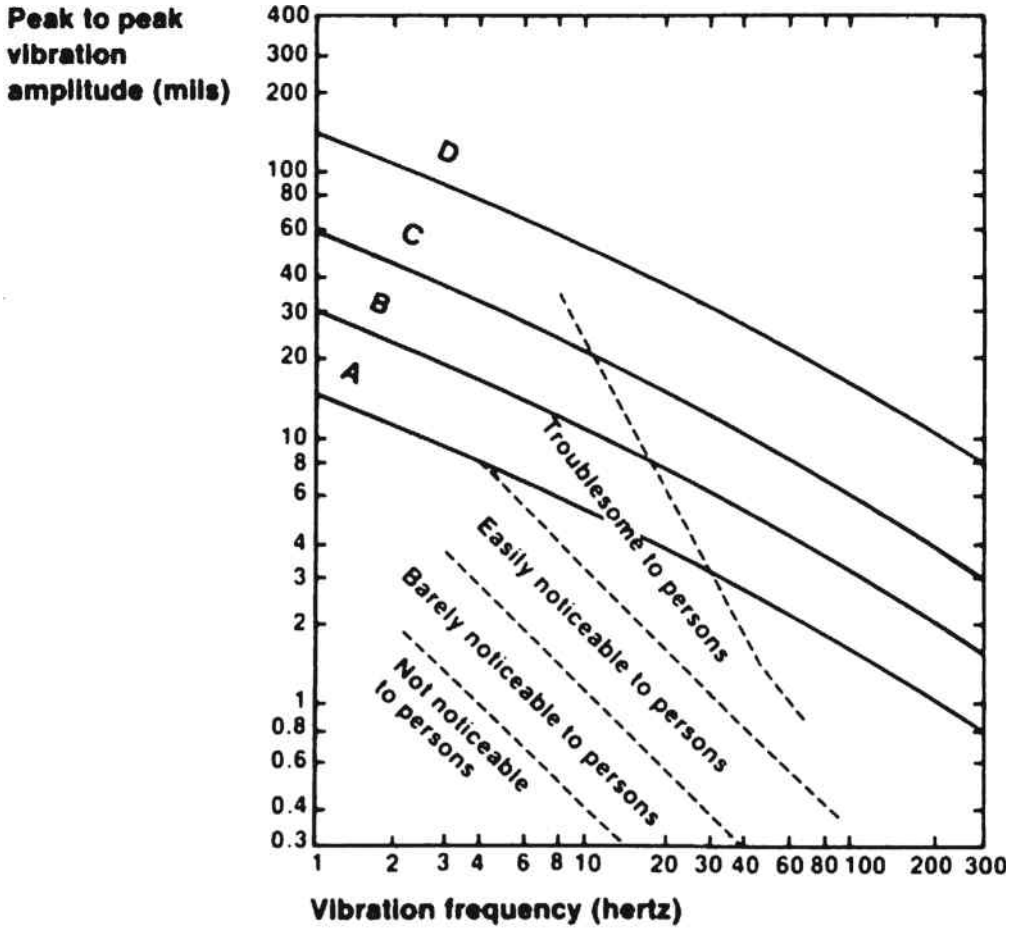


FIG. 3.21 SNUBBER MOTION-LIMITING EFFECTS

During piping walkdowns, Inspectors rely on their perceptions as well as their vibration-measuring instrumentation to determine vibration levels. An Inspector's perceptions can be used for determining where or how many measurements to take. An Inspector's ability to perceive detrimental vibration levels is demonstrated in Fig. 3.22. As seen from this figure, an Inspector can perceive (i.e., see or feel) vibration levels much smaller than those likely to cause piping failure. The vibration categories of Fig. 3.22 are



A Design piping vibration level
B Marginal piping vibration level
C Correction piping vibration level
D Danger piping vibration level

Caution: Indicated vibration limits are for average piping systems constructed in accordance with good engineering practices. Make additional allowances for critical applications, unreinforced branch connections, etc. Limits are based on experience. The values may be unconservative or overly conservative for some configurations.

FIG. 3.22 SAMPLE VIBRATION LIMITS AND PERCEPTION LEVELS

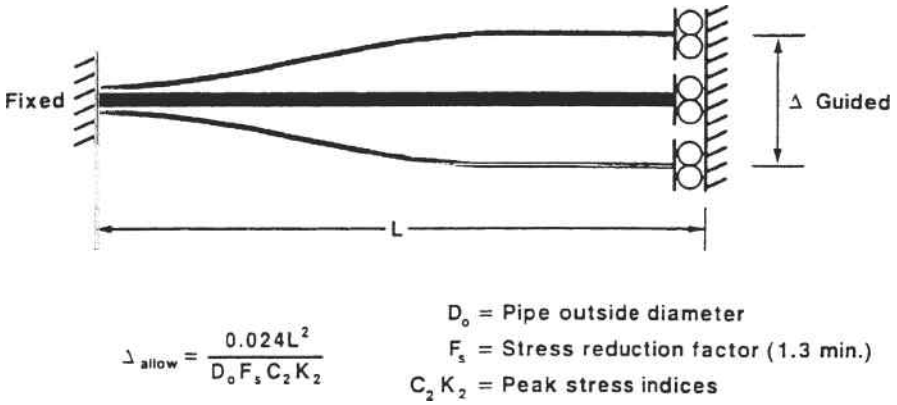


FIG. 3.23 SIMPLE-BEAM MODEL FOR DETERMINING VIBRATION LIMITS

based on "Haystack" curves developed in the 1960's by Southwest Research Institute [26]. These curves are based on empirical data from numerous tests of reciprocating compressor piping systems. (The perception levels are based on an article by Richart [27] that discusses foundation vibrations.) Although the curves on perception are based on structural vibrations which are no doubt perceived differently than piping vibrations, they still offer a basis for how humans perceive and judge various vibration levels. Experience with plant start-up test programs has also demonstrated that Inspectors, primarily through observation and by using their hands to feel piping vibration, quickly develop an ability to closely estimate actual vibration levels.

If no perceivable vibration occurs, the piping is therefore qualified. At least one vibration measurement is taken to document any measurable vibration for future reference and as baseline data against which to compare future measurements. If vibration is perceived, however, a qualitative assessment is completed first, followed by a quantitative assessment by using simplified methods. The qualitative assessment addresses items in addition to pipe stress (pipe stress is addressed by the quantitative evaluation). Judgments are made concerning the effect that vibration has on pipe supports (including the potential for fatigue and wear of the supports) and also the possibility of threaded connections becoming loosened on support hardware.

Additional judgments are made concerning the potential for pipe wear and pitting from cavitation (if present) and also the effect of vibration on in-line equipment and valve operation. In addition, if very-high-frequency vibration exists, the simplified quantitative evaluation techniques may not be appropriate; hence judgments are made concerning the applicability of the simplified evaluation methods as well.

To assess vibration severity, Inspectors can calculate an allowable vibration limit by using a simple beam analogy. A simple-beam analogy, such as that shown in Fig. 3.23, is used to obtain a conservative representation of the dynamically deflected shape of the piping and allows vibration limits to be based on the actual behavior of the piping during the witnessed mode of operation. Use of these beam analogies has proven very effective both from the standpoint of avoiding needless preliminary analysis and from being an effective tool for revealing potential vibration problems.

The next step for assessing piping vibration involves the use of simplified computer analysis. Calculations based on a simple-beam analogy typically result in conservative vibration limits [28]. This conservatism can be reduced through the use of a computer model of the vibrating segment of piping. Measured piping vibration displacement is used as analysis input. The simplified computer analysis used is basically a more sophisticated simple-beam analogy. Again, the model is based on the actual vibrational response of the piping.

If measured vibrations are still deemed excessive, the next step involves determining the most economical and time-effective method of resolving the problem. One choice is to complete a more detailed analysis and/or testing. Detailed analysis involves obtaining a more accurate, less conservative analytical representation of the piping response, whereas more detailed testing involves obtaining (such as through the use of strain gauges) sufficient measurements to allow pipe stresses to be accurately determined.

A second alternative is to modify the piping or the piping supports to mitigate the vibration response. It is frequently more cost-effective to add an additional support or (possibly) to shim an existing support than it is to expend additional money on further assessment of the problem.

The ideal solution is to determine and eliminate the source of vibration. For cases in which the entire piping system is experiencing excessive vibration, this solution may also be the most cost-effective. Adding a flow orifice downstream of a cavitating valve can eliminate the vibration source, and a change to an operating procedure is sufficient in some instances to resolve a problem.

3.7.3 Piping Structural Response

Piping typically vibrates in one or more of its structural vibration modes when subjected to vibrational loadings. Therefore, the simplified acceptance criteria and computer analyses used in the aforementioned walkdown procedure are based on simulating the response of these structural modes. Piping will have an infinite number of vibrational modes; however, the lowest frequency modes are typically the most significant. How a piping system

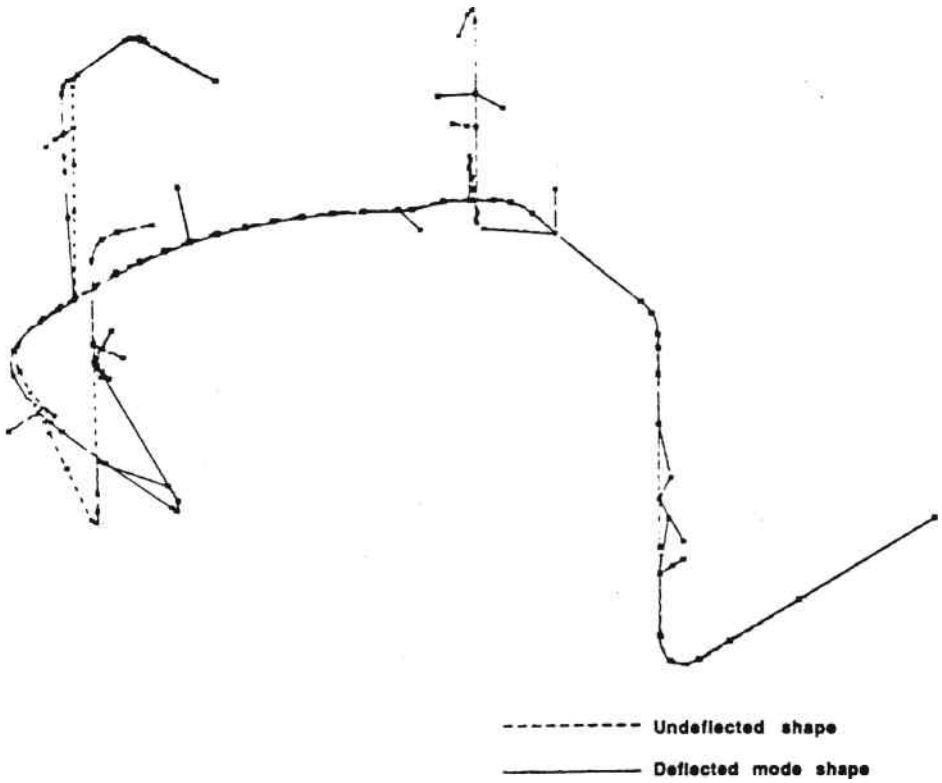


FIG. 3.24 SECOND VIBRATIONAL MODE OF A SAMPLE PIPING SYSTEM

deflects in a given mode determines the stress distribution in the piping. Figures 3.24 and 3.25 are examples of vibrational mode shapes calculated for a sample piping system.

A simple-beam model can be used to simulate the deflected shape of the piping between vibrational node points. As long as these simple-beam models provide

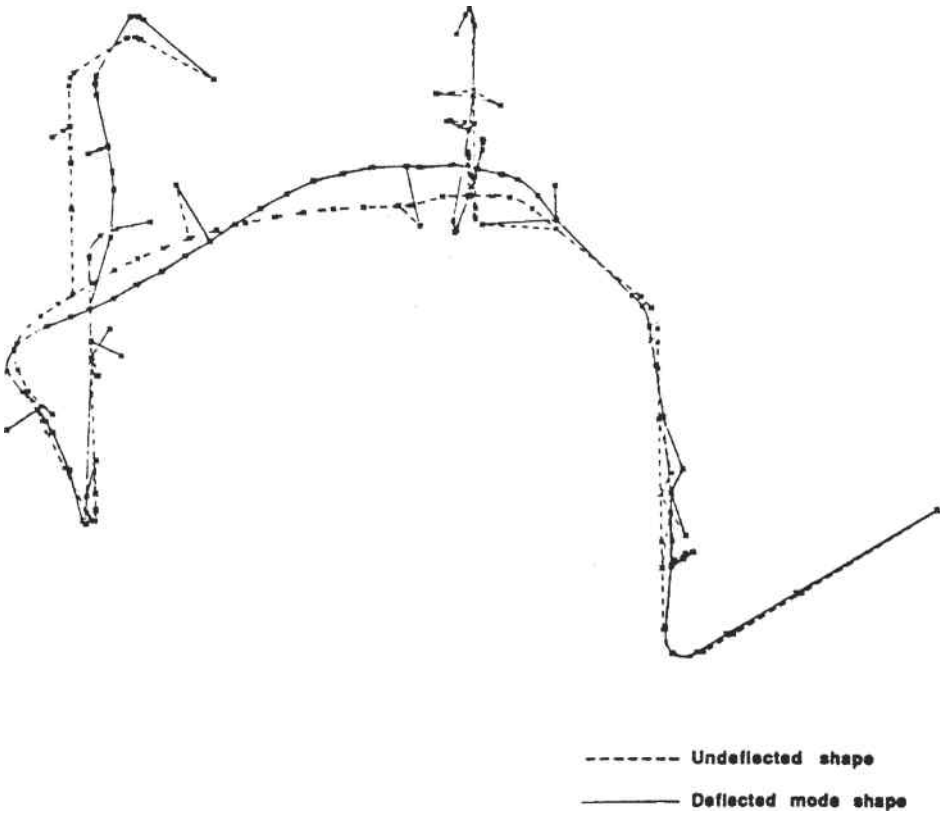


FIG. 3.25 SIXTH VIBRATIONAL MODE FOR A SAMPLE PIPING SYSTEM

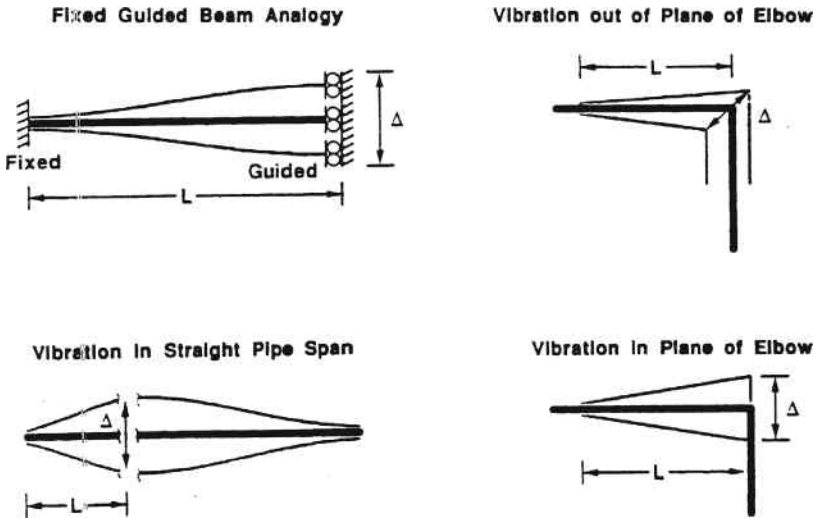


FIG. 3.26 SIMPLE-BEAM ANALOGIES

conservative representations of the deflected shapes, the deflection limit calculated by these simple models will also be conservative. Figure 3.26 shows a fixed guided-beam analogy used frequently to determine allowable deflection limits. The figure shows a simplified equation that can be used to calculate allowable deflection limits based on the beam model. This equation is based on a deflection that causes a stress equal to the endurance limit of carbon steel piping. The factors C_2 and K_2 are from the ASME B&PV Code Section III (NB); the product of these two factors is equal to the peak stress index.

Because it is peak stress that is relevant for fatigue, peak stress indices are used, the commonly used piping fittings and components of which have been tabulated by the Code. As indicated by the Fig. 3.23 equation, if a component in a vibrating span of piping has a high peak-stress index, the corresponding deflection allowable for this span of piping will be significantly less than a span equivalent in all other means (except that it does not have a component with this high peak-stress riser).

Figure 3.26 shows how the simple-beam analogy may be applied to vibrating segments of piping in the field. The vibrational node point is assumed to be the fixed end, and the largest or worst measured vibration deflection is assumed to be equal to the guided end. If a vibrational node point cannot be found, which is typically the case, then a conservative node point location must be assumed. For example, node points may be assumed at rigid supports, anchors, or snubbers. The distance between the assumed node point and the measurement location determines the span length, L, that in turn determines the allowable deflection for that location. The following is a sample application of this simple-beam analogy based on the example in Fig. 3.27.

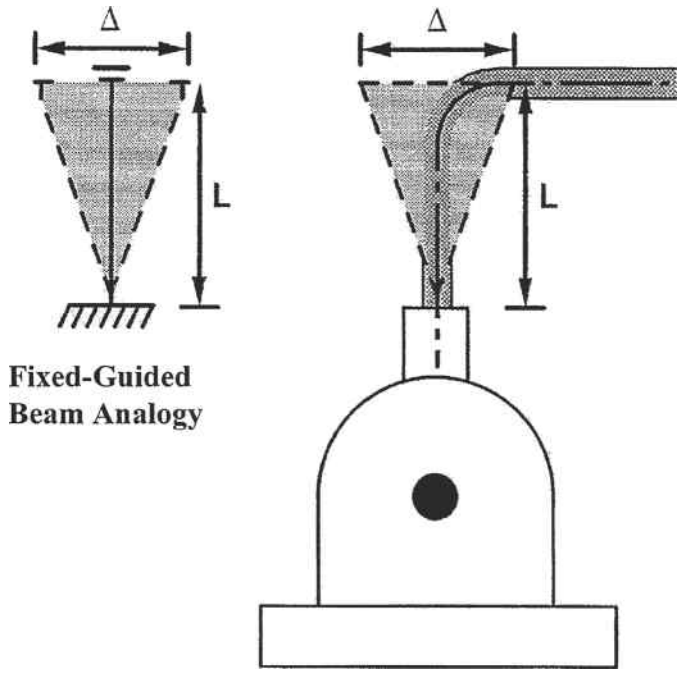


FIG. 3.27 APPLICATION OF SIMPLIFIED ACCEPTANCE CRITERIA

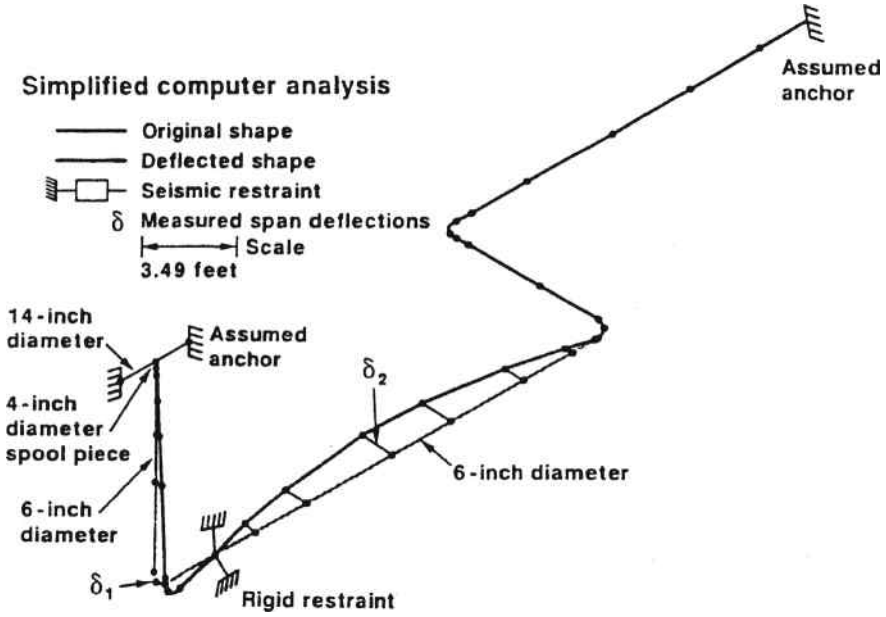


FIG. 3.28 SIMPLIFIED COMPUTER EVALUATION OF PIPING SYSTEM VIBRATION

The deflection equation for a fixed-guidedbeam model from the ASME O&M Part 3 Standard [10] for carbon steel piping is as follows:

$$\Delta_{\text{allow}} = \frac{0.024L^2}{D_0 \alpha C_2 K_2} \tag{3.11}$$

where

L = pipe length, ft.
D_0 = pipe outside diameter, in.
$\alpha = 1.3$ = stress reduction factor (from O&M Part 3).
C_2K_2 = the peak stress index (from ASME B&PV indices discussed previously)

A simplified computer analysis can also be completed to obtain a more accurate stress distribution resulting from piping vibra tional displacements. Figure 3.28 shows a model used to approximate the vibrational stresses in a segment of high-pressure core spray minimum-flow piping. This model is simplified for several reasons.

As Fig. 3.28 illustrates, only a small portion of the piping was included in the model, and a hypothetical or assumed anchor was used to shorten the piping model. Piping measurements were used to normalize the analysis results. In other words, the computer model of the piping segment was made to deflect as closely as possible in the same shape as that of the piping that deflected in the field. This type of computer modeling essentially provides a more accurate and therefore less conservative representation of the piping stresses than can be obtained from the simple-beam analogies.

Increasingly detailed computer analyses can be completed to better represent the deflected shape. More detailed analyses could include larger sections of the piping system; dynamic analyses can be completed to better represent the vibrational mode shapes of the piping and the dynamic forcing function. Typically, the more detailed the analyses, the more conservatism can be removed from the results. Finite element analyses can also be completed for pipe fittings and components to calculate a better representation of the peak stress distribution. These analyses would allow some of the conservatism of the Code C_2 and K_2 peak stress factors to be removed.

3.7.4 Determining Acceptable Vibration Limits

Acceptable vibration limits need to be determined as part of developing acceptance criteria for plant startup vibration testing. Acceptable vibration limits for steady state vibration are based on keeping the peak pipe bending stresses resulting from vibrational pipe deflections below the endurance limit. Acceptable

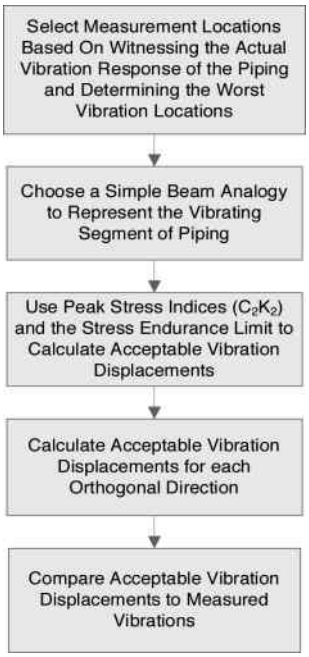


FIG. 3.29 CALCULATION OF ACCEPTABLE VIBRATION LIMITS BASED ON SIMPLE BEAM ANALOGIES

vibration limits are calculated from piping analyses that are intended to simulate how the piping deflects while vibrating. There are a large number of unknown variables involved in these analyses, including the exact nature of the fluid forcing functions and the dynamic characteristics of the piping system. This includes the effect of gaps at supports, well defined support and equipment stiffness and the complex behavior of dynamic restraints, such as snubbers.

There are a variety of analytical methods that can be used to calculate acceptable vibration limits. A simplified method is the use of simple beam analogies, as discussed earlier. This method is useful when the actual response of the piping is witnessed during walk downs and vibration measurements and appropriate beam analogies can be determined based on witnessing the actual response of the piping. The method is summarized in Fig. 3.29

Often acceptable limits must be determined prior to testing and where walkdowns cannot be completed during system operation due to, for example, elevated radiation levels. A simplified analytical method is the use of response spectra (RS) piping analyses to determine acceptable limits. This method is summarized in Fig. 3.30. RS analyses provide a relationship between pipe deflection and stress, however the analyses are not based on forcing the piping deflections in the same manner that the fluid forces are applied to the piping. Therefore RS methods are approximations of how the piping responds to fluid pulsations.

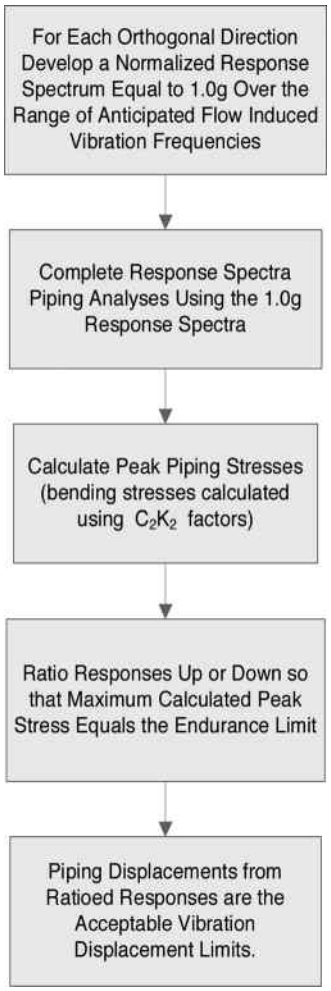


FIG. 3.30 CALCULATION OF ACCEPTABLE VIBRATION LIMITS BASED ON RESPONSE SPECTRA ANALYSIS

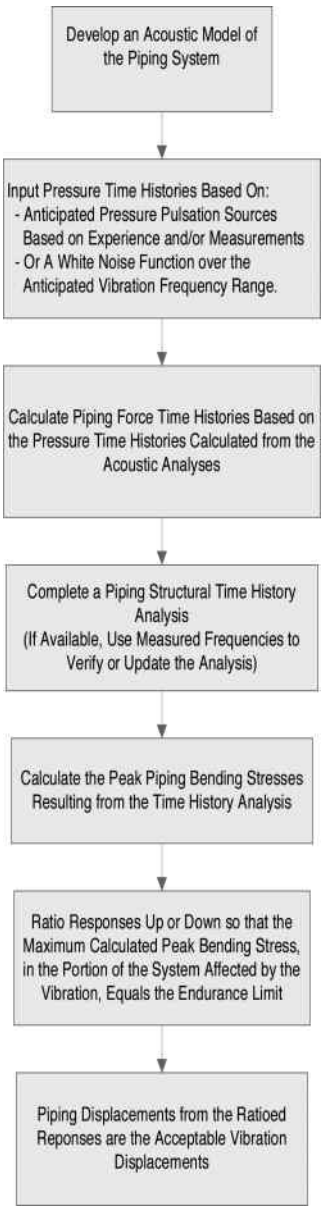


FIG. 3.31 CALCULATION OF ACCEPTABLE VIBRATION LIMITS BASED ON ACOUSTIC ANALYSIS AND TIME HISTORY PIPING ANALYSES

The method summarized in Fig. 3.31 is based on an acoustic analysis (discussed below) and time history piping analysis. This method more accurately simulates how the piping responds to and is deflected by fluid pulsations. Although the exact nature of the fluid pulsations are typically not known prior to testing, this analysis method provides a method of determining acceptable vibration limits that is based on how the piping is affected by the fluid pulsations.

3.7.5 Piping Shell-Mode Vibration

In addition to vibrating in structural or beam modes, piping can also vibrate in shell modes. Shell-mode vibration refers to vibrations

of the pipe wall itself. These vibrations are illustrated in Fig. 3.32. In this figure, *n* represents vibration wave distribution or shape around the circumference of the piping, and *m* represents the axial half-wave vibration forms [29]–[30]. Note that there are many potential shell modes in which the piping can vibrate; moreover, if the excitation frequency is high enough, it is likely to excite one of these modes. In addition, these vibration shapes are typically not stable; node points may rotate around the circumference of the piping. Two sample shell-mode shapes calculated using a finite element model of a simply supported pipe segment are shown in Fig. 3.33. The deflections of these mode shapes have been greatly exaggerated so that the mode shapes can be readily distinguished.

Shell-mode vibration causes flexure of the pipe wall itself. If severe, the vibration can result in cracks near discontinuities, such as shear lugs and branch connections including small-tap-line connections for vents, drains, and pressure taps. Shell modes are excited by high-frequency vibration sources. The following table provides examples of the lowest shell-mode frequencies for various pipe sizes. Note that, as would be expected, small piping has the highest shell-mode frequencies because of the shell's

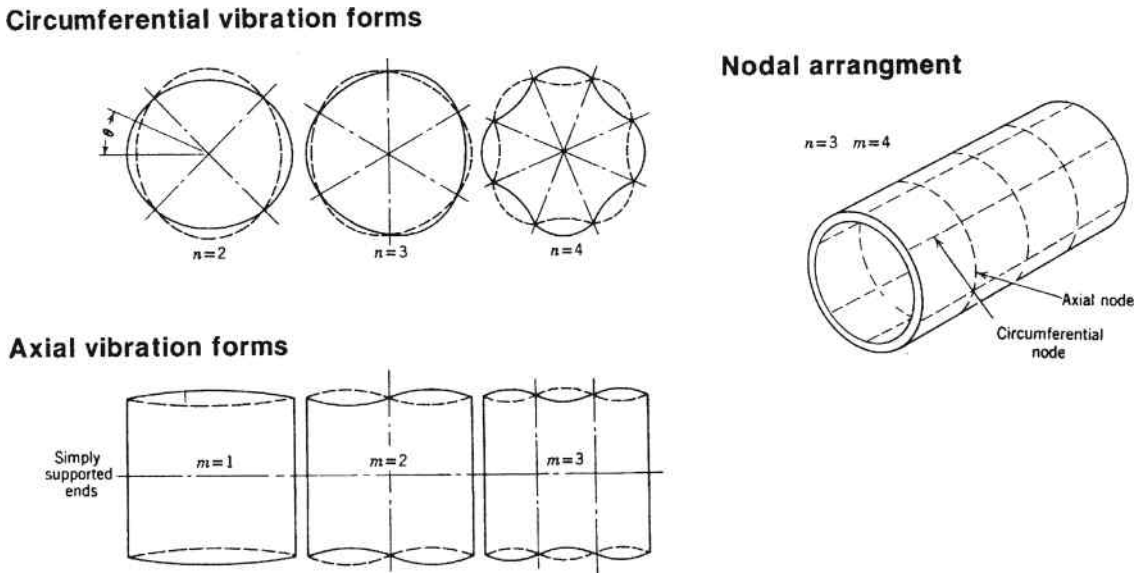


FIG. 3.32 PIPING SHELL VIBRATION MODES

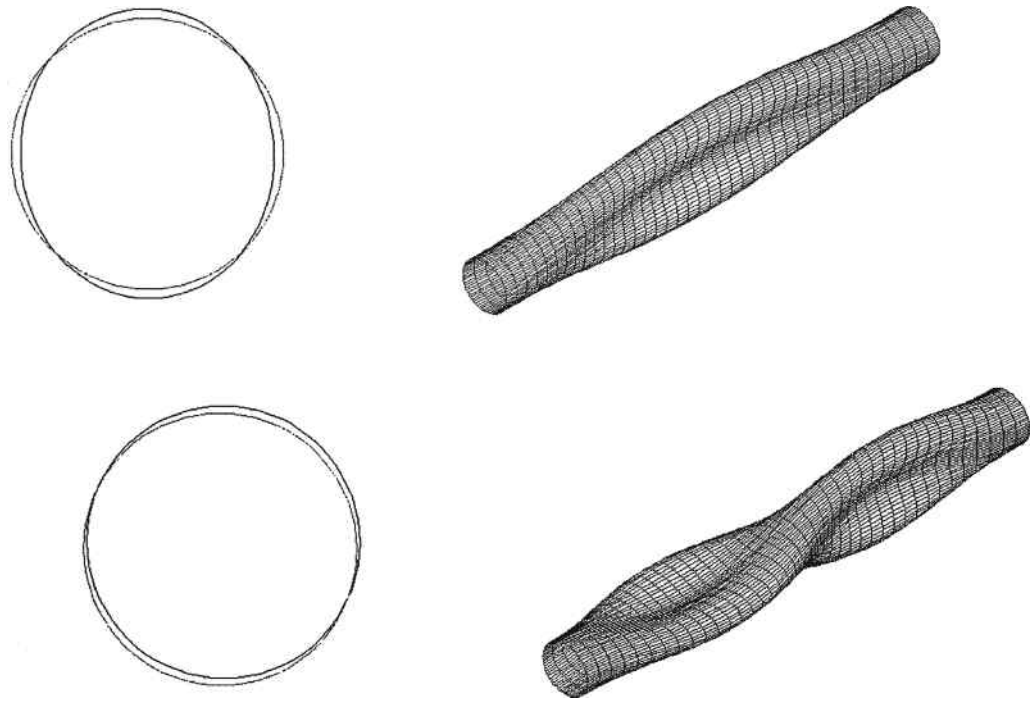


FIG. 3.33 SAMPLE PIPING SHELL-MODE SHAPES

rigidity. In addition, thick-wall piping has higher frequencies, whereas large thin-wall piping (such as that typically found in service water systems) can have fairly low shell-mode frequencies.

Pipe Size (in.)	Wall-Thickness (in.)	Approximate Lowest Shell-Mode Frequency (Hz)
4	0.237	1,960
6	0.280	1,050
10	0.365	510
14	0.438	360
18	0.562	280
24	0.688	190
34	0.500	70

Examples of potential sources of high-frequency vibration are vortex shedding and high-frequency pressure fluctuations caused by throttling at control valves. High-velocity fluid impingement on solid surfaces can cause high-frequency pressure pulsations, which in turn can excite the piping shell modes.

Since shell-mode vibration is of high frequency, it will result in noise, as human hearing is sensitive to frequencies ranging from approximately 20 to 20,000 Hz. In addition, the vibrations will have very small displacements, possibly 1 or 2 mi/s or less, and can likely result in large accelerations. Accurate measurement of these vibrations is therefore difficult with transducers that are strapped onto or held against the piping. The most effective way of quantifying the effects of shell-mode vibration is through the use of strain gauges applied to piping at areas suspected to result in the maximum peak stress.

Shell-mode vibration results in small high-frequency displacements throughout long spans of the piping; thus the addition of supports is not a solution for this type of vibration. Adding constrained-layer damping will reduce the response, and the installation of pipe clamps can be used to eliminate local vibration problems. To avoid resonance throughout the system, either the excitation source must be eliminated or the piping modified, as by replacing it with thicker wall piping.

3.7.6 Piping Acoustical Response

The acoustical response of piping refers to the propagation of pressure pulsations in the fluid medium being transported by the piping. Pressure disturbances or pulsations are transmitted through the fluid the same way that sound is transmitted through the air. Piping acoustical response is important because acoustic resonances can greatly amplify pressure pulsations, thereby increasing the potential for detrimental piping vibration.

An example of a commonly encountered acoustic resonance is shown in Fig. 3.34, which schematically represents a small pressure tap with a dial gauge. Frequently, large oscillations of the needle can be observed during plant operation for these types of configurations. The needle is basically oscillating about the static pressure in the header piping. These large fluctuations are likely not present in the header piping; if they were, severe vibration of the header piping would be experienced. These oscillations are typically caused by an acoustic resonance causing a standing pressure wave in the branch piping of the pressure tap. Since fluid damping is typically low, small pressure fluctuations can be amplified by as much as 100 by the resonance in the branch pipe.

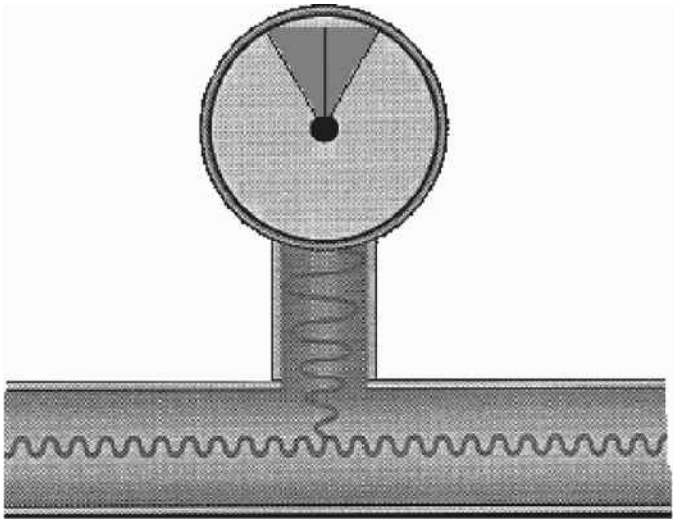


FIG. 3.34 ACOUSTIC RESONANCE IN A PRESSURE-TAP BRANCH

A pressure pulse is reflected at a flow discontinuity, such as a closed or opened end, a piping diameter change, and a pipe branch or restriction (orifice, valve, etc.) [31]. The pressure pulse moves at the speed of sound in the fluid, or sonic velocity, and a whole or partial reflection of the pressure pulse occurs at these flow discontinuities. For acoustic or pulsation waves to reinforce and result in resonance, reflections of the acoustic waves are necessary.

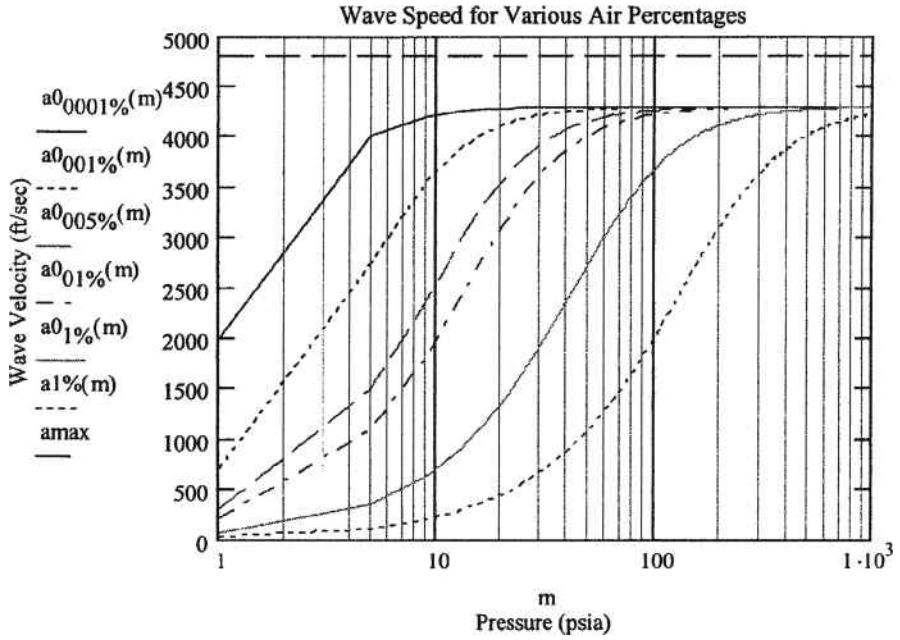
The resonance that occurs in a pressure-tap branch, such as that shown in Fig. 3.33, is an example of a standing wave pattern in a closed-end pipe. The superposition of an incident wave and a reflected wave, being the sum of the two waves traveling in opposite directions, results in a standing wave. The pressure wave exhibits pressure maximums; at the node points, it exhibits pressure minimums. In other words, the acoustic resonance has a mode shape, as does a structural resonance.

Acoustic modes are often referred to as organ pipe resonant mode shapes. Similar to structural resonances, there are basically an infinite number of acoustic resonances with the lowest resonances typically being the most easily excited. The resonant frequencies are a function of the velocity of sound in the fluid and the length of piping. The quarter-wave resonance is typically what occurs in the pressure-tap lines, as discussed in the preceding paragraph and also in Section 3.5.4 on vortex shedding.

Acoustic modes and resonances can be predicted analytically. However there are a large number of variables that go into this type of analysis and their values can vary over a wide range, making accurate prediction of acoustic properties difficult. For example the acoustic velocity of water varies as a function of the pipe thickness and schedule, water temperature and air entrained in the water. The following figure illustrates the wide range of values that just one parameter, the acoustic wave speed, can have depending on the amount of entrained air [33]. This figure illustrates the wide variance in wave speed, at least below 100 psia, that can result from entrained air percentages ranging from

0.0001% to 1% (by volume). This variance directly affects the calculated and actual acoustic properties.

There are direct analogies between acoustical, mechanical, and electrical systems as shown in Fig. 3.35 [31]–[32]. These analogies are useful in developing an understanding of acoustic response. An acoustical resistant element (R_a) is an orifice that causes dissipation of energy when the fluid is forced through the small-diameter opening. The pressure drop across the element provides damping to the dynamic pulsations. The acoustic inertance (L_a) is an inertial term characterizing a mass of gas contained in a relatively small-diameter pipe that, when forced into motion, opposes a change in volume velocity. Acoustic compliance (C_a) is represented by a volume that acts as a stiffness or storage element and opposes a change in applied pressure. These acoustic elements are directly analogous to the mechanical elements of resistance, mass, and compliance or stiffness of a



ACOUSTIC WAVE SPEED IN WATER AT 60°F VS. WATER PRESSURE FOR VARIOUS %, BY VOLUME, CONCENTRATIONS OF ENTRAINED AIR (WATER IN A 8.625″ SCH. 40 STEEL PIPE)

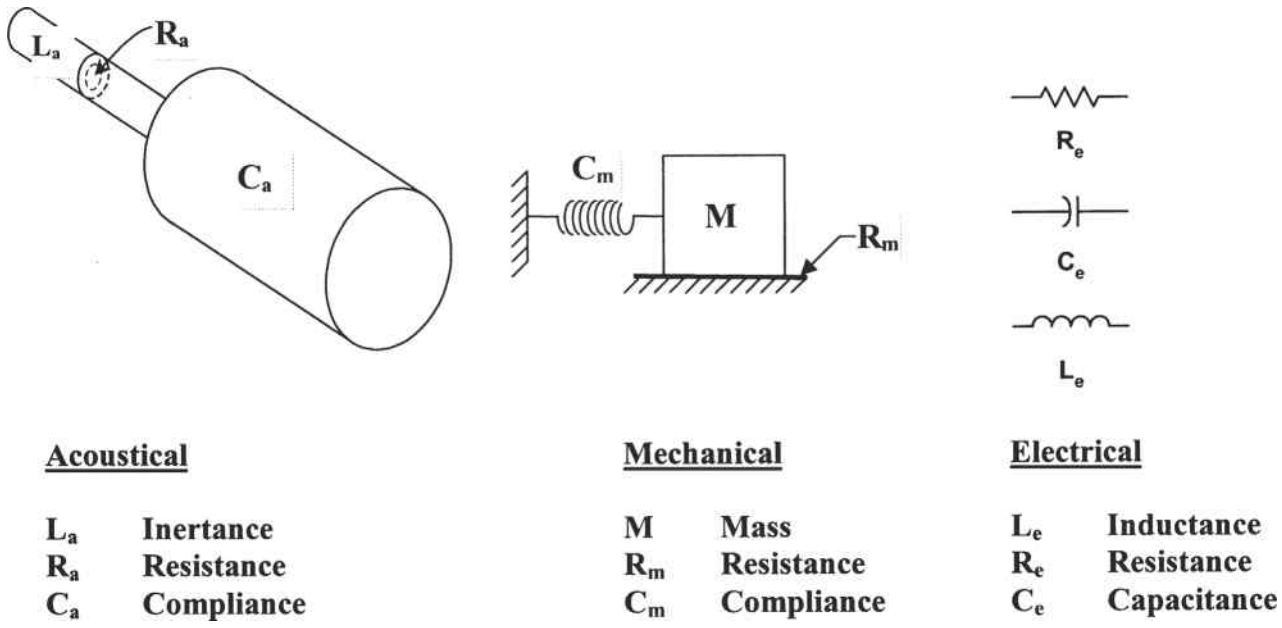


FIG. 3.35 ACOUSTICAL, MECHANICAL, AND ELECTRICAL ANALOGIES

spring, as well as analogous to electrical elements of resistance, inductance, and capacitance. These electrical analogies have enabled the acoustic properties of piping systems to be modeled on analog computers, although software is available that enables a system's acoustic properties to be effectively analyzed on digital computers.

As these acoustical–mechanical analogies help to illustrate, all the previous discussions concerning high- and low-tuning, resonance, and damping are also applicable to acoustic systems. Therefore, resonances can be avoided through acoustic modifications that high- or low-tune a system or else add damping to the system. Acoustic modification are often the most effective means of reducing piping vibration, as they act on the source of the vibrations—that is, the pressure pulsations in the fluid. Common acoustic modifications are changes in pipe length to raise or lower its acoustical natural frequency, as well as the addition of mufflers, pulsation dampers, and suction stabilizers.

3.7.7 Vibration Case Studies

The results of piping vibration testing and problem resolution completed at nuclear power plants illustrate the wide range of vibration causes and effects that can be encountered. Tables 3.1–3.11 show piping vibration problems encountered in a number of operating nuclear plants, including examples from both boiling water reactor (BWR) and pressurized water reactor (PWR) plants. These examples include a wide variety of vibration sources and piping responses. Detrimental vibrations range from low- to high-frequency; affected systems range from small thick-wall piping

TABLE 3.1 MOTOR-DRIVEN FEEDWATER PUMP DISCHARGE PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Low frequency vibration —Main discharge piping —Recirculation piping —Instrumentation piping	Displacement Strain gauges —Stresses —Loads	Frequency < 10 Hz Header pipe stresses < allowable	Control valve Pipe discontinuities	Tie-back supports for instrumentation piping Modify header supports
Failed auxiliary steel weld	Pressure transducers	Instrumentation pipe stresses > allowable	Header-induced vibrations in tap line piping	Additional rigid strut
Vibrations transmitted to floor	Dynamic piping analyses	Measured 40 Hz pressure pulsations at pressure gauges	Acoustic resonance in instrumentation piping	Acoustic Mufflers were added to filter the pressure pulsations
Large indicated pressure fluctuations				

TABLE 3.2 AUXILIARY FEEDWATER PUMP

Symptoms	Tests/Analyses	Results	Source	Corrective Action
High frequency Piping Vibration	Strain gauges	> 1000-Hz vibration	Vortex shedding at the pump run-out flow orifices	Removed pump run-out orifices and replaced them with downstream multi-stage run-out orifices
Severe noise		Measured header pipe stresses < allowable	Acoustic resonance in instrumentation tubing	
Instrument tubing resonance		Structural resonance of the pump run-out orifices		
Tubing failure		Shell mode vibration of the piping		
Large indicated pressure fluctuations				
Unable to adequately control flow				

TABLE 3.3 SAFETY-INJECTION PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
High frequency —Vibration —Noise	Strain gauges	High frequency stress and vortex shedding frequency were quantified.	Vortex shedding at pump run-out orifices	Changed socket-welded elbows to bends Increase orifice hole size
Weld failures		Stresses > allowable		

TABLE 3.4 FEEDWATER-RECIRCULATION PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Low frequency	Strain gauges —Stresses	Predominant frequency at 5 Hz	High velocity flow	Set control valve to limit flow rate to values that resulted in acceptable vibration stresses
Damaged supports	—Loads	Stresses decreased with flow	Control valve	
Loose/missing nuts	Pressure transducers	Stresses > allowable at highest flows		
	Obtained responses under varied flow conditions	Acceptable flow where conditions determined		

TABLE 3.5 CONDENSATE PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Pipe wall crack at branch connection	Strain gauges	Shell mode vibrations	Pressure pulsations	Added reinforcing pad to branch connection
Failed variable support	Finite element analysis	Structural bending mode vibration	Thin-walled pipe	Changed variable support to rigid restraint
		Stresses > allowables	Fabricated tee with high peak stress locations	

TABLE 3.6 SERVICE WATER PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Low frequency	Displacement measurements	Stresses > allowable locally	Turbulent flow	Installed lateral restraints
Restraint component wear	Simplified analysis		Few lateral restraints	Increased capacity of existing restraints

TABLE 3.7 MAIN STEAM-BYPASS PIPING

Symptoms	Tests/Analyses	Results	Source
High frequency —Vibration	Strain gauges	800-Hz vibration	High frequency noise produced at control valves
—Noise	Accelerometers	Shell mode vibration	
Pipe wall cracks			Excitation of thin-walled pipe shell modes

TABLE 3.8 MAIN STEAM-TURBINE LEADS

Symptoms	Tests/Analyses	Results	Source
High frequency vibration	Accelerometers	Shell mode vibration	Control valve noise
Failed tap lines	Strain gauges	Stresses > allowable	Tap line designs

TABLE 3.9 CHEMICAL- AND VOLUME-CONTROL PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Cavitation	Impedance analysis of pumps	Analytical predictions consistent with operating experience	Pressure pulsations and cavitation from reciprocating pump	Install suction stabilizer and pulsation dampener
Severe vibration —Discharge piping —Suction piping —Tap lines				Modify supports
Large indicated pressure fluctuations of ~ 200 psi				
Damaged insulation				
Excessive pump maintenance				

TABLE 3.10 HEATER-VENT PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Low frequency	Displacement measurements	Frequency < 10 Hz	Flashing and cavitation	Install additional restraints —Reduce stresses
Very large displacements	Dynamic analyses	Displacements up to 3 inches peak to peak	Few lateral restraints	—Eliminate rubbing
Support wear		Stresses > allowable		Modified existing restraints
Pipe wear				Replace damaged pipe
Insulation damage				Nondestructive examinations

TABLE 3.11 HEATER-DRAIN PIPING

Symptoms	Tests/Analyses	Results	Source	Corrective Action
Low frequency	Displacement measurements	Vibration frequencies at 2 Hz	Flashing/cavitation	Installed additional restraints
Very large displacements	Dynamic analyses	Displacements up to 1.5 inches peak to peak	Few lateral restraints	
Nozzle weld failure				
Damaged support steel				
Damaged insulation				

to large thin-wall piping. The examples also demonstrate the different potential fixes that are possible, such as the addition or modification of supports, detailed testing and/or analyses to demonstrate that pipe stresses are acceptable, and system modifications to eliminate or mitigate the vibration source. The problems presented in the tables were analyzed and resolved by using the vibration-monitoring techniques discussed in this chapter.

3.8 FUTURE DEVELOPMENT OF THE OM-3 PIPING VIBRATION STANDARD

"*No one believes the analysis except the analyst who performed the calculation, everyone believes the test except the technicia who performed the test*."

This quote from an anonymous source depicts a common perception of testing and is partly what the Subgroup on Piping strived to avoid through the publication of the testing standards. Overly conservative assumptions used in analyses can have undesirable impacts on the resulting designs and may cast doubt on the analysis and design process. Testing programs are completed with the intent to obtain actual response data and improve analytically predicted responses and resulting designs. Although testing can be used to improve accuracy there are just as many, if not more ways, to misinterpret test results as there are to predict erroneous responses. Test interpretations that are either too conservative or unconservative can lead to undesirable outcomes.

An objective in the development of the piping vibration (OM-3) standard is to promote testing and evaluation techniques that provide accurate and reliable results while maintaining reasonable conservatism, testing and analysis efforts.

Future plans for enhancing the OM-3 standard include further development and enhancement of the analysis sections of the standards to incorporate proven effective analysis and test-analysis methods. The intent is also to have the standards referenced, where piping vibration and thermal expansion testing are discussed, by

Section III of the ASME Boiler and Pressure Vessel Code and by the ASME B31.1 Power Piping Code. The Subgroup is also considering the development of an operating and maintenance standard for buried piping and a separate standard to address piping operability criteria, including the use of reduced seismic loads for piping configurations that are modified short term, e.g., through the addition of lead shielding, for maintenance activities.

Future work by the Subgroup on Piping will address the following:

(1) Development of analysis and testing guidelines specifically to address high frequency vibration, including providing examples of failures resulting from high frequency vibration.
(2) Add an appendix to OM-3 that describes development of the acceptance criteria.
(3) Complete an appendix that addresses sources and effects of various types of water hammer.
(4) Include additional guidelines for piping vibration analysis.
(5) Expand the section on instrumentation and data acquisition.

3.9 ACKNOWLEDGMENTS

My gratitude and appreciation goes to Mr. Brian Voll for his input and helpful comments on this chapter. Thanks also go to Mr. Glenn Pederson and Dr. P. Hoang for their help in preparing some of the figures contained herein. My appreciation also goes to K. R. Rao for his help and patience in developing this chapter.

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CHAPTER

4

STRESS INTENSIFICATION FACTORS, STRESS INDICES, AND FLEXIBILITY FACTORS

Anthony W. Paulin, Jr. and Everett C. Rodabaugh[1]

4.1 INTRODUCTION

Piping systems are often complex structures that include straight pipe and a variety of supports, elbows and tees. A typical piping system might include 50 or so components along with many intervening lengths of straight pipe. Each of the components is subjected to a complex set of loadings. The evaluation of any component by the detailed analysis methods prescribed in NB-3200 would be an onerous task.

As indicated by Tables NB/NC/ND-3132-1, many piping components are "standardized." For example, elbows and tees are included in ANSI B16.9, *Factory Made Wrought Steel Butt-Welding Fittings.*

The complexity of analyses of piping components and their "standard" aspect has led to use of stress intensification factors (also called *i*-factors) stress indices and flexibility factors for evaluations of piping systems. The intent of *i*-factors and stress indices is to provide a simple yet reasonably accurate and conservative method to determine whether a particular piping system is in compliance with required Code stress limits. Piping components (e.g., elbows and branch connections) may have directional dependent responses. The concept (in the ASME Section III and Power Piping Code) is to use the maximum directional dependent *i*-factor or stress index as a multiplier of resultant moments.

All other B31 piping codes, most notably B31.3 utilizes direction dependent *i*-factors and flexibility factors (k-factors). Inaccurate flexibility factors may lead to incorrect estimates of forces and moments, which then leads to incorrect calculation of stresses. In general, a "conservative" flexibility factor cannot be defined. When perfoming an analysis of a piping system the objective is to establish and use reasonably accurate flexibility factors for all piping components whose flexibility might influence the outcome of the Code compliance evaluation.

In this chapter, the general concepts behind the development of *i*-factors, stress indices, and flexibility factors are briefly discussed with references to details of developments. In Section 4.8, an example of a relatively simple piping system with loads is given; the piping system output analysis is used to illustrate how *i*-factors and stress indices are used to check Code compliance and—for a branch connection—to illustrate the quantitative significance of flexibility factors. The ASME Piping Codes are discussed in Sections 4.9, 4.10, and 4.11.

4.2 TERMINOLOGY AND SYMBOLS

As used herein, the word *Code* is ref. [1]. Portions of the Code are identified as they appear in the Code; for example, Table NC-3611.2(e)-1 and NB-3228.5. Equations from the Code are identified by a "B" (for Class 1 piping) and a "C" (for Class 2 or 3 piping); the number that follows the letter is the specific equation number from the Code. The elements of the Code equations are defined as follows:

B_1, B_2 = primary stress indices: B_1 for pressure and B_2 for moment

C_1, C_2, C_3, C_3' = primary-plus-secondary stress indices: C_1 for pressure, C_2 for moment, and C_3' and C_3 for thermal gradients

D_o = outside diameter of pipe (for branch connections, the run pipe)

D = mean diameter of run pipe

d = mean diameter of branch pipe

d_o = outside diameter of branch pipe

E = modulus of elasticity

f = number of cycles dependent factor, ranging from 1.0 for 7,000 or fewer cycles to 0.5 for 100,000 or more cycles (see Table NC-3611.2(e)-1)

h = tR_b/r^2; elbow characteristic

i = stress intensification factor

I = moment of inertia of pipe or elbow (I_r, I_b for run, branch-of-branch connections)

K_1, K_2, K_3 = peak stress indices: K_1 for pressure, K_2 for moment, and K_3 for thermal gradients

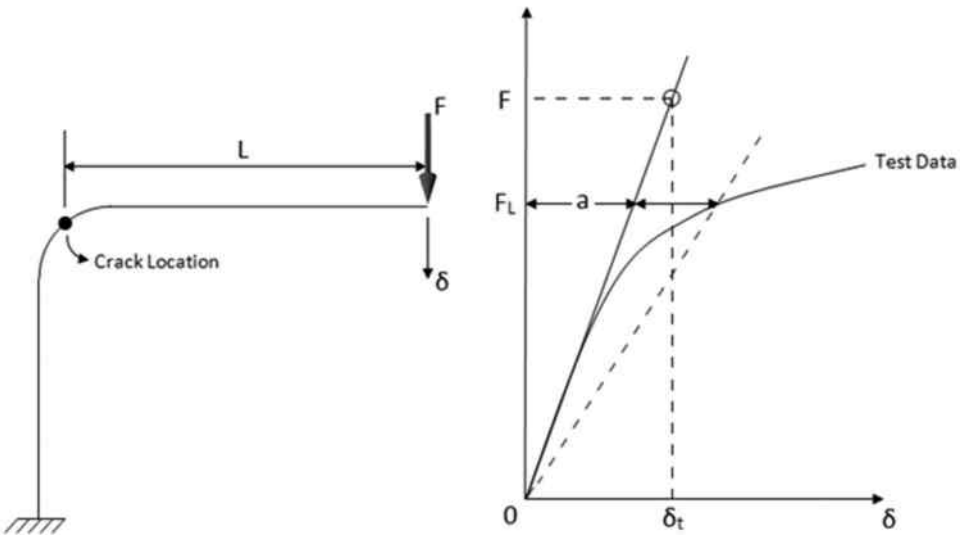
[1]Everett C. Rodabaugh was the initial author of this chapter who revised it for first, second and third editions. For the current publication, Anthony Paulin made considerable revisions. – Editor

K_e = factor used for $S_n > 3S_m$ (see NB-3228.5)
k = flexibility factor
N_f = test cycles to failure; see equation (4.1)
N_{d1} = design cycles for Class 1 piping
$N_{d2,3}$ = design cycles for Classes 2 or 3 piping
M_j = $[M_{xj}^2 + M_{yj}^2 + M_{zj}^2]^{(1/2)}$ = resultant moment: $j = A$, B, or C for M_A, M_B, and M_C. The subscripts x, y, and z denote an orthogonal set of three moments.
M_A = resultant moment from weight and other sustained loads
M_B = resultant moment from nonreversing dynamic loads
M_C = range of resultant moment from thermal expansion
M_i = resultant moment as defined in NB-3650
N_f = test cycles to failure, through-wall crack; see Equation (4.1)
P = internal pressure
r = mean radius of pipe or elbow
r_2 = radius at outside juncture between run pipe and branch pipe or nozzle
R_b = bend radius of elbow
S_{ta} = test elastic–equivalent stress amplitude (half-range); see Equation (4.1) and Fig. 4.1
S_{OL} = calculated stress by equation (C8)
S_{TE} = calculated stress by equation (C11)
S_A = allowable stress range = f(1.25S_c + 0.25S_h); see equation (C1) in NC-3611.2
S_c = basic material allowable stress at minimum temperature
S_h = basic material allowable stress at temperature consistent with loading under consideration
S_m = basic material allowable stress intensity
S_n = calculated stress by equation (B10)
S_p = calculated stress by equation (B11)
S_{alt} = calculated stress by equation (B14)
T = wall-thickness of run-pipe of branch connections
t = wall-thickness of pipe or elbow
Z = section modulus of pipe or elbow (Z_r and Z_b for run and branch-of-branch connections)

Symbols not included in the preceding list are defined where used in the text.

4.3 STRESS INTENSIFICATION FACTORS

Stress intensification factors (*i*-factors) were introduced into ASA B31.1–1955, *Code for Pressure Piping*. The *i*-factors are based on cyclic moment (displacement-controlled) fatigue tests by Markl (see refs. [2] and [4]) and also by Markl and George (see ref. [3]) and are used for Code Classes 2 and 3 piping. For the discussion in this chapter, NC-3650 (for Class 2) and ND-3650 (for Class 3) are identical.



o equivalent elastic force, F, for Markl-type fatigue tests

In Eq. (4.1), $S_{ta} = FL/Z$

x illustration of limit load criterion of II-1430 in Appendix of Ref. [1]

F_L = load at which 2a intersects the test data

FIG. 4.1 MARKL-TYPE FATIGUE TESTS AND ILLUSTRATION OF LIMIT LOAD CRITERION

Markl [2]–[4] tests were run on components made of A106 Grade B material and included the following:

(1) elbows and miters;
(2) straight pipe with a girth fillet weld;
(3) straight pipe;
(4) straight pipe with a girth butt weld;
(5) ANSI B16.9 tees, with outlet size equal to the run size; and
(6) unreinforced branch connections, with outlet size equal to the run size.

Markl [2] introduced the following equation:

$$i = 245{,}000/(S_{ta}N_f^{0.2}) \tag{4.1}$$

The force, F, was obtained from a preliminary force versus the displacement test as indicated in Fig. 4.1. As noted, the displacement used in some of the subsequent fatigue tests was in the plastic-response region. This application is consistent with the use of elastic piping–system analyses; in effect, it may be viewed as a strain control rather than a stress control—that is, fatigue is a function of the strain amplitude or range.

The constant of 245,000 (psi for S_{ta} in psi) was used by Markl for his tests on carbon steel components. Later tests on austenitic stainless steel components by Heald [5] indicate that this constant is about right for such materials. The constant is not necessarily appropriate for materials with a significantly different modulus of elasticity, as for aluminum components with $E \sim 1e7$ psi, for example. Available test data indicates that the constant of 245,000 in Equation (4.1) is about 245,000 times the modulus of elasticity ratio—that is, the constant in Equation (4.1) for aluminum components is about 82,000, which emphasizes the strain control rather than stress control of Equation (4.1). Design margins for materials with E significantly less than $3e7$ psi are discussed in Section 4.3.2.

In 2008 Hinnant [38] performed fatigue tests similar to Markl's [2]–[4] and suggested that, "Markl's results may not be representative of a larger test population." Hinnant Fig. 4.3 includes his own data along with 236 points from references [39]–[51] and shows that Markl's predicted fatigue life may be too low in the low cycle range and too high in the cycle range. The Hinnant equation used to replace the Markl Equation (4.1) is:

$$i = 947{,}500/(S_{ta}N_f^{0.3353}) \tag{4.1a}$$

Hinnant's work [38] suggests that modern i-factor tests should use Equation (4.1a) The Markl and Hinnant curves cross at 22,000 cycles and so there is a cycle range where either Equation (4.1) or (4.1a) will produce similar results. For modern Markl-type fatigue tests conducted significantly below 22,000 cycles, use of the Markl curve (4.1) is expected to produce SIFs that are too low. For modern Markl-type fatigue tests conducted significantly above 22,000 cycles, use of the Markl curve (4.1) is expected to produce SIFs that are too high.

4.3.1 Girth Butt Welds

Markl, on the premise that a girth butt weld may exist anywhere in piping systems, opted to make $i = 1.000$ for a girth butt weld using Fleetweld No. 5 stick electrodes. (They were "smooth" on neither the inside nor the outside surface.) Markl also tested "plain straight pipe" by using a forged transition piece; he obtained $i = 0.64$. In principle, if a girth butt weld is "flush" inside and outside and there is no metallurgical notch, i could be as small as 0.5.

Scavuzzo [6] presents the results of Markl-type tests on girth butt welds by using four-point bending instead of the cantilever bending used by Markl [2]–[4], Hinnant [38] and Heald [5]. Scavuzzo, for very low cycles to failure, obtained i-factors significantly less than 1.00—for example, $i = 0.3$ for $N_f = 249$, but for $N_f = 144{,}000$, Scavuzzo obtained $i = 1.02$. Rodabaugh [7], using elastic–plastic theory, showed that for tests at low N_f (significant amount of plastic response), four-point bending will result in i-factors lower than Markl's for girth butt welds. Rodabaugh [7] suggested that for use with elastic piping–system analyses, i-factors derived from cantilever testing are more appropriate than those derived from four-point bending tests. Since the cantilever tests will be more conservative, and the elastic follow-up that may occur at a fixed end in low cycle tests, is more appropriate for simulating common load stress states in piping systems.

4.3.2 Design Margins

The nominal design margin can be deduced from equation (C11) with $M_A = P = 0$.

$$S_{TE} = iM_C/Z \leq (S_h + S_A) \tag{4.2}$$

Figure 4.2 is a plot of stress range versus cycles. In equation (4.1), S_{ta} is an amplitude; in Equation (4.2), M_C is a range. This 2:1 ratio of range to amplitude is a key aspect of basic design margins. Figure 4.2 is for A106 Grade B material—the material used in Markl tests. It is apparent in Fig. 4.2 that the design margin varies as a function of cycles: at $N = 10$, the basic design margin on stress is 8.24, whereas from $N = 7{,}000$ to 100,000, the design margin on stress is about 2 and then decreases to about 1.2. For other materials with about the same modulus of elasticity, the basic design margins would be different: for example, for A106 Grade A material, $S_c = S_h = 12$ ksi, and the margins would be 15/12 times those indicated in Fig. 4.2. For A106 Grade C material, on the other hand, the margins would be 15/17.5 times those indicated in Fig. 4.2.

To further discuss margins, we look at the complete equation (C11):

$$S_{TE} = PD_o/(4t) + 0.75iM_A/Z + iM_C/Z < (S_h + S_A) \quad \text{(C11)}$$

In equation (C11), $0.75i$ shall not be taken to be less than 1.00.

Markl's tests were run with essentially zero internal pressure. Heald [5] ran tests with a constant $PD_o/(4t) = 5100$ psi, with no apparent effect on the results. However, if the pressure cycles in phase with the moments, the $PD_o/(4t)$ term provides a reasonable allowance for the combined pressure and moment cycles. It should be noted that equation (C11) is not an evaluation of the adequacy of pressure design; it is covered by NC-3640.

Markl's tests involved a minor amount of weight loading—that is, $0.75i\ M_A/Z$ was not zero. Heald's tests involved a bit more weight loading. These minor values of $0.75i\ M_A/Z$ had no effect on the results. Indeed, available data suggest that values of $0.75i\ M_A/Z$ (noncyclic) up to approximately 10 ksi would have no effect on the fatigue life. Thus the inclusion of the $0.75i\ M_A/Z$ term provides conservatism relative to Equation (4.1).

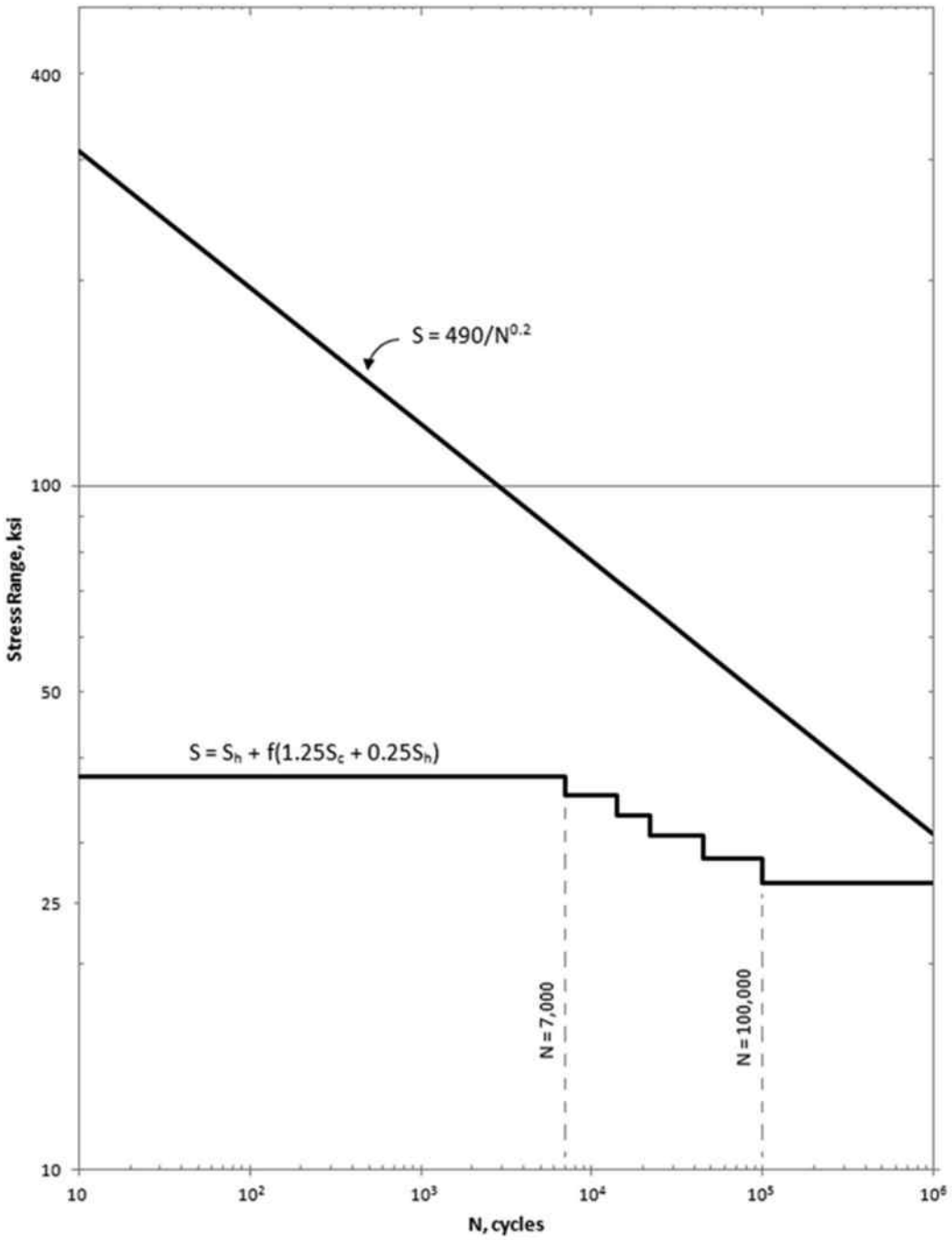


FIG. 4.2 DESIGN MARGINS FOR SA106 GRADE B: $S_c = S_h = 15$ KSI

Some nonferrous materials are permitted by the Code for Class 3 piping. For 6061-T6 aluminum material, with E = ~1e7 psi, available data indicate that the constant in Equation (4.1) is about (1/3) 245,000. For 6061-T6, as welded, S_c = 6.0 ksi; S_h (400°F) = 3.5 ksi; $S_h + S_A$ = 11.875 ksi as compared to 37.5 ksi for A106 Grade B material. Because the allowable stress for 6061-T6, as welded, is less than (1/3) of that for A106 Grade B, the design margins for 6061-T6, as welded, would be expected to be not less then indicated in Fig. 4.2.

Other nonferrous materials have not been reviewed from this standpoint. However, to the extent that allowable stresses are reduced in proportion to the reduction in E, margins indicated in Fig. 4.2 would be expected.

Buitrago [39] has provided high cycle data on girth welded carbon steel pipe that can be used to extend Fig. 4.2 Buitrago's data shows that up to about 1E8 cycles there is no knee in the endurance curve.

4.3.3 Code Guidance for *i*-Factors

Figure NC-3673.2(b)-1 gives *i*-factors for 15 types of components. These *i*-factors are applicable for D_o/t up to 100.

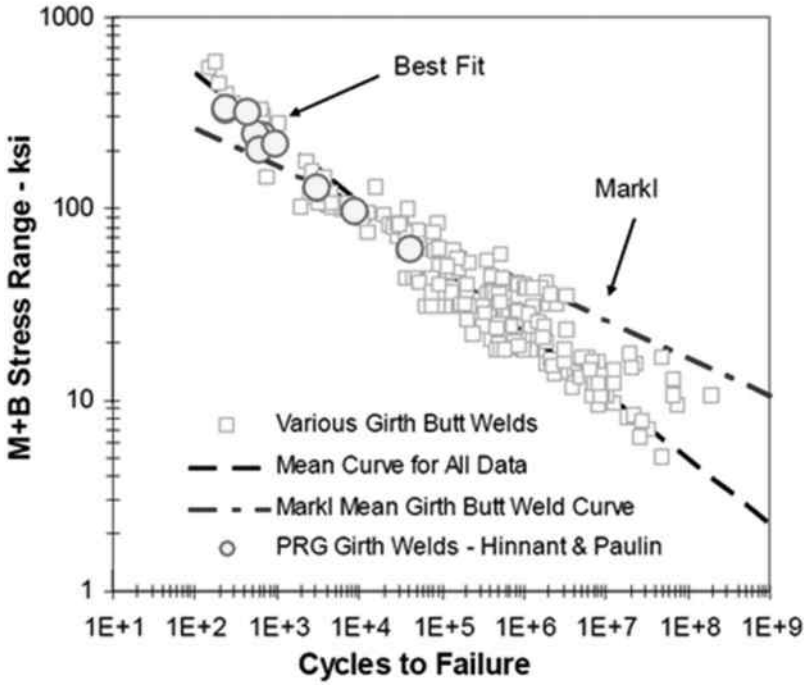


FIG. 4.3 TEST DATA FROM HINNANT [38]

Many of the *i*-factors are identical to those suggested by Markl [4]. However, in the 60 years since, the Markl tests some additions and changes have been made. These additions and changes are part of an ongoing process by the Code Working Group on Piping Design.

Minichielo [8] details a procedure for experimental determination of *i*-factors for components not covered by the Code (e.g., a branch connection in an elbow).

NC-3673.2 includes the following relationship:

$$i = C_2K_2/2 \quad \text{but not less than 1.00} \tag{4.3}$$

Equation (4.3), for moment loading, provides a link between ties NC-3650 (Class 2 piping), the B31 piping codes, and with NB-3650 (Class 1 piping).

The most relevant basis for Equation (4.3) is a combination of elbow tests and elbow theory, along with the definition that $i = 1.00$ for a "typical" girth butt weld. Fatigue tests of elbows with in-plane moments resulted in failures at the location and direction indicated by elbow theory. The failures were remote from the welds; thus $K_2 = 1.00$. By elbow theory for an in-plane moment

$$C_2 \sim 1.8/h^{(2/3)} \quad \text{for} \quad h < \sim 0.5 \tag{4.4}$$

From Equations (4.3) and (4.4),

$$i = 1.8/h^{(2/3)}/2 = 0.9/h^{(2/3)} \tag{4.5}$$

Equation (4.5) agrees with that shown in Figure NC-3673.2(b)-1 for "welding elbow or pipe bend."

For Markl's "typical" girth butt welds, in straight pipe, it is reasonable to assume that $K_2 = 2$. Then Equation (4.3) gives $i = 1.0$; in agreement with Figure NC-3673.2(b)-1 for a girth butt weld.

4.3.4 EPRI Reports

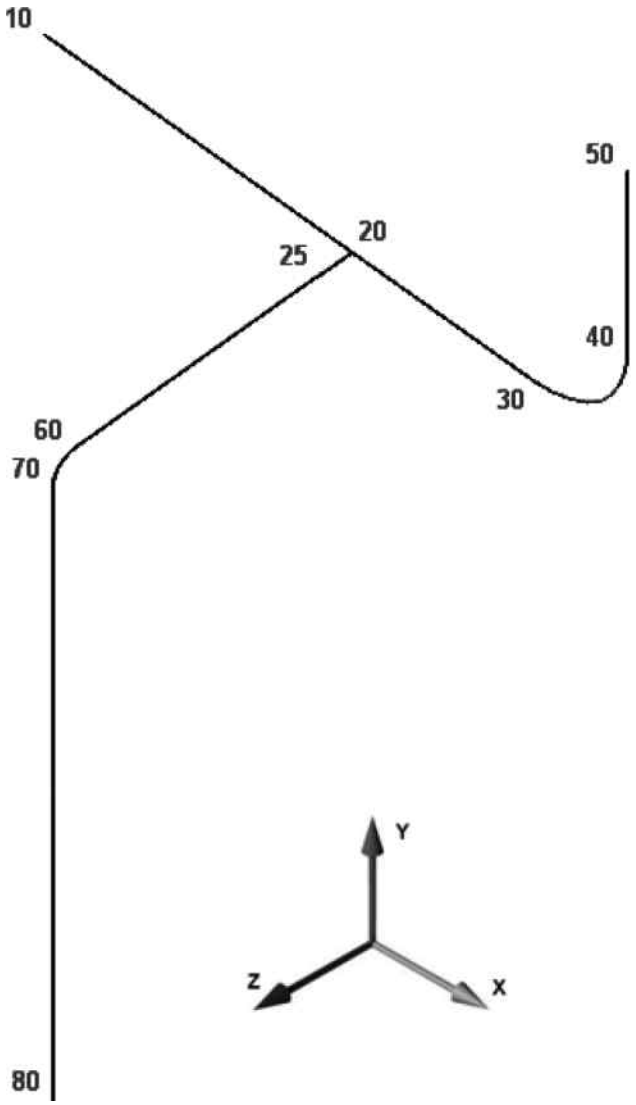
A series of reports under the sponsorship of a group of electric utility owners through the Electric Power Research Institute (EPRI) addressed a series of *i*-factor issues. Eleven of these EPRI reports were abstracted by Wais in refs. [9]–[19]. These articles include data on stress indices, flexibility factors, and *i*-factors.

Wais performed additional fatigue tests on unreinforced and pad reinforced branch connections, and on branch connections subject to combined loadings. The Wais reports also provided a method where by shell finite element solutions can be manipulated to produce *i*-factors and flexibility factors for branch connections. Using these approaches, Wais developed *i*-factors equations for torsional loads on branch and run pipe and new equations for in-plane and out-of-plane *i*-factors for branch and run pipe. Wais also extended existing flexibility factor equation to $d/D = 1$.

The Wais reports [9]–[19] also served as a basis for the 2009 ASME ST-LLC-02 *i*-factor and k-factor alignment report by Paulin [52].

Widera [53] in WRC 497 produced finite element results for unreinforced fabricated tees similar to Wais and Paulin. These references provide independently developed sources for *i*- and k-factors, Some comparison graphs are shown in Figs. 4.5 and 4.6. The results in Figs. 4.5 and 4.6 are for branch connection geometries where $D/t = 85$ and d/D is equal to the branch to run pipe thickness ratio.

Rodabaugh [9] showed that for unreinforced branch connections in the as welded condition K_2 could be taken as 1.0 when C_2 is found from shell finite element models of the branch connections for the parameter range and test data studied and no attempt is made to include welds in the models. This low value for K_2 is thought reasonable for the unreinforced branch connection full penetration fillet welds when the finite element modeling strategies used by Wais and Rodabaugh are duplicated. Since *i*-factors are based on through-wall cracks, it is likely that for branch connections, crack growth is slowed after initiation due to redistribution of load in the vicinity of the crack.



Nodes	Length or Rb (ft)	NPS	Wall (in)
10-20	10	24	0.375
20-30	6	24	0.375
30-40	Rb = 3	24	0.375
40-50	6	24	0.375
20-25	1	6	RIGID
25-60	8	6	0.280
60-70	Rb = 0.75	6	0.280
70-80	20	6	0.280

FIG. 4.4 EXAMPLE PIPING SYSTEM

Figures 4.7 and 4.8 show curves of in-plane and out-of-plane flexibility factors from different sources. Values of k_i and k_o for Class 2 (NC) piping are extended beyond their d/D limits to show how the Class 2 curves might be modified to extend their application. The Wais curve is taken from ref [9], Widera from [53], and "UFT" from [52].

4.3.5 ASME ST-LLC 07-02

In 2007 the ASME initiated the ST-LLC 07-02 project to align stress intensification and flexibility factors. In 2011 the ASME ST-LLC 07-02 report [52] was submitted and contains new *i*- and k- factor equations.

4.4 *C* AND *K* STRESS INDICES

C and *K* indices are used for Class 1 piping in equations (B10) and (B11). They are analogous to *i*-factors in that they provide the basis for fatigue evaluations and are (as for *i*-factors) subject to ongoing reviews. Table NB-3681(a)-1 provides *C* and *K* stress indices for commonly used piping system components; these are applicable for D_o/t up to 100.

4.4.1 C_1 and K_1 Stress Indices for Internal Pressure Loading

The term *stress indices* was introduced in the first (1963) edition of ASME Section III. Although it took several editions and addenda to get the definition complete, the definition now in NB-3338.2 is essentially:

> The term stress index is defined as the ratio of the stress components σ_t, σ_m, and σ_r to the computed membrane stress in the vessel, σ.
>
> $\sigma = P(D_i + T)/(4T)$ for nozzles in spherical vessels or heads
> $s = P(D_i + T)/(2T)$ for nozzles in cylindrical vessels

where

P = service pressure
D_i = inside diameter of vessel
T = wall-thickness of vessel

The stress indices shown in Table NB-3338.2(c)-1 are based on an extensive series of internal pressure tests of nozzle in vessels.

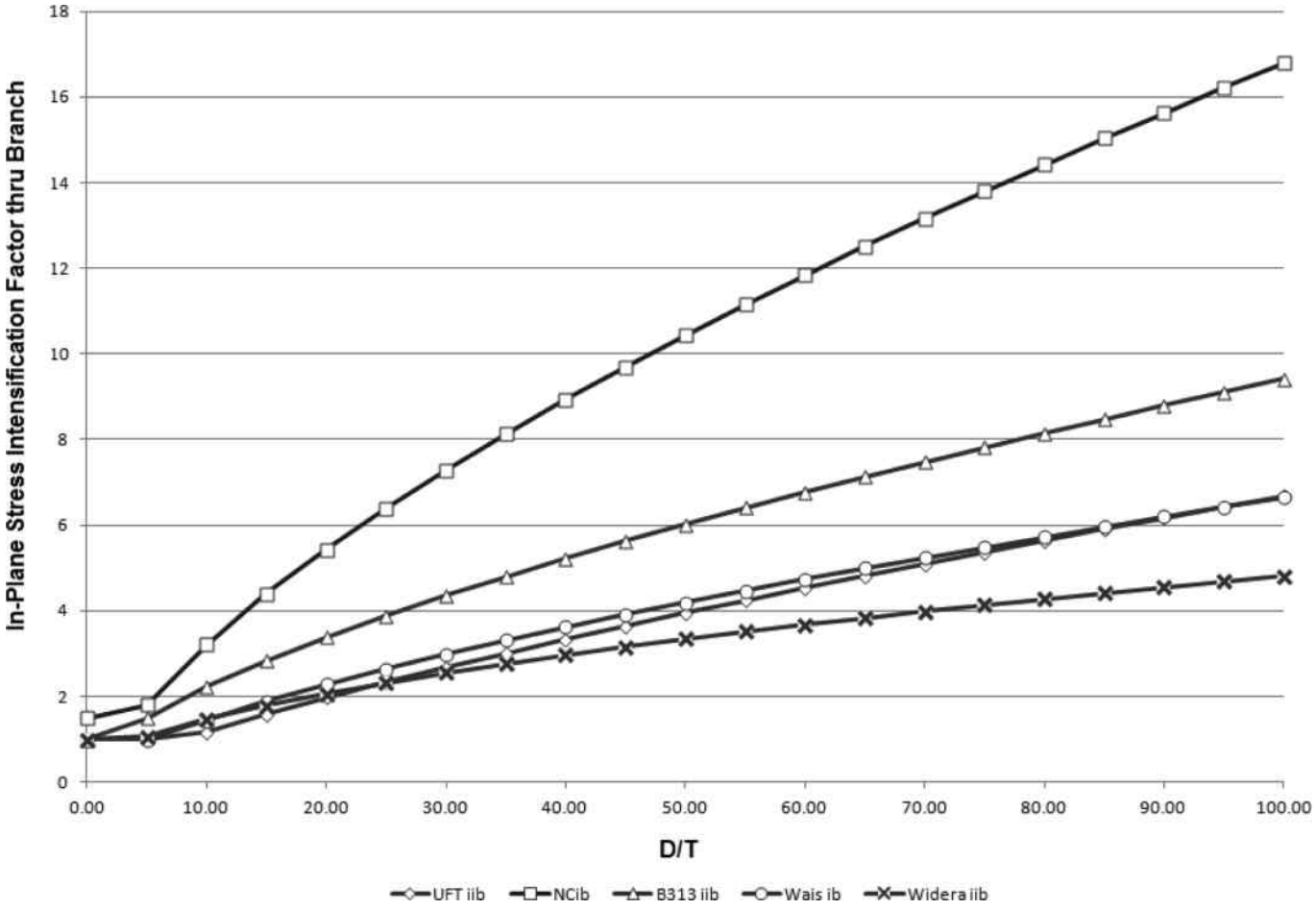


FIG. 4.5 IN-PLANE STRESS INTENSIFICATION FACTOR [52]

This data is summarized and discussed by Mershon in refs. [20] and [21].

In the early editions of ASME Section III, piping was not covered. Stress indices for pressure, moment, and thermal gradient loads were introduced in ANSI B31.7-1969. (ANSI B31.7 was transferred to ASME Section III in 1971.)

C_1 and K_1 are used in equations (B10) and (B11):

$$S_n = C_1(PD_o/2t) + \text{moment term} + \text{thermal gradient term} \quad \text{(B10)}$$

$$S_p = C_1K_1(PD_o/2t) + \text{moment term} + \text{thermal gradient terms} \quad \text{(B11)}$$

For branch connections, D_o is the outside diameter of the run pipe and t is the wall-thickness of the run pipe.

As a simple alternative to the 16 stress indices in Table NB-3338.2(c)-1, the following equation was developed for branch connections in piping systems:

$$C_1K_1 = 2.8(D/T)^{0.182}(d/D)^{0.367}(T/t)^{0.382}(t/r_2)^{0.148} \quad (4.6)$$

in which C_1 is not to be less than 1.2—thus, because $K_1 = 2$, C_1K_1 will not be less than 2.4; D is the mean diameter; T is for the run pipe; d is the mean diameter; and t is for the branch pipe or nozzle. (The basis for this equation is given by Rodabaugh [22].)

Equation (4.6) is limited to $d/D < 0.5$; and the general limitation, $D/T < 100$. Also, to use equation (4.6) as it is applied to the configuration shown in sketch (d) of Fig. NB-3338.2(a)-2, the external fillet radius, r_2, must not be less than the larger of $0.5t$ and $0.5T$.

We now discuss comparisons between Equation (4.6) and Table NB-3338.2(c)-1. Table NB-3338.2(c)-1 is limited to D/T from 10 to 100, $d/D < 0.5$. and third limit can be written in the following form:

$$(d/D)[(D/T)(T/r_2)/(t/T)]^{0.5} < 1.5$$

NB-3338.2 generally requires that r_2 must not be less than the larger of $0.5t$ and $0.5T$—that is, the same minimums that are included in the basis for Equation (4.6). With these minimum values of r_2, Table NB-3338.2(c)-1 is more restricted in coverage than Equation (4.6).

For ASME ST LLC 07-02, Hinnant, Rodabaugh, and Paulin, after reviewing volumetric finite element results of stresses in branch connections, recommended that the lower bound limit for r_2 should not be less than the smaller of 0.5t and 0.5T since the limit is provided for fatigue, and the fatigue strength of a branch connection weld is most significantly affected by the presence of the radius and not necessarily by its size.

Within the range of mutual coverage, C_1K_1 ranges from about 2.4 to 3.9 versus the $S = 3.3$ in Table NB-3338.2(c)-1. In the extended coverage of Equation (4.6), C_1K_1 can be quite a bit

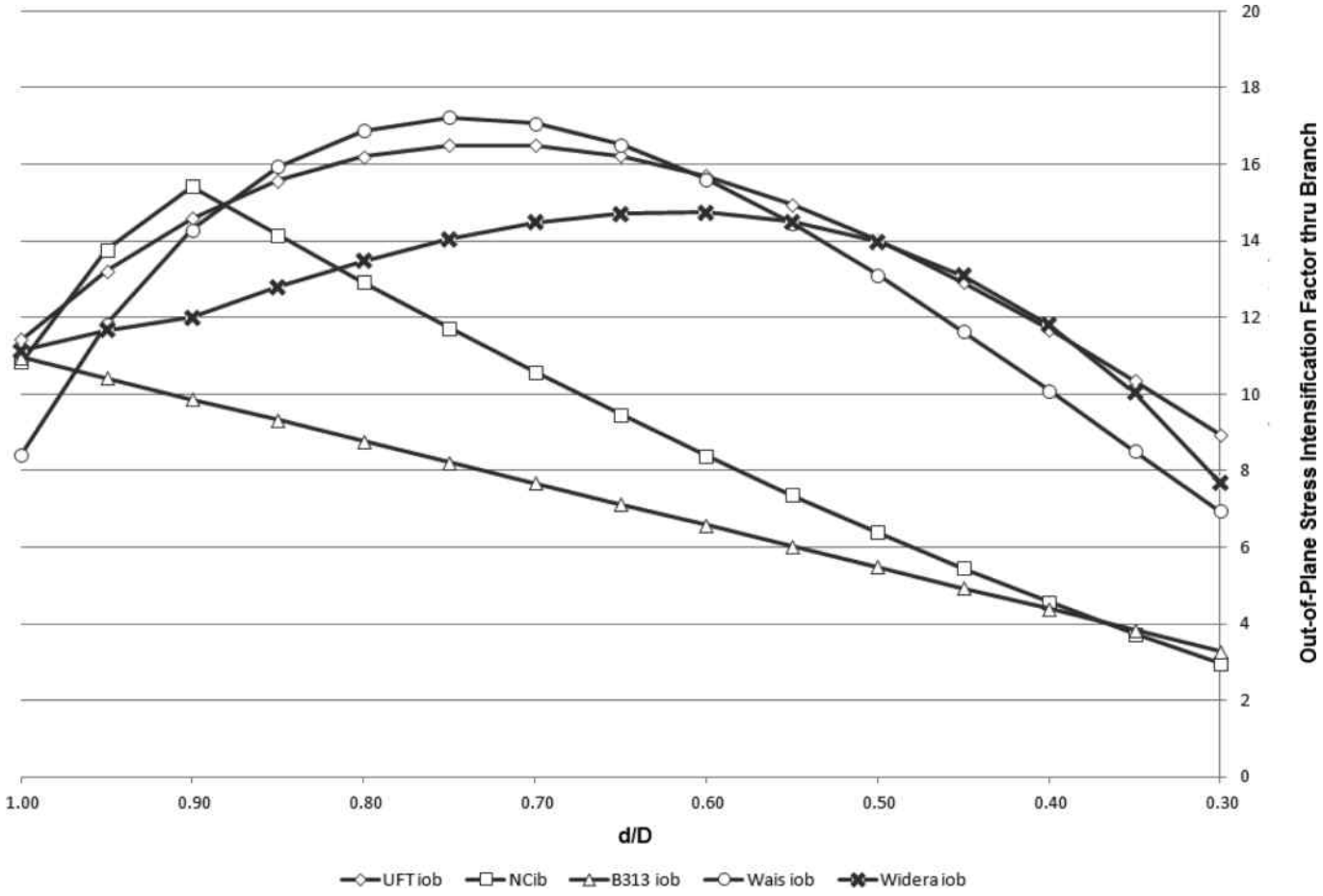


FIG. 4.6 OUT-OF-PLANE STRESS INTENSIFICATION FACTORS [52]

higher than 3.3; for example, for $D/T = 100$, $d/D = t/T = 0.5$, $t/r_2 = 1.00$, and $C_1K_1 = 6.54$.

In early editions of ASME Section III, the range of primary-plus-secondary stress was limited to $3S_m$. When piping was introduced into ASME Section III, the recognition that the range of primary-plus-secondary stress could exceed $3S_m$ and still have adequate fatigue life led to NB-3228.5, "Simplified Elastic Plastic Analysis." To implement NB-3228.5, it is necessary to separate the total stress in to a primary-plus-secondary stress and a peak stress portion of the total stress. Table NB-3681(a)-1 does that by C_1 = primary-plus-secondary stress index and C_1K_1 = total stress index.

Table NB-3681(a)-1 gives 15 sets of C_1 and K_1 for various components. One of these sets, for "branch connection," was discussed previously. The basis for indices for welds and wall-thickness transitions is given by Rodabaugh in ref. [23], and the basis for the rather complex set of C_1 and K_1 for reducers is given by Rodabaugh as well in ref. [24]. The following paragraphs provide a brief discussion of two components covered by refs. [23] and [24].

4.4.1.1 Elbows The following equation for C_1 is from shell theory for maximum stress caused by internal pressure (ignoring the effect of whatever might be welded to the ends of the elbows).

$$C_1 = (2R_b - r)/[2(R_b - r)]: \qquad K_1 = 1.0$$

The origin of the preceding equation lies with a paper published by Lorenz in 1910. Because of end effects, the maximum stress tends to occur about midway between the ends. The surface of an elbow is considered to be smooth enough so that $K_1 = 1.0$ is appropriate.

4.4.1.2 Butt-Welding Tees

$$C_1 = 1.5: \qquad K_1 = 4.0$$

Butt-welding tees made to the requirements of ANSI B16.9 are available for *d/D* ranging from about 0.5 to 1.00. Unfortunately, ANSI B16.9 controls only center-to-end dimensions, end diameters, and minimum wall-thickness not less than the nominal thickness of the designated run pipe. The requirement in ANSI B16.9 that the pressure capacity of the tee must not be less than the pressure capacity of the designated run pipe can be met by a rather nominal increase in wall-thickness over the nominal thickness of the run pipe.

In forged tees, the transition between branch and run portions consists of a fairly large radius, with wall-thickness changing smoothly between branch and run portions. B16.9 tees, however, may be machined from a forged block of material, for which a potential then exists for sharp corners at the run to branch intersection. This uncertainty regarding what constitutes a B16.9 tee,

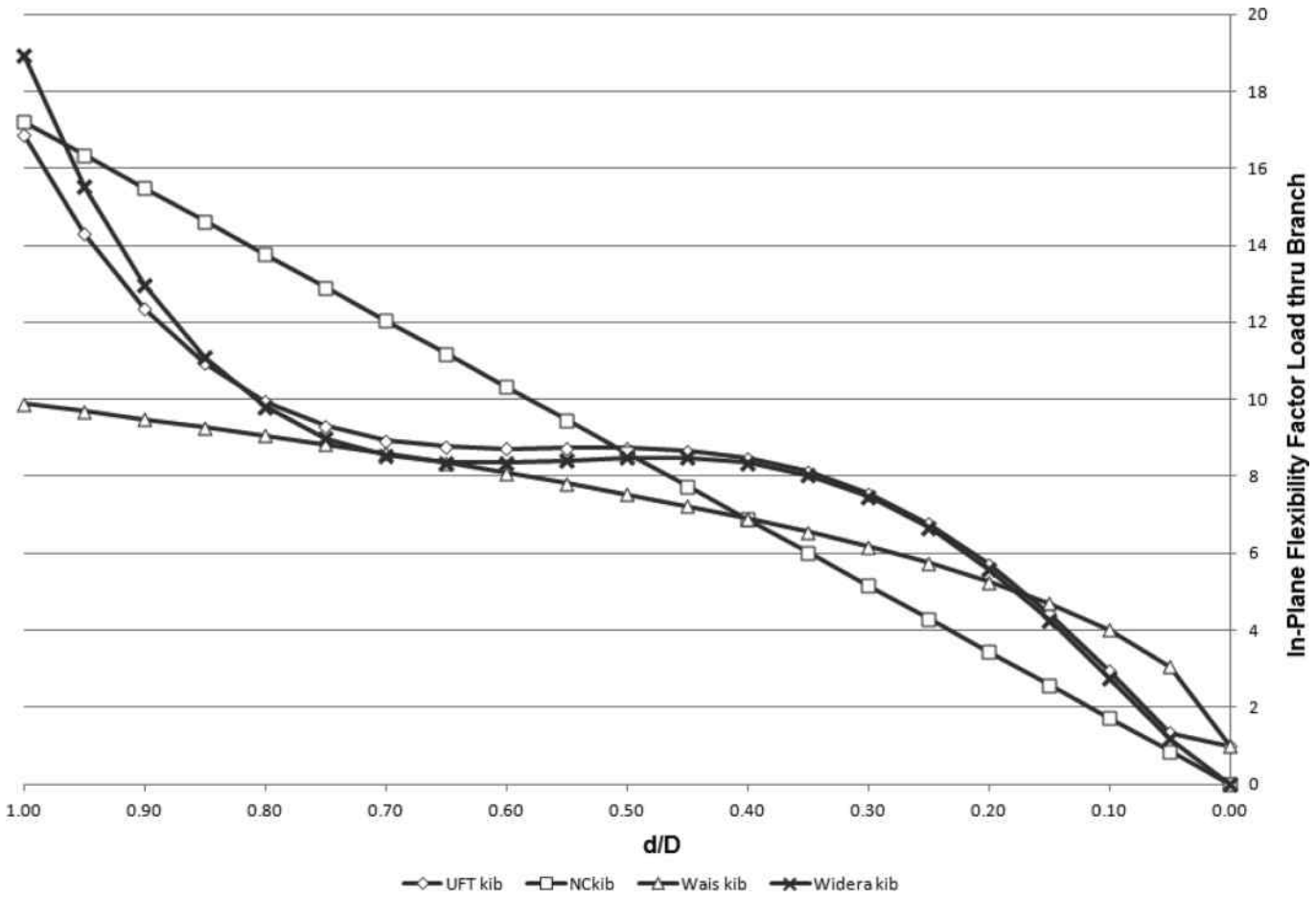


FIG. 4.7 IN-PLANE FLEXIBILITY FACTORS [52]

along with sparse data on the stresses in B16.9 tees from internal pressure, has led to the selection of $C_1 = 1.5$ and $K_1 = 4.0$, which is probably very conservative for most B16.9 tees, particularly those with $d/D < 1.00$.

Some manufacturers of B16.9 products citing B16.9 Para 1.2, and 4.4.2 provide almost any fitting sizes and dimensions as long as there is a purchaser.

ANSI B16.9 reducers pose a similar problem that has been addressed by specifying C_1 and C_2 in terms of the reducers' dimensional parameters—the cone angle, for instance. Although it is possible, no attempt has yet been made to do something similar for B16.9 tees.

4.4.2 C_2 and K_2 Stress Indices for Moment Loading

C_2 and K_2 are used in equations (B10) and (B11) as follows:

S_n = pressure term + C_2M_i/Z + thermal gradient term (B10)
S_p = pressure term + $K_2C_2M_i/Z$ + thermal gradient term (B11)

As indicated in Section 4.3.3 (and worth repeating here), NC-3673.2 includes the relationship expressed in Equation (4.3) as follows:

$$i = C_2K_2/2 \quad \text{but not less than 1.00}$$

This equation, for moment loading, serves to correlate NC-3650 (Class 2 piping) and B31 piping with NB-3650 (Class 1 piping). Thus, because of Markl [2]–[4] and others [5] [9]–[19], [38], a relatively good basis exists for the 15 sets of C_2 and K_2 shown in Table NB-3681(a)-1 for various components. At present, Equation (4.3) does not always hold, in particular for some branch connections. However, its applicability is the subject of continuing work by the ASME Working Group on Piping Design.

4.4.3 Stress Indices for Thermal Gradient Loadings

Although piping system analyses quantify the moments used in the Code equations, heat-transfer analyses or some approximation thereof is needed to quantify the thermal gradients. Such analyses start with assumed fluid-flow rates, fluid properties, and piping material properties.

C_3 and K_3 are used in equations (B10) and (B11) as follows:

$$S_n = \text{pressure term} + \text{moment term} + C_3E_{ab}|\alpha_aT_a - \alpha_bT_b| \quad \cdots |\text{indicates absolute values} \qquad \text{(B10)}$$

$$S_n = \text{pressure term} + \text{moment term} + K_3E_\alpha|\Delta T_1|/(2(1-\nu)) + K_2C_3E_{ab}|\alpha_aT_a - \alpha_bT_b| + E\alpha|\Delta T_2|/(1-\nu) \qquad \text{(B11)}$$

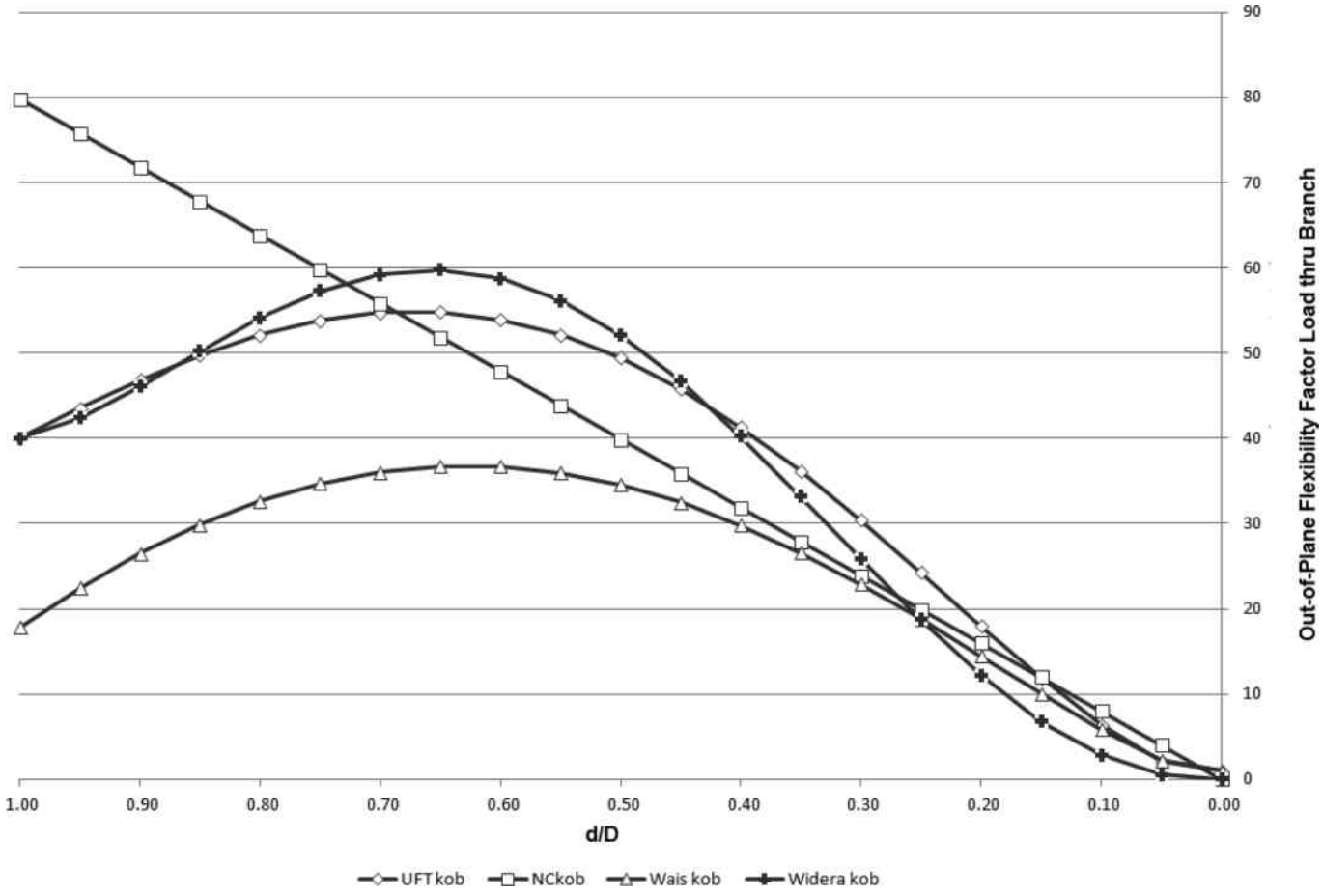


FIG. 4.8 OUT-OF-PLANE FLEXIBILITY FACTORS [52]

C_3' is used in equation (B13) as follows:

$$\text{pressure term} + \text{moment term} + C_3' E_{ab} |\alpha_a T_a - \alpha_b T_b| \quad \text{(B13)}$$

The symbols used in equations (B10), (B11), and (B13) are defined in NB-3653.1 and NB-3653.2. The temperatures T_a, T_b, ΔT_1, and ΔT_2 are quantified by a heat-transfer analysis. With respect to ΔT_1 and ΔT_2, see Fig. NB-3653.2(b)-1.

The basis for several of the thermal gradient stress indices is given by Rodabaugh [23]. For example:

Component	C_3	C_3'
Girth butt weld	0.60	0.50
NB-4250 transition	$1.0 + 0.03(D_o/t)$	1.0
1:3 slope transition	$0.35(t_{\max}/t) + 0.25$	0.60

Reference [23] gives the results of elastic stress analyses of the foregoing components, all of which are axisymmetric. The results were then bounded by the simple equations or values tabulated above. C_3 represents the primary plus secondary stresses; C_3' represents membrane stresses.

Conceptually, the NB-4250 transition is between pipe and a component such as a valve or pump nozzle, and the 1:3 transition is between two pipes of different wall-thicknesses ($t_{\max}$ is the thicker of the two pipes). K_3 indices are largely the same as the K_2 indices discussed in Section 4.4.2.

The major problem in evaluating thermal stresses lies in estimating at the design stage what will happen to the piping system in service. Class 2 and 3 piping do not include explicit rules for evaluating stresses caused by thermal gradients. However, NC-3111(g) (General Design, Loading Criteria, Loading Conditions) indicates that "temperature effects" shall be considered. If at the design stage a designer of Class 2 or 3 piping anticipates that significant stresses caused by thermal gradients might occur, he or she might use the Class 1 piping procedure for considering the effect of those stresses.

4.4.3.1 Basis for C_3 and C_3' Branch Connections One component not covered by ref. [23] is the branch connection. To illustrate the simple bounding basis of the C_3 and C_3' indices, the following explains the basis for the $C_3 = 1.8$ and $C_3' = 1.0$.

For the branch pipe considered as a thin-wall cylindrical shell rigidly restrained at one end (the run pipe is assumed to be the rigid restraint) and for a differential thermal expansion, $R|\alpha_a T_a - \alpha_b T_b|$, between the branch pipe and the run pipe at their juncture, the following two equations must be satisfied:

$$V/(2\beta\lambda^2) + M/(\beta\lambda) = 0 \quad (4.7)$$

$$V/(2\beta\lambda^3) + M(2\beta\lambda^2) = R|\alpha_a T_a - \alpha_b T_b| \quad (4.8)$$

where

V = shear force per unit length at branch pipe–run pipe juncture
M = moment per unit length at branch pipe–run pipe juncture
$\beta = Et^3[12(1 - \upsilon^2)]$: $\lambda = [3(1 - \upsilon^2)]^{0.25}/(\mathrm{Rt})^{0.5}$, E = modulus of elasticity of branch pipe material
v = Poisson's ratio
R = radius of branch pipe,
t = wall thickness of branch pipe
$\alpha_{a(b)}$ = coefficient of thermal expansion of branch–run pipe material
$T_{a(b)}$ = temperature of branch–run pipe

Solution of Equations (4.7) and (4.8) leads to the following equation:

$$M = -2R|\alpha_a T_a - \alpha_b T_b|\beta\lambda^2 \tag{4.9}$$

The axial bending stress, S_{ab}, is $\pm 6M/t^2$. For $\upsilon = 0.3$, $\beta\lambda^2 = (Et^2/R) \times 0.1513$, $S_{ab} = 1.816E|_{aa}T_a - \alpha_b T_b|$. The 1.816, rounded to 1.8, is C_3 for branch connections.

The hoop membrane stress, S_{hm}, is given by

$$S_{hm} = E \times \text{hoop strain} = 1.000E|\alpha_a T_a - \alpha_b T_b|$$

Thus $C'_3 = 1.0$.

As a rule of thumb, a 100 deg F through-the-wall thermal gradient can be taken to produce an 8,000 psi bending stress in the wall of a cylinder that would be included in equation (C11). The B31 user must decide if thermal stresses of this magnitude will exist frequently enough to contribute to fatigue damage from other sources.

4.5 FATIGUE EVALUATIONS: CLASS 2 OR 3 PIPING AND CLASS 1 PIPING

Equation (C11) is for fatigue evaluation of Class 2 or 3 piping. The limit, $S_h + S_A$, is a function of the number of anticipated cycles through the *f*-factor. Nominal design margins are discussed in Section 4.3.2. Code compliance is either a yes or no answer: if the calculated stress by equation (C11) is less than S_h S_A, then the answer is yes; otherwise it is no.

Equations (B10), (B11), and (B14) are for fatigue evaluation of Class 1 piping. For Code compliance, the allowable number of cycles, per Appendix I of ref. [1], must be less than the postulated number of cycles.

The basis for Class 1 piping fatigue evaluations consists of strain-controlled fatigue tests on polished bars, the results of which are included in the ASME Criteria Document [25]. The design curves in Figs. I-9.1, I-9.2, and I-9.3 were derived from the cycles-to-failure data by incorporating a nominal margin of 2 on stress or 20 on cycles—whichever is more conservative. The margin of 20 (on cycles) controls for low values of N_{d1}, whereas the margin of 2 (on stress) controls for high values of N_{d1}. In either case, N_{d1} is the number of allowable design cycles.

The low values of N_{d1} generally cannot be used directly because $S_n/3S_m > 1.00$. Consider, for example, the "as-welded" girth butt weld in a SA106 Grade B (S_m = 20 ksi) pipe for which $C_2 = 1.00$, $K_2 = 1.8$. For N_{d1} = 1,000, S_{alt} = 83 ksi from the second line of Table I.9-1. From equation (B14) with $K_e = 1.00$,

$$S_n = 2S_{\mathrm{alt}}/K_2 = 2 \times 83/1.8 = 92.2 \text{ ksi (range)}$$

But $S_n/3S_m = 92.2/60 = 1.537$; thus $K_e = 1 + 2[(S_n/3S_m) - 1] = 2.074$.

Appropriate values of K_e have been under investigation for several years. In the future, it is possible that different values of K_e will be in the Code.

Recalculating S_{alt} gives the following:

$$S_{\mathrm{alt}} = K_e S_p/2 = 2.074 \times 92.2 \times 1.8/2 = 172 \text{ ksi (amplitude)}$$

From the second line of Table I.9-1, for S_{alt} = 172 ksi; N_{d1} (adjusted for K_e) = about 150 design cycles.

A comparable number of design cycles for Class 2 or 3 piping can be obtained from Equation (4.1). We assume that the cycle is caused by moment loads. With that assumption, and also because $i = 1.00$, $S_{TE} = S_n$ = 92.2 ksi range. With a margin of 2 on stress,

$$N_{d2,3} = (245/92.2)^5 = 132 \text{ design cycles}$$

If the Hinnant Equation 4.1a is used in place of the Markl Equation 4.1 $N_{\mathrm{d2.3}}$ would become:

$$N_{d2,3} = (947.5/92.2)^3 = 1085 \text{ design cycles}$$

For this particular example, Class 1 = 150 design cycles, Class 2 or 3 = 132 design cycles.

And Hinnant [38] would provide 1085 design cycles. The Markl curve (4.1) safety factor on design life is $2^5 = 32$. The Hinnant curve (4.1) safety factor on design life is $2^{2.98} = 7.9$. If the Hinnant curve is accurate, using the Markl curve in the low cycle range increases the safety factor on stress to a value greater than 2, similar to the approach used for Class 1. The safety factor for Class 1 in the low cycle range is greater than 2 on stress since the safety factor of 20 on cycles governs in this range, For Class1, the safety factor of 2 on stress governs the allowable stress for low yield strength carbon steel materials above about 10,000 cycles.

Rodabaugh [26] gives broad-scope comparisons between the fatigue analyses of Class 1 and Class 2 or 3 piping. Comparisons are provided for both carbon steel and austenitic steel materials.

When considering Hinnants work [38]:

a) The Hinnant curve (4.1a) should likely replace the Markl curve (4.1) for i-factor development in fatigue tests if the cycles to failure occur below about 3,000 cycles.
b) The Hinnant curve slope (3) should replace the Markl curve slope (5) in cummulative damage equations, e.g. B31.3 Eq.1.d:
c) Use of the Markl curve below about 5,000 cycles results in an increase in the safety factor on stress above 2, and compares favorably with the use of the Class 1 approach for piping, [26].
d) The Markl curve should not be used above 500,000 cycles to predict allowable stresses or design life of welded components. When the cyclic reduction factors "f" is less than 0.4 some alternative should be used for the evaluation of S_A in the Class 2 and 3 Codes and in the B31 Codes.

For Class 1 piping, it is not necessary to use the values of K_e given in the Code. If these values are not used, a plastic analysis must be made. For Class 2 or 3 piping, the equivalent of K_e is inherent in the fatigue tests results that are characterized by Equation (4.1). Rodabaugh and Scavuzzo in Ref. [7] address this issue in more detail.

Conditions under which K_e is used involve low estimates of the number of cycles that will be applied to the piping system during its postulated life. At the high end of the cycles' spectrum, it may be noted that Equation (4.1) has no "endurance strength"—that is, a stress level below which the number of cycles is infinite. (Work is underway to extend Fig. I-9-1 to higher than 10^6 cycles.)

All three classes of piping use a linear cumulative-damage hypothesis to sum up the fatigue damage from cycles of different stress ranges.

Class 1 and B31 cumulative damage rules rely on stress ratios evaluated at each point in the piping system to quantify the life lost due to a particular load and number of cycles. The Class 2 and 3 Codes in NC/ND 3611.2 rely on the ratios of temperature changes, which for complex piping systems may not be proportional to the stresses at each node in the piping system and can only be considered a reasonable estimation for simple piping systems.

One major difficulty consists of anticipating at the design stage what will happen to the piping system in service. Fatigue damage has occurred in nuclear power plant piping because of vibration and thermal striping. These types of cycle loadings have not been routinely evaluated in the design stage. However, even if all significant cycle loadings were anticipated in the design stage, the problem of environmental effects may still exist. Markl's tests (and Markl-type tests by others) all have been run over short time periods with air or tap water inside the specimens. Analogously, the polished bar tests that form the basis of Class 1 piping system fatigue analyses have also been run over short time periods in an air environment. Thus the Code fatigue analysis procedure should be considered a check of as-built adequacy and may need to be supplemented by in-service inspections.

4.6 *B*-STRESS INDICES

B-stress indices are used for both Class 1 and Class 2 or 3 piping. Table NB-3681(a)-1 (Class 1 piping) and Fig. NC-3673.2(b)-1 (Class 2 or 3 piping) provide *B*-stress indices for D_o/t up to 100. The components covered by Table NB-3681(a)-1 and Fig. NC-3673.2(b)-1 are not all the same; but to the extent that the components are the same, the *B*-stress indices are essentially the same.

For components with two ends of the same nominal size (See 4.8.6 for branch connections), B-stress indices are used in equation (B9) and equations (C8) and (C9) as follows:

$$B_1 PD_o/(2t) + B_2 M_i/Z < 1.5\, S_m \qquad \text{(B9)}$$

$$B_1 PD_o/(2t) + B_2 M_A/Z < 1.5 S_h \qquad \text{(C8)}$$

$$B_1 PD_o/(2t) + B_2(M_A + M_B)/Z < \text{lesser of } 1.8S_h \text{ and } 1.5S_y \qquad \text{(C9)}$$

where

S_y = material yield strength

The limits shown for equations (B9) and (C8) are for design conditions; the limit shown for equation (C9) is for Levels A and B Service. The resultant moments M_i, M_A, and M_B are "nonreversing"; examples are weight, steady-state relief-valve thrust, and any load that the Code characterizes as nonreversing.

The foregoing equations are intended to prevent gross plastic deformation caused by such nonreversing loads as weight. A conceptual example is shown in Fig. 4.1. As the load F increases, the displacement first increases elastically, then it is in the plastic region. The goal is to limit the plastic response sufficiently so that elastic analyses of piping systems remains reasonably valid.

The criterion adopted for this purpose is from II-1430. The title of II-1430 (Criterion of Collapse Load) is a bit misleading; as indicated in Fig. 4.1, a piping component usually does not "collapse" at the load F_L. A more appropriate term—at least for piping to use in the title is "Limit Load."

The basis for most of the *B*-stress indices is given by Rodabaugh in ref. [27]. All of the *B*-stress indices are based on the concept and criterion discussed in the preceding paragraphs. The following sections discuss three aspects of *B*-stress indices.

4.6.1 Straight Pipe

$$B_1 = 0.5 \quad \text{and} \quad B_2 = 1.0$$

Test data indicate that for $D_o/t > 50$, the mode of plastic failure may be "buckling" rather than a limit load as noted in Fig. 4.1; thus *B*-stress indices are limited in application to pipe with $D_o/t < 100$. Also for $D_o/t < 50$, test data indicate the limit moments agree reasonably well with the theoretical equation, which follows, given by Larson [28] based on shell theory and von Mises yield criteria.

$$(3/4)[(PD/2tS_y)]^2 + [M_b/(D^2 tS_y)]^2 + [3.464M_t/(\pi D^2 tS_y)]^2 = 1.0 \qquad (4.10)$$

where

P = internal pressure
D = pipe mean diameter
t = pipe wall-thickness
S_y = pipe material yield strength
M_b = bending moment
M_t = torsional moment

Equation (B9) gives limits in terms of S_m; S_m/S_y varies with material and temperature. Thus the margins between Code-allowable moments and equation (4.10) vary with material and temperature. The lowest margin occurs for M_t, with $P = M_b = 0$. For (C8) $S_m = 1.35S_y$ (austenitic material at around 650°F). The margin is M(limit)/M(allowable) = 0.86. About the highest margin is for M_b, with $PD_o/(2t) = S_m \cdot M_t = 0$; (SA106 M(limit)/M(allowable) = 1.94.

These margins of about 0.86–1.94 are for the equation (B9) limit of $1.5S_m$. Margins for straight pipe tend to be the lowest for any of the components covered by the Code. Because elbows with high h behave like straight pipe. The margins are also low for such elbows. If margins for the design conditions are not to be less than, say, 1.5, a possible Code change would be to place a lower bound on B_2 of 2.0.

4.6.2 Elbows

$$B_1 = -0.1 + 0.4h \quad \text{but not} \quad <0 \text{ nor } >0.5$$

$$B_2 = 1.3/h^{(2/3)} \quad \text{but not} \quad <1.0$$

There is a significant amount of test data on limit loads of elbows that is abstracted and discussed in ref. [27]. The controlling condition is for an in-plane, closing moment. For an elbow with small h to undergo significant plastic deformation, the maximum elastic stress, $S_{max}/Z = 1.95/h^{(2/3)}$ (which is mainly a through-wall bending stress), can be exceeded by a through-wall plastic factor of 1.5. Thus $B_2 = (1.95/1.5)/h^{(2/3)} = 1.3/\text{h}^{(2/3)}$. The statement "but not < 1.0" arises from the nature of the equation for S_{max}. The equation is valid for $h < \sim 0.5$. For larger h, the underlying theory indicates that $S_{max} = 1.00/Z$—that is, the same as for straight pipe.

For an elbow, $B_1 = -0.1 + 0.4h$ but not < 0 and 0.5. Test data for elbows with small h show that internal pressure increases the limit moment. Thus B_1 could in principle be negative for such elbows. Reference [27] and the Code did not go quite that far: B_1 where is not to be taken as less than zero. The upper bound on B_1 of 0.5 returns to the aspect that, for large h, elbows behave like straight pipe.

Advances in the power of personal computers have made feasible the use of elastic-plastic, finite-element-analysis for parametric studies. Taboul [29] and Matzen [30,31] have published studies of B_2-Indices for elbows. This work may lead to Code revisions of B-stress indices for elbows.

4.6.3 Seismic Analyses

Before 1994, the Code did not define nonreversing loads and reversing dynamic loads. The limit on equation (B9) for Level D was the smaller of $3S_m$ and $2S_y$. These limits were based on the hypothesis that earthquakes give loads on piping that are not equivalent to those caused by such sustained loads as weight.

The long, complex history leading to the Code changes made in 1994 is given by Jaquay [32]. This work was later supplemented by a Japanese Joint Research Proprietary Report, "Simulation of Test #37 and Parametric Study," in May 1999.

The crux of the 1994 change for Class 1 piping consisted of increasing the stress limits on equation (B9) for Service Level D from the pre-1994 of smaller of $3.0S_m$ and $2.0S_y$ to the post-1994 of $4.5S_m$. Moreover, the pre-1994 limits did not distinguish between reversing and nonreversing dynamic loads. The post-1994 limits apply to "stress due to weight and inertial loading due to reversing dynamic loads in combination with the Level D coincident pressure."

That the 1994 Code changes are still being reviewed by the Code is an indication of the complexity of the Code evaluation procedure for earthquake resistance of piping systems. Underlying this complexity is the estimate of what sort of earthquake should be considered at the design stage.

4.7 PIPING SYSTEM ANALYSES AND FLEXIBILITY FACTORS

The moments used in Code equations are quantified by use of a piping system analyses. The early history of piping system analyses is discussed by Markl [33], including 124 references. Some of the early work dates back to 1911: for example, the article by Th. von Karman on stresses and flexibility of curved pipe.

At the present, piping system analyses are usually made with one of many proprietary piping system analysis computer programs. These analyses use beam-element models. The flexibility (or stiffness—the reciprocal of flexibility) of elements, such as elbows and curved pipe, are routinely included in the analyses. For elbows and curved pipe,

$$k = 1.65/h \quad \text{for in-plane and out-of-plane moments} \tag{4.11a}$$

$$k = 1.00 \quad \text{for torsional moments} \tag{4.11b}$$

The relationships between the three moments and three forces with the three rotations and three displacements can be represented by a 6×6 matrix. This rather complex matrix for elbows is part of the piping system analysis computer programs.

For the very simple case of an in-plane moment (M_i) constant, no other moment or force

$$\theta_i = k_i M_i R_b \alpha/(EI) \tag{4.11c}$$

where

$K_i = 1.65/\text{h}^{(2/3)}$
θ_i = in-plane rotation of one end of the elbow with respect to the other end of the elbow
M_i = in-plane moment; constant through arc angle, α
R_b = bend radius of elbow
α = arc angle of elbow in radians—for example, $\alpha = \pi/2$ for a 90 deg. elbow
E = modulus of elasticity of elbow material
I = moment of inertia of elbow cross section, usually taken to be the same as for the attached pipes

Equations (4.11a–c) are based on theory in which the end effects are negligible. If, for example, a flange were attached to either one or both ends of the elbow, a correction should be made. [See Code Fig. NC-3673.2(b)-1, note (1).]

That the correction "should be made" is significant because using a flexibility factor higher than the actual one is not necessarily conservative for all of the piping system analysis results. A "conservative" flexibility factor cannot be defined; the goal is to establish and use "best estimate" flexibility factors, which is discussed in Section 4.8.7. Other flexibilities, such as that indicated in NB-3686.5, can be included in piping system analyses by using a "point spring" concept—see Section 4.8.6 for an example.

Before about 1960, the loadings usually considered in piping system analysis consisted of restraint of thermal expansion, weight, and wind loadings. The purpose of the analyses was to quantify moments for Code stress evaluations and to check the adequacy of supports and hangers as well as to check loads on such equipment as pumps and compressors. Since about 1960, however, dynamic loadings, such as those from earthquake and waterhammer, are often included in piping system analysis. However, the i-factors, stress indices, and flexibility factors are the same as those discussed earlier in this chapter.

Since about 2000 the number of load cases analyzed in a piping analysis has increased by about an order magnitude. It is common for at least three or four thermal cases and dozens of seismic cases to be analyzed in a single calculation.

4.8 EXAMPLES

4.8.1 Example Piping System

The example piping system is shown in Fig. 4.4. The system, although simple, serves to illustrate aspects of the use of flexibility factors in piping system analyses and the use of *i*-factors and stress indices in the subsequent checks of Code compliance.

The material is assumed to be SA106 Grade B. For this material, at temperatures up to 370°F, $S_c = S_h = 17.1$ ksi; $S_m = 20$ ksi. Also assumed is that the temperature of the piping system rises from 70°F to 370°F, after which it returns to 70°F, and that the internal pressure rises from 0 to 100 psi and then returns to 0—in phase with the temperature change. (This cycle is assumed to occur 1,000 times during the design life of the piping system.) In addition, the temperature change is assumed to be slow enough so that no significant thermal gradients occur. Finally, it is assumed that there are no dynamic loads.

The stress range from pressure is given by $PD_o/(2t) = 100D_o/(2t)$: 3,200 psi for the NPS 24, 0.375 in. wall pipe, and 1,180 psi for the NPS 6, 0.280 in. wall pipe.

In the piping system analysis for weight, it is assumed that the pipes are filled with water and insulated so that the weight per in. of length is 24 lb./in. for the NPS 24 pipe and 2.7 lb./in. for the NPS 6 pipe.

Elbow factors are listed as follows:

NPS	h	i	B_1	B_2	C_1	C_2	K_1	K_2	k_i, k_o	k_t
24	0.09675	4.27	0.000	6.17	1.244	9.25	1.00	1.00	17.05	1.00
6	0.2504	2.27	0.000	3.27	1.272	4.91	1.00	1.00	6.589	1.00

Analyses are made for the following two assumptions concerning nozzle flexibility:

(1) no nozzle flexibility, and
(2) having nozzle flexibility modeled as a "point spring" (as prescribed in NB-3686.5).

$$k_o = 0.1(D_o/T)^{1.5}[(T/t)(d_o/D_o)]^{(1/2)}(t/T) \tag{4.12}$$

$$k_i = 0.2(D_o/T)\,[(T/t)(d_o/D_o)]^{(1/2)}(t/T) \tag{4.13}$$

The basis for equations (4.12) and (4.13) is given in ref. [22]. For this example, $D_o = 24$ in., $T = 0.375$ in., $d_o = 6.625$ in., and $t = 0.280$ in. With the dimensions in these two equations:

$$k_o = 23.2 \qquad k_i = 5.81$$

For this example, in which $d_o/D = 0.276$, the torsional flexibility, as a point spring, is close to 0; that flexibility was used in the evaluations of "with nozzle flexibility."

4.8.2 Moments

For the example piping system shown in Fig. 4.3 and for the conditions indicated in Section 4.8.1, the moments are shown in Table 4.1. Examples of details of the stress calculations are given in Sections 4.8.3–4.8.6.

4.8.3 Code Equations

Equations (C8), and (B9) are checks of sustained load capacity; (C11) is a fatigue check for Class 2 or 3 piping; and (B10), (B11), and (B14)—in conjunction with the S-N data in Appendix I of ref. [1]—represent the fatigue check for Class 1 piping.

The examples that, for simplicity, do not involve M_B or thermal gradients are considered to be in both "design conditions" and "Service Level A"; they are evaluated by (except for branch connections, see Table 4.2) the following equations:

$$S_{OL} = B_1PD_o/(2t) + B_2M_A/Z < 1.5S_h \tag{C8}$$

$$S_{TE} = PD_o/(4t) + 0.75iM_A/Z + iM_C/Z < (S_h + S_A) \tag{C11}$$

$$S_{B9} = B_1PD_o/(2t) + B_2M_i/Z < 1.5S_m \tag{B9}$$

$$S_n = C_1PD_o/(2t) + C_2M_i/Z < 3S_m \tag{B10}$$

$$S_p = K_1C_1PD_o/(2t) + K_2C_2M_i/Z \tag{B11}$$

$$S_{\text{alt}} = K_eS_p/2 \tag{B14}$$

Equation (C8) is used in this example rather than (C9) because of its lower limit for "design conditions." Values of M_A and M_C are summarized in Table 4.1. For the example assumptions, M_i in equation (B9) is equal to M_A, and M_i in equations (B10) and (B11) is equal to M_C.

For the assumed material (SA106 Grade B) and temperatures,

$S_h = S_c = 17{,}000$ psi for Class 2 and 3 piping
$S_h + S_A = S_c + f(1.25S_c + 0.25_h) = 42{,}750$ psi for Class 2 and 3 piping, $f = 1.00$ for 1,000 cycles
$S_m = 29{,}000$ psi for up to 370°F for Class 1 piping

4.8.4 Girth Butt Welds

Girth butt welds are at nodes 10, 30, 40, 50, 60, 70, and 80, and all seven locations should be checked. Table 4.1 summarizes the results for Class 2 or 3 piping. For girth butt welds, $B_1 = 0.5$, $B_2 = 1.0$, $0.75i = 1.0$ (its lower bound), and $i = 1.0$. Node 50(a) is used in the following equations as a specific example:

$$S_{OL} = 0.5 \times 3{,}200 + 1.0 \times 4{,}820 \times 12/162 = 1{,}960 \text{ psi} \tag{C8}$$

$$S_{TE} = 0.5 \times 3{,}200 + 1.0 \times 4{,}820 \times 12/162 + 1.0 \times 486{,}000 \times 12/162 = 38{,}000 \text{ psi} \tag{C11}$$

Because 1,960 psi is less than $1.5S_h = 25{,}650$ psi, and 38,000 psi is less than $(S_h + S_A) = 42{,}750$ psi, the girth butt weld at Node 50 is acceptable as Class 2 or 3 piping.

For Class 1 "as-welded" girth butt welds, $B_1 = 0.5$, $B_2 = 1.0$, $C_1 = 1.0$, $K_1 = 1.2$, $C_2 = 1.0$, $K_2 = 1.8$.

$$S_{B9} = 0.5 \times 3{,}200 + 1.0 \times 4{,}820 \times 12/162 = 1{,}960 \tag{B9}$$

$$S_n = 1.0 \times 3{,}200 + 1.0 \times 486{,}000 \times 12/162 = 39{,}200 \text{ psi} \tag{B10}$$

$$S_p = 1.2 \times 1.0 \times 3{,}200 + 1.8 \times 1.00 \times 486{,}000 \times 12/162 = 68{,}600 \text{ psi} \tag{B11}$$

TABLE 4.1 RANGE OF RESULTANT MOMENTS, MC AND MA, FT. LB.; AND STRESSES, S_{OL} BY EQUATION (C8) AND S_{TE} BY EQUATION (C11), p_{si}

Node			Girth Butt Weld		Elbow	
	M_C	M_A	S_{OL}	S_{TE}	S_{OL}	S_{TE}
(a)	(b)	(c)	(d)	(d)	(e)	(e)
10[a]	151000	12000	2490	13700	-----	-----
[b]	154000	11800	2470	13900	-----	-----
20[a]	19700	6200	-----	-----	-----	-----
[b]	14100	6000	-----	-----	-----	-----
30[a]	74000	2140	1760	7240	980	25500
[b]	74300	2140	1760	7260	980	25600
40[a]	82400	1050	1680	7780	480	27900
[b]	82600	1030	1680	7800	470	28000
50[a]	486000	4820	1960	38000	-----	-----
[b]	485000	4750	1950	37900	-----	-----
25[a]	14200	3	-----	-----	-----	-----
[b]	2560	6	-----	-----	-----	-----
60[a]	3100	3	590	4970	14	10500
[b]	2990	11	610	4830	51	10200
70[a]	4130	96	730	6560	440	14100
[b]	3280	71	690	5320	330	11300
80[a]	3120	51	660	5070	----	-----
[b]	2670	38	640	4410	-----	-----

(a) See Fig. 4.3 for node locations. "[a]" indicates no flexibility at Node 25; "[b]" indicates flexibility at Node 25, $k_o = 23.2$, $k_i = 5.81$
(b) M_C = range of resultant moment due to restraint of thermal expansion
(c) M_A = resultant moment due to weight
(d) "----" indicates no girth butt weld at the Node
(e) "----" indicates no elbow end at the Node
See 4.8.6 for discussion of Nodes 20 and 25

Because 1,960 psi is less than $1.5S_m$, equation (B9) is met. The next step is to see if the fatigue requirement is met.

Because S_n is less than $3S_m$ (= 60,000 psi at 370°F), $K_e = 1.0$, and

$$S_{\text{alt}} = 1.00 \times 68{,}600/2 = 34{,}300 \text{ psi} \qquad \text{(B14)}$$

[The division by 2 in equation (B14) converts stress range to stress amplitude as used in Table I-9-1 of ref. [1].]

From Table I-9-1 (line 2) and the interpolation equation in Table I-9-1, $N_{d1} = 14{,}000$ cycles. Because N_{d1} is greater than the postulated 1,000 cycles, the girth butt weld at Node 50(a) is acceptable as Class 1 piping.

An appropriate comparison with Class 2 or 3 piping is obtained by using $S_{TE}/2$ for S_{ta} in Equation (4.1).

$$N_f = (245{,}000 \times 2/38{,}000)^5 = 5357{,}000 \text{ cycles to failure}$$

With a margin of 2 on stress,

$$N_{d2,3} = 357{,}000/32 = 11{,}000 \text{ design cycles}$$

Thus, for Node 50[a], $N_{d1} = 14{,}000$ cycles agrees quite well with $N_{d2,3} = 11{,}000$ cycles. Refer to the discussion presented in Section 4.5.

4.8.5 Elbows

Ends of elbows are at nodes 30, 40, 60, and 70, and these four locations should at least be checked. (In unusual piping systems, the maximum stress may be somewhere between the two ends.) Table 4.1 summarizes the results for Class 2 or 3 piping.

TABLE 4.2 CODE EQUATIONS, *i*-FACTORS AND STRESS INDICES FOR THE EXAMPLE BRANCH CONNECTION

The example branch connection consists of NPS 24, 0.375 inch wall run pipe with NPS 6, 0.280 inch wall branch pipe. The intersection weld is full penetration. For Class 2 or 3 piping evaluation, r_2 (outside fillet radius) is not provided. For Class 1 piping evaluation, r_2 is provided. For Class 2 or 3 piping, Fig. NC-3672.2 (b)-1, "Branch connection or unreinforced fabricated tee" For Class 1 piping, Table NB-3681(a)-1, "Branch connection per NB-3643". See under 4.8.1 for additional details.

Code Equations For Class 2 or 3 Piping:

Run Ends:

$$S_{OL} = B_1 PD_o/(2T) + B_{2r}(M_A/Z_r) \quad \text{(C8)}$$

$$S_{TE} = PD_o/(4T) + 0.75 i_r(M_A/Z_r) + i_r(M_C/Z_r) \quad \text{(C11)}$$

Branch End

$$S_{OL} = B_1 Pd_o/(2t) + B_{2b}(M_A/Z_b) \quad \text{(C8)}$$

$$S_{TE} = Pd_o/(4t) + 0.75 i_b(M_A/Z_b) + i_b(M_C/Z_b) \quad \text{(C11)}$$

Code Equations For Class 1 Piping [See Fig. NB-3683.1(d)-1]:

$$S_{B9} = B_1 PD_o/(2T) + B_{2b}(M_b/Z_b) + B_{2r}(M_r/Z_r) \le 1.5 S_m \quad \text{(B9)}$$

$$S_n = C_1 PD_o/(2T) + C_{2b}(M_b/Z_b) + C_{2r}(M_r/Z_r) \quad \text{(B10)}$$

$$S_p = K_1 C_1 PD_o/(2T) + K_{2b} C_{2b}(M_b/Z_b) + K_{2r} C_{2r}(M_r/Z_r) \quad \text{(B11)}$$

$$S_{\text{alt}} = K_e S_p/2 \quad \text{(B14)}$$

The dimensional ratios used to calculate stress indices and *i*-factors are:

$R/T = 31.5$: $r/R = 0.269$: $t/T = 0.747$: $r/r_p = 0.958$: $r/t = 11.33$

R = mean radius of run pipe: T = wall thickness of run pipe, t = wall thickness of branch pipe, r_p = outside radius of branch pipe.

Stress Indices and *i*-factors for the example branch connection are:

B_1	C_1	K_1	B_{2b}	C_{2b}	K_{2b}	B_{2r}	C_{2r}	K_{2r}	ib	ir
0.50	2.18	2.00	2.77	5.54	1.00	1.65	2.11	1.00	5.54	2.14

Node 30(a) is used as in the following as a specific example: For the NPS 24,0.375 in. wall, R_b = 36 in. bend radius elbow.

$$i = 0.9/h^{(2/3)}$$

$$h = 0.375 \times 36/11.8125^2 = 0.09675$$

$$i = 4.27$$

For this elbow, $B_1 = -0.1 + 0.4h = 0.00$ (its lower bound) and $B_2 = 1.3/h^{(2/3)} = 6.17$.

$$S_{OL} = 0.0 \times 3{,}200 + 6.17 \times 2{,}140 \times 12/162 = 980 \text{ psi} \quad \text{(C8)}$$

$$S_{TE} = 0.5 \times 3{,}200 + 0.75 \times 4.27 \times 2{,}140 \times 12/162 + 4.27 \times 74{,}000 \times 12/162 = 25{,}500 \text{ psi} \quad \text{(C11)}$$

Because 980 psi is less than $1.5S_h$ = 25,650 psi, and 25,500 psi is less than $(S_h + S_A)$ = 42,750 psi, the elbow end at Node 30(a) is acceptable as Class 2 or 3 piping.

For Class 1 piping:

$$B_1 = 0.00 \qquad B_2 = 6.17 \qquad C_1 = 1.244$$

$$C_1 = 9.25 \qquad K_1 = K_2 = 1.00$$

$$S_{B9} = 0.0 \times 3{,}200 + 6.17 \times 2{,}140 \times 12/162 = 980 \quad \text{(B9)}$$

$$S_n = 1.244 \times 3{,}200 + 9.25 \times 74{,}000 \times 12/162 = 54{,}700 \text{ psi} \quad \text{(B10)}$$

$$S_p = 1.0 \times 1.244 \times 3{,}200 + 1.0 \times 9.25 \times 74{,}000 \times 12/162 = 54{,}700 \text{ psi} \quad \text{(B11)}$$

Because 980 psi is less than $1.5S_m$, equation (B9) is met. The next step is to see if the fatigue requirement is met.

Because S_n is less than $3S_m$ (= 60,000 at 370°F psi), K_e = 1.0, and

$$S_{\text{alt}} = 1.0 \times 54{,}700/2 = 27{,}300 \text{ psi} \quad \text{(B14)}$$

From Table I-9-1 (line 2) and the interpolation equation in Table I-9.1, N_{d1} = 30,000 cycles. Because N_{d1} is greater than the postulated 1,000 cycles, the elbow end at Node 30(a) is acceptable as Class 1 piping.

For comparison with Class 2 or 3 piping,

$$N_{d2,3} = (490{,}000/25{,}500)^5/32 = 82{,}000 \text{ design cycles}$$

Thus for this example, $N_{d1} = 30{,}000$ cycles does not agree very well with $N_{d2,3} = 82{,}000$ cycles. Refer to the discussion presented in Section 4.5.

4.8.6 Branch Connection

The nozzle is at Node 25, modeled as a "point spring" in the piping system analyses. The moments at Node 25 are shown in Table 4.1.

Code evaluation of a branch connection is more complex than for girth butt welds or elbows. Among other aspects, the evaluations involve two pipes: the run pipe and the branch pipe or nozzle, with different radii and wall-thickness. There are two *i*-factors—i_r and i_b—and two sets of B_2, C_2, and K_2.

The 2001 Edition of Ref. [1], 2002 Addenda, made significant changes to indices and *i*-factors for branch connections:

> For Class 1 piping, C_{2b} and B_{2b} were reduced by a factor of 2. For Class 2 or 3 piping, i_b and $B2_b$ were reduced by factor of 2 for r/R up to 0.5, and coverage was extended up to r/R = 1.00.

These changes are based on refs. [34,35] and constitute another example of the continuing review of the subject of this Chapter by code committees.

The *i*-factors and stress indices are summarized in Table 4.2. and will be used for the examples in the paragraphs that follow.

For Class 2 or 3 piping, the branch end and two run ends are evaluated separately. For Class 1 piping, M_b and M_r must be calculated as indicated in NB-3683.1(d) and Fig. NB-3683.1(d)-1.

4.8.6.1 Class 2 or 3 Piping: Check of Run Ends (Node 20) Both run ends should be checked. Node 20(a) will be used in the following as a specific example, in which the moments at both run ends are essentially identical. This is because the ratio of the moment of inertia of the NPS 24 run pipe to the NPS 6 branch pipe; 1,943/28.1 = 69.

From Table 4.1, $M_A = 6{,}200$ ft. lb. and $M_C = 19{,}700$ ft. lb. For factors, see Table 4.2.

$$S_{OL} = 0.5 \times 3{,}200 + 1.65 \times 6{,}200 \times 12/164 = 2{,}350\ \text{psi} \quad \text{(C8)}$$

$$S_{TE} = 0.5 \times 3{,}200 + 0.75 \times 2.143 \times 6{,}200 \times 12/164 + 2.143 \times 19{,}700 \times 12/164 = 5{,}420\ \text{psi} \quad \text{(C11)}$$

Because 2,300 psi is less than $1.5S_h = 25{,}650$ psi, and 5,420 psi is less than $(S_h + S_A) = 42{,}750$ psi, the branch connection check of run ends is acceptable as Class 2 or 3 piping.

4.8.6.2 Class 2 or 3 Piping: Check of Branch End (Node 25) See Tables 4.1 and 4.2.

For Node 25(a) (no nozzle flexibility):

$$S_{OL} = 0.5 \times 1{,}180 + 2.77 \times 3 \times 12/8.85 = 600\ \text{psi} \quad \text{(C8)}$$

$$S_{TE} = 0.5 \times 1{,}180 + 0.75 \times 5.54 \times 3 \times 12/8.85 + 5.54 \times 14{,}200 \times 12/8.85 = 107{,}000\ \text{psi} \quad \text{(C11)}$$

For Node 25(b) (with nozzle flexibility):

$$S_{OL} = 0.5 \times 1{,}180 + 2.77 \times 6 \times 12/8.85 = 610\ \text{psi} \quad \text{(C8)}$$

$$S_{TE} = 0.5 \times 1{,}180 + 0.75 \times 5.54 \times 6 \times 12/8.85 + 5.54 \times 2{,}560 \times 12/8.85 = 19{,}900\ \text{psi} \quad \text{(C11)}$$

The inclusion of nozzle flexibility in the piping system analysis turns an unacceptable system [$S_{TE} = 107{,}000$ psi $> (S_h = S_A) = 42{,}750$ psi] into an acceptable system ($S_{TE} = 19{,}900$ psi $< 42{,}750$ psi).

4.8.6.3 Class 1 Piping For Class 1 piping, M_b and M_r are calculated as indicated in NB-3683.1(d) and Fig. NB-3683.1(d)-1. For this example, the run moments do not change sign; thus $M_r = 0$.

For Node 25(a) (no nozzle flexibility):

$$S_n = 2.18 \times 3{,}200 + 5.54 \times 14{,}200 \times 12/8.85 = 114{,}000\ \text{psi} \quad \text{(B10)}$$

Because $S_n > 3S_m = 60000$ psi at 370°F without nozzle flexibility, the system is not acceptable. However, we continue the example to look at N_{d1} and $N_{d2,3}$.

$$K_e = 1 + 2[(S_n/3S_m) - 1] = 1 + 2[(114{,}000/60{,}000) - 1] = 2.80\ (\text{see NB} - 3228.5)$$

$$S_p = 2.0 \times 2.18 \times 3{,}200 + 1.00 \times 5.54 \times 14{,}200 \times 12/8.85 = 121{,}000\ \text{psi}$$

$$S_{\text{alt}} = 2.80 \times 121{,}000/2 = 169{,}000\ \text{psi}$$

$$N_{d1} = 160\ \text{design cycles and}$$

$$N_{d2,3} = (490{,}000/107{,}000)^5/32 = 63\ \text{design cycles} \quad \text{(B11)}$$

For Node 25(b) (with nozzle flexibility):

$$S_n = 2.18 \times 3{,}200 + 5.54 \times 2{,}560 \times 12/8.85 = 26{,}200\ \text{psi} \quad \text{(B10)}$$

$$S_p = 2.0 \times 2.18 \times 3{,}200 + 1.00 \times 5.54 \times 2{,}560 \times 12/8.85 = 33{,}200\ \text{psi} \quad \text{(B11)}$$

Because S_n is less than $3S_m$ (=60,000 psi), $K_e = 1.0$, and

$$S_{\text{alt}} = 1.00 \times 33200/2 = 16600\ \text{psi}$$

$$N_{d1} = 196{,}000\ \text{cycles and}$$

$$d_{2,3} = (490{,}000/19{,}900)^5/32 = 283{,}000\ \text{design cycles}$$

Thus the branch connection, without inclusion of nozzle flexibility in the piping system analyses, is unacceptable for Class 1 piping. The inclusion of nozzle flexibility turns an unacceptable system [$S_n > 3S_m$] into an acceptable system with allowable design cycles $N_{d1} = 196{,}000$ as compared to the postulated 1,000 cycles.

4.8.7 Best Estimate of Flexibility Factors

Table 4.1 shows that "best estimate" $k_o = 23.2$ and $k_i = 5.81$ reduced M_C at Node 25 from 14,200 to 2,560 ft. lb. However, for other nodes, inclusion of the nozzle flexibility sometimes increased rather than decreased the moments. Although trivial in this example for maximum calculated stresses, the example serves to illustrate that "conservative" flexibility factors cannot be defined. Thus the goal should be to use "best estimate" flexibility factors.

4.8.8 Summary of Examples

(1) The piping system is Code compliant with respect to equation (C8) for Class 2 or 3 piping and with respect to equation (B9) for Class 1 piping [1]. This is not cycle-dependent.
(2) The girth butt welds and elbows are Code-compliant for Class 1 ($N_{d1} > 1{,}000$) and Class 2 or 3 piping ($S_{TE} < 42{,}750$ psi) [1].
(3) The branch connection, with assumed no nozzle flexibility, is not Code-compliant for Class 1 or Class 2 or 3 piping [1].
(4) The branch connection, with nozzle flexibility, is Code-compliant for Class 1 ($N_{d1} > 1{,}000$) and for Class 2 or 3 piping (S_{TE} of branch and run checks $< 42{,}750$ psi.) [1].

4.9 ASME B31.1 [36] AND B31.3 [37] PIPING CODES

Stress intensification factors in B31.1 and B31.3 are identical or similar to those in NC-3600 of ref. [1] for Class 2 or 3 piping. The preceding comments concerning stress intensification factors for Class 2 or 3 piping are usually applicable to B31.1 and B31.3.

B31.1 and B31.3 do not use B-stress indices. In B31.1, the equivalent of B_2 is $0.75i$. See discussion in 4.11 regarding how B31.3 addresses sustained loads. Thus the preceding comments concerning Class 2 or 3 piping are usually applicable to refs. [36]–[37].

Stress intensification factors are covered in Appendix D of B31.1 and B31.3. Appendix D is analogous to Fig. NC-3673.2(b)-2 of ref. [1]; however, Appendix D of B31.1 is not the same as Appendix D of B31.3.

Analogies between Class 2 or 3 piping and between B31.1 and B31.3 are discussed in Sections 4.10 and 4.11.

4.10 ASME B31.1: POWER PIPING [36]

Allowable stresses in B31.1 are not the same as for Class 2 or 3 piping. For example, for A106-Grade B at temperatures up to 650F, the allowable stress is 15 ksi for B31.1; 17.1 ksi for Class 2 or 3 piping.

Allowable stresses for Class 2 or 3 piping are limited to temperatures such that creep is negligible. In B31.1, allowable stresses are given for temperatures in the creep range. For example, for A106-Grade B, the allowable stress in B31.1 at 800F is 10.8 ksi.

Equation (11) of B31.1 is

$$S_L = PD_o/(4t_n) + 0.75iM_A/Z < 1.0S_h \qquad \text{(B31.1–11)}$$

The preceding equation is for "sustained loads" and is conceptually the equivalent of equation (C8) for Levels A and B. Equation (12) of B31.1 is

$$S_{OL} = PD_O/(4t_n) + 0.75iM_A/Z + 0.75iM_B/Z < kS_h \qquad \text{(B31.1–12)}$$

where

M_A = resultant moment from weight and other sustained loads
M_B = resultant moment from occasional loads
D_o, t_n and Z = pipe (run pipe or branch pipe for reducing branch connections and tees)
k = 1.15 for occasional loads acting for no more than 8 hr at any one time and no more than 800 hr/year
k = 1.2 for occasional loads acting no more than 1 hr at any one time and no more than 80 hr/year

The preceding equation is also conceptually the equivalent of equation (C8), but for loads that might be in Level D under ref. [1], e.g., an occasional load caused by an earthquake.

Both equations (B31.1–11) and (B31.1–12), as indicated by the use of "resultant moment," are checks of the adequacy to sustain loads without gross plastic distortion.

Equation (13) of B31.1 is

$$S_E = iM_C/Z < S_A + f(S_h - S_L) \qquad \text{(B31.1–13)}$$

where

M_C = range of resultant moment from thermal expansion

Conceptually, equation (B31.1–13) is the equivalent of equation (C11). As indicated by "range of resultant moment," this is a check of fatigue adequacy.

The rules of B31.1 lead to the conclusion that the example piping system is not acceptable without nozzle flexibility; and is acceptable with nozzle flexibility. In the interest of brevity, the rather extensive details are not included herein.

4.11 ASME B31.3: PROCESS PIPING [37]

Allowable stresses in B31.3 are not the same as for Class 2 or 3 piping. For example, for A106-Grade B at temperatures up to 400F, the allowable stress is 20 ksi for B31.1; 17.1 ksi for Class 2 or 3 piping.

Allowable stresses for Class 2 or 3 piping are limited to temperatures such that creep is negligible. In B31.3, allowable stresses are given for temperatures in the creep range. For example, for A106-Grade B, the allowable stress in B31.3 at 1000F is 2.5 ksi.

The load capacity check of B31.3 is described in paragraph 302.3.6 as follows:

Details of B31.3 checks to determine whether the example piping system is or is not acceptable are shown in the following paragraphs.

S_L is calculated by the B31.3 equation (23b). In the 2010 Revision of B31.3 the equation for S_L includes sustained moment indices, or "I" factors. I_i and I_o are given as $0.75i_i$ or $0.75i_o$ respectively in the absence of more applicable data. I_a and I_t are taken as 1.0 in the absence of more applicable data.

$$S_L = \sqrt{(|S_a| + S_b)^2 + (2S_t)^2} \qquad \text{B31.3 (23a)}$$

$$S_b = \sqrt{\frac{(I_iM_i)^2 + (I_oM_o)^2}{Z}} \qquad \text{B31.3 (23b)}$$

$$S_t = \frac{I_tM_t}{2Z} \qquad \text{B31.3 (23c)}$$

$$S_a = \frac{I_aF_a}{A_p} \qquad \text{B31.3 (23d)}$$

Sustained moment indices can be thought of as conceptually similar, but not identical to the B_2 indices used in the Class 1 Code. For the example problem, S_L in the branch is 5000 psi and S_L in the run is 1667 psi.

The fatigue check of B31.3 is specified (for other than checking the branch end of reducing-branch connections) by equations B31.3–17 and 18). These two equations can be combined to give

$$S_E = [(i_i M_i)^2 + (i_o M_o)^2 + M_t^2]^{0.5}/Z < S_A \qquad \text{(B31.3–X)}$$

where

i_i = in-plane stress intensification factor
i_o = out-of-plane stress intensification factor
M_i = in-plane bending moment
M_o = out-of-plane bending moment
M_t = torsional moment
Z = section modulus

As indicated by equation (1b) of B31.3, when S_h is greater than S_L,

$$S_A = f[1.25(S_c + S_h) - S_L] \qquad \text{(B31.3–1b)}$$

For checking the branch end of reducing branch connections, based on equations (B31.3–19 and −20):

$$S_E = \{[(i_i M_i)^2 + (i_o M_o)^2]/Z_e^2 + (M_t/Z_b)^2\}^{0.5} \qquad \text{(B31.3–Y)}$$

$$Z_e = \pi r^2 T_s : T_s = \text{lesser of } T, i_i t$$

For the example UFT branch connection of Fig. 4.3, T = 0.375 inch, $i_i\, t = 6.98 \times 0.280 = 1.95$ inch; thus $T_s = 0.375$ inch and $Z_e = 11.86$ in^3.

Z_b = section modulus of branch pipe

B31.3 does not cover such a component as a branch connection in B31.1. Thus the only available comparable component in B31.3 is the unreinforced fabricated tee (UFT). For UFT, $h = T/R$; $i_o = 0.9/h^{(2/3)}$; and $i_i = 0.75 i_o + 0.25$. The lower bound on both i_o and i_i is 1.00.

For B31.3: check run ends—no nozzle flexibility (Node 20):

$M_x = M_i = 16{,}801$ ft. lb. (see Fig. 4.3 for moment directions)
$M_y = M_o = 1{,}310$ ft. lb.
$M_z = M_t = 10{,}234$ ft. lb.

Both run ends should be checked. In this example, the moments at both run ends are essentially identical. This is caused by the ratio of the moment of inertia of the NPS 24 run pipe to the NPS 6 branch pipe: 1,943/28.1 = 69.

$$S_E = \{[(8.98 \times 1{,}310)^2 + (6.98 \times 16{,}801)^2 + 10{,}234^2]\}^{0.5} \times 12/162 = 8{,}760 \text{ psi} \qquad \text{(B31.3-X)}$$

Because $S_E = 8760$ psi $< S_A = 54000$ psi, S_E is acceptable.
For B31.3: check of branch end—no nozzle flexibility (Node 25).

$M_x = M_t = 245$ ft. lb. (see Fig. 4.3 for moment directions)
$M_y = M_i = 156$ ft. lb.
$M_z = M_o = 14{,}196$ ft lb.

$$S_E = \{[(6.98 \times 156)^2 + (8.98 \times 14{,}196)^2]/11.86^2 + (245/8.50)^2\}^{0.5} \times 12 = 129{,}000 \text{ psi} \qquad \text{(B31.3-Y)}$$

Because $S_E = 129{,}000$ psi $> S_A = 58{,}000$ psi, S_E is not acceptable
For B31.3: check of run ends—with nozzle flexibility (Node 20).

$M_x = M_i = 13{,}832$ ft. lb (see Fig. 4.3 for moment directions)
$M_y = M_o = 913$ ft. lb.
$M_z = M_t = 2{,}719$ ft. lb.

Both run ends should be checked. In this example, the moments at both run ends are essentially identical. This is caused by the ratio of the moment of inertia of the NPS 24 run pipe to the NPS 6 branch pipe: 1,943/28.1 = 69.

$$S_E = [(8.98 \times 913)^2 + (6.98 \times 13{,}832)^2 + 2{,}719^2]^{0.5} \times 12/162 = 7{,}180 \text{ psi} \qquad \text{(B31.3-X)}$$

Because $S_E = 7{,}180$ psi $< S_A = 54{,}000$ psi, S_E is acceptable.
For B31.3: check of branch end—with nozzle flexibility (Node 25).

$M_x = M_t = 248$ ft. lb. (see Fig. 4.3 for moment directions)
$M_y = M_i = 117$ ft. lb.
$M_Z = M_O = 2{,}550$ ft. lb.

$$S_E = \{[(6.98 \times 117)^2 + (8.98 \times 2{,}550)^2]/11.86^2 + (248/8.50)^2\}^{0.5} \times 12 = 23{,}200 \text{ psi} \qquad \text{(B31.3-Y)}$$

Because $S_E = 23{,}100$ psi $< S_A = 58{,}000$ psi, S_E is acceptable.
The example piping system, without nozzle flexibility, is not acceptable by Code[1], Class 1: Code[1], Classes 2/3: B31.1[36]: B31.3[37]. The example piping system, with nozzle flexibility, is acceptable by all four of the Codes. Acceptable refers only to conformance with the stress limits of the four Codes.

That B31.1 and B31.3 may not be consistent with one another is mainly related to branch connections. As noted on several occasions in this chapter, the review of *i*-factors and their uses is ongoing. With respect to B31.1 and B31.3, the reviews start with the B31 Mechanical Design Technical Committee.

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CHAPTER

5

CODE DESIGN AND EVALUATION FOR CYCLIC LOADING—SECTIONS III AND VIII

William J. O'Donnell

5.1 BACKGROUND

Fatigue is one of the most frequent causes of failure in pressure vessels and piping components. Fatigue strength is sensitive to design details such as stress raisers, and to a myriad of material and fabrication factors, including welding imperfections. Fatigue is also sensitive to often unforeseen operating conditions such as flow induced vibrations, high cycle thermal mixing, thermal striations, and environmental effects. What is somewhat surprising is the large number of fatigue failures which are directly related to poorly chosen design and fabrication details. The ASME Code, and other International Codes and Standards have not been successful in preventing the use of design and fabrication details that are inappropriate for cyclic service. The ASME Code was one of the first Codes and Standards to treat design for fatigue life explicitly.

The failure of metals from fatigue appears to have been first documented by Albert in 1838 [1]. Fatigue has long been a major consideration in the design of rotating machinery and aircraft, but the number of cycles for such applications is usually in the millions, and the fatigue stresses are generally not substantially over yield. However, pressure vessels and piping tend to operate in the low cycle regime, where local stresses are far in excess of yield. Useful methods of analyzing fatigue in the low cycle regime were first developed by Langer [2]–[4], Coffin [5] and Manson [6] in the 1950's and 1960's.

The fatigue design life evaluation procedures in Section III of the ASME Boiler and Pressure Vessel Code were originally developed in the Naval Nuclear Program. W.J. (Bill) O'Donnell worked with B.F. (Bernie) Langer, W.E. (Bill) Cooper and James (Jim) Farr in the late 1950's and early 1960's on the initial formulation of this technology in the Tentative Structural Design Basis for Reactor Pressure Vessels and Directly Associated Components, which became known as "SDB-63." Section III of the ASME Code "Vessels in Nuclear Service" was the first to include specific Code rules to prevent low-cycle fatigue failure. Its first edition was published in 1963; Section VIII, Division 2, "Alternate Rules for Pressure Vessels" followed in 1968. Section VIII, Division 1 of the Code still does not include explicit fatigue design life evaluation methods.

5.2 USE OF STRAIN-CONTROLLED FATIGUE DATA

The chief difference between high-cycle fatigue and low-cycle fatigue is that the former involves little or no plastic action, whereas in the latter, only those strains in excess of the yield strain can produce failure in a few thousand cycles. In the plastic region large changes in strain can be produced by small changes in stress. Fatigue damage in the plastic region is caused by plastic strain ranges. Therefore, fatigue curves for use in this region should be based on tests in which strain, rather than stress is the controlled variable. As a matter of convenience, the strain values used in the tests are multiplied by the elastic modulus to give a fictitious stress which is not the actual applied stress, but has the advantage of being directly comparable to allowable stresses and stresses calculated on the assumption of elastic behavior.

The general procedure used in evaluating the strain-controlled fatigue data was to obtain a "best fit" for the quantities RA and S_e in the equation:

$$S = \frac{E}{4\sqrt{N}} \ln \frac{100}{100 - RA} + S_e \tag{5.1}$$

Where

E = elastic modulus (psi)
N = number of cycles to failure
S = strain amplitude times elastic modulus, psi
S_e = endurance limit, psi
RA = Reduction in area in tensile test, percent

The consideration of plastic action and the use of strain instead of stress has necessitated some additional departures from the conventional methods of design analysis.

In the past, it was common practice to use lower stress concentration factors for small numbers of cycles. This practice is still considered reasonable when the allowable stresses are based on stress-fatigue data, but such a practice is not valid when strain-fatigue data are used.

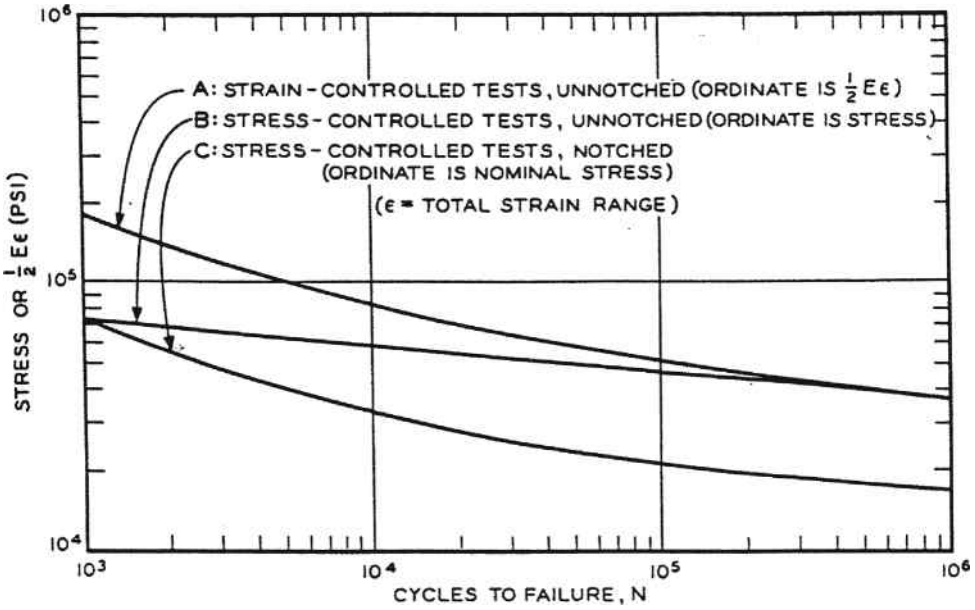


FIG. 5.1 TYPICAL RELATIONSHIP BETWEEN STRESS, STRAIN, AND CYCLES TO FAILURE

Figure 5.1 shows typical relationships between stress, S, and cycles-to-failure, N, from (A) strain cycling tests on unnotched specimens, (B) stress-cycling tests on unnotched specimens, and (C) stress-cycling tests on notched specimens. The ratio between the ordinates of curves (B) and (C) decreases with decreasing cycles-to-failure, which is the basis for the commonly-accepted practice of using lower values of K (stress concentration factor) for lower values of N. In (C), however, nominal stress is the controlled parameter, even though material in the root of the notch is really being strain cycled, for the surrounding material is at a lower stress and behaves elastically. Therefore, it should be expected that the ratio between curves (A) and (C) should be independent of N and equal to K or a value less than K for sharp notches. For this reason, the Code contains the recommendation that the same value of K be used regardless of the number of cycles involved.

5.3 STRESS/STRAIN CONCENTRATION EFFECTS

Nominal stresses must be multiplied by fatigue strength reduction factors in order to enter the fatigue design curves. Fatigue strength reduction factors include both stress/strain concentration effects and metallurgical notch effects. The choice of an appropriate fatigue strength reduction factor is an essential element of fatigue life evaluation. For fillets, grooves, holes, etc. of known geometry, it is safe to use theoretical stress concentration factors for the geometry effects. The use of the theoretical factor as a safe upper limit is usually justified because strain concentrations higher than the stress concentrations only occur when gross yielding is present in the surrounding material. This situation is generally prevented by the use of basic stress limits which assure shake-down to elastic action. However, when the linearized stress range exceeds $3S_m$ or twice the yield strength, plastic strain concentration effects must be included in the fatigue analyses. This can be done either by using cyclic elastic-plastic finite element analyses, or by using the simplified plastic strain concentration factors, K_e, given in Section III and Section VIII, Division 2 of the Code. The K_e factors in the Code have recently been being revised to be more accurate.

For very sharp notches it is well known that the theoretical factors grossly overestimate the true weakening effect of the notch in the low and medium strength materials used for pressure vessels. Therefore, no factor higher than 5 need ever be used for any configuration allowed by the design rules and an upper limit of 4 is specified for some specific constructions such as fillet welds and screw threads. When fatigue tests are made to find the appropriate factor for a given material and configuration, they should be made with a material of comparable notch sensitivity and failure should occur in a reasonably large number of cycles (>10,000) so that the test does not involve gross yielding.

5.4 EFFECT OF MEAN STRESS

As described in [4], another deviation from prior common practice occurs where the stress fluctuates around a mean value different from zero, as shown in Figure 5.2. The evaluation of the effects of mean stress is commonly accomplished by use of the modified Goodman diagram, as shown in Figure 5.3 where mean stress is plotted as the abscissa and the amplitude (half range) of the fluctuation is plotted as the ordinate. The straight line joining the stress amplitude for a given number of cycles, S_N

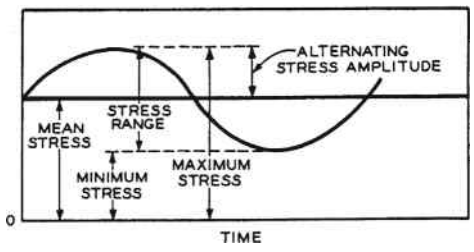


FIG. 5.2 STRESS FLUCTUATION AROUND A MEAN VALUE

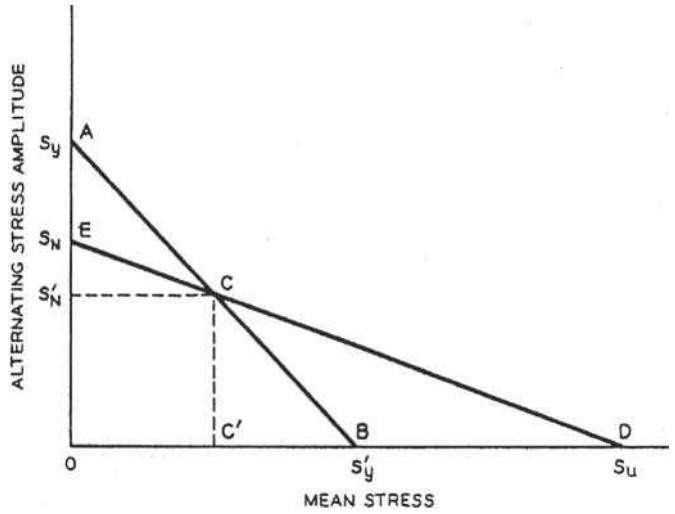


FIG. 5.3 MODIFIED GOODMAN DIAGRAM

on the vertical axis (point E) with the ultimate strength, S_u, on the horizontal axis (point D) is a conservative approximation of the combinations of mean and alternating stress that produce failure with mean stress. A little consideration of this diagram shows that not all points below the "failure" line (ED) are feasible. Any combination of mean and alternating stresses that results in a stress excursion above the yield strength will produce a shift in the mean stress that keeps the maximum stress during the cycle at the yield value. This shift is illustrated by the strain history shown in Figure 5.4.

In the presence of strain hardening, the feasible combinations of mean and alternating stress in (5.3) are all contained within the 45 degree triangle AOB, where A is the yield strength on the vertical axis and B is the yield strength on the horizontal axis. Regardless of the conditions under which any test or service cycle is started, the true conditions after the application of a few cycles must fall within this region because all combinations above line AB have a maximum stress above yield and there is a consequent reduction of mean stress that shifts the conditions to a point on the line AB or all the way to the vertical axis.

It may be seen from the preceding discussion that the value of mean stress to be used in the fatigue evaluation is not always the value that is calculated directly from the imposed loading cycle. When the loading cycle produces calculated stresses that exceed the yield strength at any time, it is necessary to calculate an adjusted value of mean stress before completing the fatigue evaluation. The rules for calculating this adjusted value may be summarized as follows

$$\begin{aligned} &\text{If } S_{alt} + S'_{mean} \le S_y,\ S_{mean} = S'_{mean} \\ &\text{If } S_{alt} + S'_{mean} > S_y \text{ and } S_{alt} < S_y,\ S_{mean} = S_y - S_{alt} \\ &\text{If } S_{alt} \ge S_y,\ S_{mean} = 0 \end{aligned} \tag{5.2}$$

Where

S'_{mean} = basic value of mean stress (calculated directly from loading cycle)
S_{mean} = adjusted value of mean stress
S_{alt} = amplitude (half range) of stress fluctuation
S_y = yield strength

The ASME Code fatigue curves are derived from test results for complete stress reversal, that is, $S_{mean} = 0$. Because the presence of a mean stress detracts from the fatigue resistance of the material, it is necessary to determine the equivalent alternating stress for zero mean stress before entering the fatigue curve. This quantity, designated S_{eq}, is the alternating stress that produces the same fatigue damage at zero mean stress as the actual alternating stress, S_{alt}, produces at the existing value of mean stress. It can be obtained graphically from the Goodman diagram by projecting a line from S_u through the point (S_{mean}, S_{alt}) to the vertical axis, as shown in Figure 5.5. It is usually easier, however, to use the simple formula:

$$S_{eq} = \frac{S_{alt}}{1 - \dfrac{S_{mean}}{S_u}} \tag{5.3}$$

Where S_{eq} is the value of stress to be used in entering the fatigue design curves which include no mean stresses to find the allowable number of cycles. The Code has included maximum mean stress effects in most of the fatigue design curves as subsequently described herein.

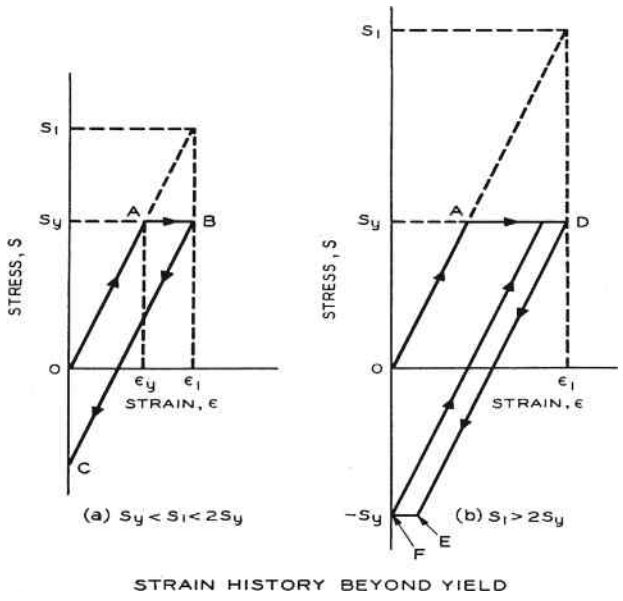


FIG. 5.4 STRAIN HISTORY BEYOND YIELD

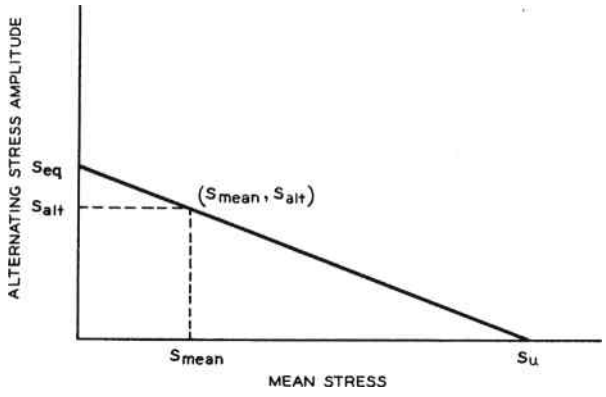


FIG. 5.5 GRAPHICAL DETERMINATION OF S_{eq}

The preceding discussion of mean stress and the shift that it undergoes when yielding occurs lead to another necessary deviation from prior procedures. In applying stress concentration factors in cases with fluctuating stresses, it was common practice to apply the factor to only the alternating component. This procedure is not logical, however, because the material will respond in the same way to a given load regardless of whether the load is steady or fluctuating. A more logical procedure is to apply the concentration factor to both the mean and the alternating component and then consider the reduction that yielding produces in the mean component. It is important to remember that the concentration factor must be applied before the adjustment for yielding is made. The following paragraph illustrates how the common practice of applying the concentration factor to only the alternating component gives a rough approximation to the real situation but can sometimes be unconservative.

Consider a material with 80,000 psi tensile strength, 40,000 psi yield strength and 30×10^6 psi modulus made into a notched bar with a stress concentration factor of 3. The bar is cycled between nominal tensile stress values of 0 and 20,000 psi. Prior practice would call S_{mean} (the mean stress) 10,000 psi and S_{alt} (the alternating component) $\frac{1}{2} \times 3 \times 20{,}000 = 30{,}000$ psi. The stress-strain history of the material at the root of the notch would be, in idealized form, as shown in Figure 5.6. The calculated maximum stress, assuming elastic behavior, is 60,000 psi. The basic value of mean stress, S'_{mean}, is 30,000 psi, but because $S_{alt} + S'_{mean} = 60{,}000$ psi $> S_y$ and $S_{alt} = 30{,}000$ psi $< S_y$,

$$S_{mean} = S_y - S_{alt} = 40{,}000 - 30{,}000 = 10{,}000 \text{ psi}$$

and

$$S_{eq} = \frac{30{,}000}{1 - \dfrac{10{,}000}{80{,}000}} = 34{,}300$$

It so happens that, for the case chosen, the former practice gives exactly the same result as the Code method. Thus, yielding during the first cycle was seen as justification for the common practice of ignoring the stress concentration factor when determining the mean stress component. The former practice, however, would give the same result regardless of the yield strength of the material; whereas the Code method gives different mean stresses for different yield strengths. For example, if the yield strength is 50,000 psi, S_{mean} would be 20,000 psi and S_{eq} by the Code method would be 40,000 psi. The common practice would give 34,300 psi for S_{eq} and too large a number of cycles would be allowed.

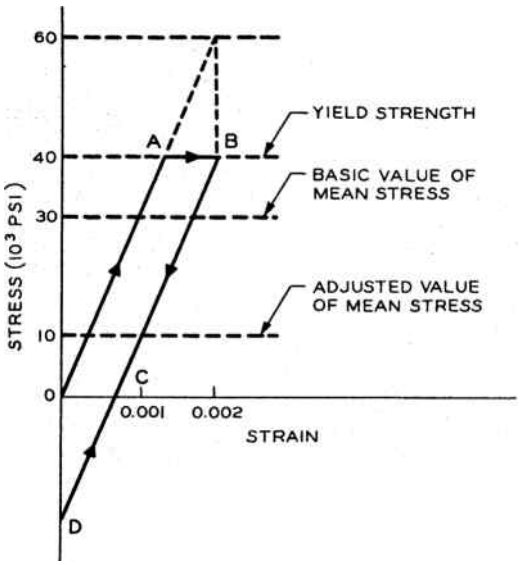


FIG. 5.6 IDEALIZED STRESS VS. STRAIN HISTORY

For parts of the structure, particularly if welding is used, the residual stress may produce a value of mean stress higher than that calculated by the procedure. Therefore, it was found to be advisable and also much easier to adjust the fatigue curve downward enough to include the maximum possible effect of mean stress. It will be shown here that this adjustment is small for the case of low and medium-strength materials.

As a first step in finding the required adjustment of the fatigue curve, let us find how the mean stress affects the amplitude of alternating stress that is required to produce fatigue failure. In the modified Goodman diagram of Figure 5.3 it may be seen that at zero mean stress, the stress amplitude for failure in N cycles is designated S_N. As the mean stress increases along OC', the amplitude of alternating stress decreases along the line EC. If we try to increase the mean stress beyond C', yielding occurs and the mean stress reverts to C'. Therefore, C' represents the highest value of mean stress which has any effect on fatigue life. Since S'_N in Figure 5.3 is the alternating stress required to produce failure in N cycles when the mean stress is at C', S'_N is the value to which the point on the fatigue curve at N cycles must be adjusted if the effects of mean stress are to be ignored. From the geometry of Figure 5.3, it can be shown that:

$$S'_N = S_n\left[\frac{S_u - S_y}{S_u - S_N}\right] \quad \text{for} \quad S_N < S_y \tag{5.4}$$

When N decreases to the point where $S_N \geq S_y$, then $S'_N = S_N$ and no adjustment of this region of the curve is required.

5.5 FATIGUE FAILURE DATA

Figures 5.7, 5.8, and 5.9 show the fatigue data that was used to construct the original fatigue design curves used in the Code. This data is quite useful in the fatigue analysis of aged equipment.

In each case the solid line is the best-fit failure curve for zero mean stress and the dotted line is the curve adjusted in accordance with Equation 5.4. Figure 5.9 for stainless steel and nickel-chrome-iron alloys has no dotted line because the fatigue limit is higher than the yield strength over the whole range of cycles.

In Section III a single design curve is used for carbon and low-alloy steels below 80,000 psi ultimate tensile strength because, as noted from Figures 5.7 and 5.8, the adjusted curves for these classes of material are nearly identical.

For the case of high-strength, heat treated bolting materials, heat treatment increases the yield strength of the material much more than it increases either the ultimate strength, S_u, or the fatigue limit, S_N. Inspection of Equation 5.4 shows that for such cases, S'_N becomes a small fraction of S_N and thus the correction for the maximum effect of mean stress becomes unduly conservative.

Test data indicate that use of the Peterson cubic equation:

$$S_{eq} = \frac{7S_a}{8 - \left(1 + \dfrac{S_{mean}}{S_a}\right)^3}$$

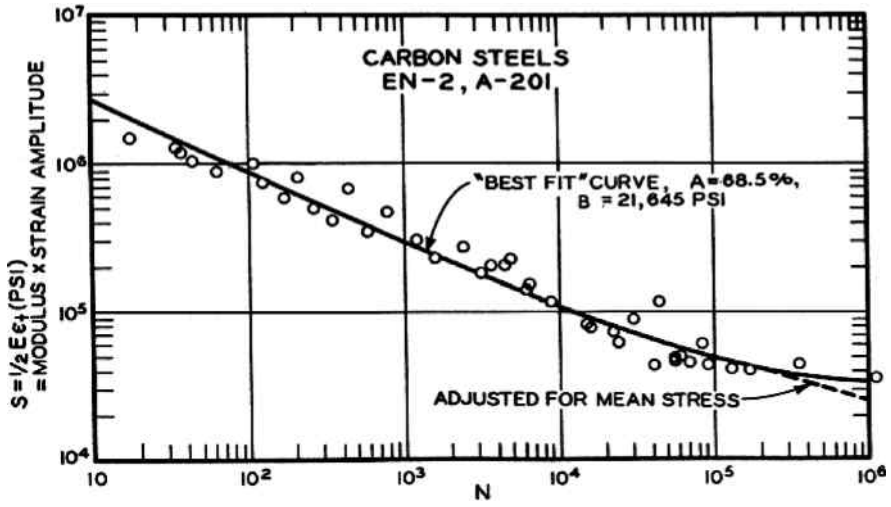


FIG. 5.7 FATIGUE DATA — LOW ALLOY STEELS [4]

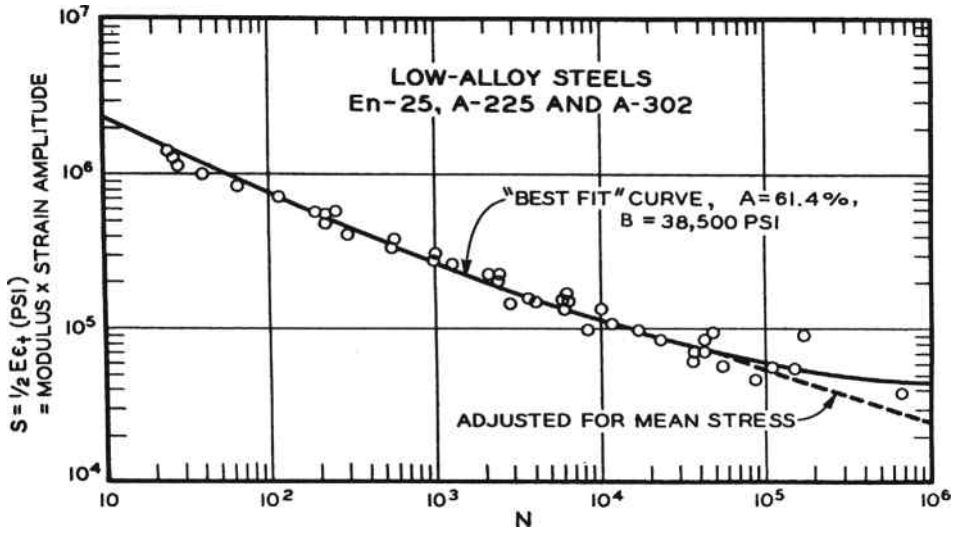


FIG. 5.8 FATIGUE DATA — LOW ALLOY STEELS

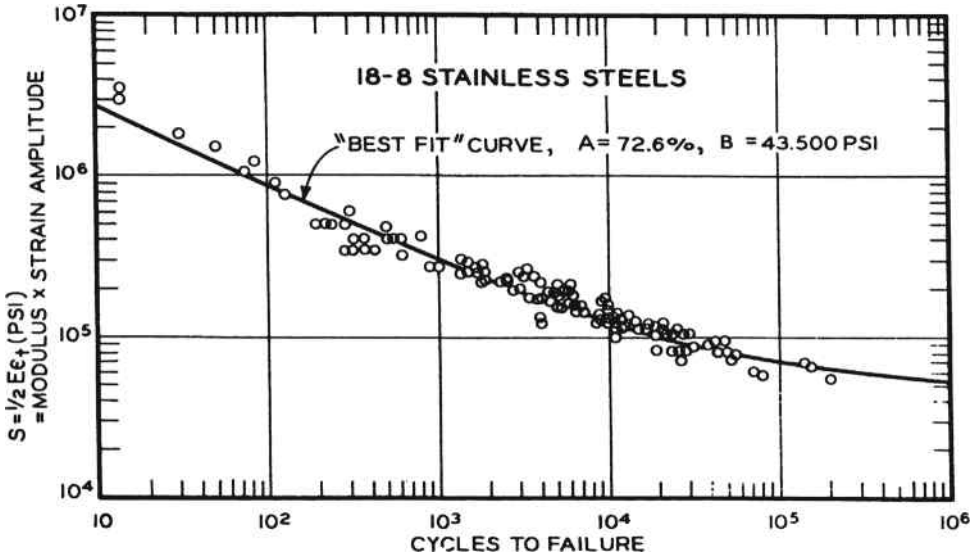


FIG. 5.9 FATIGUE DATA — STAINLESS STEELS

results in an improved method for high strength bolting materials. This equation has been used in preparing design fatigue curves for such bolts [7].

5.6 PROCEDURE FOR FATIGUE EVALUATION

The detailed step-by-step procedure for determining the design life for the fluctuation of stresses at a given point is given in detail in the Code. This procedure is based on the maximum shear stress theory of failure and consists of finding the amplitude (half full range) through which the maximum shear stress fluctuates. Just as in the case of the basic stress limits, stress differences and stress intensities (twice maximum shear stress) are used in place of the shear stress itself.

There are three principal stresses, σ_1, σ_2, σ_3, and three stress differences, S_{12}, S_{23}, S_{31} at each point in the vessel at any given time, and stress intensities are usually considered to not have direction or sign, just as for the strain energy of distortion (Mises Theory). When considering fluctuating stresses, however, this concept of non-directionality can lead to errors when the sign of the shear stress changes during the cycle. Therefore, the range of fluctuation must be determined from the stress differences in order to find the full algebraic range. The alternating stress intensity, S_{alt}, is the largest of the amplitudes of the three stress differences. This feature of being able to recognize directionality and thus find the algebraic range of fluctuation when the stresses are reversed is one reason why the maximum shear stress theory, rather than the strain energy of distortion theory is used.

When the directions of the principal stresses change during the cycle (regardless of whether the stress differences change sign), the non-directional strain energy of distortion theory fails to track the range of stress acting on a particular plane. It is the corresponding range of shear strain that produces fatigue damage, which Findley and his associates demonstrated experimentally by producing fatigue failures in a rotating specimen compressed across a diameter [8]. The load was fixed while the specimen rotated; thus, the principal stresses rotated, but the strain energy of distortion remained constant. The procedure used in the Code is consistent with the results of Findley's tests and uses the range of shear stress on a fixed plane as the criterion of failure. The procedure reveals the effect of rotation of the principal stresses by considering only the *changes* in shear stress that occur in each plane between the two extremes of the stress cycle.

5.7 CUMULATIVE DAMAGE

In many cases a point on a vessel will be subjected to a variety of stress cycles during its lifetime. The cumulative effect of these various cycles is evaluated by means of a linear damage relationship in which it is assumed that if N_1 cycles produce failure at a stress level S_1, the n_1 cycles at the same stress level would exhaust the fraction n_1/N_1 of the total life. Failure occurs when the cumulative usage factor, which is the sum $n_1/N_1 + n_2/N_2 + n_3/N_3 + \ldots\ldots$ is equal to 1.0. Other hypothesis for estimating cumulative fatigue damage have been proposed, some of which have been shown to be more accurate than the linear damage assumption. However, better accuracy could be obtained only if the sequence of the stress cycles were known in considerable detail, and this information is not likely to be known with any certainty at the time the vessel is being designed.

Tests have shown that the linear assumption is quite good when cycles of large and small stress magnitude are fairly evenly distributed throughout the life of the member, and therefore this assumption was considered to cover the majority of cases with sufficient accuracy. It is of interest to note that for unnotched geometries, having the larger stress cycles near the beginning of life tends to accelerate failure because cracks are initiated early in life and can propagate under lower stress amplitudes. If the smaller stresses are applied first and progressively higher stresses follow, the cumulative usage factor can be "coaxed" up to a value as high as 4 or 5. Load sequence effects are reversed for severely notched geometries where notch blunting can occur before crack initiation.

The term "crack initiation" is used to mean that a crack has been generated that is large enough to be treated using continuum fracture mechanics and ignoring microstructural barriers. The process of "initiating" such a crack is itself a crack propagation process involving the growth of small cracks across microstructural barriers.

When stress cycles of various amplitudes are intermixed through the life of the vessel, correct identification of the range and number of repetitions of each type of cycle is important. It must be remembered that a small increase in stress range can produce a large decrease in fatigue life, and this relationship varies for different portions of the fatigue curve. Therefore the effect of superposing two stress amplitudes cannot be evaluated by adding the usage factors obtained from each amplitude by itself. The stresses must be added before calculating the usage factors. Consider, for example, the case of a thermal transient that occurs in a pressurized vessel. Suppose that at a given point the pressure stress is 20,000 psi tension and the added stress from the thermal transient is 70,000 psi tension. If the thermal cycle occurs 10,000 times during the design life and the vessel is pressurized 1000 times, the usage factor should be based on 1000 cycles with a range from zero to 90,000 psi and 9000 cycles with a range from 20,000 psi to 90,000 psi.

5.8 EXEMPTION FROM FATIGUE ANALYSIS

Fatigue analyses are not required for vessels that are not subjected to cyclic operation. However, there is no obvious borderline between cyclic and non-cyclic operation. No operation is completely non-cyclic, since startup and shutdown together form a cycle. Therefore, fatigue cannot be completely ignored, and the Code gives a set of rules which may be used to justify the bypassing of the detailed fatigue analysis for vessels in which the danger of fatigue failure is remote. The application of these rules requires only that the designer know the specified pressure fluctuations and have some knowledge of the temperature differences which will exist between different points in the vessel. It is not essential for the designer to determine stress concentration factors or to calculate cyclic thermal stress ranges. But the designer must ensure that the basic stress limits of the Code are met, which may involve calculation of the most severe thermal stresses. The rules for exemption from a fatigue analysis are based on a set of assumptions, some of which are highly conservative and some of which are nonconservative. The conservatisms are believed to outweigh the nonconservatisms. These assumptions are:

(1) The worst geometrical stress concentration factor to be considered is 2. This assumption is unconservative because K = 4 is specified for some geometries.
(2) The concentration factor of 2 occurs at a point where the nominal stress is 3 S_m, the highest allowable value of primary-plus-secondary stress. This is a conservative assumption. The net result of assumptions (1) and (2) is that

the peak stress from pressure is assumed to be $6S_m$, which appears to be a safe assumption for a good design.

(3) *All* significant pressure cycles and thermal cycles have the same stress range as the *most severe* cycle. This is a highly conservative assumption. (A "significant" cycle is defined as one which produces a stress amplitude higher than the endurance limit of the material).

(4) The highest stress produced by a pressure cycle does not coincide with the highest stress produced by a thermal cycle. This assumption is unconservative and must be balanced against the conservatism of assumption (3).

(5) The calculated stress produced by a temperature difference ΔT between two points does not exceed $2E\alpha\Delta T$, but the peak stress is raised to $4E\alpha\Delta T$ because of the assumption that a K value of 2 is present. This assumption is conservative, as evidenced by the following examples of thermal stress:

(a) For the case of a linear thermal gradient through the thickness of a vessel wall, if the temperature difference between the inside and the outside of the wall is ΔT, the surface thermal stresses are

$$\sigma = \frac{E\alpha\ \Delta T}{2(1 - \nu)} = .715E\alpha\Delta T \qquad (\text{for } \nu = 0.3)$$

(b) When a vessel wall is subjected to a sudden change of temperature, ΔT, so that the temperature change only penetrates a short distance into the wall thickness, the thermal stress is

$$\sigma = \frac{E\alpha\Delta T}{1 - \nu} = 1.43E\alpha\Delta T \qquad (\text{for } \nu = 0.3)$$

(c) When the average temperature of a nozzle is ΔT degrees different from that of the rigid wall to which it is attached, the upper limit to the magnitude of the discontinuity stress is

$$\sigma = 1.83\ E\alpha\Delta T \qquad (\text{for v 5 0.3})$$

Thus, the coefficient of $E\alpha\Delta T$ is always less than the assumed value of 2.0.

When two points in a vessel with temperatures that differ by ΔT are separated from each other by more than $2\sqrt{Rt}$, there is sufficient flexibility between the two points to produce a significant reduction in thermal stress. Therefore only temperature differences between "adjacent" points need be considered.

5.9 EXPERIMENTAL VERIFICATION OF DESIGN FATIGUE CURVES

The design fatigue curves are based primarily on strain-controlled fatigue tests of small polished specimens. A best fit to the experimental data was obtained by applying the method of least squares to the logarithms of the experimental values. The design stress values were obtained from the best-fit curves by applying a factor of two on stress or a factor of twenty on cycles, whichever was more conservative at each point. These factors were intended to cover such effects as environment, size effect, and scatter of data, and thus it is not to be expected that a vessel will actually operate safely for twenty times its design life.

The appropriateness of the chosen safety factors for fatigue was originally demonstrated by tests conducted by the Pressure Vessel Research Committee (PVRC [11] and [26]). In these tests 12-in. diameter model vessels and 3 ft. diameter full-size vessels were tested by cyclic pressurization after a comprehensive strain gage survey was made of the peak stresses. Figure 5.10 shows a

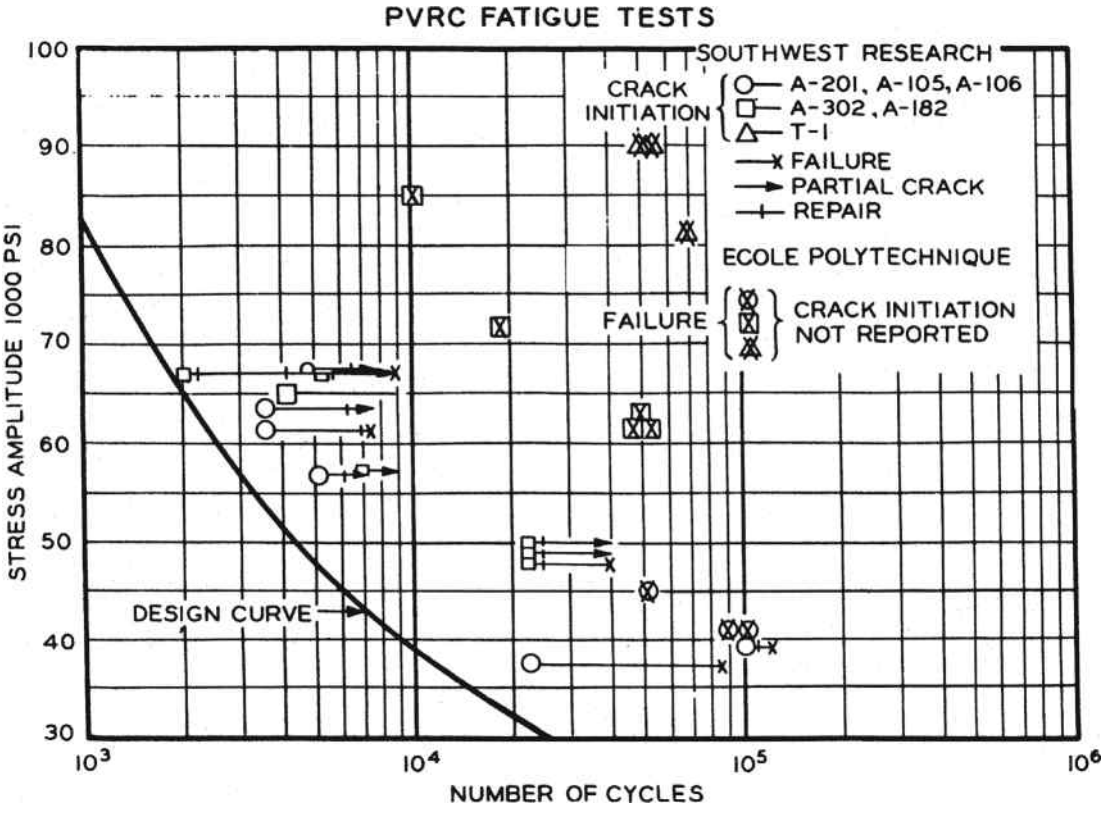


FIG. 5.10 PVRC FATIGUE TESTS

summary of the PVRC test results compared to the Code design fatigue curve for carbon and low-alloy steels. It is seen that no cracks large enough to be detected at the time of the tests occurred below the allowable stress. Furthermore, no crack progressed through a vessel wall in less than three times the allowable number of cycles. It is also well known that cracks a few thousandths of an inch deep occur below the fatigue design curve in the low cycle regime. Lawton [12] provides additional data.

5.10 USE OF MEAN STRESS CORRECTIONS AND CYCLIC STRESS-STRAIN PROPERTIES

A compilation and analysis of fatigue data for pressure vessel alloys is given by Jaske and O'Donnell [13]. Cyclic stress-strain properties, mean stress effects and other design factors are considered.

Some austenitic alloys can cyclically harden such that the 0.2 percent offset yield strength can increase to 150% or 200% of the monotonic value as illustrated in Figure 5.11. This situation is further complicated by the fact that the history of prior strain levels has a significant effect on the subsequent stress-strain response of austenitic alloys. Step tests carried out on 304 stainless steel gave the upper curve results shown in Figure 5.11, and similar results have been obtained at 800°F on both 304 and 316 stainless steel.

The constant amplitude cyclic curve is lower at the low strain ranges of interest, as shown. Periodic overstrains tend to keep the material in the cyclically hardened condition. Cyclic stress-strain behavior is important in evaluating plastic strain concentration effects and mean stress effects on fatigue.

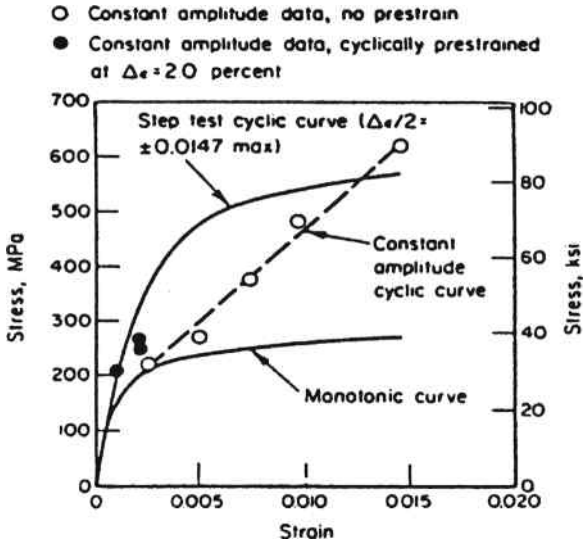


FIG. 5.11 STABLE (AT N/2) CYCLIC STRESS-STRAIN RESPONSE OF TYPE 304 STAINLESS STEEL AT 21°C (70°F) [13]

In contrast, Alloy 718 tends to cyclically soften as shown in Figure 5.12. However, since it is primarily strengthened by heat

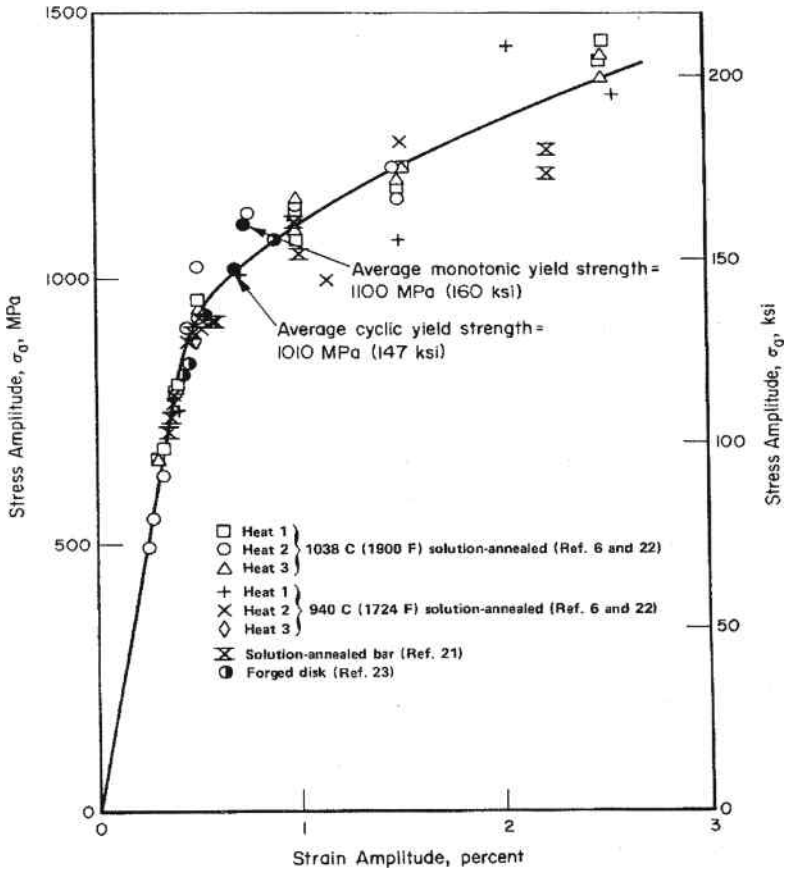


FIG. 5.12 STABLE (AT N/2) CYCLIC STRESS-STRAIN RESPONSE OF NICKEL-CHROMIUM ALLOY 718 AT ROOM TEMPERATURE

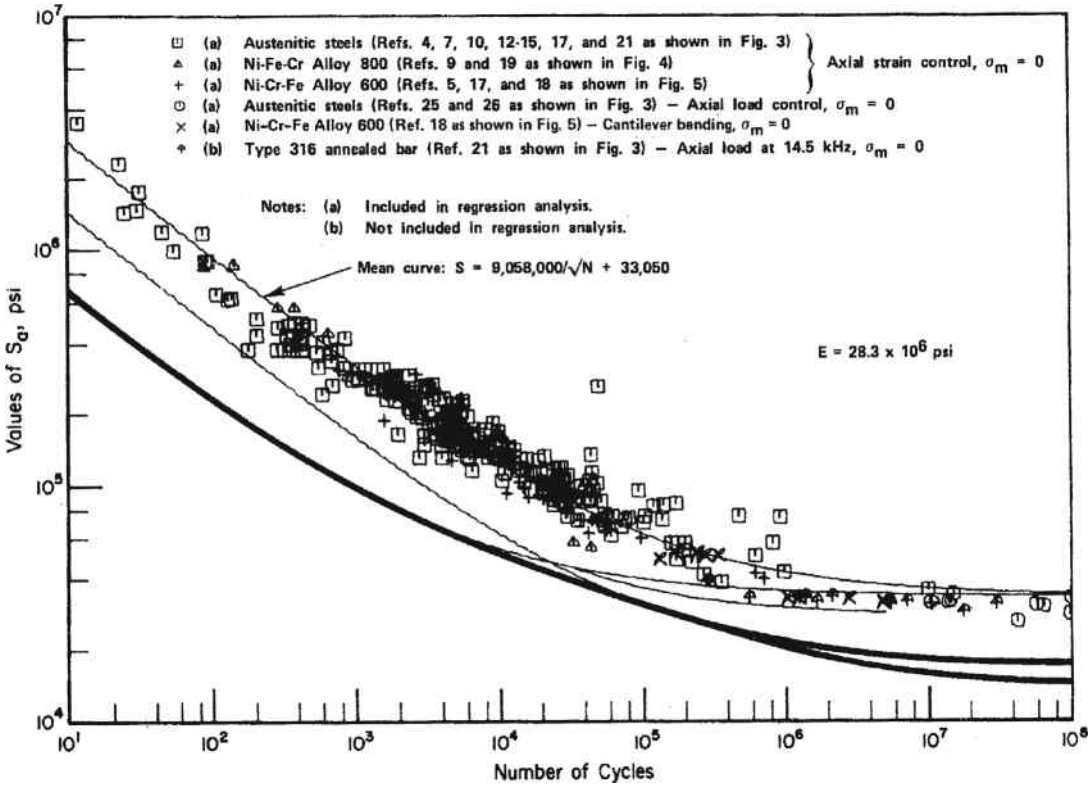


FIG. 5.13 FATIGUE CURVE FOR AUSTENITIC STAINLESS STEELS AND NICKEL-IRON-CHROMIUM ALLOYS 600 AND 800 [13]

treatment rather than cold working, cyclic history effects for this alloy are not as severe.

The temperature dependence of the fatigue design curves in the Code is introduced via a required elastic modulus ratio correction. The Code requires that the S_{alt} values used to enter the fatigue design curves be multiplied by the ratio of the room temperature elastic modulus given on the curves to the temperature dependent elastic modulus used in the design analyses.

This correction is used regardless of whether the temperature varies during the cycle. Accordingly, the strain controlled fatigue data obtained over the entire range of temperature from 70°F to 800°F are all plotted using the room temperature modulus given on the curves.

The lack of conservatism in the original Code fatigue design curve for austenitic stainless steels is particularly prominent in the high-cycle regime. Because the original curve ended at 10^6 cycles, it was left unchanged, but a new fatigue design curve starting at 10^6 cycles and extending to 10^{11} cycles was added. The sharp drop in the allowable stress range between 10^6 and 10^7 cycles in the new curve was intended to compensate for the lack of conservatism in the curve ending at 10^6 cycles.

The fatigue behavior of Ni Cr alloy 718 was found to be significantly different than for the materials of Figure 5.13. The 86 data points which were available were analyzed independently. The high yield to ultimate strength ratio of this alloy indicates that mean stress effects can be pronounced. Curves for various mean stresses are derived in [13].

5.11 CURRENT CODE DETERMINATIONS FOR NEW FATIGUE DESIGN LIFE EVALUATION CURVES

Experience with cracking from mechanical vibrations and high frequency thermal mixing has placed new emphasis on the very high cycle regime. Fatigue strength in this regime is more sensitive to material imperfections, weldment details and mean stresses. Fatigue design curves that are intended to cover the as-fabricated imperfections show fatigue strength reductions continuing beyond 10^6 cycles. For carbon and low alloy steels, the reduction is about 40% from 10^6 to 10^{11} cycles, and fatigue design curves for this regime were recently added to the Code.

Crack propagation technology has progressed to the point where cracks found during in-service inspections can be reliably evaluated using fracture mechanics. Crack propagation technology appears destined to play a major role in the fatigue design methods of the future. Of course, conventional unnotched fatigue specimens are tested well into the plastic regime where elastic-plastic fracture mechanics is needed. J-integral solutions for conventional fatigue test specimens are discussed in [14] through [18].

With respect to fatigue design life criteria, the ASME Code has long played a key role in setting design allowables and criteria world-wide. Recent work is aimed at keeping the Code current with advancing technology (References [19] through [24]).

Determination No. 1 Safety margins for the Primary Stress Allowables in pressure vessels are currently being reduced in Section VIII of the ASME Code in recognition of improved technology. With respect to the fatigue design life, PVRC Committees and the Subgroup on Fatigue Strength have reviewed the safety margins and concluded that they are smaller in terms of probability of failure and reliability than the Primary Stress allowable margins, and that no basic Code safety margin reductions can be justified for the fatigue design life.

Determination No. 2 The use of finite element analyses has allowed much more accurate thermal transient stress analyses for new pressure vessel and reactor component designs. This has taken a great deal of conservatism out of component fatigue

design calculations previously performed using conservative approximations. Accordingly, it is necessary to use accurate fatigue design curves which include environmental effects in modern finite element based design analyses.

Determination No. 3 The individual factors for surface finish, environmental effects, size effects and scatter in the data which were used to develop the current fatigue design curves in the Code are not accurate. However, the net factors of 2 on stress amplitude or 20 on cycles to failure, whichever is more limiting in each regime, when applied to the mean failure curve, provide the desired consideration of these combined factors, except for the environmental and K_e issues described in Section 5.13 herein.

Determination No. 4 The fatigue design curves in the Code are based on data for complete failure and not on crack initiation data. Conventional unnotched strain controlled fatigue specimens are only about 0.25 inches in diameter. Following crack initiation, the fatigue cracks propagate at an accelerating rate in Mode 2 tensile crack propagation and achieve very high propagation rates at a depth of 3 mm (0.12 inches), or half the conventional fatigue specimen diameter. Cracks larger than this propagate at a very high rate. Accordingly, the cycles to failure are not substantially greater for fatigue test specimens or thick walls which are an order of magnitude heavier than conventional fatigue specimens. Further, failure data obtained based on a 25 percent load drop in strain-controlled testing are equivalent to complete failure because the difference in cycles to complete failure is negligibly small. (Of course, the situation is different in notched specimens or components, where the fatigue strength reduction factor is a function of geometry.)

Determination No. 5 Analyses of fatigue data and fatigue failures can most effectively be performed by treating crack initiation as the development of a crack large enough to be treated using continuum mechanics without regard to microstructural barriers such as grain boundaries, triple points and the like. The total failure mechanism is then the process of crack initiation, propagation, and final rupture. A schematic illustration of the crack initiation and propagation behavior is shown in Figure 5.14, modified from [25]. The initiation stage involves the growth of microstructurally small cracks, characterized by decelerating crack growth rates [region A-B in Figure 5.14]. This initiation stage is quite sensitive to microstructure. Microcracks too small to grow through microstructural barriers, or subjected to low alternating stress levels, are nonpropagating cracks, as shown in Figure 5.14. Larger microcracks, or those subjected to higher cyclic stress levels, propagate from grain boundaries across the microstructural barriers. They then begin to propagate at an accelerating rate as Stage II tensile cracks. They are characterized by striated crack growth with the fracture surfaces normal to the maximum principal stress. These cracks are called mechanically small cracks, and they show little or no influence of microstructure. They can be treated using fracture mechanics continuum theory, using either the linear elastic fracture mechanics stress intensity, ΔK; or elastic plastic fracture mechanics J-integral (ΔJ) approaches.

Determination No. 6 In the low cycle regime, the cycles to failure are dominated by crack propagation, as crack initiation occurs at a small fraction of the cycles-to-failure. In the high cycle regime, once crack initiation occurs, only a small portion of the cycles-to-failure remains. Thus, crack propagation dominates failure life in the low cycle regime and the cycles required for crack initiation dominate life in the high cycle regime.

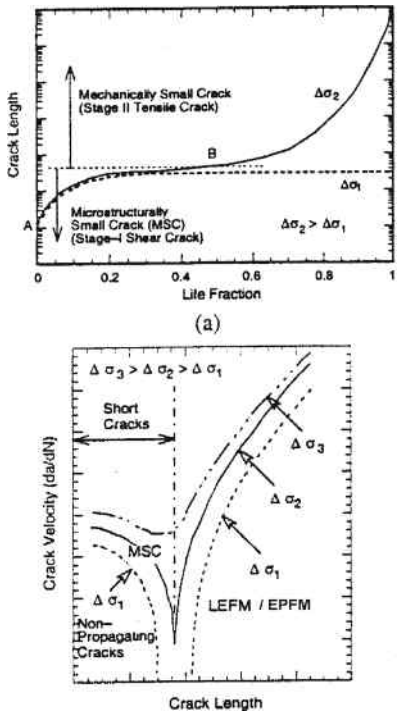


FIG. 5.14 SCHEMATIC ILLUSTRATION OF (A) GROWTH OF SHORT CRACKS IN SMOOTH SPECIMENS AS A FUNCTION OF FATIGUE LIFE FRACTION AND (B) CRACK VELOCITY AS A FUNCTION OF CRACK LENGTH. LEFM = LINEAR ELASTIC FRACTURE MECHANICS EPFM = ELASTIC-PLASTIC FRACTURE MECHANICS

Determination No. 7 The new fatigue design curves under development are intended to maintain the safety margins inherent in the existing air curves. One of the most significant inaccuracies or deficiencies in the current fatigue design criteria in the ASME Code is the treatment of stress raisers and notches. Fatigue strength reduction factors for many notches have been experimentally determined, as, for example, bolting.[1] The Code does not currently include much guidance on the factors that should be used.[2] By using the high surface strain ranges at notches (converted to fictitious stress amplitudes) the current method does not take credit for the reduction in crack growth rate that occurs when the crack grows past the shadow of the notch. This introduces considerable over-conservatism in some cases. The degree of this conservatism is reduced by the fact that the fatigue crack may be quite large in fracture mechanics terms by the time it gets beyond the notch effect, given that the notch itself tends to add to the effective crack length for ΔK or ΔJ purposes. Fatigue strength reduction factors can be derived for any geometry provided

[1]Of course much work remains to be done on bolting fatigue including consideration of rolled vs. cut threads, and recognition of potentially high strain concentrations in heat treated bolts with high yield to tensile strength ratios.

[2]The requirement to use a factor of 4 for fillet welds is an example of useful guidance.

that the crack initiation and propagation can be quantified. The ratio of the stress amplitude for the unnotched geometry giving the same cycles-to-failure, divided by the nominal stress amplitude for the notched geometry, is equal to the fatigue strength reduction factor.

5.12 PROPOSED NEW FATIGUE DESIGN CURVES FOR AUSTENITIC STAINLESS STEELS, ALLOY 600 AND ALLOY 800 IN AIR

The existing ASME fatigue design curves combine austenitic stainless steels, nickel-chromium-iron alloys, nickel-iron-chromium alloys, and nickel-copper alloys into a single fatigue design curve. It has long been recognized that the Alloy 800 and Alloy 600 fatigue properties are significantly different than series 3XX high alloy steel Properties [13]. The new fatigue design curves proposed for air herein recognize this difference.

Moreover, the existing fatigue design curve for the series 3XX austenitic stainless steels was previously recognized as being too high in the regime from about 10^2 to 10^6 cycles [13]. In order to correct this problem, an extension to the fatigue design curve was added, starting at 10^6 cycles and extending to 10^{11} cycles. This curve reduces the allowable stress amplitude between 10^6 and 10^8 cycles by a factor of 2, and was intended to provide protection against high cycle thermal mixing and vibrations. However, corrections for cyclic loading in the 10^2 to 10^6 range were not made.

Existing fatigue data for austenitic stainless steels in air showed the need to revise the existing ASME Code fatigue design curves for air. Figures 5.15, 5.16, and 5.17 show compilations of available data for austenitic stainless steels. Figure 5.15 shows the room temperature data, Figure 5.16 shows the data at 550 ºF and Figure 5.17 shows a compilation.

The new best fit curves and the proposed new design curve are also shown on all figures. These failure curves were used to derive the new design curves including maximum mean stress effects.

Figure 5.18 herein shows a comparison of the existing and new fatigue design curves for austenitic stainless steels in air.

The fatigue design curves for nickel—chromium—iron Alloy 800 and Alloy 600 in air were lumped together with the austenitic stainless steels in the previous versions of the Code. However, the fatigue properties are significantly different and a Determination was made that they should be separated. The data for Alloy 800 and Alloy 600 are shown in Figures 5.19A and 5.19B from [13].

Figure 5.20 herein shows the proposed new Fatigue design curve for Low Strength Nickel Based Alloys, Alloy 600 and Alloy 800, for temperature not exceeding 800ºF (427ºC). Note the warning about stress corrosion cracking in Alloy 600 at elevated temperatures.

5.13 DEVELOPMENTS IN ENVIRONMENTAL FATIGUE DESIGN CURVES FOR CARBON AND LOW ALLOY STEELS IN HIGH TEMPERATURE WATER

High temperature (>300ºF, 149ºC) water has been found to greatly accelerate fatigue crack growth rates in carbon, low alloy, and stainless steels, to reduce their S-N fatigue strengths quite significantly.

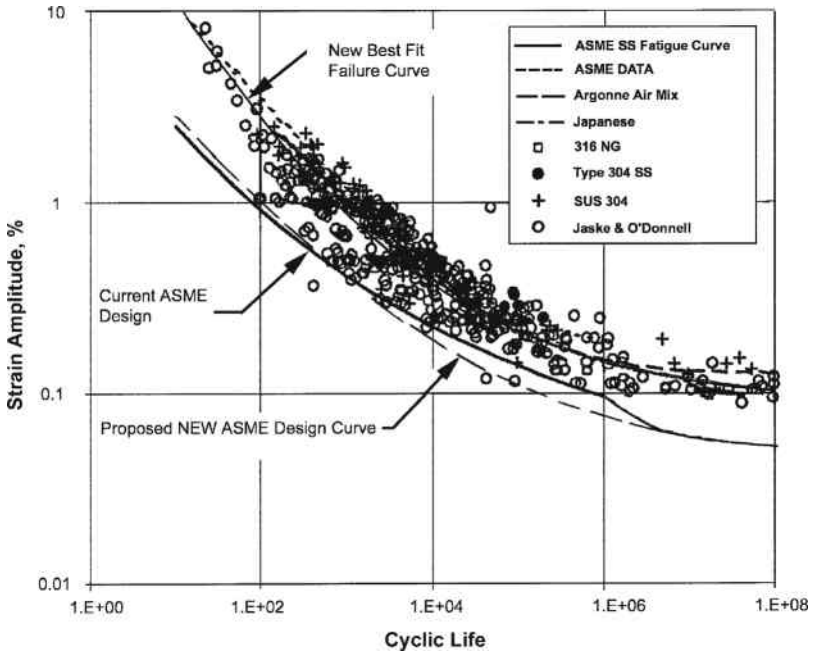


FIG. 5.15 PVRC DATA FOR AUSTENITIC STAINLESS STEELS IN AIR AT ROOM TEMPERATURE WITH DATA FROM JASKE AND O'DONNELL

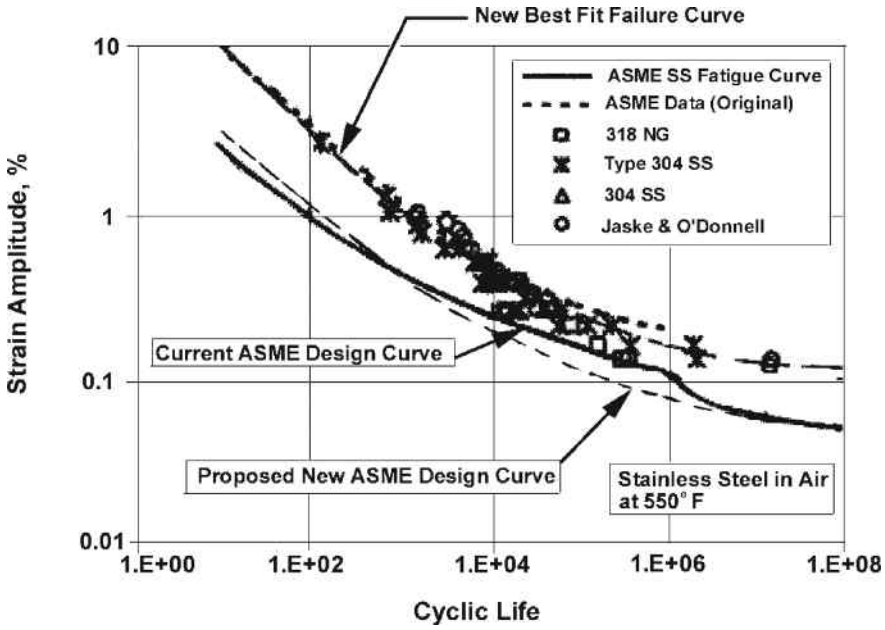


FIG. 5.16 PVRC DATA FOR AUSTENITIC STAINLESS STEEL IN AIR AT 288°C WITH DATA FROM JASKE AND O'DONNELL

Current ASME Code fatigue design curves are based entirely on data obtained in air. While a factor of two on life was applied to the air data to account for environmental effects, the actual effects have been found to be an order of magnitude greater in the low cycle regime. A great deal of work has been carried out on these environmental effects by talented investigators worldwide. The ASME Code Subgroup on Fatigue Strength has been working for 25 years on the development of new fatigue design methods and curves to account for high temperature water environmental effects. This effort is intended to formulate proposed new environmental fatigue design curves which maintain the same safety margins as existing Code fatigue design curves for air environments.

It has been known for some time that the low cycle fatigue properties of carbon and low alloy steels can be significantly degraded by elevated temperature water environments. Tests conducted 25 years ago by General Electric [27] and [28] showed that both welded and non-welded material have shown a significantly reduced fatigue performance.

In the 1980's several laboratories worldwide were generating fatigue crack growth rate data in elevated temperature water environments.

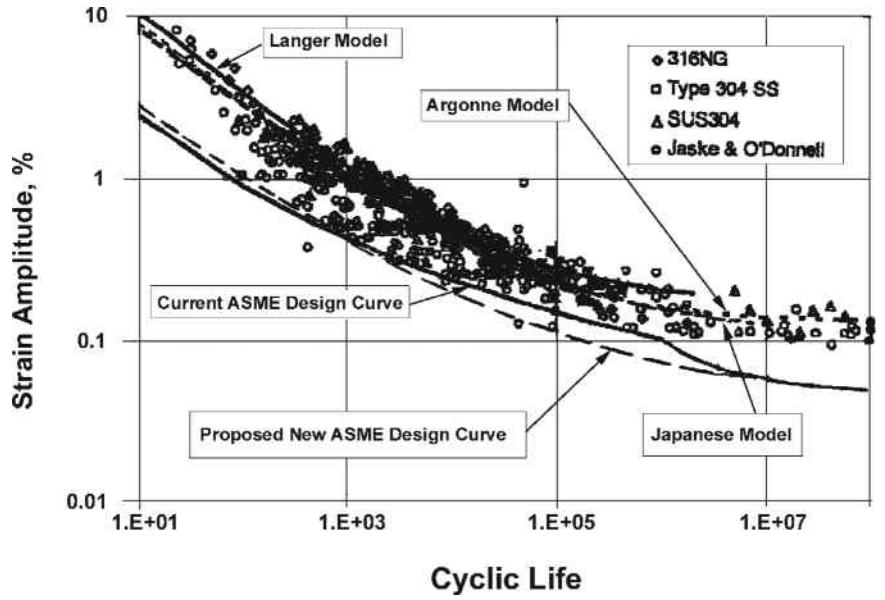


FIG. 5.17 COMPILATION OF STAINLESS STEEL FATIGUE DATA IN AIR FROM WRC BULLETIN 487

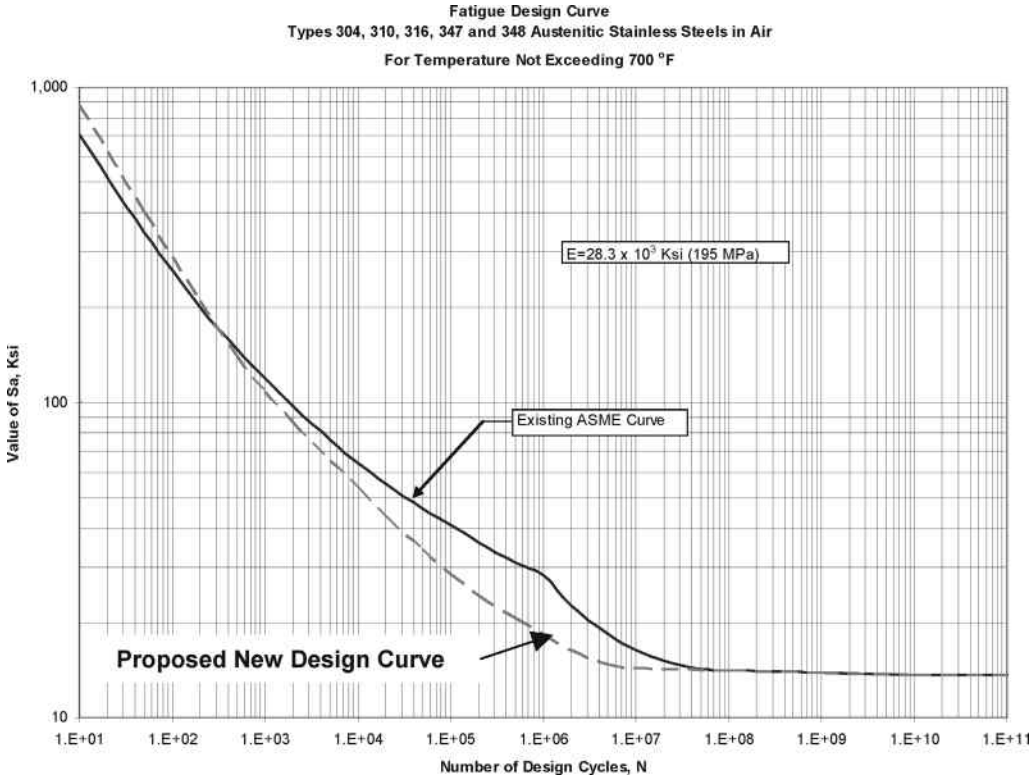


FIG. 5.18

This effort was organized by the International Cooperative Group on Cyclic Crack Growth Rates (ICCGR) and its successor the International Cooperative Group for Environmentally-assisted Cracking (ICG-EAC). Most of this data was included in the EPRI Database on Environmentally-assisted Cracking (EDEAC), [29]. Eason, et. al. [30 and 31], made extensive studies of the EPRI database. Data showing crack growth rates which were a factor of two or so faster in hot water than in air, and which were independent of the strain rate, were considered to represent general corrosion. Such data were largely covered by the factor of 2 on fatigue design life for environmental effects in the Code.

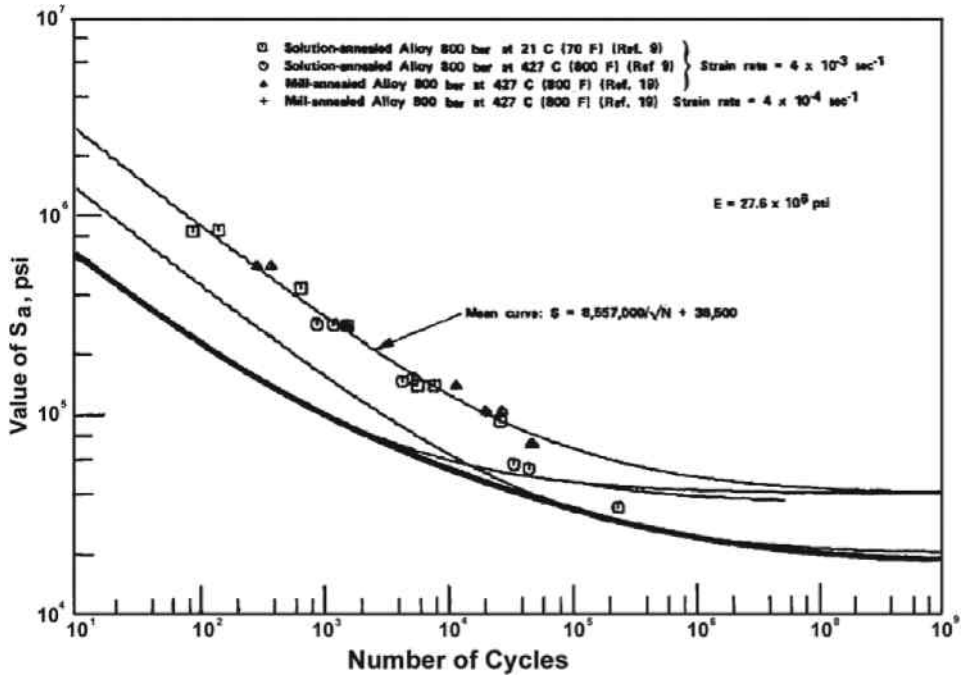


FIG. 5.19 (A) FATIGUE CURVE FOR NICKEL-IRON-CHROMIUM ALLOY 600 FROM O'DONNELL-JASKE

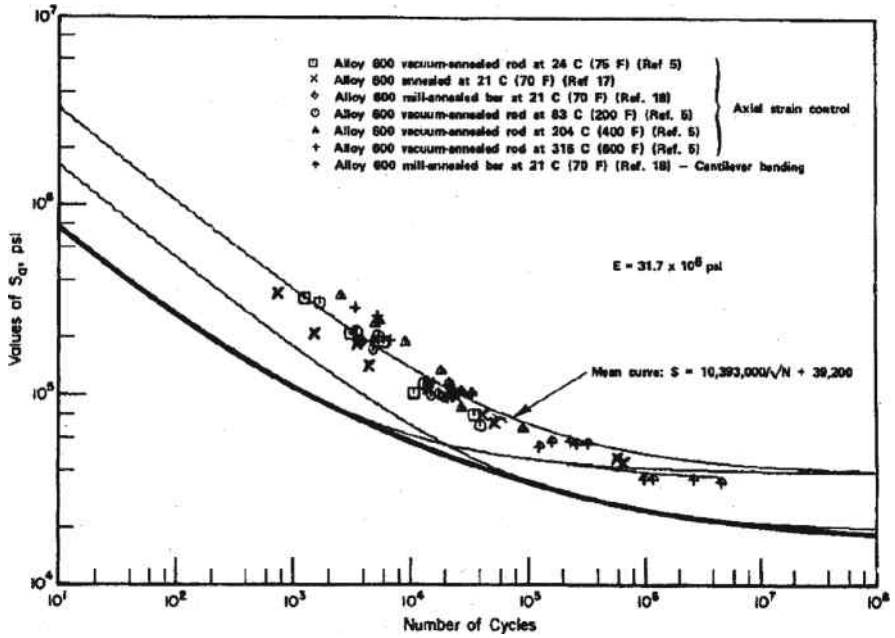


FIG. 5.19 (B) FATIGUE CURVE FOR NICKEL-IRON-CHROMIUM ALLOY 800 FROM O'DONNELL-JASKE

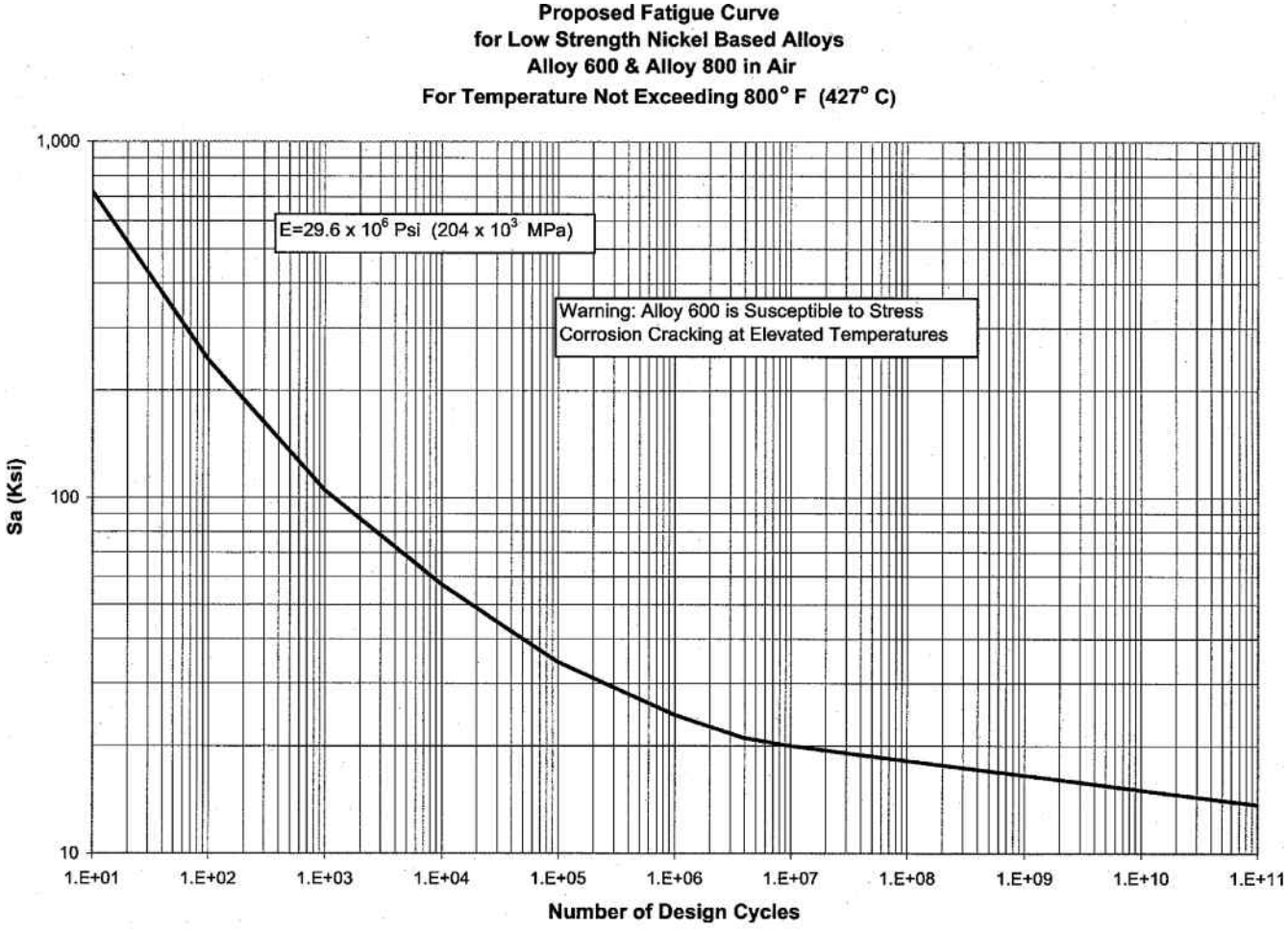


FIG. 5.20

Cracking under conditions where growth rates were 10 to 50 times faster than in air, and strongly dependent on cyclic rate, was referred to as environmentally-assisted cracking (EAC). Conditions which produced high crack growth rates included high material sulfur content, high dissolved oxygen in the water (for carbon and low-alloy steels), low cyclic strain rates, elevated temperature, and high stress intensity ranges. The transition threshold conditions from low general corrosion growth rates to EAC were determined using specimen testing at constant ΔK or ΔJ. Cyclic rate conditions change crack growth rates by an order of magnitude. It was quite apparent that modification to the ASME Code fatigue design method for pressure vessel steels was needed to quantify the effects of elevated temperature water environments.

The ASME Subgroup on Fatigue Strength examined this and other data including corrosion studies being reported worldwide. They determined that the fatigue design curves do not provide the desired margin of safety against failure in two areas:

(1) Elevated temperature water environmental effects were not adequately covered by the factor of 2 on life applied to the air data, and
(2) The simplified Elastic Plastic strain concentration factors K_e then in the Code were not accurate and needed to be corrected. This has subsequently been accomplished.

This determination was presented to the ASME Code Subcommittee on Design which voted unanimously in 1988 to change its policy on corrosion effects. They directed the Subgroup on Fatigue Strength to develop new water environmental fatigue design curves.

Important technical issues directly involved include: (1) the extensive use of finite element analysis which removes much of the conservatism previously introduced by simplified hand calculations; (2) metallurgical notch issues associated with material chemistry and heat treatment, weldment and HAZ microstructure and the resulting differences in properties; (3) fabrication issues involving residual stresses, and imperfections acting as potential crack starters; (4) operation issues including water coolant chemistry, corrosion potential and oxygen content, transient rates, and cyclic loading complexities; (5) crevice corrosion effects; (6) operating temperatures; (7) applied thermal and mechanical stress levels; (8) stress corrosion cracking issues; and (9) corrosion accelerated crack propagation.

References [15], [20] and [21] show that just the difference in crack growth rates in high temperature water require that the S-N fatigue design curves in the Code which are based on air data alone needed to be corrected. Starting with a compilation of all the strain controlled pressure vessel fatigue data available worldwide [see light data points in Figure 5.22] J-Integral elastic-plastic fracture mechanics were used to back-calculate the crack growth from the known cycles-to-failure based on the ΔK air curves in Section XI of the ASME Code. The crack growth rates in high temperature water were then used to calculate the growth of cracks from crack initiation to failure of the individual specimens.

Crack growth rate tests conducted in dry air or a vacuum show little dependence on the rate of the applied cyclic load. However, crack growth rate experiments conducted in aggressive environments such as high temperature water show an important dependence on the rate of cycling as well as the presence of mean stress. Strain rate and mean stress effects on S-N fatigue life in high temperature water environments can be investigated using appropriate crack growth rate correlations. Crack growth rate correlations which include strain rate effects are shown in Figure 5.21 from PVRC work [32]. Strain rate and mean stress are accounted for in these correlations through the rise time of tensile loading, T_R, or θ,

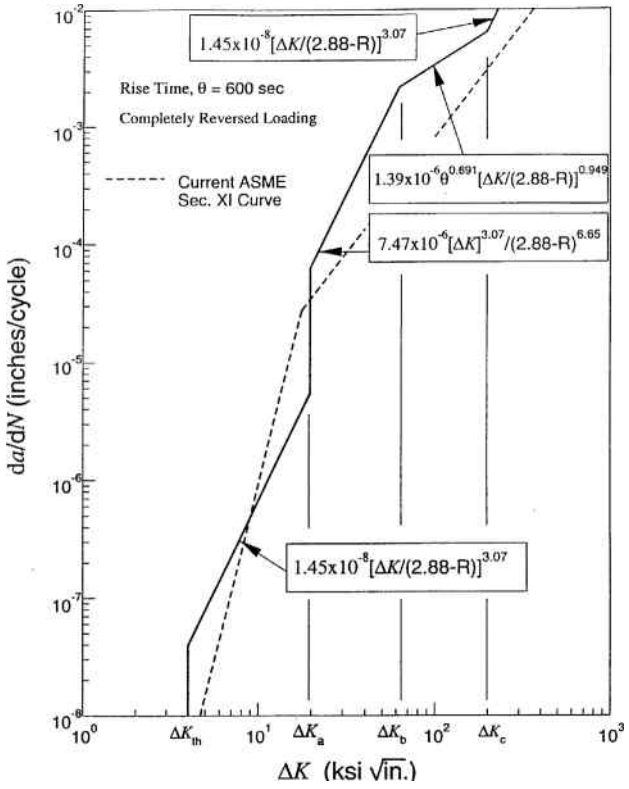


FIG. 5.21 PROPOSED REFERENCE FATIGUE CRACK GROWTH CURVES FOR LOW ALLOY FERRITIC MATERIAL IN WATER ENVIRONMENTS [15] FOR A RISE TIME OF 10 MIN. WITH R = −1

and the R-ratio. The curves of Figure 5.21 were obtained assuming a rise time of 600 sec and an R-ratio of 1. This rise time is representative of cyclic conditions experienced by some in-service components in operating plants. The ΔK values were converted to ΔJ for use in the analyses.

Figure 5.22 shows the original air data (light points with longer lives), and the corresponding fatigue failure points obtained just by correcting the crack growth rates for water environmentally assisted cracking. A comparison of these analytically derived failure points with S-N fatigue failure points obtained in simulated reactor water suggests that for carbon and low alloy steels, EAC accounts for water environmental effects on S-N properties. This would allow the wealth of environmental da/dN data to be used to estimate strain rate effects, mean stress effects, oxygen level effects and temperature on the S-N life.

A study of data obtained on carbon and low alloy steels shows that there are significant temperature effects not included in the existing air fatigue curves. However, operating transients typically occur over a range of temperatures.

Curves could be developed for constant temperature cycling of carbon and low alloy steels (due for example to vibrations). However, the summation of damage obtained using constant temperature curves with damage incurred for cycles occurring over a range of temperatures does not provide accurate cumulative fatigue summations. The Code Technical Committees have determined that the additional accuracy that could be achieved in fatigue design life evaluation methods by adding constant temperature fatigue design curves is not sufficient to justify adding this complexity.

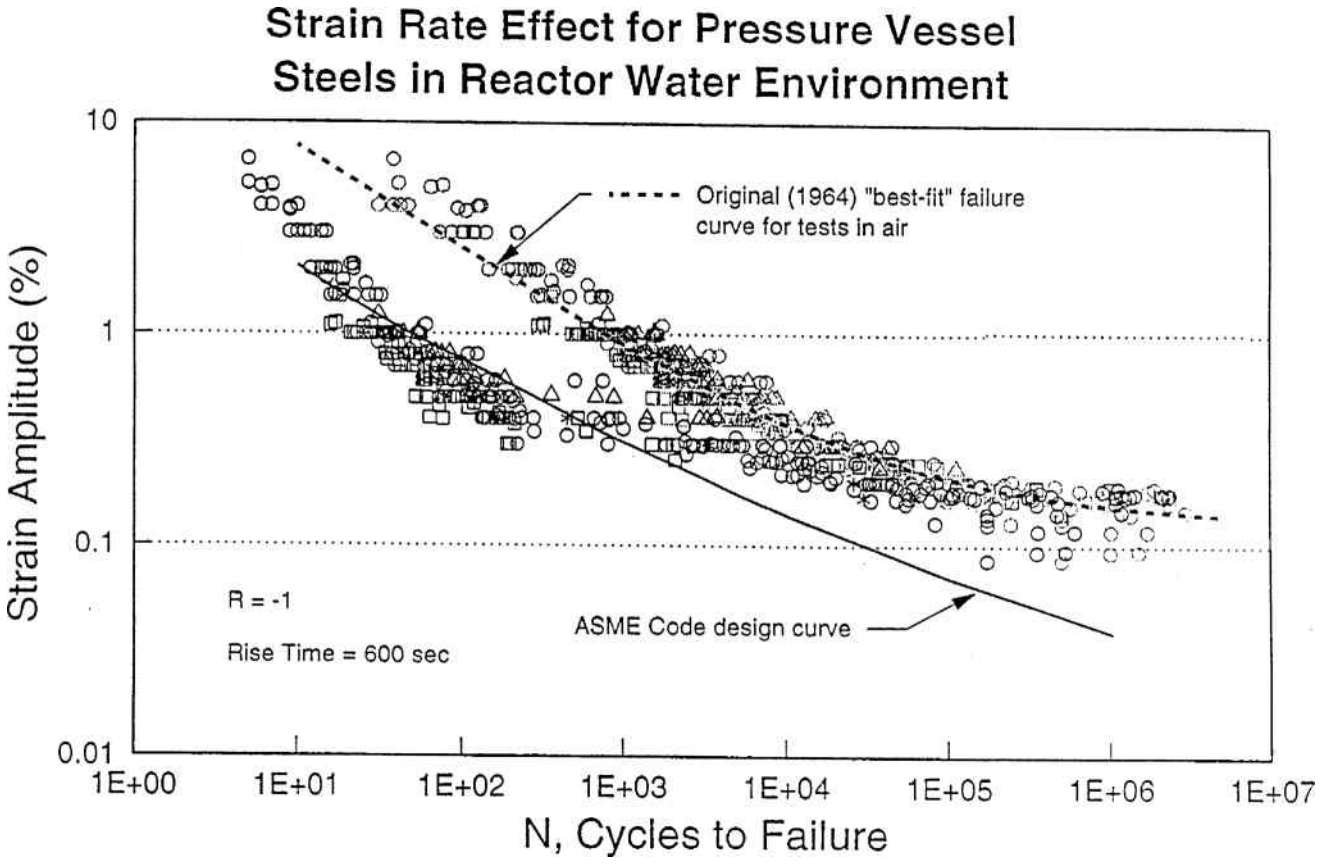


FIG. 5.22

5.13.1 Carbon and Low Alloy S-N Environmental Data

Figures 5.23, 5.24, 5.25, 5.26, and 5.27 show a compilation of available environmental fatigue data on carbon and low alloy steels. Figure 5.23 shows data for carbon steels in simulated PWR conditions. Figure 5.24 shows data for carbon steels in simulated BWR water. Figure 5.25 shows data for low alloy steels in simulated BWR conditions. Figure 5.26 shows the total data compilation for carbon steels and Figure 5.27 shows the total data compilation for low alloy steels.

The environmental effects of interest in carbon and low alloy steels appear to be largely effects on the crack propagation rates. Measurements of crack growth rates in high temperature water show environmental conditions where the rates are an order of magnitude higher than in air. Correlations with S-N data confirm that water environmental effects in carbon and low alloy steels are largely crack propagation effects. The fact that the effects of high temperature water are apparently nil below stress ranges which produce cyclic plastic shear also indicates that such environmental effects on crack initiation are small.

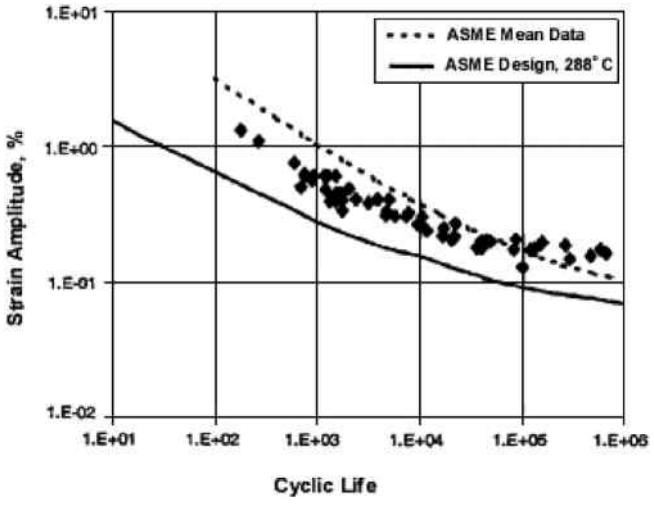


FIG. 5.23 PVRC DATA FOR CARBON STEELS OBTAINED UNDER SIMULATED PWR CONDITIONS FROM WRC BULLETIN 487

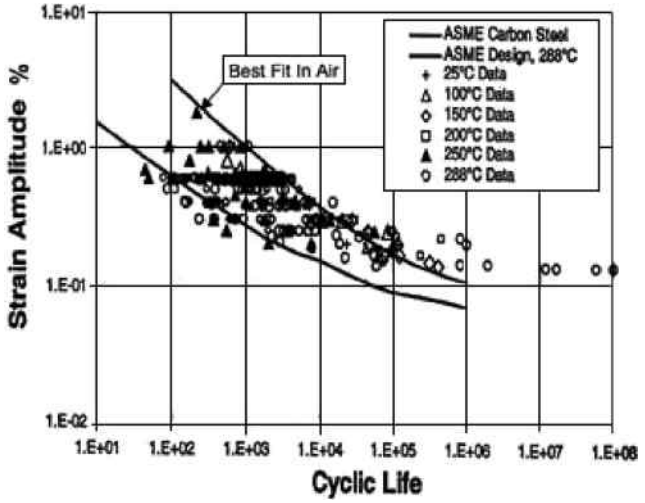


FIG. 5.24 PVRC LABORATORY DATA FOR CARBON STEEL OBTAINED UNDER SIMULATED BWR REACTOR WATER ENVIRONMENTS FROM WRC BULLETIN 487

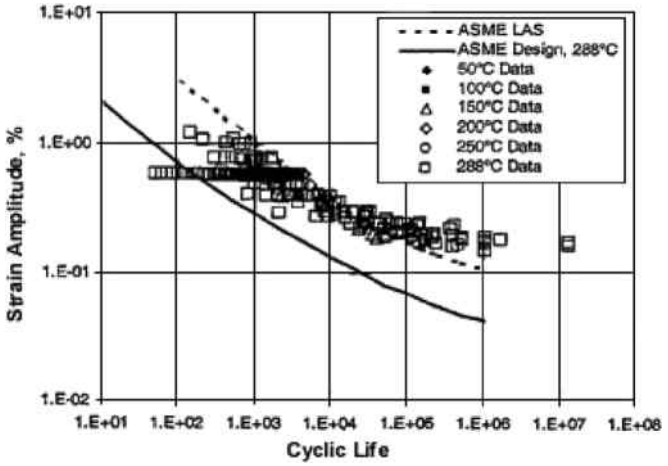


FIG. 5.25 PVRC DATA FOR LOW ALLOY STEELS OBTAINED UNDER SIMULATED BWR CONDITIONS FROM WRC BULLETIN 487

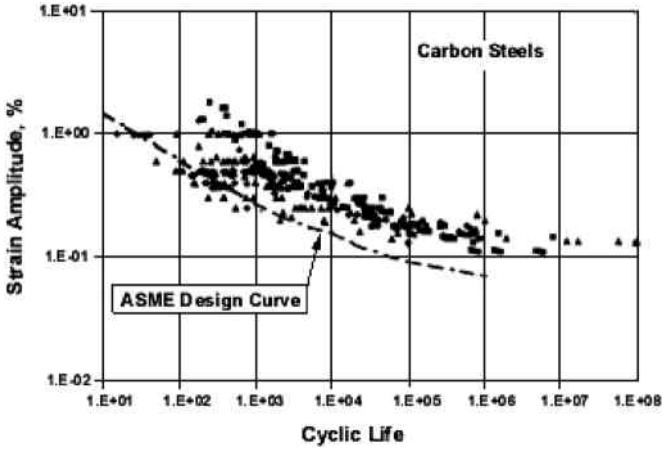


FIG. 5.26 COMPILATION OF ENVIRONMENTAL FATIGUE DATA FOR CARBON STEELS

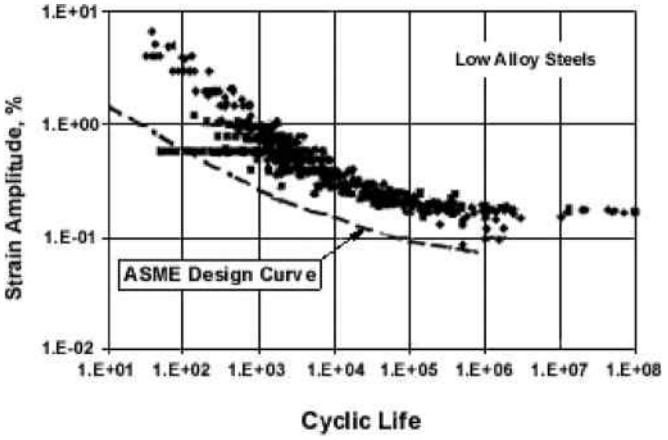


FIG. 5.27 COMPILATION OF ENVIRONMENTAL FATIGUE DATA FOR LOW ALLOY STEELS

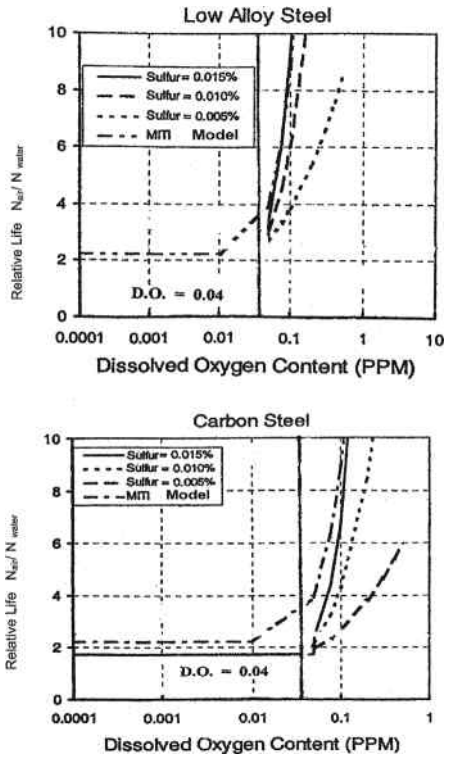


FIG. 5.28 DISSOLVED OXYGEN EFFECTS AT 290°C (554°F) AT A STRAIN RATE OF 0.001 % SEC

Of course, the actual S-N environmental data includes crack initiation, propagation, and final fracture phases of failure, and this data is the basis for the fatigue design curves proposed for Code use.

Experimental data suggests that the sulfur content of carbon and low alloy steels is a variable in the determination of environmental effects. However, there is a lack of sufficient experimental evidence to support a threshold value or a correlation with sulfur content.

A study of carbon and low alloy steel data shows that there is not enough difference in environmental effects to distinguish materials other than the current dependence on ultimate strength.

Although the supporting data on temperature dependence is somewhat meager, water environmental effects on carbon and low alloy steels appear to be less than a factor of 2 on failure life below 300 ºF. While undoubtedly temperature dependent at higher temperatures, it is not feasible to make the Code fatigue design curves temperature dependent because the plant operating transients which limit fatigue life occur over a range of temperatures. Cumulative fatigue damage must be obtained including varying temperature effects.

For carbon and low alloy steels, water environmental effects on fatigue appear to be less than a factor of 2 on life for coolant dissolved oxygen levels below 0.04 PPM. Figure 5.28 from [19] shows the deleterious effects of Dissolved Oxygen Content (PPM) for carbon and low alloy steels, respectively. While these effects are oxygen level dependent above 0.04 PPM, this dependence is tied to the temperature level and therefore changes during the transient. Accordingly, it would not be feasible to make the Code Fatigue Design Life dependent on oxygen levels above 0.04 PPM.[3]

[3]Such a dependence would also be undesirable for the plant operator, since losing control of the oxygen level could raise future design life regulatory issues.

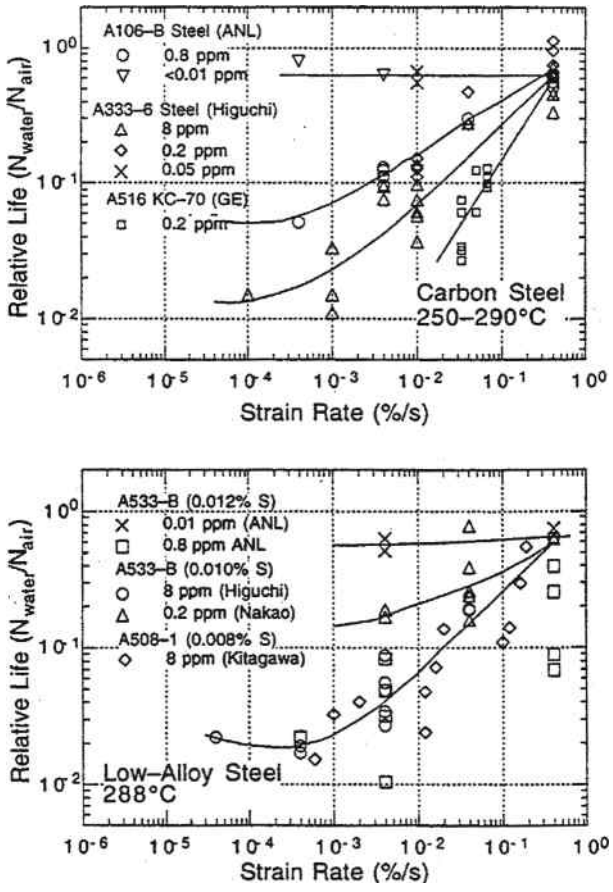


FIG. 5.29 RELATIVE FATIGUE LIFE OF SEVERAL HEATS OF CARBON AND LOW-ALLOY STEELS AT DIFFERENT LEVELS OF DISSOLVED OXYGEN AND STRAIN RATE

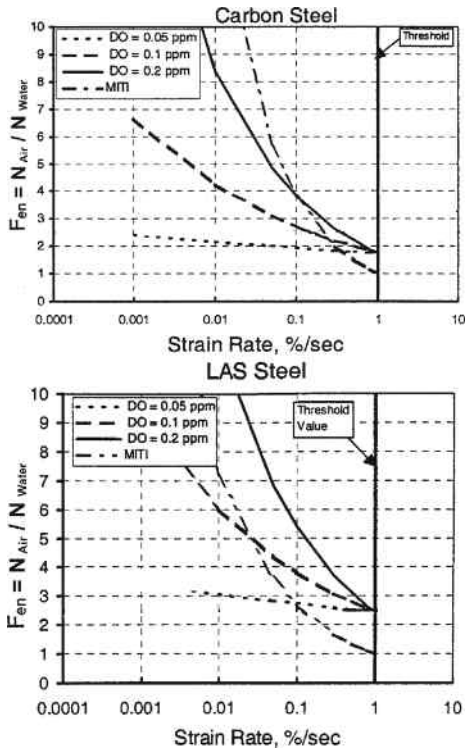


FIG. 5.30 COMPARISON OF THE FEN MODELS WITH THE PVRC STRAIN RATE THRESHOLDS FOR CARBON AND LOW ALLOY STEELS FROM WRC BULLETIN 487

Strain rate[4] is a sensitive parameter for high temperature environmental effects on carbon and low alloy steels. Figure 5.29 shows a compilation of the environmental degradation for carbon steels as a function of strain rate from [19]. The data shows that at strain rates faster than 1% in/in/sec., the environmental effects are usually less than a factor of 2 on life. There is also a threshold effect at very slow strain rates. When strain rates are slower than 0.001% in/in/sec. in carbon and low alloy steels, the strain rate effects appear to saturate so that further decreases in strain rate do not produce further degradation of the environmental fatigue life. Thus, the air curve and the (saturated) low strain rate curves provide bounds on the phenomenon. Between these strain rates, it is possible to interpolate between the two extreme curves, based on data such as shown in Figure 5.30.

Statistical strain rate models from Argonne, plotted by VanDerSluys in WRC Bulletin 487, are shown in Figure 5.30. Strain rate dependent intermediate environmental fatigue curves were developed by the Subgroup on Fatigue Strength for Code use based on all available data.

5.13.2 Proposed Environmental Fatigue Design Curves for Carbon and Alloy Steels

Figure 5.31 shows a comparison of the data analyses and models developed by Higuchi, and others in Japan, Chopra at ANL, and Mehta at G.E. The design curve proposed by the Subgroup on Fatigue Strength is also shown in Figure 5.31 for comparison purposes. The data, models, and curves developed worldwide are quite compatible.

The heavy curve proposed for Code use curve includes the saturated low strain rate (0.001% in/in/sec) and the oxygen levels, sulfur levels and temperatures of interest in the design of new plants. Its use will prevent downstream regulatory uncertainties and risks.

The air curve is suitable for all areas not exposed to high temperature water and for all transients at strain rates exceeding 1% in/in/sec. The latter includes seismic events, mechanical vibrations, including flow induced vibrations and thermal mixing. The environmental curve includes a factor of 10 on life vs. the mean failure curves, whereas the air curve includes a factor of 20. The factor of 2 on stress which is used in the high cycle regime is maintained, but is not controlling because the environmental effects are not prevalent in this regime. The proposed fatigue design curves are intended to maintain current fatigue design safety margins in the Code.

The resulting proposed environmental design curves for Carbon and Low Alloy Steels with ultimate tensile strengths below 80 ksi (552 MPA) are given in Figure 5.32. The proposed environmental fatigue design curves for higher strength materials, UTS 115–130 ksi (793–896 MPA) are given in Figure 5.33. Figures 5.32 and 5.33 do not include the very high cycle regime ($N > 10^6$ cycles). Figure 5.34 provides the curves for the very high cycle regime beyond 10^6 cycles where water environmental effects are believed to be covered by the factor of 2 on life. Use of the strain rate dependent intermediate curves

[4]The strain rate which governs environmental effects is the average strain rate during increasing tensile straining during the cycle.

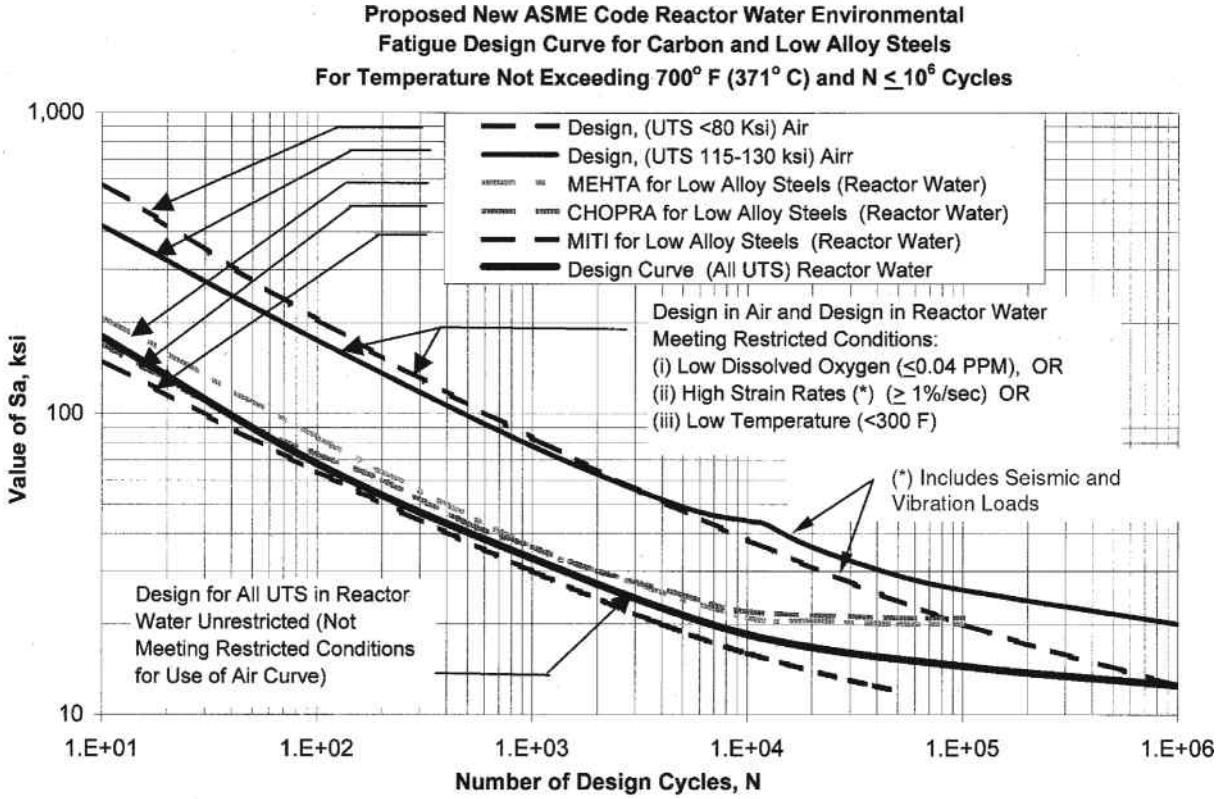


FIG. 5.31

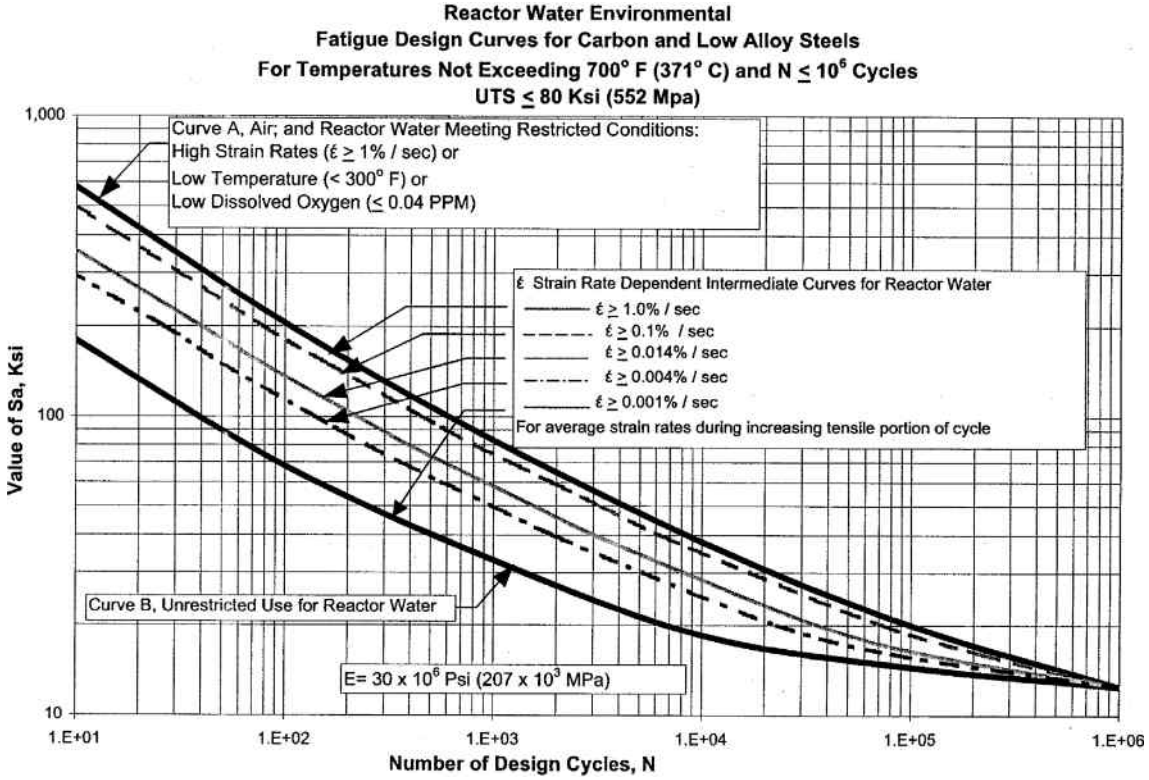


FIG. 5.32

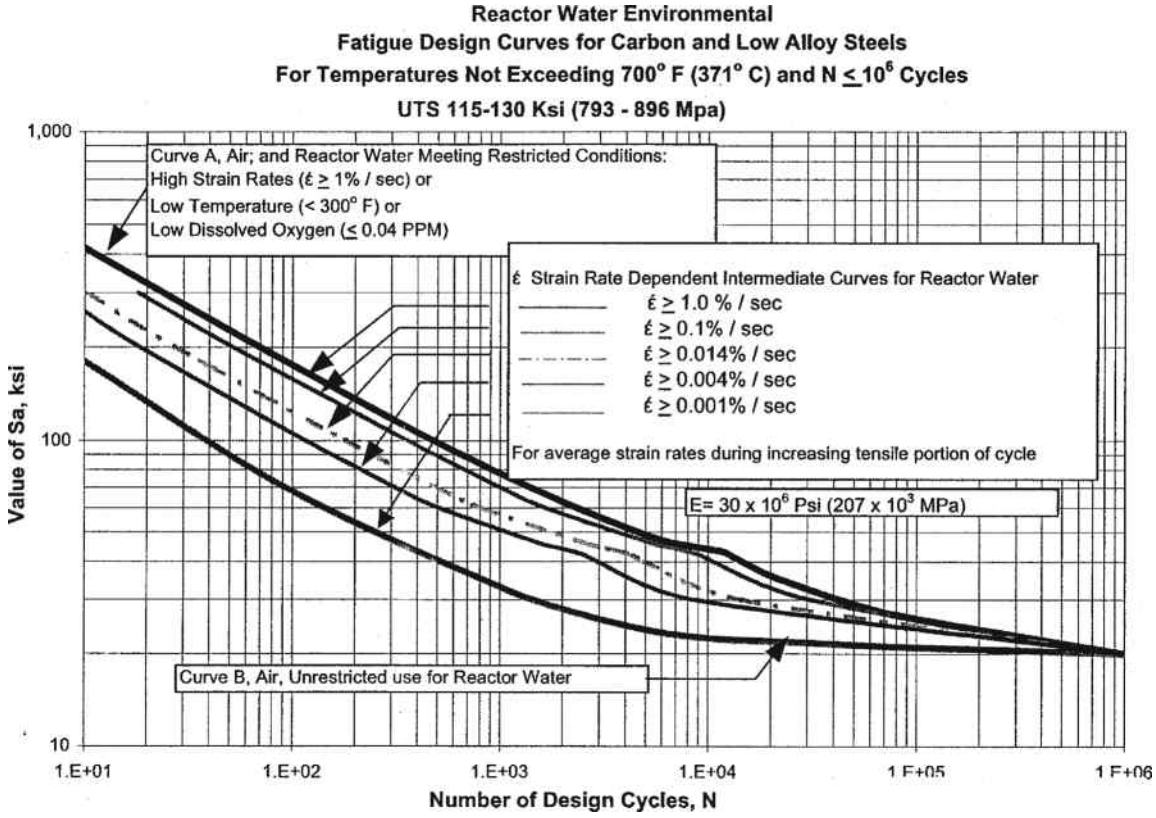
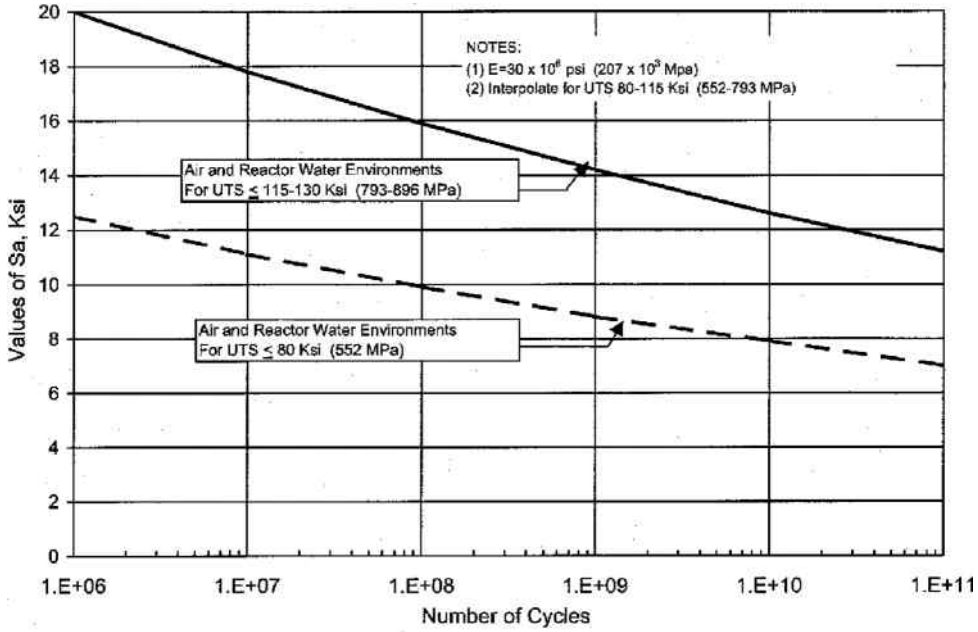


FIG. 5.33



No. of Cycles	1.E+06	1.E+07	1.E+08	1.E+09	1.E+10	1.E+11
Curve A	20	17.8	15.9	14.2	12.6	11.2
Curve B	12.5	11.1	9.9	8.8	7.9	7.0

FIG. 5.34

is difficult for the component designer since the operating transient rates are generally not precisely known and may be changed by the system operator.

Accordingly, it may be advisable to use the limiting curve for transients not satisfying conditions for using the air curves. Fatigue cycling caused by seismic events, mechanical vibrations and thermal mixing occur at rapid strain rates where the air curve should be used.

5.14 DEVELOPMENTS IN ENVIRONMENTAL FATIGUE DESIGN CURVES FOR AUSTENITIC STAINLESS STEELS

The deleterious effects of high temperature water on the fatigue strength of austenitic stainless steels was not recognized until the mid 1980s. The Japanese did some of the earliest work [33] on environmental effects on the important 304 and 316SS series of materials. Many investigators were surprised by test results showing that high temperature water accelerates the fatigue crack growth rates by an order of magnitude and reduces the fatigue life accordingly. Moreover, low dissolved oxygen levels have a greater effect than higher oxygen levels. It became apparent that the ASME Code fatigue design criteria for austenitic stainless steels needed to be corrected to include the effects of high temperature water environments.

The ASME Code Subgroup on Fatigue Strength has made a determination that the fatigue design curves do not provide the desired margin of safety against failure in the same two areas previously described for carbon and low alloy steels.

5.14.1 Austenitic Stainless Steel S-N Environmental Data

For austenitic stainless steels, water environmental effects are surprisingly high at very low coolant dissolved oxygen levels, and show an increasing trend with lower oxygen levels. Consequently, no practical lower bound oxygen threshold level can be used to allow the use of the air curves at lower oxygen levels for stainless steels. Figures 5.35, 5.36, and 5.37 show compilations of reactor water fatigue data for austenitic stainless steels. Figure 5.35 shows the PVRC Bulletin 487 Compilation of Simulated BWR Conditions; Figure 5.36 shows data for 316 NG Stainless Steels obtained under Simulated BWR Conditions, and Figure 5.37 shows the combined PVRC data compilation.

Athough the supporting data on temperature dependence is somewhat meager, water environmental effects on stainless steels appear to be less than a factor of 2 on failure life below 360° F (182°C). While the fatigue properties are undoubtedly temperature dependent at higher temperatures, it is not feasible to make the Code fatigue design curves temperature dependent because the plant operating transients which limit fatigue life occur over a range of temperatures. Cumulative fatigue damage must be quantified including varying temperature effects.

Strain rate[5] is a sensitive parameter for water environmental effects on stainless steels. However, the data shows that at strain rates faster than 1% in/in/sec., the environmental effects are usually less than a factor of 2 on life. There is also a threshold effect at very slow strain rates. When strain rates are slower than 0.0004% in/in/sec in stainless steels, the strain rate effects appear to satu-

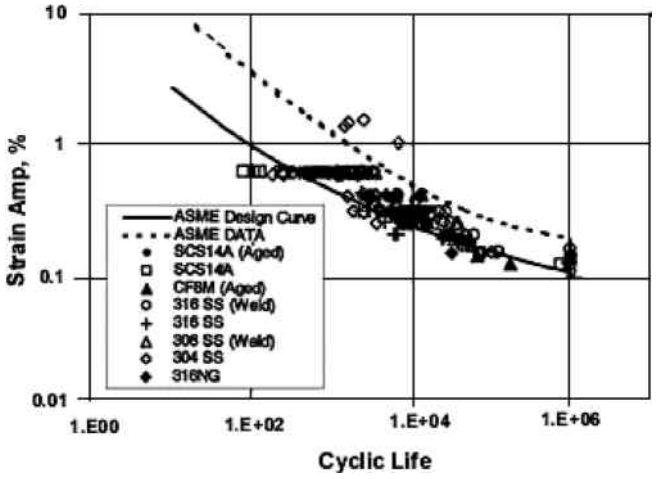


FIG. 5.35 DATA FOR AUSTENITIC STAINLESS STEEL OBTAINED UNDER SIMULATED BWR CONDITIONS FROM WRC BULLETIN 487

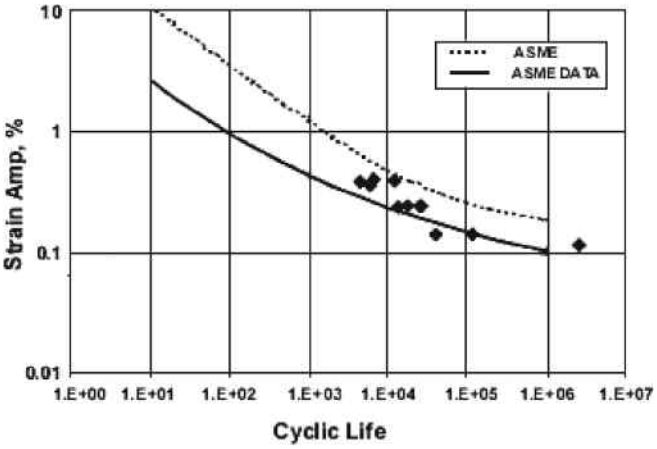


FIG. 5.36

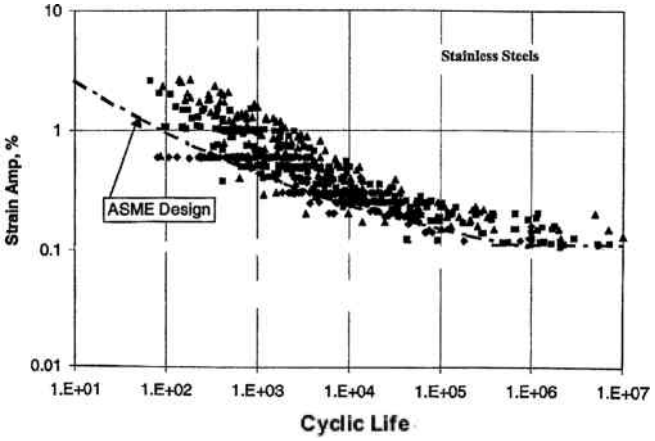


FIG. 5.37 COMPILATION OF ENVIRONMENTAL FATIGUE DATA FOR STAINLESS STEELS

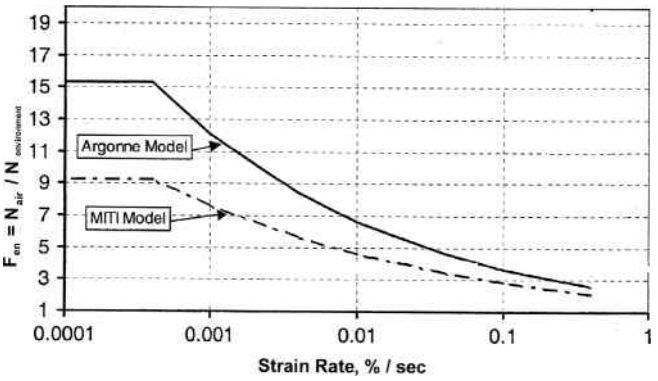


FIG. 5.38 RESULTS OF ARGONNE AND MITI MODELS FOR STRAIN RATE EFFECTS ON AUSTENITIC STAINLESS STEEL FROM WRC BULLETIN 487

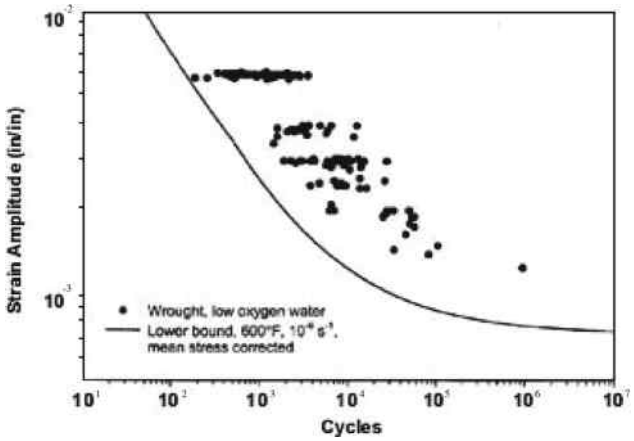


FIG. 5.39 FATIGUE DATA ON WROUGHT STEELS IN LOW OXYGEN WATER COMPARED TO THE LOWER BOUND (600°, 10^{-6} S^{-1}) CURVE FROM T.R. LEAX [34]

rate so that further decreases in strain rate do not produce further degradation of the environmental fatigue life. The air curve and the saturated low strain rate environmental curves, therefore provide bounds on the total phenomenon.

Figure 5.38 shows the results of the Argonne and MITI models for strain rate effects on the austenitic stainless steels taken from the PVRC study of [19]. In addition to the data evaluations of Figures 5.35, 5.36, and 5.37, the models developed by Argonne and MITI, and the studies of [19]), T. R. Leax of Bechtel Bettis [34] performed analyses of temperature and strain-rate effects. For application to the design of new plant components, it is difficult to accurately establish operating temperature and strain-rate conditions for every anticipated and unanticipated operating transient. Moreover, Section III of the Code [NB-3222.4 (e)(5)] requires evaluation of stress ranges from cycles of various origins. The total stress difference range must be used in the fatigue evaluation when it is larger than the stress ranges of individual cycles. Since both temperature and strain rate are varying during cyclic operation, it is very desirable to have fatigue design curves which are independent of temperature and strain rate.

Leax [34] developed a model by analyzing the available data on austenitic stainless steels in LWR environments, excluding sensitizing material and high oxygen water data. The remaining fatigue data included 383 failure points. A proposed fatigue design curve was developed for 600 ºF and low strain rates representative of worst case conditions. A proposed design curve was developed using a factor of five on the lower bound statistical curve. The corresponding data and lower bound curve are shown in Figure 5.39.

5.14.2 Proposed New Environmental Fatigue Design Curves for Austenitic Stainless Steels

Proposed new environmental fatigue design curves for 304, 310, 316, and 348 Austenitic Stainless Steels were developed by the ASME Subgroup on Fatigue Strength based on the technology represented by Figures 5.35 through 5.39 herein, and all available data. These curves are shown in Figure 5.40. It is possible to interpolate between the two extreme curves, and strain rate dependant intermediate curves are provided as an aid to this interpolation. This is a difficult interpolation for the component designer since the operating transient rates are generally not precisely known and may be subsequently changed by the plant operator. Accordingly, it may be advisable to use the limiting environmental curve for transients not satisfying the conditions for using the air curves. Fatigue cycling caused by seismic events, mechanical vibrations and thermal mixing occur at rapid strain rates where the air curve can be used.

[5] The strain rate which governs environmental effects is the average strain rate during increasing tensile straining during the cycle.

5.15 ENVIRONMENTAL FATIGUE TEMPERATURE CORRECTIONS

Recent studies of the environmental fatigue data for carbon, low alloy and austenitic stainless steels have shown that reactor water effects are significantly less deleterious as temperatures are reduced below 350 ºC (662 ºF). At temperatures below 150 ºC (302 ºF) the reduction in life due to reactor water environmental effects is less than a factor of 2, and the existing ASME Code Section III fatigue design curves for air can be used. The latter include a factor of 20 on cycles whereas the ASME Subgroup on Fatigue Strength (SGFS) has determined that a factor of 10 should be used on the mean failure curves which include reactor water effects. These factors account for scatter in the data, surface finish effects, size effects, and environmental effects.

Reactor water environmental degradation dependence on temperature is determined using variations of the statistical models developed by Chopra and Shack, Higuchi, Iiada, Asada, Nakamura, Van Der Sluys, Yukawa, Mehta, Leax and Gosselin, References [7, 9, 10, 13, 15, 19, 23, 24, 34 thru 38, 40, 44, 48, 51, 53, 57 and 58]. Comparisons of the resulting proposed environmental fatigue design criteria with reactor water environmental fatigue data were made. These comparisons showed that the Code factors of 2 and 20 on stress and cycles are maintained for air environments, and the 2 and 10 Code factors are maintained for the reactor water environments. Environmental fatigue criteria are given for both worst case strain rates and for arbitrary strain rates. These design criteria do not require the designer to consider sequence of loading, hold

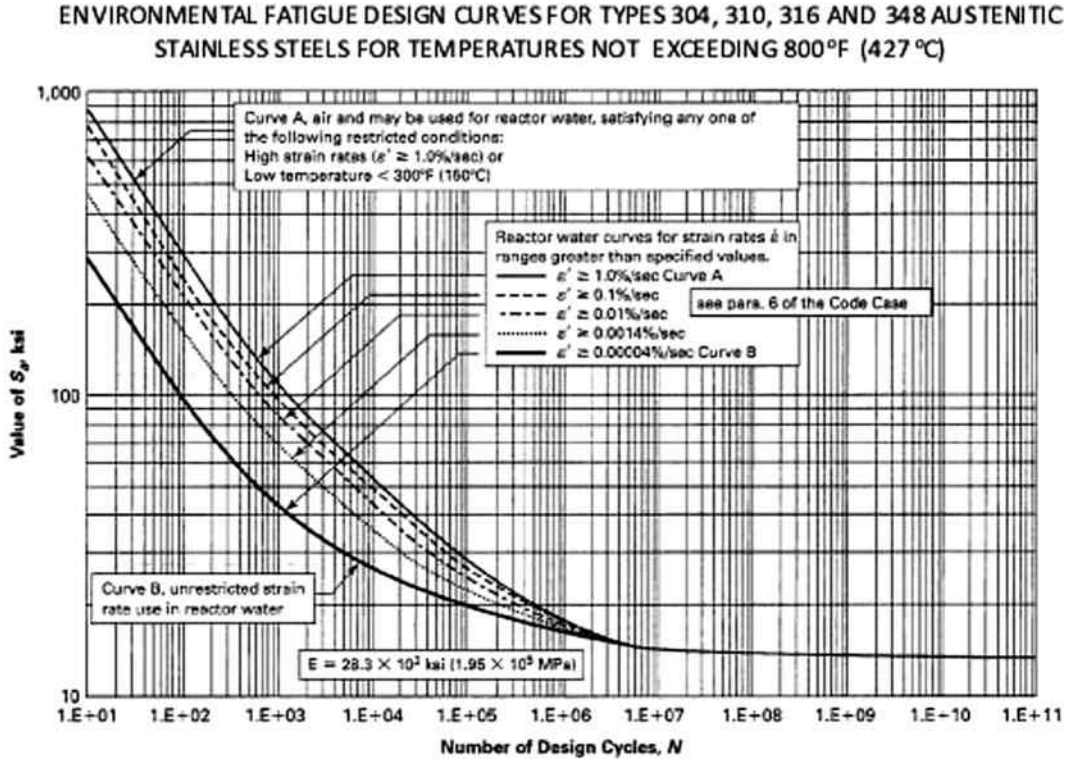


FIG. 5.40

times, transient rates, and other operating details which may change during 60 years of plant operation.

Chopra and Shack (References [7, 9 10, 35 38, 44, 57 and 58]) developed statistical models of the temperature dependence of the environmental fatigue properties between 150ºC and 350ºC. These models use a linear relationship between (Ln N) and temperature in this range, per Figures 5.41 and 5.42, except that their relation for austenitic materials uses an upper limit of 325ºC. The resulting temperature dependence is given by Equation (5.5) in terms of ºC in Code Case N-761 for austenitic stainless steels:

$$\ln N_D = \ln N_a + (\ln \overline{N_e} - \ln N_a)\frac{(T - 150°\text{C})}{200°\text{C}}; \quad \textit{for } 150°\text{C} \le \text{T} \le 350°\text{C} \tag{5.5}$$

where

N_D = allowable design cycles including temperature correction and environmental effects
N_a = allowable design cycles in air
$\overline{N_e}$ = N_e, or N_{eu} = allowable design cycles for the strain rate dependent environmental fatigue curves, N_e; or optionally using curve B which covers unrestricted strain rates, N_{eu}
T = Maximum metal temperature in cycle

5.15.1 Carbon and Low Alloy Steels

Figure 5.41 shows the temperature dependent environmental fatigue data from Figure 16 of NUREG/CR-6909 (Reference [9]) for A333-Grade 6 carbon steel at a strain amplitude of 0.6% (stress amplitude of 180 ksi) at strain rates of 0.002%/sec and 0.004%/sec. The fatigue design lives obtained from the proposed ASME Code design criteria using Figure 5.32 herein (from Reference [24]) with a temperature correction, are plotted in Figure 5.41. Note that the design lives for unrestricted strain rates (Curve B in Figure 5.32) are quite realistic and would allow plant operators complete freedom to reduce the operating transient rates. The proposed ASME Code design criteria also allows the designer to take credit for the presumed strain rate, and the design curve for the 0.004%/sec. test data rate is also shown in Figure 5.41. Curves at 10x the design cycles are shown for the environmental data and at 20x for the air data for comparison with the polished specimen data, Figure 5.34. shows that the proposed reactor water fatigue design curve and the fatigue design curve for air are the same beyond 10^6 cycles.

5.15.2 Austentic Stainless Steels

Figure 5.42 shows the temperature dependent environmental fatigue data from Figure 47 of NUREG/CR-6909 (Ref. [9]) for austenitic stainless steels at a strain amplitude of 0.6% (stress amplitude of 169.8 Ksi) at strain rates of 0.01%/sec and 0.4%/sec. Figure 5.18 shows the proposed new ASME Code fatigue design curve for austenitic stainless steels in air. Note that in the very high cycle regime ($>10^6$ cycles) the older existing ASME Code includes three design curves. Only the lowest curve is shown in Figure 5.18 because: (1) the highest existing curve includes no weld residual stress effects, and (2) the intermediate existing curve has been found to apply only to cold worked material cycled at very low nominal (linearized) stress amplitudes. Figure 5.40 shows the proposed new fatigue design curves for austenitic stainless steels in reactor water environments. See Reference [7] for more details. The fatigue design lives obtained from these proposed ASME Code design criteria with the Equation 5.5 temperature correction, are plotted in Figure 5.42. The design lives for unrestricted strain rates (curve B in Figure 5.40) are shown, along with the design curves for strain rates of 0.01%/sec. and 0.4%/sec. Note that the factor of 10 on environmental life data on polished specimens is covered by the proposed unrestricted strain rate design curve.

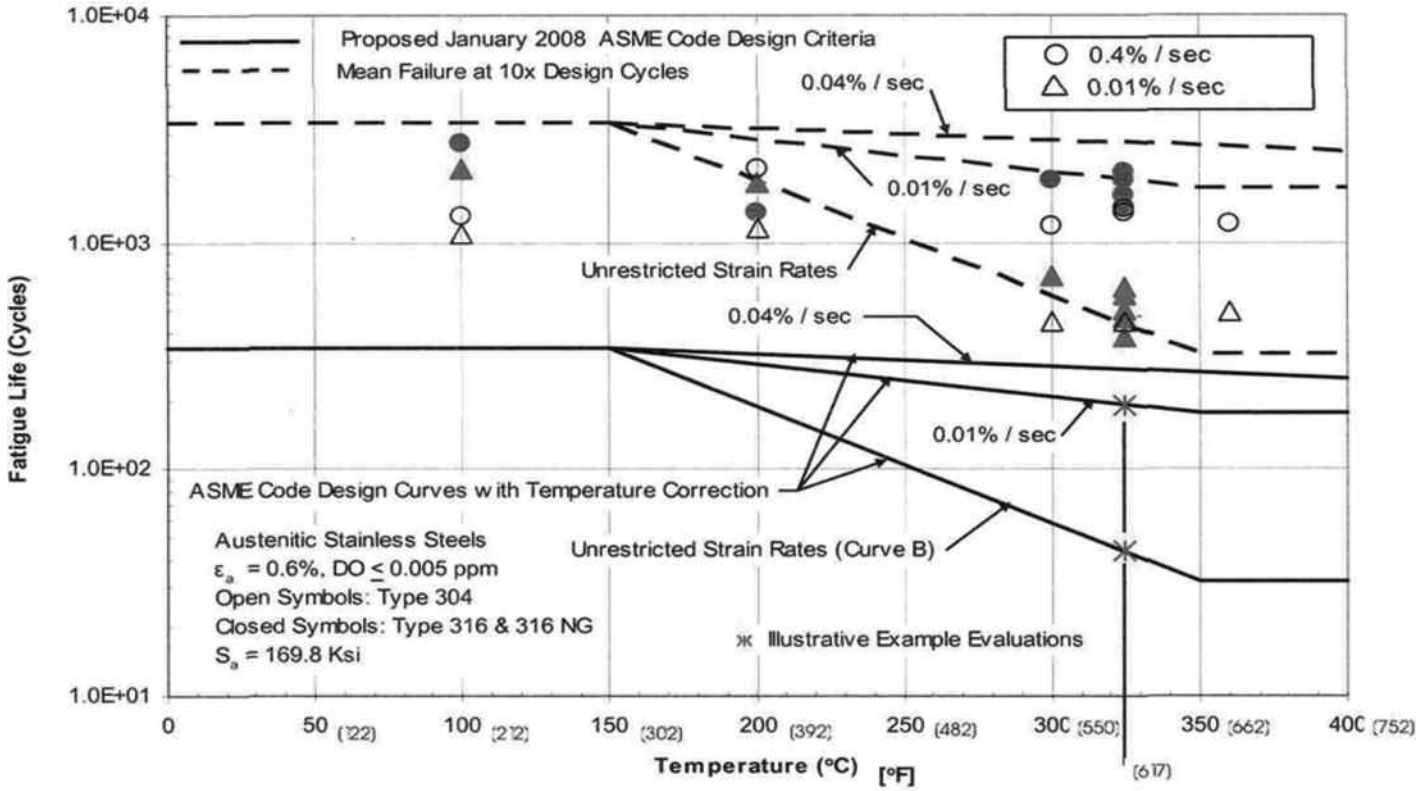


FIG. 5.41 COMPARISON OF NUREG/CR-6909 (REF. [9] FIGURE 47) EXPERIMENTAL ENVIRONMENTAL FATIGUE DATA WITH PROPOSED FATIGUE DESIGN CURVES FOR AUSTENITIC STAINLESS STEELS WITH TEMPERATURE CORRECTION

5.16 CURRENT REGULATORY STATUS

Industry and the ASME Code technical specialists have generated two Code Cases: N-761 and N-792 [Refs. 345 and 346] and are developing a third. [Ref. 347] to cover environmental fatigue in nuclear plants. These include environmental fatigue design curves, Fen technology, and Flaw Tolerance design criteria. NRC has not accepted any of these environmental fatigue design criteria and has stated that without significant revisions to make them equivalent to their criteria in NUREG-6909, Rev. 1 [Ref. 348], they cannot be used for the design of new nuclear plants. NRC is also in the process of completing a revision to NUREG 6909 [Ref. 348]. Future Code efforts are aimed at providing acceptable environmental fatigue design criteria in the Code.

5.17 KEY LITERATURE

In addition to the references previously cited as sources of specific data or concepts, other key technical papers have also been published by very talented engineers and scientists in this interdisciplinary field of expertise. References [39] through [186] make key contributions to the understanding and quantification of high temperature environmental effects on the crack growth and fatigue properties of the materials of interest. References [187] through [210] advance the state-of-the-art in ductile crack propagation technology, including J-integral theory, a very important element of low cycle fatigue. References [211]–[267] discuss the very difficult and important area of crack initiation, which consists of the growth of microscopic cracks up to the macroscopic sizes which can be treated by conventional continuum fracture mechanics. References [268] through [285] describe international flaw acceptance criteria. References [286] through [304] describe stress intensity factors and crack growth. References [305] through [326] cover a variety of directly relevant issues. References [327 through 348] were added since the last Edition of the Companion Guide to the ASME Boiler and Pressure Vessel Code. [Refs. 345 thru 348] describe the current regulatory status.

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CHAPTER

6

PERSPECTIVE ON CYCLIC, IMPACT, AND IMPULSE LOADS

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6.1 INTRODUCTION

In past editions of the handbook, this chapter has primarily addressed issues as they pertained to Section III of the ASME B&PV Code. In particular, it has addressed issues concerning the seismic response of nuclear facilities. Currently, many other facilities covered by the ASME B&PV Code have had to address these same issues, often with little guidance from the appropriate Code section. Modern LNG terminals, for example, have had to undergo extensive seismic reviews. These facilities contain equipment covered by Section VIII and B31.3 of the Code. Neither of these Code section give any guidance to the designer concerning seismic analysis, other than to require that seismic loads be addressed. In this revision of the chapter, some of these issues will be addressed. In addition, a new section discussing the use of computer software for analysis has been included. This section will address some of the issues associated with different computer codes used for different parts of a plant.

Dynamic loads applied to the design of mechanical systems and components are of three basic types: cyclic, impulse, and impact. In addition, a fourth potential cyclic type load exists: the vibratory motion category. Although vibratory motion is often not considered in the original design basis, it may be observed during steady-state or transient operation such that remediation may be required. This vibratory effect may be of such magnitude or frequency to cause premature fatigue or ratchet failure of metal components. In such instances, reconfiguration or modified support of the mechanical system or component may be required to reduce the vibratory effects to within tolerable limits during the operating life of the particular plant, system, or component. As originally defined in the ASME B&PV Code Section III, the operating life of the plant includes any design-basis normal, abnormal, emergency, or faulted conditions defined in the Design Specifications. These conditions should not be confused with Service Levels A, B, C, and D that are currently defined in the Code for design purposes. It is possible to have different Service Level design conditions for the same operating condition; depending on the required response of a component.

Many standards or guidelines are available to provide criteria for the design of mechanical (metal) systems and components to resist dynamic loads. The primary guidance is found in Appendix N (Dynamic Analysis Methods) [1] of the ASME B&PV Code, Section III. This guideline is defined as a Non-Mandatory Appendix to ASME Section III and at the present, it is primarily concerned with cyclic dynamic loads associated with earthquakes and fluid flow–induced vibration of structures contained within the cross-flow of fluids. For completeness, this chapter considers other types of dynamic loads not currently addressed explicitly by Appendix N that the designer of a pressure-retaining nuclear component may need to consider.

Another standard that complements ASME Section III, Appendix N guideline is the ASCE Standard 4-98, which is used to define earthquake motions in the building foundation and the building structure that houses or supports the mechanical system or component [2]. (ASCE refers to the American Society of Civil Engineers.) From this standard can be developed the specific earthquake motion transmitted through a building foundation and the building structure as earthquake load–design input to a mechanical or electrical system or component. Both the ASME Section III and the ASCE Standard deal primarily with earth-quake cyclic–type dynamic loads.

Additional guidance for non-nuclear structures is provided by ASCE Standard 7-02, *Minimum Design Loads for Buildings and Other Structures* [3]. This ASCE Standard is referenced as the basis for the earthquake load requirements contained in the International Building Code [4].

Other guidelines for dynamic analysis of mechanical systems and components are those associated with dynamic-impulse and impact-type loadings. This guidance is developed as ANS Standard 58.2, 1988 [5] (for impulse) and ANS Standard 58.3, Appendix B [6] (for impact) in addition to Appendix II of the ASME B31.1 Code [7]. (ANS refers to the American Nuclear Society.) Yet another guideline was developed to address impulse and impact loads: this is the report of the ASCE Committee on Impact and Impulse Loads [8]. Finally, ASME OM-S/G, Part 3 contains a standard for determining the effect of vibratory motion from operation that is independent of the cause of vibration [9].

By using the standards and guidelines of refs. [1]–[9], it is possible to develop a fairly clear understanding of current design or

[1]The original chapter was authored by John D. Stevenson in the first and second editions of the publication "Companion Guide to the ASME Boiler & Pressure Vessel Code". In the third edition of that publication, this chapter appearing as Chapter 34 was revised in its entirety by Michael Porter, the current contributor of this chapter. – Editor

analysis procedures and methods for first-order (approximate-methods) mechanical systems and components designed to resist dynamic loads. Such procedures and methods are for engineers who possess a background in structural dynamics without recourse to complex, specialized computer codes. For impulse-type loads, any analytical rigor beyond a single simplified rectangular- or triangular-forcing function will require the use of hydrodynamic computer codes that use control volumes to more accurately define the time dependence and location of multiple forcing functions [15].

6.2 TYPES OF DYNAMIC LOADS

6.2.1 Cyclic Loads

6.2.1.1 Earthquake or Other Building Filter-Cyclic Loads Cyclic loads are characterized as alternating ± loads or displacements that are applied to mechanical systems or components. These earthquake-associated loads are caused by the intertial response of a structure, system, or component (SSC) to the earth-quake-induced motion of the SSC supports or the foundations of the supports. The response of a system or component is highly dependent on the damping of the system. In addition, the system or component response depends on the closeness of the time-dependent forcing-function frequency (which defines the input) to the dominant response frequency of the seismically loaded system or component. If the system or component has a natural frequency close to that of the applied forcing function, resonance can occur, resulting in large amplification of an equivalent static load applicable to the mechanical system or component. Such amplification could theoretically be as high as 100 times the peak cyclic-force level at low-damping and near-resonance (system or component frequency is very near the cyclic-load frequency). For real structures under seismic excitation, the amplification factor rarely exceeds 25.

Examples of cyclic loads are earthquake- and operational-vibratory loads. Guidelines or standards that address these phenomena in detail are found in refs. [1], [2], and [9].

6.2.1.2 Vibratory Loads These loads have not historically been considered in original design. They are observed to occur during steady-state or transient operation of the system. In such instances, the amplitude, frequency, and structural layout of the vibrating component should be monitored. The concern is that the vibratory motion will cause a premature failure of the component (piping system) with respect to its design life. Reference [7] gives recommended procedures and limits for evaluating the need to reduce the amplitude or frequency of vibration so that they will not impact the service life of the component. Different procedures and limits are given as a function of ASME Class piping.

Recent improvements in computer codes and available computer hardware have made the prediction of these loads more accessible at the design stage. Computer programs such as PULS [10] and PULSIM [11] have made the prediction of pulsation in fluid lines due to pump or compressor excitation relatively easy to do in the design stage. Additionally, the use of Computational Fluid Dynamics computer codes (e.g., Fluent [12] or Star CCM+ [13]) to assess systems has become a reasonable and cost-effective option at the design stage.

6.2.1.3 Fluter or Vortex-Shedding Loads When a smooth-surface tubular structure is in a fluid-flow stream, vortices in the flow become established from the effect of the tube. When the velocity and density of the fluid are such that vortices become established (hence the same dominant frequency of the tube), a resonant condition develops that can produce cyclic loads perpendicular to the direction of flow. At resonance, the amplitude and number of cycles can cause failure of the tube. This particular loading phenomenon for pressure-type vessels is covered in Appendix N [1].

6.2.2 Impact Loads

Dynamic-impact loads are characterized as an external force or moment applied suddenly to a target SSC relative to the response period of the target. These loads typically have a finite amount of kinetic energy associated with a missile or fluid slug of known mass, velocity, area, and duration striking a target structure, mechanical system, or component because of a sudden change in fluid-flow conditions. For relatively slow-moving missiles, the kinetic energy or momentum of the missile must be absorbed by the target by potential strain energy, which is defined by strain limits of the material and structural configuration of the target (including its supports). In addition to evaluating the impact energy or momentum transfer, it may be necessary to evaluate the potential for local-penetration or perforation effects on the target. Relatively high-velocity, small-contact–area missile impacts typically absorb the missile-impact energy by local crushing of the missile or target as well as strain energy in the target. In such cases, the force and duration of the missile impact are limited by the crushing strength of the missile and/or target.

In the penetration-type analysis, it is common to use local-penetration formulas developed from experiments reported in refs. [7], [8], and [9]. However, with the relatively recent advent of nonlinear, dynamic, finite-element computer codes, it has become possible to compare computed strains in the target directly with allowable strains to determine design adequacy and the potential for penetration of the target.

Simple use of acceleration criteria alone—without any reference to the duration of acceleration as acceptance criteria—should be avoided; acceleration alone without duration does not define the dynamic-input load.

6.2.3 Impulse Loads

Similar to impact loads, impulse loads are external loads applied suddenly to the target; however, they typically are relatively long-lasting compared to the response period of the target. In this category of loads are fluid jets from postulated rupture of pressurized systems and exterior or interior blast waves from an explosion on a target or shield structure. Also included are the effects of the injection of high-energy gases or vapors into a liquid body (i.e., pressure-suppression containment types used to reduce NPP-containment design pressures). This type of loading is associated with relief-valve discharge and fluidhammer (i.e., steam- and waterhammer) phenomena. The fluidhammer phenomena are generally associated with the sudden termination of fluid flow by a stop valve, but they may also be associated with a slug of liquid being accelerated by the differential fluid pressure introduced into a piping system as a transient-load effect. These differential pressures and associated shock waves generally result in pressure and velocity changes varying with time at each change in area or direction in the system or component, thereby generating time-dependent forcing functions at multiple points in the system or component. For first-order design from postulated fluid-impulse load, a single forcing function is typically applied at a discharge nozzle, a postulated break location and orientation, or a postulated

liquid-slug location. General guidance for the simplified fluid-impulse design can be found in ref. [5].

Increasingly, computer codes are being employed to address these issues. AFT Impulse [14] is a typical implicit integration computer code used to analyze waterhammer in fluid piping systems. CFD Finite Element (FE) codes are now used extensively to model both impulsive loads and their effect on structures.

6.2.4 Multi-Phase Flow

In addition to the liquid-slug associated with fluidhammer, a similar phenomenon is common in multi-phase systems comprising some combination of gas, liquids and solids [40]–[51]. In these systems, the gas can travel at a different rate than the liquid or solid. Additionally, the mass flow rate of the liquid is often transient. These systems can be classified in different flow regimes including stratified, annular, slug, mist and churn. Reference [52] presents a spreadsheet calculation for the various flow regimes based on the flow rates, densities and pipe diameter for oil, gas and water. The variable mass flow rate of the liquid and the associated changes in the momentum of the liquid exert forces on the containment system. These forces tend to occur as randomly occurring impulses. The solid particles can exert both impulse and impact forces on the system. In many cases erosion of the containment system will result because of the impact of the solid particles.

Multi-phase flow loading is a serious problem for many types of equipment used in both offshore and onshore oil and gas production. Erosion due to the entrainment of particles (e.g., sand) in high velocity gas and oil lines is also a multi-phase related problem. In almost any piping system carrying high velocity fluids, multi-phase flow loading can become problematic, especially at points in the system where the piping changes direction or size.

Previously, most of these phenomena have been studied using physical flow models or analytical approximations. As computer speeds have increased, however, and more model physics have been incorporated, computational fluid dynamics (CFD) has gained acceptance as a tool to study multi-phase problems due to their ability to achieve perfect similitude and to allow virtually limitless interrogation of the model results, which are both limitations of physical flow testing.

6.3 GLOSSARY

Acceptable Damage This is damage resulting from an event (or the appropriate combination of events) in which the safety design requirements for the appropriate category of events are met. Events (and appropriate combinations of events) are categorized by plant conditions.

Active Failure This is a malfunction (excluding passive failures) of a component that prevents it from completing its intended safety function on demand. Examples of active failures include the failure of a valve or check valve to move to its desired position, or the failure of a pump, fan, or diesel generator to stop or start. Spurious action of a powered component originating within its actuation or control system shall be regarded as an active failure unless specific design features or operating restrictions preclude such spurious action. An example is the unintended energization of a powered valve to cause it to open or close.

Apparent Wave-Propagation Speed This is the propagation speed of seismic waves through a media relative to a fixed local coordinate system on the object analyzed.

Barrier This is a structure meant to intercept an impulsive or impact loading.

Bounding Spectra These are the ground-response spectra for a site for which equipment items are considered seismically qualified by experience.

Broadband-Response Spectrum This is a response spectrum that describes motion in which amplified response occurs over a wide (broad) range of frequencies.

Coherence The coherence function defines a comparative relationship between two time histories. It provides a statistical estimate of how much two time-history motions are related as a function of frequency. The numerical range is from zero (for unrelated) to one (for perfectly correlated motions).

Correlation Coefficient The correlation coefficient function defines a comparative relationship between two time histories. It provides a statistical estimate of how much two motions are related as a function of time delay. The numerical range is from zero (for unrelated) to ± 1.0 (for related motions).

Coupled This is a descriptive term for mathematical models of structures and items of plant equipment that are interconnected by their respective mass, stiffness, and damping properties and, because of their coupling, influence the dynamic response of each other.

Cutoff Frequency This is the frequency in the response spectrum in which the zero period acceleration (ZPA) asymptote essentially begins. This is the frequency beyond which the single–degree-of-freedom (SDOF) oscillators exhibit very little or no amplification of motion. In addition, it indicates the upper limit of the frequency content of the waveform being analyzed.

Cycle This is one complete sequence of values of an alternating quantity.

Damage States Although not expressly identified by the Code, there are typically four damage states considered in developing the four Service Levels (A, B, C, and D) of the Code.

(1) The first damage state is associated with active system components or support function (i.e., move or change state) during the strong-motion phase of design-basis–earthquake or design-basis–impact or –impulse loading. This state is roughly comparable to Service Level A as defined by the Code.
(2) The second damage state is associated with active-system, -component, or -support function (i.e., move or change state) after the strong-motion earthquake, impulse, or impact loads have passed. This state is roughly comparable to Service Level B as defined by the Code.
(3) The third damage state is associated with passive (maintain leak-tight and structural integrity) or active (may require operator action to reset) systems, components, or supports, (i.e., move or change state). This state is roughly comparable to Service Level C as defined by the Code.
(4) The fourth damage state is associated with a passive-system or -component threshold loss of leak-tight or structural integrity. This state is roughly comparable to Service Level D as defined in the Code.

Damping This is the generic name ascribed to the energy dissipation mechanisms that reduce the amplification and broaden the vibratory response in the region of resonance. One hundred percent critical damping is defined as the least amount of equivalent viscous damping that causes a SDOF system to return to its original position without oscillation after an initial disturbance.

Typically, three types of damping exist that are used in design: material, structural, and impact.

Design-Basis Earthquake This is a term for an earthquake time-history or response-spectra motion designated for design purposes.

Design-Ground Acceleration This is the value of the acceleration that corresponds to acceleration at zero period in the design ground–response spectrum.

Design Ground–Response Spectrum This is a smooth-response spectrum of the free-field input motion typically obtained by analyzing, evaluating, and statistically combining a number of individual response spectra derived from the actual motion records of past earthquakes.

Direct-Integration Time-History Method This uses numerical step-by-step integration of the equations of motion of a time history of the input motion.

Effective Mass Ratio This is the ratio of the secondary system or component mass to the effective mass of the supporting primary system or structure.

Effective Mass This is the mass of the structure or equipment that helps to determine the dynamic response of the structure or equipment.

Equipment, Flexible Equipment (including the effects of the equipment supports) in which the lowest natural frequency is less than the frequency value at the start of the ZPA or the cutoff frequency of the applicable response spectrum.

Equipment, Rigid Equipment (including the effects of the equipment supports) in which the lowest natural frequency is greater than the frequency value at the start of the ZPA or the cut-off frequency of the applicable response spectrum.

Equivalent Static Load This is a term for an equivalent statically applied load or acceleration that is usually based on a function of the peak of the applicable response spectrum. It may be used as an alternative to response spectrum or time history to define seismic input for design of systems and components.

Floor Acceleration This term is for the acceleration of a particular building floor (or equipment mounting) resulting from the motion of a given earthquake time history.

Foundation This is the structure that supports or otherwise provides restraint to systems, components, and structures.

Fourier Spectrum This is a complex valued function that provides amplitude and phase information as a function of frequency for a time-domain waveform.

Fragility This is a term for the susceptibility of equipment to malfunction resulting from structural or operational limitations (or both) when the equipment is subjected to dynamic excitation.

Fragility Level This is a term for the highest level of excitation parameters that equipment can withstand and still perform the specified functions. (Note: the fragility level may include the interdependence of amplitude, frequency, and time.)

Fragility Response Spectrum This is a test response spectrum (TRS) that defines the fragility level of equipment.

Ground Acceleration This is a term for the acceleration time history of the ground resulting from the motion of a given earthquake. The maximum amplitude ground acceleration is the ZPA of the ground response spectrum.

High-Energy Piping System Any system—or portion of a system—in which the maximum operating pressure exceeds 275 psig (1.87 MPa) or the maximum operating temperature exceeds 200ºF (93ºC) during normal plant operating conditions. Piping systems that operate above these limits but for only a relatively short time (i.e., less than approximately 2% of the time) during which they perform their intended function may be classified as moderate energy.

Intensity This is a measure of the damage or potential for damage observed at a particular site because of an earthquake.

Leak-Tight Integrity This is a condition describing an assembly or grouping of systems or components relative to their ability to leak.

Low-Cycle Fatigue This is a progressive fracture or cumulative fatigue damage of the material that may be inflicted by less than 1,000 cycles of load because of localized stress concentration at high strains under fluctuating loads.

Magnitude This is a measure of the size of an earthquake and is related to the energy released by the earthquake.

Maximum (Peak) Ground Acceleration For a given site, this is defined as the value of acceleration that corresponds to the zero period in the design-response spectra for that site. At zero period, the design-response spectra acceleration is identical for all damping values and is equal to the maximum (peak) ground acceleration specified for that site.

Moderate-Energy Piping System Any system—or portion of a system—in which the maximum operating pressure is 275 psig (1.87 MPa) or less and the maximum operating temperature is 200ºF (93ºC) or less during normal plant-operating conditions. All piping systems pressurized above atmospheric conditions and not classified as high energy shall be classified as moderate-energy piping systems.

Narrow Band–Response Spectrum This is a response spectrum that describes motion in which the amplified response occurs over a limited (narrow) range of frequencies.

Natural Frequency This is a term for the frequency or frequencies at which a body vibrates because of its own physical characteristics (mass and stiffness) when the body is pertubated in a specific direction and then released.

Normal Mode Time-history methods may use the normal mode theory and a time history of the input motion. When normal mode theory is used, the maximum response is determined by obtaining the combined response of all individual modes at a particular instant of time.

Nuclear Safety–Related This modifier is of importance because it applies to the following:

(1) SSCs designed to perform a nuclear safety function.
(2) Drawings, specifications, procedures, analyses, and other documents used to determine or describe parameters affecting SSCs that are designed to perform a nuclear safety function.
(3) Services to design, purchase, fabricate, handle, ship, store, clean, erect, install, test, operate, maintain, repair, refuel, and modify SSCs that are designed to perform a nuclear safety function.

Octave This is the interval between two frequencies that have a frequency ratio of 2.

Operating-Basis Earthquake (OBE) This is an earthquake that, considering the regional and local geology and seismology as well as specific characteristics of local subsurface material, could reasonably be expected to affect the plant site during its operating life (100 yr. return period). In new plant design, the OBE is not considered in design if it is defined as having a PGA less than one-third of the safe shutdown earthquake (SSE).

Owner This is the organization responsible for the operation, maintenance, safety, and power generation of the nuclear power plant.

Passive Failure This is the blockage of a process-flow path, or failure of a component to maintain its structural integrity or stability, so that it cannot provide its intended nuclear safety function upon demand.

Pipe Whip This is a term for the rapid motion of a pipe resulting from the forces exerted from a postulated pipe break.

Pipe-Whip Restraint This is a device, including its anchorage, used to control pipe whip.

Piping Network This is an interconnected system of main or branch runs (or both) used in the analytical model.

Piping Run This is a section of piping with at least one terminal end. It may also originate as a branch of another piping section.

Postulated Pipe Break This is a term for a postulated circumferential or longitudinal break including orientation in a piping system.

Power Spectral Density (PSD) This is the mean squared amplitude per frequency for acceleration waveforms. It is expressed in g^2/Hz versus frequency for acceleration waveforms.

Proof Test This is a seismic test performed after choosing the appropriate type of test to be performed to demonstrate a seismic motion design requirement to be met. In this case, the seismic motion (required response spectrum [RRS], or g value) is specified and the type of seismic test is chosen to meet that specification.

Prototype This is a term for a system built on the basis of an original design for which no previous system test results are available.

Required Input Motion (RIM) This is the input motion in terms of acceleration, velocity, or displacement expressed as a function of frequency, for which the equipment or component shall be qualified for its acceptance.

Required Response Spectrum (RRS) This is the response spectrum issued by the Owner (or agent) as part of the specification for seismically qualifying equipment. The RRS constitutes a requirement to be met in qualifying equipment.

Resonance Frequency The frequency at which the system's natural frequency matches the forcing function frequency. This is a frequency at which peak response occurs in a system subject to forced vibration.

Response Spectrum This is a plot of the maximum response, as a function of frequency (or period), of an array of SDOF-damped oscillators subjected to the same time history–base excitation.

Rigid This is a descriptive term for structures or components in which the fundamental frequency is equal to or greater than the ZPA frequency.

Rigid Range This term is used to describe those frequencies of SSCs in which the natural frequencies are greater than some value at which dynamic response acceleration is essentially the same as that of the input acceleration.

Rock For the purposes of this chapter, *rock* is defined as any material with shear-wave velocity of 3,500 ft/sec (1,100 m/sec) or greater.

Ruggedness This is the ability of equipment to perform its specified function when subjected to dynamic excitation.

Safe Shutdown Earthquake (SSE) This is an earthquake that produces the maximum vibratory ground motion for which SSCs important to safety are designed to remain functional. The basis of determining what constitutes an SSE is an evaluation of the maximum earthquake potential at a plant site that considers regional and local seismology in addition to specific characteristics of local subsurface material. In current new plant design it is associated with a 10^{-4}/yr. to 10^{-5}/yr. earthquake exceedence level based on the shape of the response spectra used to represent the SSE.

Seismic Category I This is the category of nuclear safety-related SSCs that are required to perform their nuclear safety function during or after an SSE as necessary to accommodate any design-basis event involving an SSE.

Service Level A Service Level A Limits are those sets of limits that must be satisfied for all Service Level A Loadings identified in the Design Specifications to which the system, component, or support may be subjected in the performance of its specified service function.

Service Level B Service Level B Limits are those sets of limits that must be satisfied for all Service Level B Loadings identified in the Design Specifications for which these Service Limits are designated. The system, component, or support must withstand these loadings without damage requiring repair.

Service Level C Service Level C Limits are those sets of limits that must be satisfied for all Service Level C Loadings identified in the Design Specifications for which these Service Limits are designated. These sets of limits permit large deformations in areas of structural discontinuity that may necessitate the removal of the system, component, or support from service for inspection or repair of damage to the component or support. Therefore, the selection of this limit shall be reviewed by the Owner for compatibility with established system safety criteria.

Service Level D Service Level D Limits are those sets of limits that must be satisfied for all Service Level D Loadings identified in the Design Specifications for which these Service Limits are designated. These sets of limits permit gross general deformations with some consequent loss of dimensional stability and damage requiring repair. Removal of the component or support from service may be required. Therefore, the selection of this limit shall be reviewed by the Owner for compatibility with established system safety criteria.

Sine Beat This is a continuous sinusoid, of one frequency, with its amplitude modulated by a sinusoid of a lower frequency.

Slug Flow A phenomena associated with two phase flow wherein the liquid phase travels at a different speed than the gas and is non-uniform in its mass flow rate. This results in a time varying force on the containment system due to changes in the momentum of the transported fluid.

Spectrum-Consistent Time History This is a time history that is generated artificially to essentially envelop a given design-response spectrum.

Steady-State Vibrations These are repetitive vibrations that occur for relatively long time periods during normal plant operation.

Structural Integrity This is a condition that describes an assembly or grouping of systems or components relative to their ability to carry applicable loads within the limits of acceptable structural behavior.

Structure This is a term for a combination of physical members that constitutes an item—a building or a support, for example—that is designed to sustain a load.

Synthetic Time History This is a time history that is typically developed numerically so that its response-spectrum characteristics match or exceed those of the specified design-response spectrum.

System This is a term for an assembly or grouping of equipment or components that performs a specific plant function.

Terminal End This is the section of piping originating at a structure or component (such as a vessel or component nozzle or structural piping anchor) that acts as an essentially rigid constraint to the piping thermal expansion. Typically, an anchor assumed for

the piping code stress analysis is a terminal end. A branch connection to a main run is one of the terminal ends of a branch run, except for the special case in which the branch pipe is classified as part of a main run (see the definition for branch run). In-line fittings (such as valves) that are not anchored in the piping stress analysis are not considered terminal ends.

Test Response Spectrum (TRS) This is the response spectrum developed from the actual time-history motion of the shake table or other dynamic-input test device.

Transfer Function This is a complex frequency-response function that defines the dynamic characteristics of a constant parameter linear system. For an ideal system, the transfer function is the ratio of the Fourier transform of the output to that of a given input. The output-input ratio function versus frequency is called a transmissibility function.

Transient Vibrations These are vibrations occurring for relatively short time periods and resulting in less than 10^6 stress cycles. Examples of transient sources of vibration are pump actuation and pump switching, rapid valve opening or closing, and safety-relief valve operation.

Uncoupled This is a term for structures and plant equipment that, because of their mass and stiffness properties, do not significantly influence the dynamic response of each other and can be considered in separate dynamic analyses.

Zero Period Acceleration (ZPA) This is the high-frequency acceleration level of the nonamplified portion of the response spectrum. The acceleration corresponds to the maximum acceleration amplitude of the time history used to derive the spectrum.

Zero-Period Acceleration This is the response-spectrum acceleration in the rigid range of the spectrum (typically above 33 Hz).

ZPA Frequency This is the lowest frequency at which a response spectrum returns to approximately the zero-period acceleration. In Appendix N [1], this frequency is defined as 33 Hz.

6.4 BASIC EQUATIONS OF MOTION AND TIME-DEPENDENT LOADING FUNCTIONS

6.4.1 Cyclic Loads

The basic equations of motion can be found in ref. [15] or other similar introductory texts on structural dynamics. Those equations involve the following parameters:

$$m\ddot{x} + c\dot{x} + kx = f(t) \tag{6.1}$$

where

m = mass of the system or component
k = stiffness of the system or component
c = damping coefficient, due to energy absorption in the material and system
$f(t)$ = dynamic forcing function
x = displacement of the system or component for a particular degree of freedom
x = velocity of the system or component for a particular degree of freedom, dx/dt
$\ddot{x}$ = acceleration of the system or component for a particular degree of freedom, d^2x/dt^2

The actual formulation and method of solution of the general differential equation of motion depends considerably on the nature and location of the forcing function $f(t)$. For cyclic loads, the system or component is usually represented as a multi–degree-of-freedom system with multidirectional input in which the force applied to a given mass point is a function of that mass point's inertial properties in response to a base-input motion rather than an external force applied to the system or component. This type of loading lends itself to solution by the modal response spectrum method of analysis [15].

Associated with the solution of the basic equation of motion, ignoring damping and the forcing function, are the following relationships:

$$w = \sqrt{\frac{k}{m}} \tag{6.2}$$

where

w = is the natural frequency of the system or component in radians/sec

And,

$$f = \frac{1}{2\pi}\sqrt{\frac{k}{m}} \tag{6.3}$$

where

f = natural frequency of the system or component in cycles/sec or Hz
π = 3.1416

It has been found for cyclic (earthquake and vibratory) design loads in which the dynamic force is the result of inertial response to a base motion loading, the solution is expedited by variable substitution such as a modal equation of motion becomes

$$\ddot{A}_i + 2w_i\beta_i\dot{A}_i + w_i^2A_i = P_i\,\ddot{x}_s \tag{6.4}$$

where

A_i = modal displacement (rotation) of mode i relative to the base
$\dot{A}_i$ = modal velocity (rotational) of mode i relative to the base
$\ddot{A}_i$ = modal acceleration (rotational) of mode i relative to the base
w_i = natural frequency in mode i in radians/sec
β_i = percent critical damping in the ith mode
$\ddot{x}_s$ = absolute translational (angular) acceleration of the base
P_i = modal participation factor of the ith mode

$$P_i = \sum_{r-1}^{n} m_r\Phi'_{ri}/m_r\Phi_{ri}^2 \tag{6.5}$$

Finally, the inertial force applied to the rth mass in the ith mode becomes

$$f_{ri} = m_r a_{ri} = m_r(P_iS_{ai}\Phi_{ri}) \tag{6.6}$$

where

a_{ri} = inertia acceleration applied to the r mass in the ith mode
m_r = the rth mass
P_i = modal participation factor in the ith mode
f_{ri} = inertia force applied to the rth mass in the ith mode
S_{ai} = response spectra acceleration in the ith mode (damping is built into this parameter) response spectra are a plot

of the maximum response of a series of SDOFs to the earthquake time-history input

Φ'_{ri} = modal displacement of the rth mass in the ith mode in the direction of the applied earthquake motion

Φ_{ri} = all modal displacements of the rth masses in the ith mode

The Φ_{ri} are Eigen vectors; the w_i^2 are the Eigen-values solution of the modal equation of motion.

6.4.2 Impulse Loads

For impulse loads, the time-dependent force is external and is usually applied to a limited number of node points of the target. In first-order analysis, it is often considered applicable to a single mass point at a discharge point or postulated break location; an equivalent static load is determined by the response of the mass point including its stiffness restraint to the time dependent loading [7], [15]. This equivalent static external load is then applied to nodes of a static model of the target to obtain resultant internal forces and moments.

$$F_e = D_f \times C_T \times K \left[\frac{W}{g} V_e + (P - P_o) \right] A \tag{6.7}$$

where

C_T = fluid thrust coefficient, 1.26 for saturated steam and 2.0 for subcooled liquid

F_e = equivalent static reaction force at exit or break plane (lbf; N)

W = mass flow rate (lbm/sec; kg/sec)

V_e = exit velocity of fluid (ft/sec; m/sec)

g = gravitational constant (32.2 lbm × ft/lbf × sec^2; 9.8 kg × m/N × sec^2)

D_f = dynamic load factor for suddenly applied loads (see Fig. 6.1)

P = static pressure at exit (psia; kPa)

P_0 = ambient pressure (psia; kPa)

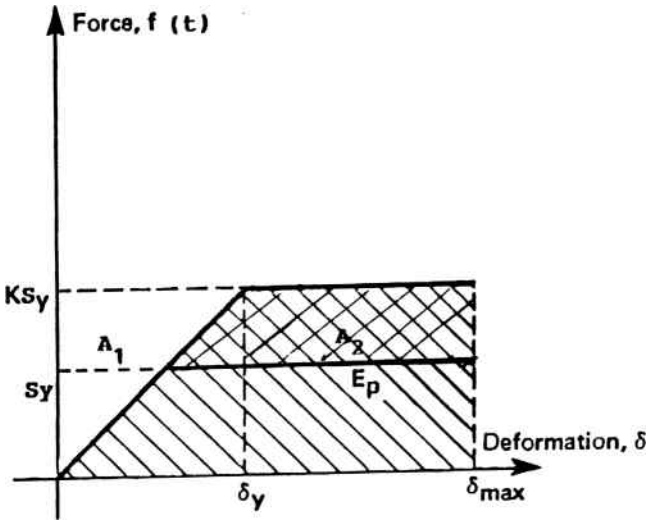


FIG. 6.1 ELASTIC–PLASTIC STRUCTURAL RESPONSE DIAGRAM KS_Y IS DETERMINED SO THAT THE AREA A_2 IS EQUAL TO A_1 GIVEN, AND THE FORCE $F(t)$ HAS BEEN SUDDENLY APPLIED TO A SDOF SYSTEM; IN THE LIMIT, K = 2.0 IF THE RESPONSE IS REQUIRED TO BE ELASTIC

A = exit area

K = exit orifice coefficient depending on the shape of the nozzle or opening (it can vary between 2.0 and 1.0 and it is usually taken equal to 1.0 for pipe break impulsive loads)

The term P_0 is often set to zero because it is taken as atmospheric pressure, 14.7 psia (100 kPa) or somewhat higher if it is discharging into a partially enclosed space. A more detailed discussion of the pressure relief valve–discharge loading can be found in ref. [7].

The analysis of a closed discharge system is considerably more complex; as such, it is usually solved by computer programs that consider transient flow conditions and reflected pressure waves in a closed fluid system. This process is normally done by hydrodynamic computer codes based on control volumes with different time-dependent boundary conditions, as discussed in ref. [16].

6.4.3 Impact Loads

For relatively hard or nondeformable missile impact, the overall deflection of a target structure or barrier during impact is considered negligible when compared to penetration in which the work done by the missile as it penetrates the structure is equal to the initial kinetic energy. Thus

$$F_t = 0.5 \frac{w}{g} v_0^2 \tag{6.8}$$

where

F_t = time-dependent force of impact

g = acceleration of gravity

W = weight of missile

y = initial velocity of missile

x = penetration

The assumption that the velocity reduces linearly to 0 is used to determine the time of impulse or duration of the impact force.

$$t = 2x/v \tag{6.9}$$

The value of F and t therefore define a rectangular-impulse loading applied to a deformable target structure impacted by a rigid, nondeformable missile.

For relatively soft or deformable missile impacts, the forcing function can be determined as follows:

$$F = P + 1.0uv^2 \tag{6.10}$$

where

P = missile crushing-strength at impact interface

u = mass/unit length of the uncrushed missile at impact interface

v = velocity of the uncrushed portion of missile relative to the barrier

F = force applied to the rigid structure

As it acts on the target structure barrier, the force F_t can be determined by integrating the motion of the missile to determine the point of missile in contact with the barrier and its instantaneous velocity.

The first-order evaluation of impact or impulse dynamic loads is usually taken as a rectangular or triangular forcing function

applied perpendicular to the plane of the relief-valve discharge or postulated break. The system or component frequency excited by the forcing function represented as an SDOF system is used to determine an equivalent static load.

6.5 EARTHQUAKE LOADS

6.5.1 Introduction

This type of motion is generally taken as cyclic. Loads associated with this cyclic input can be generally solved by time-step integration of the equations of motion, but more often the simplified method of response spectrum modal analysis is used.

Historically for nuclear power plant (NPP) design, three generic earthquake free-field–ground-surface time-histories have been used in addition to many site-specific time-histories of motion. Analyses have generally used response-spectra representations of these time-history motions.

6.5.2 Ground-Response Spectra

Four sets of response-spectra-shape-amplification parameters for various damping values are found in Table 6.1 for various damping values and, as shown in Fig. 6.2, for 5% damping. The Housner spectrum a weighted-average spectrum is based on four different earthquake-response time-histories. The Regulatory Guide 1.60 spectrum is a mean-plus-one standard deviation in the amplified region that reduces to a mean acceleration in the high-frequency unamplified region; it is based on 14 recorded earthquake time-histories. Both of these spectra have some degree of conservatism by defining damping at lowerbound values and using weighted-average or mean-plus-one standard deviation spectral shapes. The spectral shape designated as NUREG/CR-0098 has recently become popular; it is generally considered a generic free-field–ground-surface median spectral shape and employs best-estimate damping values. It has been used excessively for verifying seismic design adequacy of existing plants and is generically recommended for the design of new NPPs, where the use of site-specific spectra has not been specified [17]. For completeness, the spectral shape contained in the International Building Code—applicable to the United States—is also given in Fig. 6.2. In general, it can be expected that site-specific spectra can be developed either by deterministic and/or probabilistic means that can be used as earthquake input to a particular site, which will somewhat reduce the energy content of the generic spectra shown in Fig. 6.2.

The current (2010) Appendix N, Tables N-1221(a & b)-1, presents inflection point values for the construction of response spectra based on the percent of critical damping. These values are illustrated in Table 6.2.

When these data are plotted on a log-log scale as shown in Fig. 6.3, a significant difference in the spectra is evident. The spectra in the current Appendix N uses a straight line interpolation between the spectral values on the log-log chart whereas the previous spectra were developed using a straight line on a chart with the period on a linear scale. This results in an added degree of conservatism in the new spectra.

The introduction of floor response spectra (covered in the next section) resulted in higher loads being placed on equipment in upper stories of structures. The cost implications of these higher design loads have led many owners to call for the development of site-specific time histories and ground response spectra. As stated in ASCE 7-02 [3] "A site-specific study shall account for the regional seismicity and geology, the expected recurrence rates and maximum magnitudes of events on known faults and source zones, the location of the site with respect to these near source effects, if any, and the characteristics of subsurface site conditions." Generally, the uses of this site-specific data tend to be less conservative than the generic data that has been discussed.

For an existing NPP site, a 10^{-3}/yr. to 10^{-5}/yr. occurrence or exceedence probability is used for most safety-related SSCs in conjunction with the Regulatory Guide 1.60 shaped spectrum. A 10^{-4}/yr. probability of exceedence is expected to be used in conjunction with the median NUREG/CR-0098 shaped spectra. The IBC spectrum is associated with a 4 10^{-4}/yr. earthquake occurrence exceedence level; it is sometimes applied to safety-related items associated with radioactive material storage and processing at NPP sites rather than safety-related SSCs associated with nuclear reactor operation.

TABLE 6.1 GENERIC EARTHQUAKE GROUND-RESPONSE–HORIZONTAL COMPONENT-AMPLIFICATION FACTOR [Note (1)]

	weighted average Housner			RG 1.60 horizontal, median plus one standard deviation			NUREG CR/0098 horizontal median		
% crit damp	acc.	velocity	disp.	acc.	Velocity	disp.	acc.	Velocity	disp.
0.5	6.2	2.7	1.4	5.95	3.7	3.2	3.68	2.59	2.01
1	4.6	--	--	--	--	--	3.21	2.31	1.82
2	3.1	--	--	4.25	3.2	2.5	2.74	2.03	1.63
5	2.3	1.6	1.2	3.13	2.4	2.05	2.12	1.65	1.39
7	1.5	1.3	1.0	2.72	2.1	1.88	1.89	1.51	1.29
10	--	--	--	2.28	1.8	1.70	1.64	1.37	1.20
20	--	--	--	--	--	--	1.17	1.08	1.01

General Note: (a) Based on standard relative earthquake maximum values of ground motion, acceleration = 0.10 g, velocity = 4.8 in./sec, and displacement = 3.6 in.

Note:
(1) For vertical motion, slightly different amplification values are sometimes defined. The PGA spectral in the vertical direction is reduced to 0.67 of the horizontal spectral values.

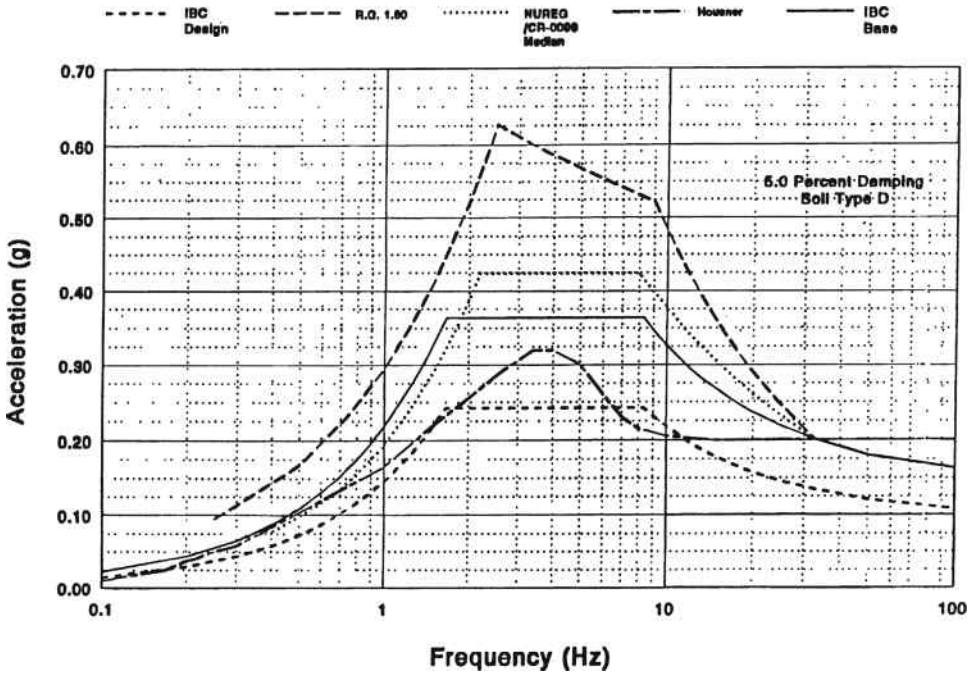


FIG. 6.2 GENERIC EARTHQUAKE-RESPONSE SPECTRAL SHAPE

TABLE 6.2 APPENDIX N HORIZONTAL RESPONSE SPECTRA VALUES - IN/SEC

	Percent Critical Damping				
Frequency -Hz	0.5	2	5	7	10
0.1	72.38	56.55	46.37	42.52	38.45
0.25	180.96	141.37	115.92	106.31	96.13
2.5	146.36	104.55	104.55	66.91	56.09
9	33.89	24.19	24.19	15.51	12.98
33	1.86	1.86	1.86	1.86	1.86

It is anticipated that any new zero period acceleration NPP safety related SSC will use a 10^{-5}/yr. median probability of occurrence or exceedence with median damping and shaped spectra as shown in NUREG/CR-0098 (as noted in Table 6.1). Alternatively, a 10^{-4}/yr. median-plus-one standard deviation as defined in R.G 1.60 or mean zero period ground acceleration with the spectral shape as shown in Fig. 6.2 and the associated damping of R.G 1.61 [37] will be used.

6.5.3 Floor-Response Spectra

The earthquake motion applicable to mechanical systems or components in the form of a response spectrum or a time-history acceleration are usually affected by the building structures through which they are transmitted. Such building structures tend to vibrate at their own dominant natural frequencies. Consequently, the near-random or white-noise earthquake ground motion introduced at the base of the building (primary) structure is made more sinusoidal, which gives a significantly higher response at a given percent critical damping to systems and components (secondary) near the dominant frequency of the building (primary) structure.

Most equipment will have negligible interaction effects on the primary structure—as in the case of equipment with relatively small mass and high frequency—and will only need to be included in the mass distribution of the primary system model. However, there are major equipment systems, such as a reactor coolant system or large pressure vessel, in which the stiffness, mass, and resulting frequency range should be considered for representation in the building model to account for possible dynamic-interaction effects.

For most architectural, mechanical, and electrical systems and components (secondary), a separate analysis of the secondary system may be performed using output from the building analysis. If building–equipment interaction is significant, as defined in refs. [1] and [2], the equipment should be included in an integrated mathematical model of the structure. The representation of the equipment included in the building model should be adequate to consider major interaction effects, but it need not be as detailed as the mathematical model used in a separate analysis of the equipment.

When a coupled model is used additional concern, is that some of the stresses in the secondary system will be primary (inertia-induced) and some secondary (building static deformation–induced). Because the allowable stress limits in mechanical systems and components have different allowable stresses for primary and secondary stresses, it is important that a means be found to distinguish between these primary and secondary stress resultants. One such approach is to reanalyze the coupled model and set the secondary mass to near 0; the resulting stress in mechanical system or component should be secondary in nature. Another method

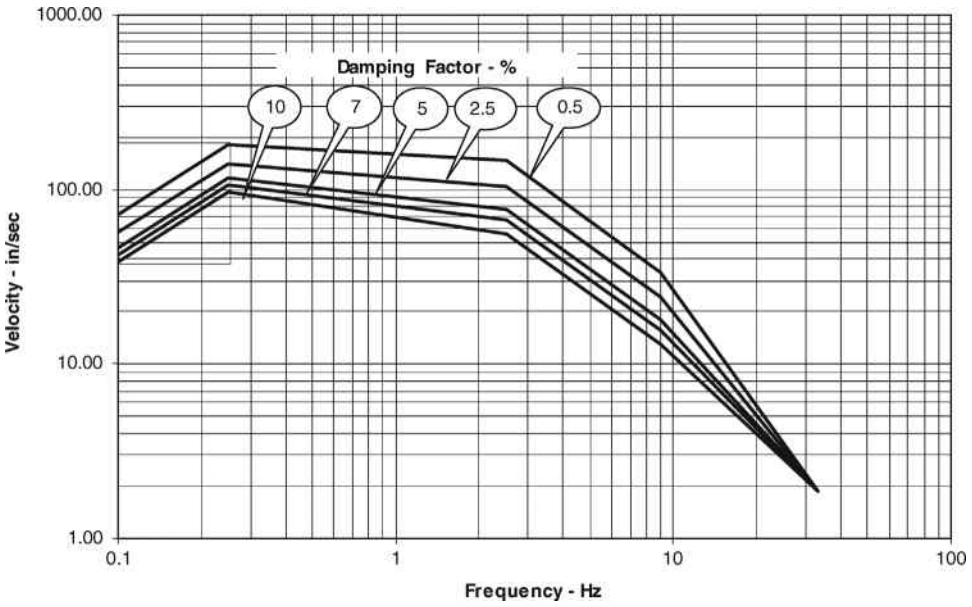


FIG. 6.3 HORIZONTAL DESIGN RESPONSE SPECTRA SCALED TO 1 G HORIZONTAL GROUND ACCELERATION (APPENDIX N, FIGURE N-1211(A)-1)

is to record the maximum displacements in each mode and apply them to a model of the secondary systems, thereby determining the stress resultants in each mode. The model stresses, when combined on an SRSS basis, would yield the secondary stress component of the secondary system.

Systems and components (secondary) may be analyzed by combining the complete secondary model with the support structure (primary) model and applying the proper excitation to the base of the primary model. In this method, no separate equipment-decoupled support excitations need to be generated, as the equipment will be excited directly through the structure.

For equipment that is not analyzed as part of the building structural model, the response may be obtained by a separate analysis using floor-response spectra curves, time-history excitations at the point of the support(s), or other frequency-domain methods.

It should be noted that in dynamically coupled system, both stiffness and mass of both systems are represented, not just mass alone when generating primary-structure floor-response spectra applicable to the secondary system. Oftentimes significant coupling can result in higher loads in the primary system and lower loads in the secondary system than when they are analyzed considering no dynamic coupling. A secondary to primary effective mass ratio of as little as 0.1% can add the effect of 3% more damping [17]. However, the U.S. Nuclear Regulatory Commission (USNRC) has not permitted the use of the mass ratio effect in the generation of floor-response spectra, although it is included in the result of a coupled model analysis.

6.5.4 Time Histories

A series of time-history input motions can be used to represent the earthquake's motions at a site as a function of distance from the earthquake epicenter, stress drop, earthquake magnitude, and local site and foundation conditions. These input motions can be solved for resultant inertial and displacement-induced stresses by numerical methods used to solve the equations of motion, or else by transformation to the solution of modal equations of motion. Alternatively, for each response spectra defined in Section 6.5.2, independent artificial time history in each direction can be generated that (when applied with the desired damping) will envelop the specified generic response spectra with similar power spectral content.

6.5.5 Time-History Duration

Generally, the minimum duration of the strong seismic motion required may be taken as 6 sec for ASME systems and components [1]. If this minimum 6 sec strong-motion duration is used, then a buildup duration of about 4 sec is recommended to precede the strong motion. The buildup region may be taken as the time duration from when motion is 0 to the time from when stationary or strong motion begins. For modal analysis, the number of maximum earthquake duration stress cycles can be taken as 10 for any earthquake event. Earthquake strong-motion durations and full-cyclic equivalency are also a function of earthquake magnitude. Values given herein are applicable to M_r equal to or less than about 7.0.

6.5.6 Direction and Time-Phase Considerations

Three orthogonal components of earthquake excitations are normally considered for NPP safety–related system and component design. (Rotational ground motion in the three directions, however, may be neglected.) The triaxial-input excitations are characterized by the relative magnitudes of the peak accelerations of the three excitations and the relative values of the response spectra over the frequency range of interest. The artificially generated time histories used to represent the generic response spectra may not have time-phase relationships similar to those of past

earthquake records. The procedures of refs. [1] or [2] may be used to ensure that time-phasing is acceptable.

The peak acceleration of the three orthogonal artificially generated time histories generally need not occur at the same time. To stimulate natural earthquake occurrences, the correlation of the synthesized time histories may be evaluated by calculating the cross-correlation coefficients and the coherence functions [1]–[2]. The artificially generated time histories are acceptable if both their cross-correlation coefficients and their coherence functions are approximately equal to the respective functions for past earthquake records. An absolute value of the correlation coefficient less than 0.16 is acceptable. For the correlation function, the numerical values ranging between 0.0 and 0.3 (with an average of approximately 0.2) are acceptable.

6.5.7 Methods of Dynamic-Earthquake Analysis

Methods commonly used to determine resultant earthquake stresses in architectural, mechanical, or electrical systems and components can be found in refs. [1], [2], and [3].

It is common practice today to use computer FE codes to compute the response of systems to earthquake loads. This practice is not without problems however. First, it can easily result in answers that have little to do with the actual problem unless the analyst is able to manually follow the load path and bound the expected results. Second, not only are there a multiplicity of FE codes, but there are wholly different "flavors" of FE codes used by different disciplines in the plant design process.

Civil/structural engineers tend to use FE codes that specifically address the issues associated with building codes. These FE programs such as STAAD [18] and RISA [19] will generate input response spectra for the system based on existing building code data or allow the input of site-specific data. They have a high level of sophistication for seismic analysis and, with an experienced analyst, can be quite accurate.

Piping engineers also have highly sophisticated FE codes that specifically address piping issues such as the various types of piping supports and snubbers. FE-based codes such as Caesar-II [20] and PIPESTRESS [21] are specifically tailored to the needs of piping engineers. As with the civil/structural codes, the seismic capabilities of the piping analysis codes have been refined over a long period of time and have been well vetted.

Vessel and equipment engineers have increasingly employed general purpose FE codes such as Algor [22], Ansys [23] and Nastran [24] for stress analysis. These codes normally do not have the nearly automatic response spectra-generating capabilities of the structural and piping codes. Nonetheless, once generated, the response spectra can be entered as input data and the responses computed.

While the availability and utility of the various codes is quite good, there remains a significant problem. In a typical plant, the structure, piping, vessels and other equipment are generally interconnected. One system can impose loads on the other or, under circumstances mentioned in 6.5.3, they can provide damping. Since there currently exists no clear way to determine whether one system loads or damps the other by separate analyses, we are left with an unresolved solution that must be "covered" by conservatism in the analysis. Manually passing data from one type of code to the other to define the boundary conditions can help remove *some* of the uncertainty. However, at this time, there is no automatic way to couple the results from the different flavors of FE software.

Several methods for the analysis have been proposed. An evaluation [25] of the various techniques has been conducted by the USNRC. The results of the evaluation seem to indicate that at least some of the techniques provide acceptable results. At this time, however, no commercially available implementation of the techniques is known to the author.

Finally, the bad news must be addressed. While all of the currently available FE codes can accurately compute the displacements and stresses associated with seismic excitation according to the principals established primarily by the nuclear industry, the process itself is inherently flawed.

The long established practice has been to compute the deflection associated with each modes of the response and to then sum the deflections using some variant of the SRSS procedure. Unfortunately, when this is done, all directional information is lost and the computed deflection sum is always positive. The stresses are then computed based on the resultant deflection. Thus, computed stresses are based on a fictitious deflected shape and are correspondingly fictitious. It is generally accepted that the computed stresses represent an upper bound on the actual stress, but the degree of conservatism (if any) is not known.

The current process was developed in the 1960's and 1970's when computational resources were miniscule compared to what is available today. Unfortunately, the nuclear industry, which drove the development of the original process, has not exactly prospered during the ensuing time period. Thus, no updates have been made on the process that was developed as an estimate of the actual stresses. A process that computed the stress associated with each mode on an element or nodal basis and then summed the stresses would be computationally reasonable today and would likely provide better stress estimates.

6.5.8 Damping

The phenomenon of energy loss called damping occurs because motions in a structural system will usually dissipate energy from the system. Damping as it relates to the equation of motion may be mathematically represented in many ways, including Coulomb and viscous damping [15]—the latter being the one normally used in NPP design, as represented in equation (6.1). Total system or component damping is composed of many energy-absorption mechanisms—material damping, for instance, caused by internal friction with the material, as well as geometric damping (caused by the working of joints, connections, and associated small nonlinearities such as cracking in concrete) and impact damping (caused by gaps that open and close, thereby dissipating energy by local impact). Taken together, these various components of damping are structural damping as shown in Table 6.3.

In the current (2007) version of Appendix N, a more compact table of damping values is presented, as illustrated in Table 6.4.

Two values for each component are listed. The smaller damping value is to be used for the OBE. A second, higher value is indicated for the SSE. This reflects the fact that a higher load in the SSE will result in higher deflections and some associated plastic deformation is permissible. Notably missing from Table 6.4 are any values associated with fluid sloshing. All of the existing codes and guidelines suggest a value of 0.5% for sloshing, whether for the OBE or the SSE.

6.5.9 Cutoff-Frequency and Missing-Mass Effects

Generally, the piping response-spectrum analysis is terminated at a frequency called the cutoff frequency. The cutoff frequency is usually specified as the frequency beyond which the spectral acceleration remains constant, which is known as the zero period acceleration (ZPA).

TABLE 6.3 STRUCTURAL PERCENT CRITICAL MODAL DAMPING

ITEMS	DAMPING (% of critical damping)		
	with stress levels<yield		with stress levels ≥yield
	Old [Notes (1)–(2)]	New [Note (3)]	
(a) Structures:			
(1) Reinforced concrete structures:	7.0	7.0	10.0
(2) Welded steel structures:	4.0	5.0	7.0
(3) Bolted or riveted steel structures:	7.0	7.0	10.0
(4) Reinforced masonry walls:	4.0	7.0	10.0
(5) Unreinforced masonry walls:	--	5.0	7.0
(6) Steel structures with precast panels:	--	7.0	7.0
(b) Soil: For simplified soil-structure interaction analysis (SSI) radiation damping as a function of structural foundation geometry and material properties will not be limited but resultant composite modal damping should not exceed values in typical national standards (i.e., 15.0 percent). However, the use of higher values, if properly justified and determined, would be permitted.			
(c) Systems and Components: (except the following):	3.0	5.0	5.0
(1) Tank liquid sloshing:	0.5	0.5	0.5
(2) Cable Raceway: if at least one quarter full of loose cable	7.0	10.0	15.0
(3) HVAC Duct:	7.0	7.0	7.0
(4) Vertical pumps: (deep well and emersion)	3.0	3.0	3.0
(5) Instrument racks	4.0	3.0	3.0

Notes: (1) Old damping values are based on the use of USNRC Regulatory Guide 1.61 (damping) and Regulatory Guide 1.60 (shaped spectra).
(2) Housner damping limited to 0.5% damping for piping.
(3) Based on the use of NUREG/CR-0098 shaped spectra.

Assuming that a piping system is so designed and supported that the first mode frequency (or another significant higher frequency) is higher than the cutoff frequency, this piping system does not receive seismic excitation from a mode higher than the cutoff frequency as far as the computer program is concerned. The result of this seismic analysis may be invalid because of the artificial constraint on frequency specified by the stress analyst.

Most of the computer programs currently used for piping stress analysis have the capability to evaluate the missing-mass effect. These programs usually use the acceleration from the spectrum at the cutoff frequency (ZPA) to calculate the missing-mass effect. However, because the programs do not use the higher frequency-mode shapes, the missing-mass correction factor should not be used unless at least 70% of the model effective mass is included in the modes evaluated up to and including the cutoff frequency.

TABLE 6.4 APPENDIX N DAMPING VALUES - % CRITICAL

	Earthquake Magnitude	
Structure or Component	OBE	SSE
Equipment	2	3
Piping systems	5	5
Welded steel structures	2	4
Bolted steel structures	4	7
Prestressed concrete structures	2	5
Reinforced concrete structures	4	7

6.5.10 Combinations of Closely Spaced Modes

Normally, the various response modes determined from a modal analysis are considered independent of each other and may be combined on a statistical square root–sum of squares basis. However, in some cases for systems with closely spaced modes (within 10% frequency or in-phase of each other with essentially the same mode shape), the modes tend to move in unison. In such instances, the combination of modal resultants should be on absolute sum basis.

6.5.11 Combination of Primary Inertia Effects with Secondary Seismic Anchor Motions

When a coupled primary (building) and secondary (piping) system analysis is performed, the result will be time-dependent internal forces and moment: as well as the resultant stresses in the combined system. In general, it is not possible to tell from such a combined dynamic analysis which of the computed stresses are primary and which are secondary. As a practical matter, the secondary stress allowable limits are much higher than the primary stress limit used in design.

One procedure to determine which portion of the dynamically analyzed coupled system–secondary system stresses is secondary is to statically impose on the secondary system the limiting system-support displacements. The stresses resulting from this analysis are secondary. A second method to determine secondary stresses is to rerun the combined model with the masses of the secondary system set to near 0. The results are considered to be secondary stresses.

Seismic excitation can excite long period sloshing response in liquid storage tanks. The sloshing liquid can, in turn, result in large loads applied to the tank supports. In addition, unless sufficient freeboard exists at the top of the tank, a large uplifting force can be exerted on the top of the tank. These phenomena are not directly addressed by the ASME Code.

It is, however, addressed by ASCE Standard 7-02 [3], API Standard 620 [26] and API Standard 650 [27]. The ASCE Standard, in paragraph 9.14.7.3.8.1 states:

> Welded steel petrochemical and industrial tanks and vessels storing liquids shall be designed in accordance with the seismic requirements of [26] and [27] except that the design input forces for allowable stress design procedures shall be modified as follows: . . .

and it then goes on to provide alternate constants for the computation of the overturning moment on the tank. Of the API standards, API 650 is the most applicable to most pressure vessels. In Appendix E-Seismic Design of Storage Tanks, a procedure for computing the sloshing period, the overturning moment and the shell compression is presented. The natural period of the first sloshing period is calculated using the tank diameter and fluid level. The weight and dimensions of the tank, along with the weight and depth of the fluid are used to develop effective masses and centroids of seismic forces from a series of charts. This information must then be used to compute the overturning moments using equation 9.14.7.3.8.1-1 or 9.14.7.3.8.1-2 of ASCE 7-02. Then, the overturning moment calculated from ASCE 7-02 can be used to compute the shell and support stresses in API 650.

This procedure works reasonably well for vertical cylindrical tanks. Horizontal tanks, however, are not addresses in either the ASCE on the API standards. Sloshing in horizontal tanks, such a liquid propane storage tanks, can be problematic during seismic events. Recently, in a paper by Playrrachos and Karamanos [28], a graphical solution for the sloshing period and the forces was presented. This method breaks the forces into impulsive and convective components consistent with the requirements of API 650 and may thus be used to develop the loads on horizontal storage tanks.

6.6 VIBRATORY LOADS

6.6.1 Introduction

Vibratory loads in mechanical systems and components are cyclic and usually arise from the operating environment of the system or component. The following operating conditions may lead to vibratory loads:

(a) inlet or outlet:
  (1) response to rotating or reciprocal pumps,
  (2) fluid pulsation, and
  (3) flow-induced vibration.

6.6.2 Computation of Vibratory Stress

Vibrations in general are very difficult to predict during the design phase of the system or component. The reason is because very small changes in stiffness or mass characteristics of the system can have a major impact on vibratory amplitudes and the number of cycles. In practice, whenever vibratory motions are detected, the vibratory displacement is measured during operation (start-up), and the observed displacement magnitude and cycles are superimposed on a model of the piping system either statically or dynamically. Doing so gives rise to stresses in the piping system. These cyclic vibrational stresses are then considered by using a fatigue or ratchet analysis to determine if the usage factor of 1.0 is exceeded during the operating life of the system or component, for if it is, the vibration may be allowed to continue. It should be understood that vibratory loads can occur during a transient (start-up or shutdown) condition as well as a design-basis accident condition and a steady static-operating condition.

In ref. [9], one can find a detailed discussion of the vibratory-loading phenomena and also simplified but more rigorous procedures for determining the vibratory motions.

6.6.3 Design Considerations

6.6.3.1 Mechanical Vibration The current (2008) state of the art in the computational dynamic analysis of mechanical systems is such that many instances of vibratory excitation and resultant stress can be identified in the design stage. The load imposed on a structure by a rotating or reciprocating component can normally be approximated based on known equipment characteristics. Using FE methods, the supporting structure can be analyzed to determine the lower modal (natural) frequencies. Simply ensuring that the support frequencies do not match (and are ideally higher than) the excitation frequencies can often eliminate potential problems.

Where the support frequency cannot be easily separated from the forcing frequency or where the support frequency is lower than the forcing frequency, it is normally possible to compute the resultant stress in the system. While these methods are not exact (there are details in all real structures that cannot be realistically modeled), they can provide significant guidance in the design process. With today's computational tools, the analysis cost in the design stage can be dwarfed by the remedial cost once the design is cast in concrete and steel.

Similarly, the measurement and analysis tools available should relegate most of the "trial and error" techniques for the solution of vibration problems to the dust bin of history. Accurate, portable, systems for the characterization of vibration in existing systems is readily available. Software that can be used to compare the actual motion of the system to FE models [29] [30] is also readily available. Changes can be evaluated using the software for a fraction of the "trial and error" costs. In addition, the time saved in arriving at a workable solution can often pay for the analysis costs.

6.6.3.2 Pulsation It has been common practice in the natural gas industry to use computational methods to identify and eliminate problems associated with gas pulsations in piping systems driven by reciprocating compressors. Originally, this was done using analog computers. Currently, this is normally accomplished using digital computation procedures using computational codes such as PULS [10]. These techniques have also proven to be very useful in the solution of problems associated with centrifugal pumps and compressors in both compressible and incompressible fluid systems.

6.6.3.3 Flow Induced Vibration Vibration of heat exchanger tube bundles, tall towers and stacks are all examples of flow induced vibration. When the fluid flow around an object reaches a critical velocity, it separates from the object. Under the right circumstances, vortices form behind the object and, coupled with the natural mechanical frequency of the object produce vibrations.

Over time, these vibrations can result in mechanical failure, whether it be in a tube or a tower.

One of the best sources of information on this phenomenon is the book *Flow-Induced Vibration* by Blevins [31]. Many closed form solutions to the prediction of flow-induced vibration are included in this book. Many common problems can be identified using these techniques. Much of this information and additional information pertaining specifically to the vibration of heat exchanger tube banks are presented in Appendix N [1]. For specific problems, the use of CFD techniques has become common. Modeling the flow in a heat exchanger using current CFD tools is now well within the realm of the design process. Where problems are known to exist on existing equipment, the use of CFD can often lead to the most expeditious and economical solution.

6.7 RELIEF-VALVE DISCHARGE LOAD

6.7.1 Introduction

Relief-valve discharge loads belong to the impulse family of loads in that they tend to be applied suddenly and last for a relatively long time period. They are caused primarily by the opening of a pressurized system-relief valve. In general, two types of systems exist that are associated with relief-valve discharges: the open discharge system, in which the back pressure (P_0) is very small or zero, and the closed discharge system. Additional guidance is provided in ref. [7].

6.7.2 Computation of Discharge Loads

Fluid-discharge load effects (as first-order effects) can be computed approximately by applying the equivalent static load equation (6.7) of Section 6.4.2 perpendicular to the plane of the opening. For more rigorous analyses, the hydrodynamic model of the pressurized system is employed by the use of controlled volumes to determine time-dependent changes in pressures and directions throughout the system. Doing so gives rise to many time-dependent forcing functions applied at changes in area and direction through the system.

6.8 FLUIDHAMMER

6.8.1 Introduction

Fluidhammer can occur in any fluid line—hot or cold. Its effects can be even more pronounced in heterogeneous or biphase systems. Biphase systems carry fluids in two states: as a liquid and as a gas or vapor. Such a condition exists in a steam system where condensate coexists with live or flashing steam: in heat exchangers; tracer, steam, and feedwater mains; bypass, let-down, and condensate return lines; and, in some cases, pump discharge lines.

6.8.2 Types of Fluidhammer

Three conditions are identified as having the potential to cause the violent reaction known as fluidhammer: hydraulic shock, thermal shock, and differential shock.

6.8.2.1 Hydraulic Shock When a valve is open, water moves through pipes from the point where it enters the valve housing. When the valve is suddenly shut, a reflected shock wave equal to stragnation pressure in the fluid is generated. The shock pressure wave is reflected back and forth from end to end or from direction changes in the system or component until the energy is dissipated. Similar action can take place in the suction or discharge piping of a pump when the pump starts and stops if check valves are in the line. If the slug of water is slowed before it is stopped, its momentum is reduced gradually, and damaging fluidhammer is not produced. The pressure rise in the system caused by fluidhammer can be several times the equivalent static design pressure, hence the impulse can cause system deformations or rupture.

6.8.2.2 Thermal Shock In biphase systems, vapor bubbles may become trapped in pools of liquid condensing in a flooded main, branch, or tracer by pass- and let-down line as well as in heat-exchanger tubing and pressurized condensate-return lines. Because temperature is almost always below saturation, the vapor bubble will rapidly collapse.

When the steam bubble collapses, water is accelerated into the resulting vacuum from all directions. This happens when a steam trap discharges relatively high-pressure flashing into a pump-discharge line. It can also happen in water-type–pressure suppression NPP containments.

Another cause of waterhammer is lack of proper drainage ahead of a steam-control valve. When the valve opens, a slug of condensate will enter the equipment at a high velocity, producing the liquidhammer when it impinges on obstruction or change in the fluid flow direction. In addition, the mixing of the vapor that follows with the relatively cool condensate will produce hammer from thermal shock. Differential shock, like thermal shock, occurs in biphase systems. It can occur whenever vapor and condensate liquid flow in the same line but at different velocities, such as in condensate-return lines.

In biphase systems, the velocity of the steam is often many times the velocity of the liquid. If condensate fills a pipe, a seal is formed with the pressure of the vapor behind it. Because the steam cannot flow through the condensate seal, pressure drops on the downstream side, and the condensate seal now becomes a "piston" accelerated downstream by this pressure differential. As it is driven downstream, it picks up more liquid, which adds to the condensate slug mass. There is a differential force on the slug, so the velocity of the slug increases, creating a high-impulse load when stopped.

If this slug of condensate gains sufficient momentum, and if it is then required to change direction (e.g., at a tee, elbow, or valve), resultant reaction forces can be of such magnitude that they cause rupture or leakage. To control differential shock, a condensate seal must be prevented from forming in a biphase system. Steam-condensate lines must be sized and pitched correctly (including the sag effects) to ensure that condensates do not collect in the pipe.

6.8.3 Design Considerations

The use of computation software [14] that employs the Method of Characteristics [32] to predict and model fluidhammer has become common in many industries. Whether it is in an NPP or an LNG terminal, the potential for damage to piping and equipment can be eliminated or greatly reduced through analysis of the system in the design stage. Changes to piping lengths, valve closing speeds and sequences, pump shut down and startup characteristics, and/or the addition of expansion chambers can be evaluated at the

design stage. Such changes can often be made with little or no significant effect on the overall system cost. Certainly, such changes are much less expensive that remedial measures, especially when system down-time is considered.

6.9 MULTI-PHASE FLOW ANALYSIS WITH CFD

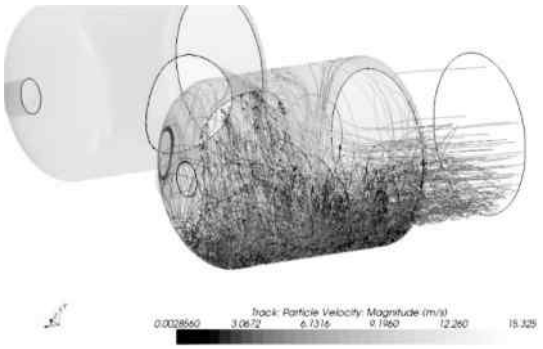
Current CFD physics include three (3) methods to predict the behavior of multi-phase flows: Lagrangian, volume of fluid (VOF), and Eulerian multi-phase (EMP) methods. Using examples of successful analyses that have been used in industry, the following section will demonstrate the application of each of these methods in the solution of multi-phase flow problems. Multi-phase flow physics modeling with CFD has advanced significantly in the recent past, making the use of CFD the preferred choice to model these phenomena.

6.9.1 Lagrangian Methods

In a Lagrangian solution, the dispersed phase is modeled using a statistical tracking algorithm where the particles under consideration are allowed to move through the Eulerian grid used for the fluid solution. This method is appropriate when the discrete phase volume loading is less than 10%. The Lagrangian phase can include size distributions, particle/droplet break-up and coalescence, wall interaction (including the prediction of erosion rates), and mass and heat transfer between the phases in the model.

For this section's Lagrangian example, a waste heat boiler (WHB) displayed high rates of erosive wear on the refractory and on the steel shell. To determine why the high levels of erosive wear were occurring, a CFD model was constructed of the original design configuration. In the Lagrangian analysis, particles with concrete material properties were released into the second-pass bonnet. Erosion tracking was enabled and the results of the analysis indicated high rates of erosive wear (comparable to the damage rates seen in service) within 3 inches of where the actual physical damage was seen in service. This validated the damage mechanism seen in-service and confirmed the selection of model physics.

The figure below shows the calculated particle tracks for one of the design variants that was analyzed.



Using the Lagrangian CFD model allowed validated analysis of five design variants in less than a month. In this case prototypes would have been prohibitively expensive and could not have been physically tested in such a short time-frame.

In addition to the example above, Lagrangian methods are suitable for:

- Concrete plants
- Fuel sprays
- Coal combustion

6.9.2 Volume of Flow Methods

VOF methods assume that the fluids considered in the model are immiscible. In this case the interface between the fluids is explicitly tracked, while the fluids are assumed to have the same velocity within any computational cell. Due to the interface tracking requirements, VOF methods require much more refined grids for accurate solution than other multi-phase flow modeling methods. Additionally, the allowable time-step for VOF solutions can become quite small due to the requirement that the interface cannot be tracked as it translates through more than one grid cell per time-step. VOF analysis techniques can be used to model:

- Evaporation and condensation
- Boiling
- Gas dissolution
- Cavitation, and
- Melting and solidification

Two (2) VOF examples will presented in this paper, a kettle type WHB and the free stream flow and mixing from a nozzle.

6.9.2.1 Kettle Type WHB There are two (2) general types of WHBs. In the kettle type, the flow is driven completely by buoyancy forces caused by the difference in density between the steam and water phases. In the separate steam drum (thermosiphon) type, the head from a separate steam drum is used to create more recirculating flow than the magnitudes caused by only buoyancy. Kettle type boilers can experience a departure from nucleate boiling (DNB) event where the fluid heated by the tubes does not leave the tube surface in jets and streams, and instead a film is produced on the tube limiting heat transfer. In such an event, while the tube metal temperature continues to rise, the amount of heat transferred (to the gaseous steam) decreases. In this case the boiler tubes can be said to have "fallen-off-the-cliff" and if steps are not taken to immediately reduce the level of flux being transferred through the tube, the metal temperature can reach excessively high levels in seconds or minutes. When this occurs the temperatures can reach levels where short-term creep failure can occur.

In an example case, a WHB had experienced a short-term creep failure, resulting in a dimpled tube, as shown in the figure below.



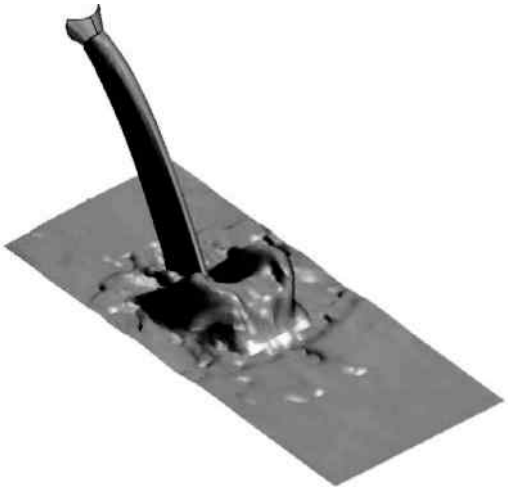
To determine the cause of the failure, CFD models were constructed of both the process (gas) and shell (water/steam) side of the boilers. A coupled analysis was performed to determine the reason that the creep failure occurred.

To perform the shell side analysis, a modification to the CFD model was required to allow the heat flux to be predicted based on the local steam volume fraction, local heat flux, and the temperature differential between the steel tube surface and the water. Through a series of analyses, it was shown that certain operational conditions caused high heat fluxes and, due to the flow patterns on the shell side, that local areas of high

steam volume fraction existed in the design. Both of these conditions can lead to a DNB event. Using the results of the analyses, an operational limit curve was developed for the boiler using measurable process parameters (process side gas mass flow and temperature). The figure below shows the calculated steam volume fraction above each of the boiler's tubes and at the degassing surface within the boiler.



6.9.2.2 Scum Busting Nozzle A series of analyses were being performed to estimate the performance of an anaerobic digester used for sewage treatment. The digester had several nozzles to distribute the return flows and provide mixing. In addition to the under fluid nozzles, the digester had three (3) nozzles placed above the digester to break up "scum" that forms on the free surface of the digester. To determine the performance of the nozzles, a VOF model was developed and analyzed. As shown in the figure below, the analysis of the VOF model indicated a high level of mixing occurring where the nozzle's flow interacted with the free surface of the digester. Due to this interaction, it was determined that the nozzle's flow would actually contribute to creating foaming within the digester rather than reducing. In this case the flow to the nozzles was redirected to the lower level nozzles to provide more mixing energy into the system and to reduce the probability of foaming.

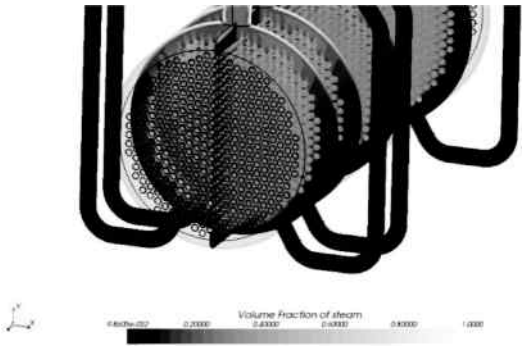


6.9.3 Eulerian Multi-Phase Models

As mentioned in the previous subsection, the VOF model assumes that the phases are immiscible. For situations where there can be interpenetration of species and/or it is known that – locally - the fluids have different velocities, the Eulerian multiphase (EMP) framework has been developed. In this framework the momentum and turbulence equations for each phase are solved independently. While the computational expense for solving the complete set of momentum and turbulence equations for each phase is greater than that for single phase flow, the grid requirements for tracking the phase interface are greatly reduced. In this case the use of an EMP may be less computationally intensive then the use of an equivalent VOF model. Generally, equivalent model physics such as those discussed for the two previous modeling techniques are available with EMP models. Two EMP examples will be presented in this paper: a WHB with a separate steam drum and a distillate charge heater.

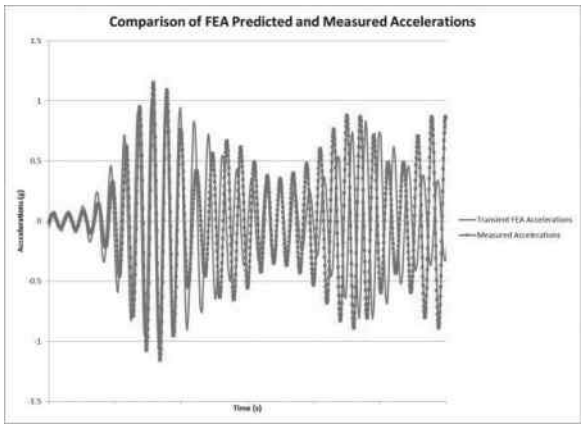
6.9.3.1 Separate Steam Drum WHB The authors have pioneered a variety of the techniques for analyzing WHBs to determine recommended operational limits. Most of the ". . . original work was performed using VOF techniques, primarily because of limitations with EMP models. Proper analysis with a steam drum requires inclusion of the entire first pass of the boiler along with the steam drum and the interconnecting pipe. With recent advances in solution technology and hardware, it has become possible to use EMP techniques to analyze WHBs. This has allowed consideration of separate steam drums. Inclusion of such volumes in a VOF model would be computationally prohibitive.

In this case a series of analyses needed to be performed on a WHB that had experienced failures. The purpose of the analyses was to determine how operational conditions affected the performance of the boiler. A procedure similar to the previous VOF WHB analysis was used to model the process and shell sides of the boiler. The analyses successfully predicted the recirculation rate between the steam drum and the boiler and the maximum fluxes and their associated tube temperatures. The figure below shows the predicted steam volume fractions in the boiler.



6.9.3.2 Distillate Charge Heater A distillate charge heater was experiencing large amplitude vibrations during service. While it was desired to increase the total flow rate to the heater, there was concern that permanent mechanical damage could occur to the heater at higher flow rates. The authors began the analysis of the performance of the heater by taking on-site vibration measurements at different charge feed rates. Through a series of CFD analyses, it was determined that highly complex two-phase flow occurred in the vertical radiant section. Forcing functions based on the unit throughput were developed and used as inputs to transient structural analyses. The response from the structural analysis was

almost identical to the measured performance in the field, as shown in the figure below.



With a validated model it was possible to explore options to change the unit's operation. Additionally, from the information extracted from the structural analysis model, the expected fatigue life (as a function of flow rates and changes in operation) was predicted. Using these analysis procedures, additional design options were explored to determine the best course of action to eliminate the in-service vibrations.

6.10 PIPE BREAK

6.10.1 Introduction

The forcing loads acting on pressurized systems that experience pipe break are essentially the same as those applicable to relief-valve discharge. One important difference exists, however: pipe-break loads are usually of such magnitude and orientation that they cause motion of the broken system. Both suddenly applied load and the resultant kinetic energy picked up by the broken system motion must be accommodated by the supports or restraints on the system.

6.10.2 Computation of Support or Restraint Loads

The equivalent static load to be resisted by a pipe-break restraint or support is

$$R_m = \frac{KE}{\mu S_e} + kPa\left(\frac{1}{1 - \frac{1}{2}\mu}\right) \tag{6.11}$$

where

R_m = the equivalent static load on the support or restraint
KE = kinetic energy picked up by the pipe system before impacting the restraint
μ = allowable ductility S_{all}/S_e
δ_{all} = allowable total deformation of the restraint
δ_e = deformation at yield of the restraint
kPa = same as equation (6.7): F_e with D_f is equal to 1.0
P_a = initial pressure in the system

Equation (6.11) can be rewritten as follows by equating KE to the work done on the system.

$$KE = kPa \times GAP \tag{6.12}$$

Then,

$$R_m = \frac{kPa \times GAP}{\mu S_e} + kPa(1/\left(1 - \frac{1}{2}\mu\right) \tag{6.13}$$

where

GAP = space through which the pipe system is being accelerated

6.11 FLUID JETS

Fluid jets, whether they are caused by a relief-valve discharge or rupture of a high-pressure system, need to be considered for both the discharging system and any target system or component affected by the jet. However, the equivalent static load that a jet has on a jet target or shield depends on the dynamic characteristics of the jet target or shield as well as the jet. In ref. [5], one can find a detailed discussion of jet loads and effects.

6.12 MISSILES

6.12.1 Types of Missiles

(Note: Ref. [33] contains more detailed information about the missile types listed here.)

Gravitational Potential Energy Type This refers to suspended loads from cranes or objects that move above safety-related equipment (cask drop). They shall be evaluated where postulated missiles are identified.

Contained Fluid Energy Type This refers to postulated missiles of the contained-energy type that originally are in direct contact with a pressurized system and can be acted on by a force for some distance. They shall be characterized according to either of the two following types of acceleration: piston-type action (e.g., valve stems and control rod drives) or a jet of escaping fluid (e.g., head covers and valve bonnet pipe breaks).

Rotational Energy Type This refers to postulated missiles in which a conversion of rotational mechanical energy into translational kinetic energy can occur. They shall be characterized on the basis of evaluation of the structure and failure modes of the rotating machinery postulated to be the source of the missile. For rotating assemblies built up in parts, intact separation of such parts (e.g., turbine blades, flywheels, and generator end-turns) should be evaluated as a function of their probability of occurrence. The postulated missile from a flywheel or similar solid-rotating disc shall be one of N symmetrical pieces of the disc, where the value of N depends on a balance between size and shape effects.

Stored Strain Energy Type This refers to postulated missiles resulting from parts that stored strain energy. They shall be characterized on the basis of the stored energy and the postulated mechanism failure.

Chemical Energy Type This refers to postulated missiles resulting from a violent chemical reaction within a vessel or pipe component. They shall be characterized as developing the most severe missile from the standpoint of effects on targets.

Nuclear Excursion Type This refers to postulated missiles resulting from heating and rapid expansion of coolant fluid caused by an abnormal nuclear energy transient. They may require evaluation in special cases of coolant-fluid energy.

Secondary Missiles These can result through energy transfer from a postulated primary missile. They shall be characterized as yielding the most severe missile from the standpoint of effects on critical targets.

Natural Phenomena Type This refers to tornado-driven and other postulated wind-driven missiles characterized in a manner that considers the site and type of missiles, as specified in applicable Codes, standards, and guidelines [34].

Transport Missiles Material and personnel vehicles routinely on or near the site (e.g., trucks, automobiles, and aircraft) may be characterized where they are postulated to become missiles [35].

Construction and Maintenance Type In the case of multiple nuclear units or other adjacent construction, postulated missiles caused by proximate construction activity shall be conservatively characterized.

Postulated explosions in the plant vicinity resulting from detonations in fixed or transportation facilities cause blast waves and potential missiles. (See ref. [36] for additional information.)

6.12.2 Missile Characteristics

For each postulated missile, the following characteristics should at least be considered:

(1) mass;
(2) velocity;
(3) shape;
(4) size;
(5) material properties (e.g., hardness and density);
(6) structural characteristics (e.g., crushing strength);
(7) orientation and trajectory;
(8) impact area; and
(9) probability and generation.

6.12.3 Missile Effects on Targets

Targets to be considered include safety-related systems, components, and barriers or shields. Of the probable approach configurations of a given missile, two shall be considered:

(1) The configuration that is the most damaging to the exposed targets.
(2) The configuration that results in the most damaging secondary missiles, including rebound of the primary missile. The missile velocity considered shall be the maximum probable impact velocity. Each secondary missile shall be evaluated as the primary missile.

Missile effects are typically divided into two types: local effects and overall effects. Local effects are confined to the immediate area of impact and are essentially independent of the target geometry and boundary conditions, except for target thickness. Examples of local effects are penetration, perforation, and spalling. Overall effects are those associated with the structural response of the target, for which the structural characteristics and boundary conditions of the target are of importance. Examples of overall effects are bending, shear and buckling. Should local effects be sufficient to significantly influence the overall response, they must be considered in evaluating such response.

6.12.3.1 Penetration Penetration of a missile into a target is the most significant local effect. Penetration depends on missile mass, velocity, shape, size, material properties, orientation, and trajectory as well as target thickness and material properties. Penetration depth can be evaluated using empirical formulas or appropriate analytical procedures. For ductile metals, useful references include the penetration equation of the Ballistic Research Laboratory [38]. For concrete, some useful references include the formula of the National Defense Research Committee and the French CEA-EDF formulation [8]. If perforation, spalling or secondary missile generation is a hazard that should be prevented by a proper target or shielding design which usually involves increasing the thickness of the target structure. In evaluating the significance of the expected penetration, applicable loads on the target and layout or orientation must be considered in conjunction with the expected missile penetration parameters. Where perforation occurs, the velocity of the continuing primary missile should be considered.

6.12.3.2 Secondary Missiles Secondary missiles commonly arise from primary missiles that strike concrete, other masonry, or other relatively brittle material. Spalling can occur on either side of a wall composed of such material, with the fragments absorbing some of the primary missile energy in kinetic form. In general, the secondary missiles created on the impact side of the wall are not of concern; their energy and velocities are much less than that of the impinging primary missile. If the primary missile penetrates beyond a threshold depth, it creates secondary missiles on the opposite side of the wall [8]. Methods to determine whether such secondary missiles occur are provided in ref. [8]. In general, target or barrier walls should be at least three times the computed penetration depth to assure no opposite wall spalling. Spalling can also occur in ductile metal target structures but only at very high velocity missile impacts.

6.12.4 Forcing Functions Used to Represent Missile Impact

During the process of a missile striking a target or barrier, a force is external at the missile-barrier or target interface. The magnitude of this force is a function of missile velocity, force-deformation characteristics, angle of attack, impact area, and mass of both missile and barrier and the relative crushability of the target and missile.

In computing the forcing function or load the target can be represented by an equivalent mass and a nonlinear spring that can describe the missile and barrier force deformation relationship up to total barrier collapse. Forcing functions representing missile impact—whether of a hard or soft nature—are described in Section 6.4.3 and also in ref. [8].

6.12.4.1 Hard Missile Impact For cases in which missile penetration into the target structure is significant, relationships can be developed for the forcing function applied to the structure by the missile, based on application of the equation of motion during deacceleration of the missile as determined from equation (6.9) of Section 6.4.3, and also from ref. [8]. It is assumed that the velocity varies linearly from velocity at impact to 0 as a function

of time as the missile penetrates the target structure. Implicit in this assumption is a constant deacceleration and, consequently, a constant force of impact or rectangular-shaped forcing function. Because the assumption of hard impact may be too conservative in many cases, it is necessary to determine the forcing function more accurately by considering the impact to be soft whenever possible.

6.12.4.2 Soft Impact As indicated in ref. [8], the terminology "soft missile impact" is used herein to describe the class of missiles characterized by significant local deformation or crushing of the missile and/or target structure during impact. Tornado-driven objects (such as reinforcing bars and small pipes) and internally generated accident missiles (such as bolts, valve stems, and fragments from rotating equipment) will penetrate into concrete and steel targets upon impact. Missiles such as an aircraft fuselage, automobile body, and wood pole or plank will themselves deform upon striking concrete or steel structures. Cases in which the missile or impact areas of the target are crushed, the forcing function can be determined from equation (6.10) of Section 6.4.3 and also from ref. [8].

6.12.4.3 Typical Missile Forcing Functions In Table 6.3 can be found the magnitude and duration of typical missile forcing functions for tornado missiles defined by the U.S. Nuclear Regulatory Commission [34,39].

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CHAPTER

7

OPERABILITY AND FUNCTIONALITY QUALIFICATION

Stephen R. Gosselin and Thomas C. Esselman[1]

7.1 INTRODUCTION

7.1.1 Objectives

If plant systems, structures, or components (SSCs) are found to be degraded, nonconforming, or subject to an unanalyzed condition during operation, an evaluation of their functionality or operability may be necessary to demonstrate the capability of the nuclear power generating station to continue operating safely. This evaluation establishes the ability of the SSCs to perform their assigned safety functions. This chapter discusses the methodology and acceptance criteria applicable to this evaluation. It describes typical SSCs that may require operability evaluations and also provides definitions related to operability. Examples of the operating conditions and events to consider are described, as are the evaluation methods and acceptance criteria for short- and long-term operability.

This chapter discusses basic concepts, definitions, evaluation methods, and acceptance criteria as they relate to mechanical systems, their components and structures.

7.1.2 Operability and Functionality

In a typical nuclear plant in the United States, "operability determinations" are associated with SSCs described in the plant technical specifications (TSs) and form the basis for compliance with regulatory requirements and limiting conditions for operation [1]. The scope of SSCs considered within the operability determination process include: SSCs required to be operable by TSs and SSCs that are not explicitly required to be operable by TSs, but that perform required support functions. Conversely, "functionality assessments" are performed for SSCs not described in the plant TSs. From a practical standpoint these distinctions serve as a means differentiating the evaluation processes employed to assess the fitness for service of safety related and non-safety related SSCs. In fact the fundamental basis for either "operability" or "functionality" rests in the measure of the SSC's capability to perform its intended function(s). For the most part, the technical evaluation methods and acceptances criteria employed to make these determination are common for technical specification and non-technical specification SSCs.

7.1.2.1 Operable/Operability. The U.S. NRC Standard Technical Specifications [2, 3, 4, 5, 6, 7] define "operable/operability" as follows:

> "A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety functions, and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s)."

Several variations of the preceding definition may exist in the plant specific Technical Specifications. In all cases, however, a licensee's plant-specific definition should be accepted as governing how one applies the terms operable and operability. The specified functions referenced in the foregoing definition are the specified "safety" functions described in the current licensing basis for the facility. The following are some examples of specified safety functions for several SSCs.

For piping:

(1) structural integrity where structural failure would interfere with other systems being able to perform their safety functions;
(2) pressure integrity to the extent that leakage is limited to levels permitted by the licensing basis and through-wall flaws remain stable when subjected to faulted loads; and
(3) ability to pass required flow rates.

For supports:

(1) Motion control of the system or component within the limits required for the system or component to perform its safety function or else to maintain the structural integrity of the system or component.

For valves:

(1) pressure integrity to the extent that leakage is limited to levels permitted by the licensing basis;
(2) structural integrity; and
(3) the ability to open or close as required in the licensing basis.

[1]Guy H. DeBoo was the author of the initial write-up and subsequent Second Edition of this chapter that appeared in the "Companion Guide to the ASME Boiler & Pressure Vessel Code, Volume 2." This was subsequently updated by **Stephen R. Gosselin** in the Third Edition and is now updated by **Stephen R. Gosselin** and Thomas C. Esselman for this current publication. – Editor

In addition to providing the specified safety functions, a system, subsystem, train, component, or device (referred to as system in this section) is expected to perform as designed, tested, and maintained. When system capability is so degraded that it cannot perform with reasonable certainty or reliability, the system should be judged inoperable even if it is shown to provide the specified safety functions [1]. Required action ranges included in the acceptance criteria of ASME O&M Code [7] or Section XI [8] are examples of degraded capabilities for SSCs. Plant Technical Specifications also contain limiting values, such as leakage rate and set point pressure, for component performance. These values constitute the technical specification-based operability verification criteria that, if they are not met, necessitate the entering of the applicable Limiting Condition for Operation (LCO) and Allowed Outage Times (AOTs).

In some cases, the ASME O&M Code–required or Section XI–required action ranges for certain components may be more conservative than the plant technical specification limits. However, the component in question must be declared inoperable even if the existing performance meets the technical specification safety limit because of the imposed ASME operability limit. An example is a pump that is capable of delivering rated flow but exhibits vibration in excess of the reference values and falls in the required action range.

The discussion in this section accentuates the often complex, sometimes inconsistent, nature of operability concepts and criteria. Common practice involves a process having a consensus of regulator viewpoints, plant-specific technical specification requirements, applicable Codes and Standards, regulatory commitments, and other licensing-basis compliance requirements. The general scope of SSCs that might require operability determinations include:

(1) Safety-related SSCs that are relied upon to: (a) ensure reactor-coolant pressure boundary integrity; (b) shut down and/or maintain the reactor in a safe shutdown condition; or (c) prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11, as applicable [9].
(2) SSCs whose failure could prevent any of the SSCs identified in (a), (b), and (c) from performing their require functions.
(3) SSCs that are required to function by safety analyses or plant evaluations that are a part of the current licensing basis. These analyses and evaluations include those that are submitted to support any license amendment requests, exemption requests, or relief requests, and also those submitted to demonstrate compliance with regulations such as fire protection in 10CFR50.48, environmental qualification in 10CFR50.49, pressurized thermal shock in 10CFR50.61, anticipated transients without scram in 10CFR50.62, and station blackout in 10CFR50.63 [9].
(4) SSCs that are subject to: 10CFR50, Appendix B; 10CFR50, Appendix A, Criterion 1; plant facility Technical Specifications; or plant Technical specifications through the definition of operability (i.e., support SSCs outside technical specifications) [10].
(5) SSCs described in the Updated Final Safety Analysis Report (UFSAR).

7.1.2.2 Functional/Functionality. As previously mentioned, the U.S. NRC [1] defines functionality as an attribute of SSCs not controlled by the plant technical specifications which warrant programmatic controls to ensure SSC availability and reliability (e.g., quality standards and records in Appendix B to 10 CFR 50, maintenance rule in 10 CFR 50.65, etc.) or other functionality requirements in the current license basis. A non-technical specification SSC is "functional" when it is capable of performing its intended function(s) as specified in the plants current license basis.

A detailed discussion of the U.S. regulatory requirements associated with the scope of "operability" determinations and "functionality" assessments is contained in NRC Inspection Manual Part 9900 [1]. The NRC's distinction between these two assessments is summarized in Figures 7.1 and 7.2.

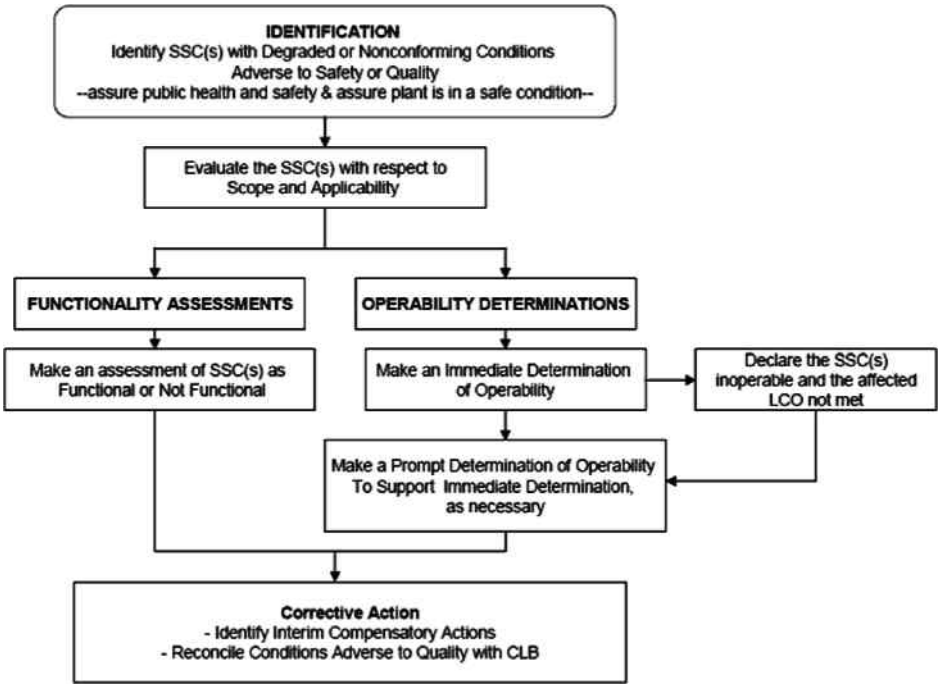


FIG. 7.1 NRC OPERABILITY DETERMINATION AND FUNCTIONALITY ASSESSMENT FLOW CHART [1]

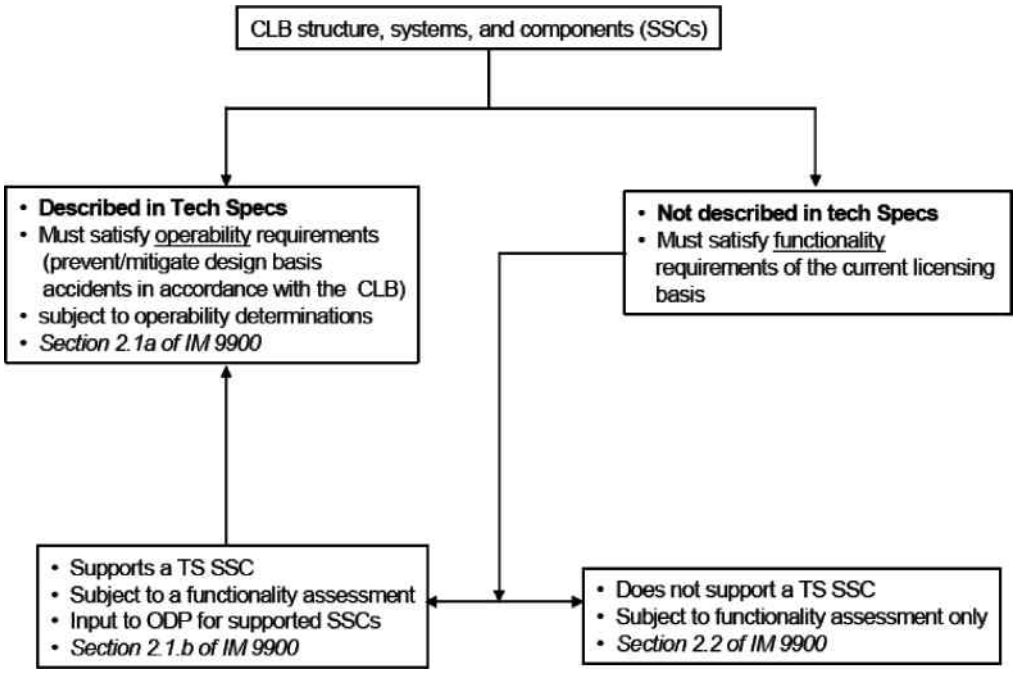


FIG. 7.2 NRC SCOPE OF AN OPERABILITY DETERMINATION AS IT RELATES TO THE SCOPE OF A FUNCTIONALITY ASSESSMENT [1]

7.2 MECHANICAL COMPONENTS AND FAILURE MODES

Typical failure modes for SSCs can be determined from extensive industry experience reported in the Nuclear Plant Reliability Data System (NPRDS), Licensee Event Reports (LERs), and other industry studies.

7.2.1 Piping Components

Since the early 1990's, significant attention has been placed on developing comprehensive databases that compile service induced degradation in operating nuclear power plant piping components. The most significant work in this area has been done as part of an OECD Pipe Failure Data Exchange (OPDE) Project which has established an international database of piping and component failures (service induced cracks/wall thinning, leaks, and large breaks) in commercial nuclear power plants worldwide [37]. Pipe failure data has been collected from operating nuclear power plants worldwide, representing approximately 11,000 commercial reactor operating years from 1970 through 2007. Considering that there are thousands of numbers of piping components in nuclear power plants this represents tens of millions of component years of service experience from which to derive insights.

Figure 7.3 shows the total number reported piping failures reported from 1970 through 2007 as a function of the piping component in-service life at the time of failure [11]. The relatively high incidence of failures for the interval 11-15 years is largely attributed to IGSCC in BWR plants, FAC in PWR plants and corrosion of raw water piping in all plant types.

In Figure 7.4, U.S. failure data is organized by degradation mechanisms or cause of failure. It shows that design/construction defects and thermal fatigue (which are the degradation mechanisms that form the basis of the current Section XI preservice and inservice inspection requirements) account for approximately 8% of the failures in U.S. commercial light water reactor (LWR) plants since 1970. Of these on 1.5% of the failures were primarily due thermal fatigue, thermal mixing and thermal stratification mechanisms and loading conditions not considered in the original design. Over 87% of the piping failures resulted from flow accelerated corrosion (FAC), stress corrosion cracking (SCC), vibration and fretting fatigue, and corrosion mechanisms including crevice corrosion, microbiologically induced corrosion (MIC), and pitting.

The total number of failures per year is a useful way to measure progress in the commercial nuclear industry. Figure 7.5 shows the number of failures (database records) per year from 1970 to 2011 [12]. The number of failures per year has reduced nearly linearly since 2003. The numbers of failures due to specific mechanisms such as FAC and SCC have also declined significantly. The number of failures per year for SCC, as an example, is shown in Figure 7.6 [12]. The number of failures per year is lower than 2003 and much lower than the 1982 to 1987 time period.

Figure 7.7 shows all U.S. pipe failure data since 1970 organized by pipe safety classification. Generally service induced failures in safety related have been evenly distributed throughout the three safety classes. Over 1/3rd of the failures occurred in non-safety pipe which are normally not reported to the regulatory authorities. The Class 1 piping failures are dominated by stress corrosion cracking in BWR piping and Class 2 piping failures are primarily associated with vibration fatigue, thermal stratification and FAC mechanisms. The Class 3 failures are dominated by corrosion mechanisms. This data shows that, in all cases, piping reliability is not a function of design safety class; but, is dominated by service loading and degradation mechanisms That are generally not specifically addressed in the ASME Section III design standards.

Generally service experience shows that failures (cracks, wall thinning, leaks, and breaks) in light water reactor (LWR) piping do not correlate with high stress or thermal fatigue usage values

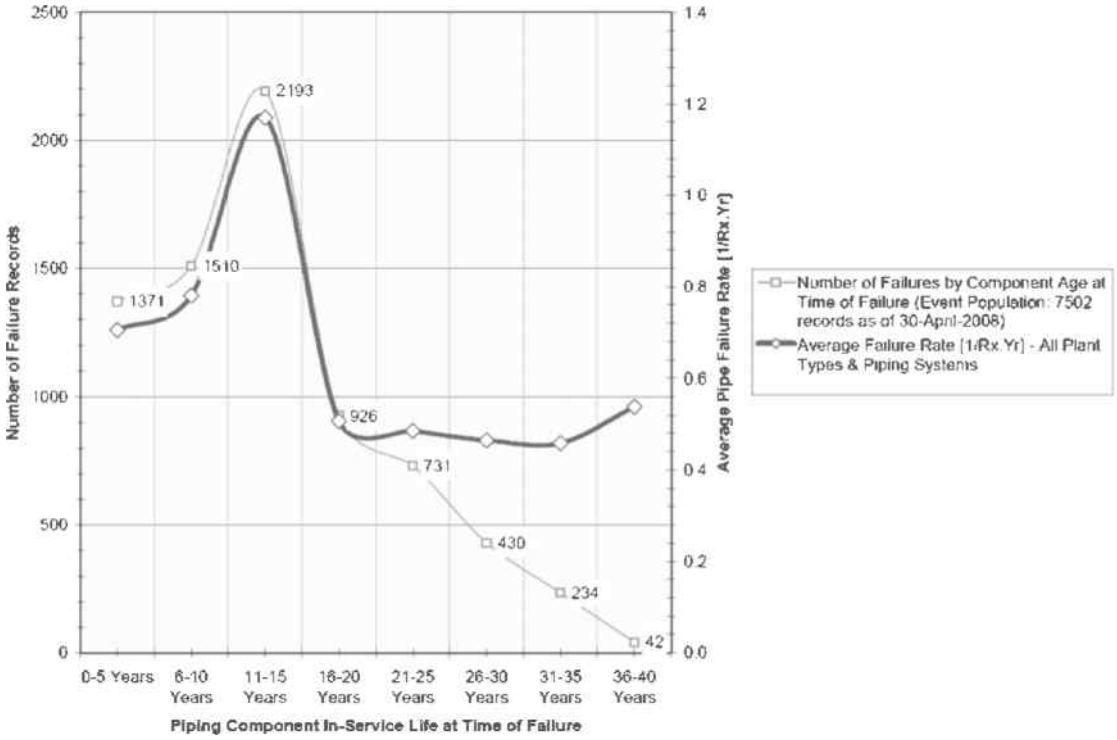


FIG. 7.3 PIPING FAILURE TRENDS IN COMMERCIAL NUCLEAR POWER PLANTS COVERING THE PERIOD BETWEEN 1970 THROUGH 2007 [11]

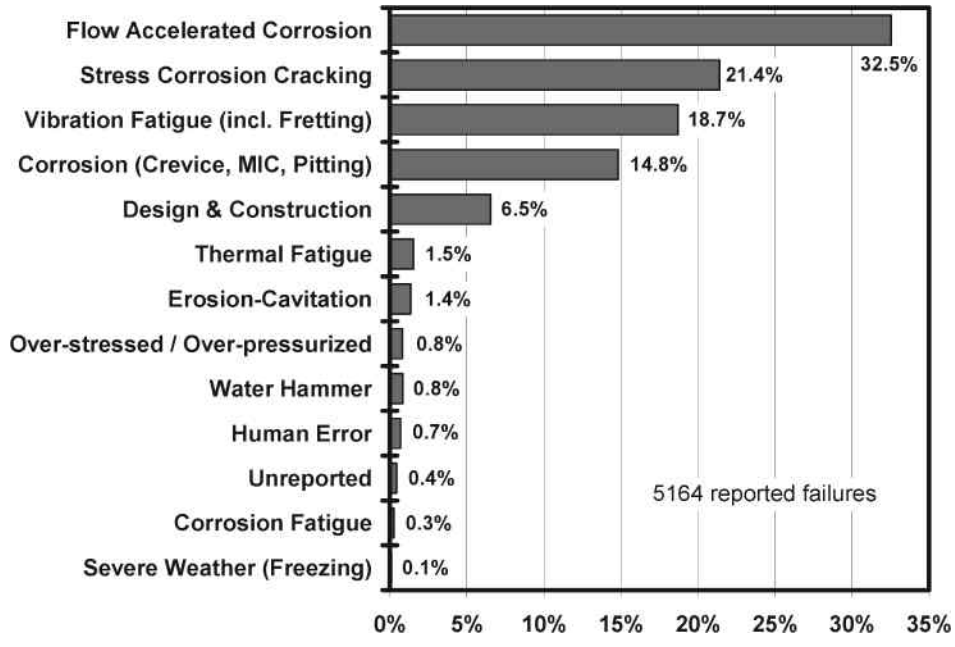


FIG. 7.4 U.S. PIPE FAILURE DATA BY DEGRADATION MECHANISMS AND OTHER CAUSES [11]

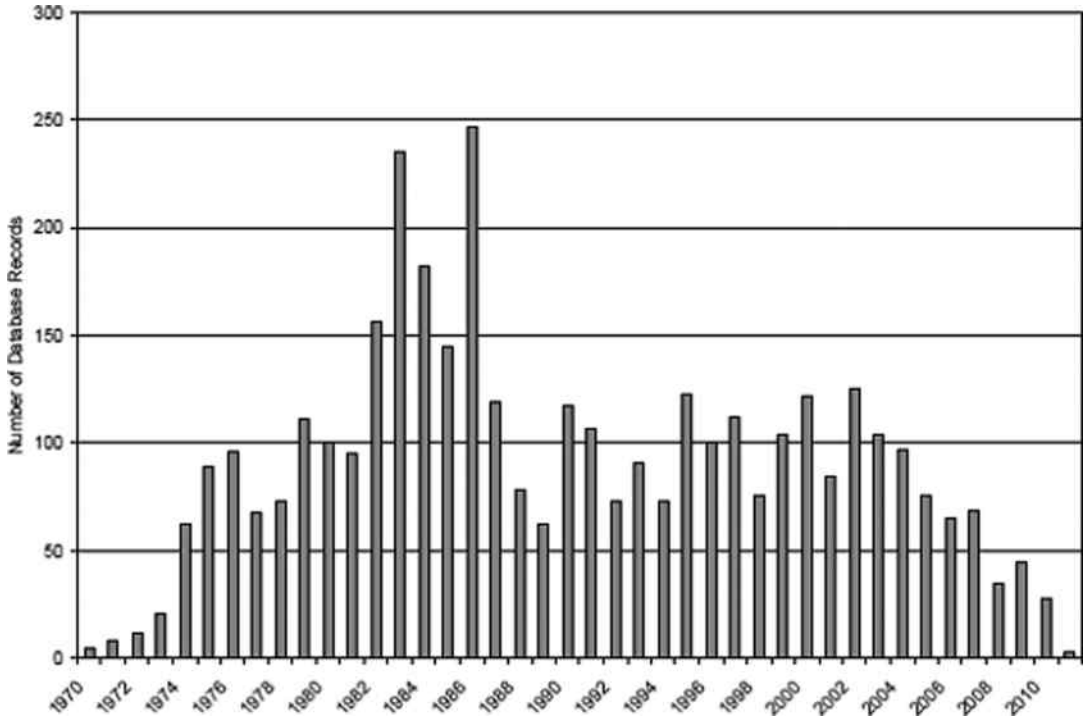


FIG. 7.5 PIPE FAILURES BY CALENDAR

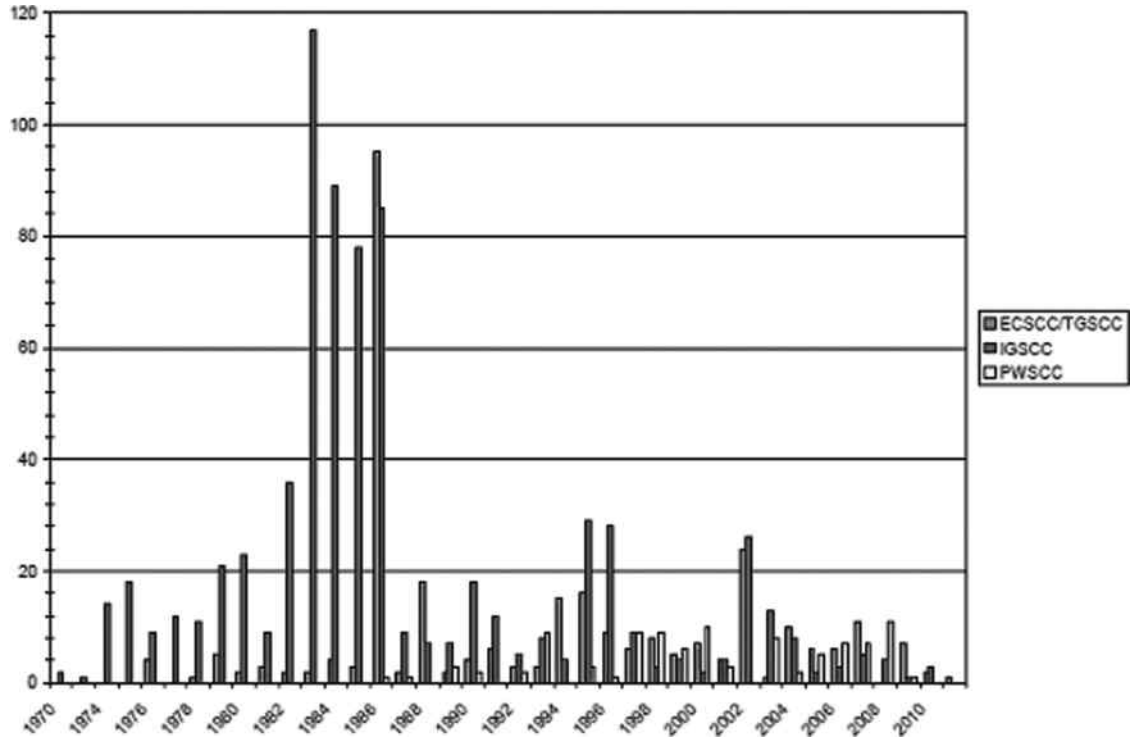


FIG. 7.6 PIPING FAILURES CAUSED BY STRESS CORROSION CRACKING BY CALENDAR YEAR [12] (ECSCC IS EXTERNAL CHLORIDE STRESS CORROSION CRACKING, TGSCC IS TRANSGRANULAR STRESS CORROSION CRACKING, IGSCC IS INTERGRANULAR STRESS CORROSION CRACKING, PWSCC IS PRIMARY WATER STRESS CORROSION CRACKING)

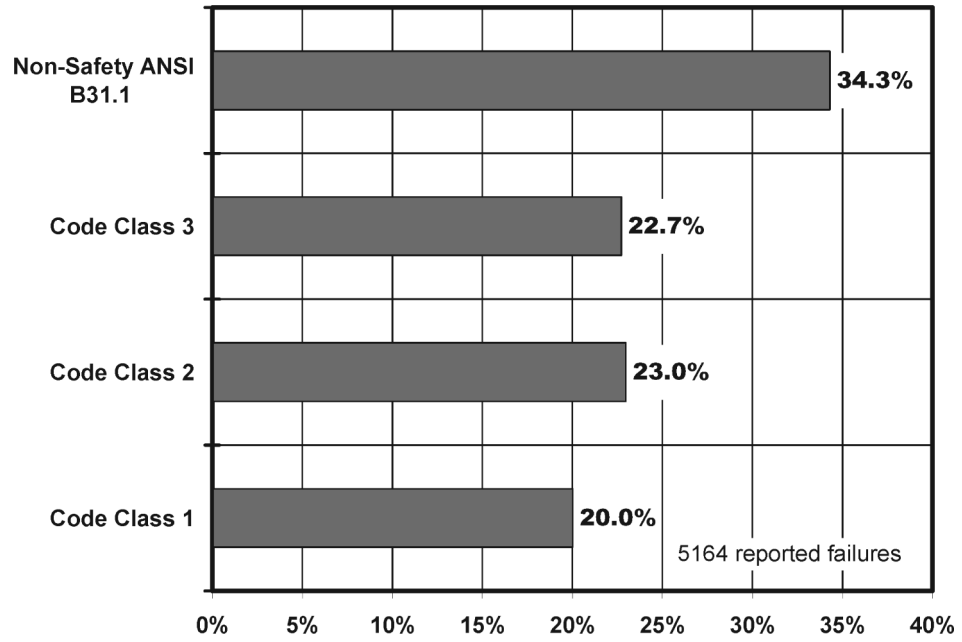


FIG. 7.7 U.S. PIPE FAILURE DATA BY SAFETY CLASSIFICATION [36]

reported in plant Design Reports [13]; in fact, service induced failures typically result from either degradation mechanisms or loading conditions not specifically considered in the original plant design.

The Code stress calculations are used to qualify a design and provide reasonable confidence that the plant will provide reliable service throughout its design life. For the most part the peak stress and fatigue usage values in the plant's Design Reports do not necessarily provide an accurate indicator of failure potential [14]. The peak stress and fatigue usage values in the Design Reports are typically based on extremely conservative postulated thermal transient loading conditions and numbers of cycles. Also, the sequencing of these design thermal transients in the fatigue analyses adds significant conservatism. Finally, the high calculated fatigue usage is dominated by those design transient load pair combinations that not only result in large thermal stresses at the inside surface thermal gradients but also large thermal stress gradients through the wall. The large thermal stresses would result in a low number of allowable stress cycles for crack initiation (high fatigue usage); however, because of the large through-wall thermal gradient, stresses drop-off rapidly as you move away from the inside surface. Consequently, if all anticipated loading conditions are accounted for, the time to grow a crack through-wall can be significantly longer then the original design and extended life of the plant [15].

7.2.2 Supports

EPRI reported failure information on standard supports in nuclear power plants was obtained from the Institute of Nuclear Plant Operations' (INPO) NPRDS database [16]. Figure 7.8 provides a breakdown of standard support service data by failure mode. Most of the reported degraded supports were associated with missing/loose components or improper hanger settings. One third support problems involved snubbers. Snubbers frequently failed drag and motion criteria and experienced wear, fatigue, lock-up, and seal leakage mainly due to mechanical vibration.

In Figure 7.9, the breakdown of the NPRDS data is shown by cause/degradation mechanism. We can see that the cause of nearly 50% of the reported support failures was unknown. These cases were typically associated with missing or loose components, improper hanger settings, and the failure of snubbers to pass functional tests [16].



FIG. 7.8 STANDARD SUPPORT FAILURES BY FAILURE MODE [16]

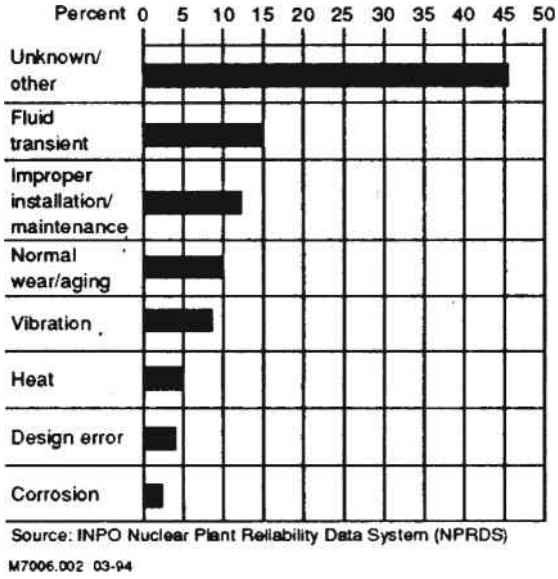


FIG. 7.9 STANDARD SUPPORT FAILURES BY ROOT CAUSE [16]

7.2.3 Pumps

Typical failure modes for pumps are the following:

(1) Fails to start: This failure mode is used to describe faults involving pumps that do not start upon demand or that start only to operate for a brief time period before tripping offline.
(2) Fails to run: This failure mode indicates that an operating pump is automatically or manually tripped off-line to prevent damage to the pump. It also includes pumps that fail to meet design and/or operating specifications.
(3) External leakage: This failure mode describes a fault in which the pump is operational but is removed from service because of excessive leakage of the pumped medium. A common example is a seal or packing leak.

A pumping system can also be challenged by the fluid that is ingested. The potential for air being trapped in piping systems upstream of a pump inlet has been examined [17]. This is highly dependent on the piping configuration and the plant operating procedures. The capability of various pump designs to be able to ingest different amounts of air has also been examined [18]. Some pump designs can withstand small amounts of accumulated air, like several percent and other designs are capable of withstanding much more air and still operate satisfactorily.

7.2.4 Valves

Typical failure modes for valves are the following:

(1) Fails to open: Valve fails to fully open on demand.
(2) Fails to close: Valve fails to fully close on demand. Included are safety/relief valves that fail to reseat.
(3) External leakage: A leak or rupture of the valve that allows the contained medium to escape from the component boundary. The most common examples are packing or flange leaks.
(4) Plugged (i.e., fails to remain open): This failure mode refers to any event that would stop or limit the flow through a normally open valve. However, the following are not considered plugged valves: those that fail to open or those that are either intentionally or unintentionally closed by human activity when they are required to be open. Two examples of a plugging event are
   (a) a valve disc that separates from the stem and falls into the closed position, and
   (b) the air supply to an air-operated valve that fails, allowing the valve to close.
(5) Fails to operate as required: The fails-to-operate-as-required mode is to be used whenever
   (a) a valve fails to meet specific requirements such as stroke time, or
   (b) a valve loses its ability to control system parameters.
(6) Internal leakage (reverse leakage): This failure mode is used to describe internal leakage through a check valve.
(7) Opens (prematurely): This failure mode applies strictly to relief and safety valves. Valve opening before its pressure setting is a typical example of this mode, but the cause is not always a pressure transient.

7.3 OPERABILITY/FUNCTIONALITY EVALUATIONS

7.3.1 Conditions Requiring Assessment

Conditions requiring operability and functionality evaluations are usually identified through plant walkdowns, in-service inspection and testing programs, non-destructive examinations, misoperation, and augmented inspection programs. The conditions that lead to the requirement for an operability or functionality evaluation can be quite varied. Some examples of conditions identified by the in-service inspection and testing programs are wall-thinning from an FAC mechanism, snubber failures and pipe or nozzle cracking from fatigue and IGSCC mechanisms, leakage exceeding Technical Specification limits for valves, and excessive pump vibrations. In some instances, a system-operating excursion subjects a system and its components to an unanalyzed condition that requires an evaluation.

Unanticipated operating events require operability evaluations. Examples of such events include fluid transients such as water hammer; temperature and pressure excursions; and thermal stratification. Flow-induced system vibration from pump operation, cavitation, two-phase flow conditions, and acoustic pressure waves are known to lead to snubber wear, piping erosion, and fatigue failure, especially in socket-welded fittings.

Functionality evaluations are required for temporary loading conditions such as lead shielding, rigging for maintenance or modification installation and scaffolding support. The loading to be considered in conjunction with the temporary loads is dependent on the system operating status while the temporary condition exists. The seismic load may not need to be considered with the temporary condition if the affected system is declared out of service and the seismic failure of the system would not undermine the ability of other systems or components to perform their safety functions.

A functionality evaluation is required for as-built/as-found conditions that are not consistent with the design-basis configuration. Examples of these conditions include support system discrepancies, which might consist of such missing, damaged, or failed supports, a snubber failing to activate and provide the required restraint, or support members found to have missing or undersized welds. Additional or unwanted restraints, such as snubbers that

lock up or exceed the drag force restrictions, or a support design with insufficient rotational clearance, are other examples of other supporting system discrepancies. The functionality evaluation would consider the capability of a degraded system to have performed acceptably had a required load case occurred.

7.3.2 Scoping Operability Evaluations

Determining the conditions to be evaluated requires a clearly defined scope of the operability determination. To define the scope of the evaluation, the following actions are required:

(1) Identify the equipment or SSC that is degraded, potentially nonconforming, or subject to the unanticipated event.
(2) Establish the safety functions performed by the equipment.
(3) Assess the possible failure mechanisms.
(4) Define the operating events or loading conditions concurrent with the evaluation period.
(5) Determine the acceptance criteria to be used to determine that the affected system would be operable through any of the following conditions:
(6) Perform the work to determine whether the system is operable. The methods that can be used include analysis, test or partial test, operating experience; or engineering judgment. The basis for engineering judgment, if used, should be well documented.

Any operability evaluation should consider the operational status of the SSC for the time period during which it is degraded or nonconforming. As one defines the operating events and loading conditions for the evaluation, it is important to distinguish between an SSC that was restored to its licensing basis and one that is expected to operate in the degraded or nonconforming condition. The evaluation of an SSC that was restored to its current licensing basis is initially based on all operating events that actually occurred while the SSC was in the nonconforming or degraded condition. Included in such operating events are unanticipated events that were determined to have occurred. This evaluation may include an evaluation of the expected performance of the degraded condition assuming that a design-basis event had occurred, such as a loss-of-coolant accident (LOCA), post-LOCA thermal modes, and seismic loads.

An example of a degraded and nonconforming SSC not restored to its current licensing basis is a degraded snubber found during the Inservice Testing program to have exceeded its drag limit. An operability evaluation is required to determine the impact of the excessive drag on the piping system. When seismic and LOCA events did not occur, only the thermal modes that did occur since the last time the snubber was determined to have operated normally are considered in the evaluation. A root-cause analysis would need to be performed to ensure that some unanticipated operating event, such as waterhammer or system vibration, did not degrade the snubber. If the root-cause analysis determines that some unanticipated operating event did occur, the evaluation would include this unanticipated event. The root-cause analysis should be performed to establish that the degradation mechanism or nonconformance was eliminated and also to determine which other SSCs may be impacted by it.

If the SSC is to continue operating while in the degraded condition, the operability evaluation must demonstrate its functionality, as previously defined, for design-basis events required by plant licensing commitments. If the SSC has been degraded by an unanticipated operating event, the operability evaluation must demonstrate its functionality for the design-basis events and the effects of the unanticipated operating event. The effects of the unanticipated operating event would need to be included in the operability evaluation until the cause of the event can be eliminated or contingencies are put in place to significantly reduce the possibility of the event occurring. Additionally, if an SSC that had been degraded by an unanticipated operating event is restored to its design-basis condition, an operability evaluation must demonstrate the functionality of the SCC for its design-basis events and the effects of the unanticipated operating event.

TABLE 7.1 FAULTED OR SERVICE LEVEL D LOADS TO CONSIDER IN OPERABILITY EVALUATIONS

Load	Vessels	Piping	Supports	Valves	Pumps
Gravity	Yes	Yes	Yes	Yes	Yes
Thermal expansion	No	No	Yes [Note (2)]	Yes [Note (1)]	Yes [Note (3)]
TAM	No	No	Yes [Note (2)]	Yes [Note (1)]	Yes [Note (3)]
SSE inertia	Yes	Yes	Yes	Yes	Yes
SSE–SAM	No	No	No	No	No
LOCA [Note (4)]	No	No	No	No	No
Design-basis dynamic loads	Yes	Yes	Yes	Yes	Yes
Other dynamic loads [Note (5)]	Yes	Yes	Yes	Yes	Yes

General Notes:
(a) Acronyms are as follows: LOCA = loss-of-coolant accident; SAM = seismic anchor motions; SSE = safe shutdown earthquake; and TAM = thermal anchor motions.

Notes:
(1) Thermal expansion modes and TAMs shall be considered only for valves which are active and have supports on the operator.
(2) Thermal expansion modes and TAMs shall be considered for supports susceptible to nonductile failure (such as buckling) unless functionality of the system without the support can be demonstrated.
(3) Required for active pumps only.
(4) The probability of extreme design-basis loads (such as LOCA) occurring during the time that the component is degraded or nonconforming is so low that consideration of these loads is not required.
(5) Other dynamic loads are those associated with unanticipated operating events that have occurred and may have degraded the component or caused it to be nonconforming.

In general, only the failure mechanisms and loads from the faulted or Service Level D condition are required for the evaluation. This being the case, displacement-controlled loading is not considered for piping or pressure boundary items. (Displacement-controlled loading refers to self-limiting loads such as thermal expansion, thermal-anchor movement, and seismic-anchor movement.) For support designs susceptible to non-ductile failure, such as buckling and anchor-bolt failure, or support designs that deform so severely that an active component might be unable to perform its required safety function, the thermal-anchor motion and seismic-anchor motion loadings must be considered. Table 7.1 presents this load consideration philosophy in a matrix form.

7.4 ASME CODE REQUIREMENTS

The ASME B&PV Code Section III [19], Section XI [8], and the ASME O&M Code [7] all contain requirements directly and indirectly related to the operability of components. The Section III rules encompass requirements for the design, construction, stamping, and overpressure protection for nuclear plant items. These rules are for new construction and give consideration to mechanical and thermal stresses caused by cyclic operation; they typically do not address deterioration that might occur in service because of radiation effects, corrosion, erosion, or other material degradation mechanisms. The rules of this section are not applicable to valve operators, controllers, position indicators, pump impellers, and other non-pressure-retaining items (except for those within the scope of Subsection NF), as well as motor drives and instruments.

Functional acceptability aspects of some components are not mentioned in Section III and a disclaimer statement is provided. Such a disclaimer is provided for valves, for example, stating that Code valve design acceptability requirements are not intended to ensure functional adequacy of the valves. However, rules are provided for pressure-relief valves that cover set pressure, lift, blowdown, and closure (NX-7000) [19].

The rules of Section XI and the O&M Code, on the other hand, are more directly related to various aspects of component operability. These Codes define inspection and testing requirements to identify degraded and nonconforming conditions for SSCs. Each defines the acceptance criteria and evaluation methods.

The following paragraphs itemize some specific stipulations applicable to pumps and valves from the O&M Code and vessels and piping from Section XI. The pumps and valves covered by these stipulations are components required for the following conditions:

(1) shutting down the reactor to the cold shutdown condition;
(2) maintaining the reactor in a cold shutdown condition; and
(3) mitigating the consequences of an accident.

7.4.1 Valves

Valves within the scope of the inservice testing program are placed in at least one of the following four categories as defined in Subsection ISTC of the O&M Code [7]:

Category A—valves for which seat leakage is limited to a specific maximum amount in the closed position to fulfill their required functions.

Category B—valves for which seat leakage in the closed position is inconsequential for fulfillment of the required functions.

Category C—valves that are self-actuating in response to a system characteristic, such as pressure (relief valves) or flow-direction (check valves) to fulfill the required functions.

Category D—valves that are actuated by an energy source capable of only one operation such as rupture discs or explosively actuated valves.

The test requirements for each of these valve categories are specified in ISTC3500 [7] and summarized in Table 7.2. These requirements define test intervals, leakage tests, and stroke times.

Table 7.3 provides the leak-testing criteria defined in ISTC-3600 [7]. Valves or valve combinations exceeding the specified criteria shall be declared inoperable and either repaired or replaced. An example of typical leakage rates from an operating pressurized water reactor (PWR) is provided in Table 7.4.

Stroke-time acceptance criteria for active Category A and B valves are defined in ISTC-5000 [7] and summarized in Table 7.5.

TABLE 7.2 INSERVICE TEST REQUIREMENTS FOR VALVES [7]

Category	Valve Function	Leakage Test	Exercise Test	Special Test
A	Active	Yes	Yes	None
A	Passive	Yes	None	None
B	Active	None	Yes	None
B	Passive	None	None	None
C (safety/relief)	Active [Note (1)]	None	Yes	None
C (check)	Active [Note (1)]	None	Yes	None
D	Active	None	None	Yes

Note:
(1) Classification may vary with plant age and licensing base.

TABLE 7.3 LEAKAGE CRITERIA FOR CATEGORY A VALVES [7]

Valve type	Criteria
Containment isolation	10CFR50, Appendix J
Other than containment isolation	As defined by the Owner or the following: for water, a minimum of 0.5D gpm or 5.0 gpm; for air, 7.5D gpm SCFD

General Notes:
(a) D = nominal valve size, in.

TABLE 7.4 EXAMPLE OF TYPICAL PWR LEAKAGE RATES

	Component Administrative Limits		
Primary Containment (Total)	Leakage Rate Range (SCFH)	Status	Action
Not to exceed 277.77 SCFH	0.0–14.9	Pass	None
	15.0–24.9	Alert	Notify
	>25.0	Fail	Inoperable

TABLE 7.5 STROKE-TIME ACCEPTANCE CRITERIA FOR ACTIVE CATEGORY A AND B VALVES [7]

	Reference Stroke Time, T_r (sec.)	Acceptance Range, % of T_r
Electric MOV	>10	±15%
Electric MOV	≤10	Larger of ±25% or ±1 sec.
Other POV	>10	±25%
Other POV	≤10	±50%
Any valve	<2	Maximum: 2 sec.

If a valve fails to exhibit the required change of operator position or exceeds the limiting required stroke time, the valve shall be declared inoperable. Valves declared inoperable may be repaired or replaced; in some cases, if the data can be analyzed to determine the cause of deviation, they may even be defined as operating within limits.

For Category C pressure-relief devices, testing requirements are defined in the O&M Code, Appendix I [7]. The general rule for pressure-relief valves is that they shall not exceed the stamped set-pressure criteria by more than 3%. Non-reclosing pressure-relief devices are not required to be tested. They are required, by the O&M Code, Appendix I [7], to be replaced at least every five years, unless historical operating experience indicates more frequent replacement is required. Facility Owners may have testing or replacement criteria varying from what is given here, which is based on system and valve design requirements or TS requirements. In most cases, if such criteria are not met, valves are repaired, refurbished, or replaced.

Category C check valves are exercised for obturator movement. If a check valve fails to exhibit the required change of obturator position, it shall be declared inoperable.

7.4.2 Pumps

For the subject pumps, inservice test parameters and parameter ranges are specified in Subsection ISTB of the O&M Code [7] and examples of the test parameters with acceptance limits are summarized in Tables 7.6, 7.7, and 7.8. Figure 7.10 depicts the pump vibration limits in graphical form.

As shown in Table 7.7, the test parameter ranges are grouped as acceptable, alert, and required-action for the various parameters considered. The acceptance criteria for these pumps are defined as the alert range, which indicates incipient degradation of performance, and the required action range. If deviations fall within the alert range, the specified frequency of testing shall be doubled until the cause of the deviation is determined and the condition corrected; if they fall within the required action range, the pump shall be declared inoperable until the cause of the deviation is determined and the condition corrected.

TABLE 7.6 INSERVICE TEST PARAMETERS FOR PUMPS [7]

Quantity	Remarks
Speed, N	If variable speed
Differential pressure, ΔP	Centrifugal pumps, including vertical line shaft pumps
Discharge pressure, P	Positive displacement pumps
Flow rate, Q	—
Vibration:	
Displacement, V_d	Peak to peak
Velocity, V_v	Peak

7.4.3 Snubbers

Inservice test requirements for snubbers are specified in O&M Code, Subsection ISTD, "Inservice Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Power Plants" [7]. This sub-section specifies the scope, test intervals, sample sizes, and operability test requirements for snubbers. The operability test requirements for snubbers include the following parameters:

(1) The breakaway and drag force;
(2) The activation-velocity or acceleration; and
(3) The release rate.

The acceptance criteria for each of these tested parameters are specified as part of the test program and are determined by the restraint and motion requirements of the restrained component. Guidelines for determining the generic acceptance criteria greater than the manufacturer's specified criteria are provided in EPRI Report NP-6443, "Improved Criteria for Snubber Testing" [20]. These improved criteria for snubber operability are based on the restraint requirements of the piping system or component being restrained. By evaluating the piping system or component thermal flexibility, increased snubber drag or breakaway forces may be justified.

7.4.4 Piping

The rules of Section XI [8] define requirements for the evaluation and acceptance of degraded piping components. These requirements have been developed for piping that is flawed or degraded from a corrosion mechanism and are used to demonstrate the piping fitness for service when subjected to design-basis loads. (More detailed information regarding the flaw evaluation requirements for piping is found in Chapter 29.) For the specific case of through-wall flaws in Class 3 moderate-energy piping in which the maximum operating temperature does not exceed 200°F and the maximum operating pressure does not exceed 250 psig, Code Case N-513 [25] specifies flaw evaluation methods and acceptance criteria to justify the temporary acceptance of this condition. The USNRC has approved the use of this Code Case in the revision of 10CRF50.55a [11].

TABLE 7.7 TEST PARAMETER RANGES FOR PUMPS [7]

Pump Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range
Centrifugal and vertical line shaft	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils	$>6V_r$ or >22 mils
Centrifugal and vertical line shaft	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec.	$>6V_r$ or >0.70 in./sec.
Reciprocating		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$	$>6V_r$

Note: V_d denotes vibration displacement measurements, V_v denotes vibration velocity measurements, and V_r denotes the vibration reference value defined in ISTB-3000 [7].

TABLE 7.8 TEST PARAMETER RANGES FOR PUMPS [7]

Test Parameter	Acceptable Range	Alert Range	Required Action Range	
			Low	High
P (positive displacement pumps)	$0.93–1.10P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.10P_r$
ΔP (vertical line shaft pumps)	$0.95–1.10\Delta P_r$	0.93 to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.10\Delta P_r$
Q (positive displacement and vertical line shaft pumps)	$0.95–1.10Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
ΔP (centrifugal pumps)	$0.90–1.10\Delta P_r$	—	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Q (centrifugal pumps)	$0.90–1.10Q_r$	—	$<0.90Q_r$	$>1.10Q_r$

Note: Subscript r denote refererence values.

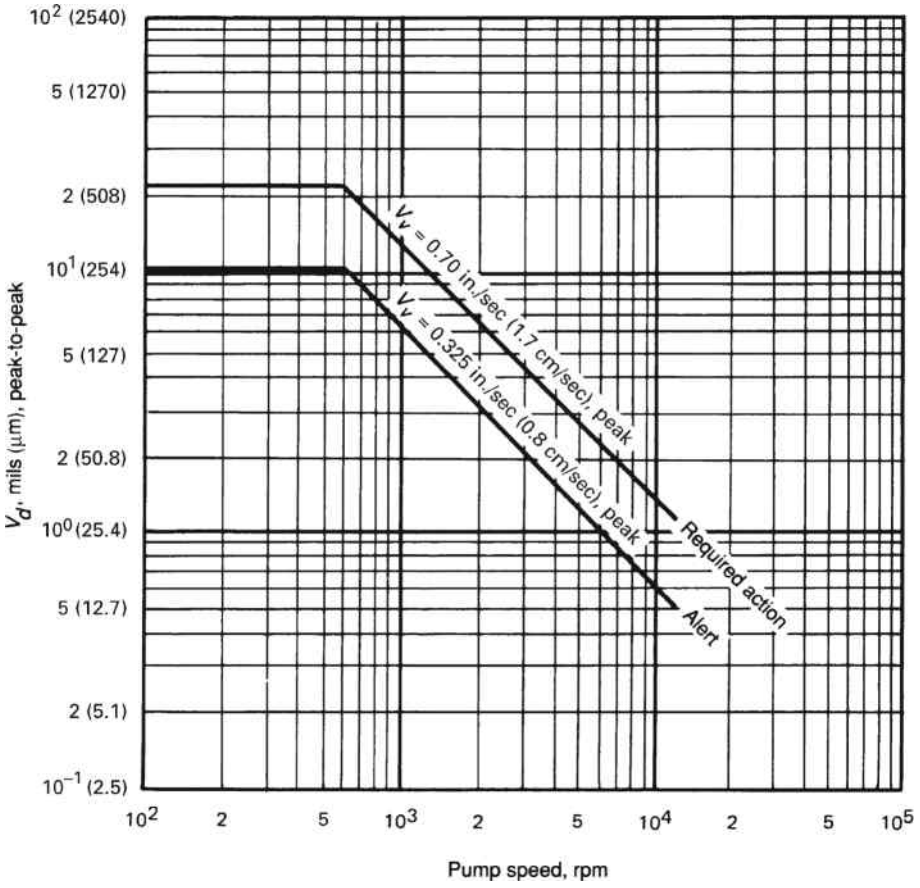


FIG. 7.10 PUMP VIBRATION LIMITS (*Source:* Fig. ISTB-5200-1 of the ASME O&M Code)

7.4.5 Reactor Vessel

The rules of Section XI [8] define requirements for the evaluation and acceptance of flaws and radiation embrittlement the reactor vessel. These requirements are used to demonstrate the vessel's fitness for service when it is subject to design-basis loads. (More detailed information regarding flaw evaluation requirements is found in Chapter 29.) Appendix E of Section XI Code [8] provides evaluation methods and acceptance criteria for the reactor vessel when it is subject to pressure in excess of the pressure-temperature limits required by 10CFR50.60 and Appendix G of 10CFR50 [9]. Meeting the requirements of this appendix ensures adequate structural integrity for returning the vessel to service. The Appendix E evaluation method reduces some of the margins inherent in the development of pressure-temperature limits by reducing both the postulated flaw depth and the safety factor on the pressure-stress intensity factor, and by increasing the vessel material fracture-toughness. This increase in vessel material fracture-toughness provides a significant margin for this structural integrity evaluation. The Appendix E evaluation changes the vessel material fracture toughness from Section XI, Appendix G [8], limits of K_{Ia} to the K_{Ic} limit defined in Section XI, Appendix A, Fig. A-4200-1. Figure 7.11 presents the K_{Ia} and K_{Ic} fracture-toughness values used for vessel evaluations. It should be noted that the Section XI, Appendix G criteria for developing the vessel pressure-temperature limits have been modified in Code Case N640 [21] to permit use of the K_{Ic} vessel

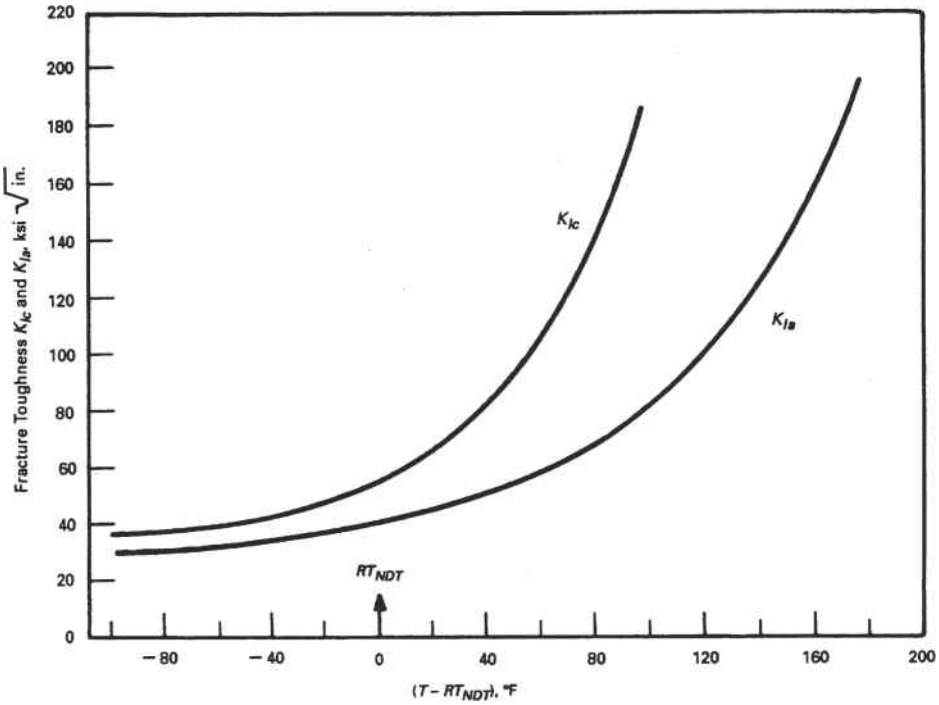


FIG. 7.11 LOWERBOUND K_{LA} AND K_{LC} TEST DATA REACTOR VESSELS
(*Source:* Fig. A-4200-1, Appendix A of the ASME B&PV Code)

material-fracture toughness, but such vessel pressure-temperature limits do not have this additional margin for their structural integrity assessments.

7.5 OPERABILITY EVALUATION METHODS

Design analysis methods and acceptance criteria applicable to piping systems, components and supports inherently contain conservatisms to compensate for uncertainties in the operation, fabrication, and construction of systems. Generally, design analysis methods employ a conservative finite element model and small deformation linear-elastic theory to estimate the system response to the design-basis loads. This is an approach that generates conservative system stresses for the following reasons:

(1) Piping system nonlinearity;
(2) Energy losses from localized plastic deformation;
(3) Load redistribution associated with items (1) and (2) of this list;
(4) Conservatism of building structure response spectra;
(5) Conservatism of Enveloped/Uniform Response Spectra analysis method; and
(6) Conservatism of the critical damping values.

These areas of conservatism have been substantiated by many research and testing programs. Some of these test programs are the Electric Power Research Institute (EPRI) multiple structure piping system tests [22] and the EPRI- and USNRC-sponsored Piping and Fitting Dynamic Reliability Program [23].

7.5.1 Piping Systems

For piping systems, the evaluation method used to demonstrate operability usually is to examine the design-basis analysis methods to define and understand the conservatism in the methods used. The analytical methods generally employed for the design basis of the piping are based on conservative models, load definitions, and solution methods. The intent for an operability demonstration is to refine the analytical model to more realistic parameters. This may be to include support and equipment nozzle stiffness values that may reduce some of the conservatism inherent in the calculation of nozzle loads. It may include performing a time-history analysis to calculate more accurate stresses rather than using an enveloped response spectra method of analysis. Support nonlinearities may be included to more accurately define support loads and to reduce the restraint on the pipe. Instead of using a uniform response spectra method of analysis, the independent support motion method described in Welding Research Council (WRC) Bulletin 352 [24] together with an alternative system damping (such as Code Case N-411 [25]) can be used to reduce the response of seismic and other building-filtered loads evaluated by response spectra methods. Section III, Appendix N [25] provides detailed descriptions of these alternative, more rigorous methods that may be used to determine system responses to seismic and other building-filtered dynamic loads. Also, the combination of dynamic loading responses from different events permits the use of the square root-sum-of-the-squares method. This combination method is justified when the predominant frequencies of the events being combined are sufficiently separated to make the probability of simultaneous maximum responses for each event very unlikely [26].

The methods that are selected are based on the conditions being analyzed. The expected loading or the degraded condition will provide insight that the analyst can use to select the methods that will provide a more accurate representation of the system response that would be expected.

7.5.2 Supports

For supports, the evaluation method usually used to demonstrate operability is a structural analysis method. Although for supports

and especially expansion anchors, the operability evaluation may be based on test results or a combination of test results and analysis.

Generally, support designs are based on conservative models, load definitions, and solution methods. Many times the support design may be based on hand calculations or simplified computer analyses. Developing more rigorous analytical models can be used to recognize the redistribution of loads in the support structure. In many cases support operability is demonstrated by evaluating the system or component being supported—an evaluation that is performed to reduce the loads acting through the degraded or nonconforming support. In other cases, the system or component evaluation demonstrates that support functionality is not needed for the system or component to perform as required.

7.5.3 Valves

Operability evaluations of valves are generally based on the determination of margins available in the original qualification documents. In most cases, the typical parameter to consider is the dynamic acceleration limit used for the qualification. Valve qualifications are often performed for generic specification acceleration values that would be seen in a seismic event. For plant-specific applications, the actual seismic acceleration and resulting stresses can be compared to allowables for qualification.

An effective approach for valve operability evaluation is to verify that the available margins between the qualified loads and the loads determined for the conditions requiring operability verification are sufficient for accepting the critical operability parameter (e.g., stress level, deformation, and load). In cases where this direct comparison does not provide the required relief, a more realistic determination of the actual loads may be useful. Methods previously discussed for the reevaluation of piping and support systems may result in reduced loads at valve locations. This can include a reduction in accelerations or a reduction in nozzle loads. Valves may also be analyzed by using finite element methods to assess stress and deformation at critical locations for increased loads. These analyses often indicate only localized high stress and deformation conditions that do not affect the valve's functionality.

A particular valve operability problem is related to the increased torque or thrust requirements to meet certain system demands related to the assigned safety function. In most cases, it is possible to show analytically that the weakest link on the postulated load paths have sufficient capacity and integrity to meet the increased demand. However, in extreme cases in which an analytical approach does not provide the required verification, testing may be useful to ensure the functionality.

7.5.4 Pumps, Tanks, and Heat Exchangers

Typically, equipment items such as pumps, tanks, and heat exchangers have allowable nozzle load limits. There are also dynamic loads usually due to seismic events that load the support attachment locations, the supports, and anchor bolts. As with valves, the Vendor Equipment Qualification Report should be reviewed to determine the basis of the allowable nozzle loads and the dynamic inertia loads applied to the component.

In a typical pump, tank, or heat exchanger, the allowable nozzle loads and the dynamic loads are used to check the following:

(1) The nozzle at the junction with the shell;
(2) The shell in the region of the nozzle;
(3) Gross shell stresses;
(4) Localized shell stresses at the saddles;
(5) Gross stresses in the saddle supports; and
(6) Gross loads on the anchor bolts.

Items (1) and (2) of the preceding list use the loads for their respective nozzles. Items (3)–(6), however, use the combined effects of weight, dynamic inertia, operational loads (e.g., as motor torque in a pump), and all nozzles.

In many cases, particularly on Class 2 and 3 vessels, the shell in the region of the nozzle is the limiting component. For this location, the local stress analysis of the shell should be reviewed. Such analyses are typically done using the methods of WRC Bulletin 107 [27] and WRC Bulletin 297 [28]. This review should assure that the vendors have properly identified the membrane and bending stresses in the shell. For Service Level D conditions, local membrane effects should be checked in the shell at the shell nozzle junction, but not local membrane plus local bending ($P_L + P_b + Q$). The requirements for local checks are taken directly from Appendix F of the ASME Boiler and Pressure Vessel Code [19].

Through-wall bending effects (the M terms) are secondary effects and, as such, do not need to be considered, which can provide substantial relief.

Alternate analyses may also be performed by using finite element models at critical areas to assess the stresses and deformations.

For pumps, there may be a need for the component to remain in operation or to start with the loading. In this case, it may be necessary to limit the stresses to assure that the deformation of the pump will not prevent operation. These conditions require additional consideration when performing operability analyses.

7.5.5 Specific Inspections

For those operability evaluations on components that have been restored to their current licensing basis before being placed back into service, or on components subjected to a significant unanticipated operating event, an evaluation may be based on augmented inspections. Analyzing the degraded or nonconforming component, or analyzing the unanticipated event to identify those areas of the component that are most likely to sustain damage will guide these augmented inspections. The results of the inspection will be included in the evaluation to demonstrate the functionality of the component, after which they will be documented. These inspections will largely be visual and may include surface or volumetric examination at highly stressed locations.

Whenever damage is found, the results of the inspections and tests require an engineering evaluation to determine the functionality of the affected component. The nature of this evaluation will depend on the type and extent of the damage found.

The following lists describe the possible inspection locations and the damage that may affect the performance of the components.

7.5.5.1 Piping Systems. This may largely be a visual inspection of the piping system including the supports to determine whether any significant damage has occurred. The examination for damage may include the following:

(1) Distortion of the piping cross section;
(2) Local denting or buckling of the wall;
(3) Leaks;
(4) Permanent distortion of piping;
(5) Interaction with adjacent structures or components;
(6) Broken or bent bolts;
(7) Distortion of flanged connections;
(8) Cracked socket welds; and
(9) Interferences or unintentional restraints.

7.5.5.2 Component Supports. This may largely be a visual inspection of the supports to determine whether any significant damage has occurred. The examination for damage may include the following:

(1) Buckling of members or rods;
(2) Local distortion of members;
(3) Cracks at welds;
(4) Pullout of concrete expansion anchors;
(5) Broken or bent bolts;
(6) Stripped-bolt threads;
(7) Spalled concrete;
(8) Distorted baseplate; and
(9) Hydraulic snubber fluid leaks.

The examination for snubbers and other supports, which are relied upon to change positions, may include internal examination or stroking them through their expected range of operation to determine whether any internal damage has occurred.

7.5.5.3 Valves. The valves may be visually examined for leakage of and damage to bolts, as well as distortion to the yoke and stem. Examination of the welds to the pipe will be performed. Valves required to change position during the remainder of the operating cycle will be stroked to the extent practicable to determine their functionality. Stroke times may be measured and compared to requirements.

7.5.5.4 Pumps. Pumps that were operating during the event can be monitored for vibration and flow and can also be visually examined for leakage. Standby pumps that were not operating during the event but that may be required to perform a safety function may require testing (to the extent practicable) for vibration and flow or pressure, and may also require a visual examination for leakage.

7.6 SHORT-TERM OPERABILITY ACCEPTANCE CRITERIA

Short-term operability criteria are generally specified in plant-specific requirements. Provided below are criteria for short-term operability that were based on ASME Section III, Appendix F [19].

7.6.1 Short-Term Operability Acceptance Criteria for Piping

The short-term operability acceptance criteria presented here are for piping systems designed to various ASME and ANSI Codes and Code editions [19], [29]–[30]. The loads to consider in the operability evaluations for piping are defined in Table 7.1. These criteria are intended for piping and typical piping components. If the evaluated system includes specialty piping components such as flanges and expansion joints, these specialty piping components are expected to meet the current licensing-basis service Level D/faulted condition limits.

7.6.1.1 Criteria for Piping Designed to ANSI B31.1, B31.7 Classes 1 and 3, or ASME Section III, Classes 2 and 3 (Prewinter 1981). For Level A/normal loads:

$$\frac{PD}{4t} + 0.75i\frac{M_A}{Z} < S_y \tag{7.1}$$

For Level D/faulted loads:

$$\frac{P_{\max}D}{4t} + 0.75i\frac{(M_A + M_D)}{Z} < 2S_y \tag{7.2}$$

$$P_{\max} \le 2P_a \tag{7.3}$$

The criteria presented in the preceding equations were developed for operability criteria based on a 1% strain acceptance criterion for carbon steel piping and 2% strain acceptance criterion for stainless steel piping, which were both approved by the USNRC [31]. In developing the strain limit acceptance criterion, a stress acceptance criterion of $2S_y$, was shown to be more limiting than that when the stress values were calculated using elastic methods.

7.6.1.2 Criteria for Piping Designed to ANSI B31.7, Class 1, or to ASME Section III, Class 1. For Level A/normal loads:

$$B_1\frac{PD}{2t} + B_2\frac{M_A}{Z} < \text{the greater of } 1.5S_m \text{ or } S_y \tag{7.4}$$

For Level D/faulted loads:

$$B_1\frac{P_{max}D}{2t} + B_2\frac{(M_A + M_D)}{Z} < 2S_y \tag{7.5}$$

$$P_{\max} \le 2P_a \tag{7.6}$$

The criteria presented in the preceding equations were founded on the evaluations and acceptance criteria specified in Appendix F of Section III [19]. This stress limit has been specified as $2S_y$, not the lesser of $3S_m$ or $2S_y$, based on prior acceptance of this limit [32].

7.6.1.3 Criteria for Piping Designed to ASME Section III, Classes 2 and 3, Winter 1981 or Later Edition. For Level A/normal loads:

$$B_1\frac{PD}{2t} + B_2\frac{M_A}{Z} < \text{the greater of } 1.5\,S_h \text{ or } S_y \tag{7.7}$$

For Level D/faulted loads:

$$B_1\frac{P_{max}D}{2t} + B_2\frac{(M_A + M_D)}{Z} < \text{greater of } 3\,S_h \text{ or } 2S_y \tag{7.8}$$

$$P_{\max} \le 2P_a \tag{7.9}$$

The criteria presented in the preceding equations were founded on the evaluations and acceptance criteria specified in Appendix F of Section III [19].

7.6.2 Short-Term Operability Acceptance Criteria for Supports

The proposed operability acceptance criteria are developed for component standard supports, spring hangers, snubbers, linear-type supports, structural bolts, and concrete expansion anchors. These criteria were developed to address the load-carrying capability of the supports. However, the other support failure modes must also be addressed when applicable. Support design stability, including the potential for buckling, should be evaluated unless the system is shown to be functional without the support. Support binding should also be addressed in the support operability

evaluation and the operability evaluation for the system. Table 7.1 provides guidance to consider for the loadings in the support evaluation. If the necessity of including seismic anchor motion is determined, it should be combined with the seismic inertia load by a square root-sum-of-the-square method.

7.6.2.1 Component Standard Supports. Component standard supports are supplied by support manufacturers with defined load capacities. The following criteria will be used to determine the operability of these components when they are subject to Service Level D/faulted condition loads as defined in Table 7.1.

(a) The manufacturer's ultimate tested load divided by a safety factor of 1.5 except for the side load on U-bolts, which should be 3.0. In determining this limit, the allowable should be modified by the temperature effects on the material ultimate strength.
(b) The manufacturer's allowable load for Service Level D.
(c) The manufacturer's allowable load for Service Level A multiplied by either of the following:
  (i) the lesser of 2 or 1.167 (S_u/S_y) when $S_u > 1.2\ S_y$ or
  (ii) 1.4 when $S_u < 1.2S_y$.

If the criteria in the preceding list cannot be met, the criteria in the paragraphs that follow for linear-type supports can be used to demonstrate the operability of the standard component.

7.6.2.2 Linear-Type Supports. For linear-type supports, ASME Section III, Appendix F, paragraph F-1334 [19] provides the basis for the operability criteria. The following limits summarize the criteria of this subparagraph, although not all of the criteria specified in this subparagraph are presented here.

For Tension Stress, $F = \min(1.2S_y, 0.7S_u)$ except at pinholes, which use $\min(0.9S_y, 0.5S_u)$.

For Shear Stress, $F_v = \min(0.72S_y, 0.42S_u)$.

For Bending Stress, $F_b = (f) \times S_y$ for compact sections where (f) = the plastic shape factor. For noncompact sections, see Appendix F, paragraph F-1334.4(c) [19].

For Compression, $F_a = \min(F_t, 0.67S_{cr})$.

For Combined Axial Tension and Bending, the stress of members subjected to both axial tension and bending must be proportioned to satisfy the requirements of equation (7.10), which follows.

$$\frac{f_a}{F_a} + \frac{f_{bx}}{F_{bx}} + \frac{f_{by}}{F_{by}} \leq 1 \tag{7.10}$$

Where

F_a = the smaller of $1.2S_y$ or $0.7S_u$

For Combined Axial Compression and Bending, the stresses of members subjected to both axial compression and bending must be proportioned to satisfy the requirements of equations (20), (21), and (22) of ASME Section III, NF-3322.1(e)(1) [19]. The NF-3322.1(e)(1) equations are modified to use the F_a, F_b, and F_e definitions of Section III, Appendix F, paragraph F-1334.5 [19].

7.6.2.3 Structural Bolts. Structural bolting will meet the requirements of Section III, Appendix F, paragraph F-1335. For all structural bolts, the average tensile stress computed on the basis of the average tensile stress area will not exceed the lesser of $1.0S_y$ and $0.7S_u$. The average shear stress will not exceed the lesser of $0.6S_y$ and $0.42S_y$. For high-strength structural bolts ($S_u > 100$ ksi at operating temperature), the maximum stress at the periphery of the cross section caused by direct tension plus bending but excluding stress concentrations—will not exceed S_u. If structural bolts are subject to combined tensile and shear loads, the tensile and shear stresses must be proportioned so that the following equation is satisfied.

$$\frac{f_t^2}{F_{tb}^2} + \frac{f_v^2}{F_{vb}^2} \leq 1 \tag{7.11}$$

7.6.2.4 Concrete Expansion Anchors. As previously described in Section 7.3.2, displacement-controlled loads should be considered when evaluating the operability of concrete expansion anchors. An exception to this requirement is for undercut anchors if the failure mode is in the bolt, not in the concrete. The operability limits for tension and shear loads acting on concrete expansion anchors are obtained from the ultimate capacities determined by the manufacturer. A safety factor of 2 on these limits is required by the NRC Inspection and Enforcement Bulletin 79-02 [33]. For the bolt ductile failure mode of undercut anchors, a safety factor of 1.5 may be used. Also, anchors near free edges are subject to shear failure in the concrete and should use a safety factor of 2. Anchors subject to combined tension and shear will be evaluated using the following interaction equation.

$$\left(\frac{F_t}{F_{to}}\right)^{5/3} + \left(\frac{F_v}{F_{vo}}\right) \leq 1.0 \tag{7.12}$$

Reductions in the tensile and shear capacities of the expansion anchor caused by center-to-center and edge distance violations must be determined before multiplying by the required safety factor of 2 or 1.5.

Some anchorages are installed with gaps between the plant and concrete or plate-and-bolt head. In these cases, the prying force typically included in such analyses may be neglected. Anchor bolts with gaps up to $^1/_8$ in. are shown to develop full capacity and, therefore, are acceptable [34].

7.6.2.5 Integral Welded Attachments. For integral welded attachments to straight pipe, the methodologies defined in Code Cases N-122 and N-318 will be used for rectangular attachments, and those defined in Code Cases N-391 and N-392 will be used for circular attachments. The stress limit to use for evaluations based on each of these Code Case is $2.0S_y$.

7.6.2.6 Spring Hangers. Spring hangers will be evaluated for loading clearances. The maximum pipe movement will be checked against the stroke of the hanger, and where the spring hanger was subjected to an excessive weight load, the individual components will be evaluated for the excess load.

7.6.2.7 Snubbers. Snubbers that are subject to an unanticipated dynamic load will be evaluated against the manufacturer's Service Level D allowable or against the "one time" allowable test load.

The primary failure mode for snubbers is excess drag and lockup. In these cases the impact of the snubber failure on the piping system requires evaluation, which includes a fatigue evaluation for piping systems with fatigue design requirements. The fatigue analysis considers the operating events and their thermal transients known to occur while the snubber is degraded. Using the guidance provided in EPRI Report NP-6443 [20], increased snubber breakaway and running drag loads can be justified; for example, depending on the piping size, allowable drag loads of 5% of the snubber load rating are justified. For hydraulic snubbers, the common failure mode is leakage, resulting in a lack of restraint [35].

This failure mode requires the system or component to be evaluated without the snubber.

7.7 LONG-TERM OPERABILITY

Generic Letter 91-18 provides specific guidance for long-term operability by requiring that the degraded or nonconforming SSC be brought back into complete compliance with the licensing basis requirements. This task requires the repair or replacement of the SSC in accordance with ASME Section XI requirements. Alternative tasks include a more detailed, sophisticated analysis to demonstrate that the SSC complies with licensing commitments, as well as revising the licensing basis to make it conform to the required USNRC review and approval to bring the SSC into compliance.

7.8 PROBABILISTIC ASSESSMENT OF OPERABILITY

Licensees should ensure operability in accordance with the technical specifications and should assess and manage the risk impact of maintenance activities per 10 CFR 50.65 (a)(4) and NUMARC 93-0 1, Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. Regulatory Guide 1.182, issued June 1, 2000, endorses the industry guidance on 10 CFR 50.65(a)(4) provided in Section 11 of NUMARC 93-01, Revision 3, August 2000. Such an evaluation typically uses deterministic analyses with qualitative judgments being made on acceptability. The use of probabilistic analyses can augment such analyses effectively. The use of probabilistic analyses for a variety of topics is being used more in the industry. 10CFR50 Appendix A General Design Criteria for Nuclear Power Plants refers to the use of probability to determine design bases. It states "…dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping." The extension to operability will be effective.

Classical operability for a case involving the continued operation of a degraded SSC assesses whether the likelihood of a failure/malfunction of the SSC has increased more than minimally. Traditionally, these determinations are based on both quantitative and qualitative conclusions derived from deterministic calculations based on "bounding" assumptions for materials and operating stressors. The resulting safety impact associated with degraded component continued operation will also be qualitative.

The application of Probabilistic analyses provide distinct advantages over qualitative likelihood of failure estimates. Unlike the qualitative assessments, probabilistic calculations quantify the probability SSC failure. In these analyses, the operating variables represent how the system/component will actually be or was operated. Uncertainties associated with the component design, materials, and operation are addressed probabilistically. The likelihood of failure is typically expressed as failure probability/frequency with respect to time. The resulting probability of failure can be used to quantify the safety "risk" impact associated the time a degraded SSC operates.

Probabilistic analyses present challenges to an analyst. Improved understanding of many facets of the design and operation is important. These include material properties, characteristics of the degraded condition, actual loads imposed, and actual predicted behavior. The analyses that are chosen may include effects such as gaps and plasticity. What is also required is an ability to judge an acceptable probability. This is generally also qualitative and will involve personnel that perform risk analyses for a plant.

Guidance for acceptance is available. The DOE has published criteria that provide a hazard evaluation ranking mechanisms for acceptability [36]. There are many ways to make these judgments. An example of a hazard evaluation ranking table used by the DOE [36] as a sample is provided in Table 7.9. For a specific application at a power plant, plant-specific guidance should be used.

7.9 COMMON TERM DEFINITIONS

Current Licensing Basis Current licensing basis (CLB) is the set of USNRC requirements applicable to a specific plant composed of a licensee's written commitments for ensuring compliance

TABLE 7.9 QUALITATIVE LIKELIHOOD CLASSIFICATION TABLE

Descriptive Word	Estimated Annual likelihood of Occurrence	Description
Anticipated	$10^{-1} > p > 10^{-2}$	Incidents that may occur several times during the lifetime of the facility. (Incidents that commonly occur)
Unlikely	$10^{-2} > p > 10^{-4}$	Accidents that are not anticipated to occur during the lifetime of the facility. Natural phenomena of this probability class include: Uniform Building Code-level earthquake, 100-year flood, maximum wind gust, etc.
Extremely unlikely	$10^{-4} > p > 10^{-6}$	Accidents that will probably not occur during the life cycle of the facility. This class includes the design basis accidents.
Beyond extremely unlikely	$10^{-6} > p$	All other accidents.

with and operation within the applicable USNRC requirements and also the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the following:

(1) The USNRC regulations contained in 10CFR Parts 2, 19, 20, 21, 30, 40, 50, 51, 55, 72, 73, and 100, as well as appendices to those Parts.
(2) Orders, license conditions, exemptions, and the Technical Specifications (TSs).
(3) The plant-specific design-basis information defined in 10CFR50.2, as documented in the most recent Final Safety Analysis Report (FSAR) as required by 10CFR50.71.
(4) Docketed licensing correspondence such as licensee responses to USNRC bulletins, generic letters, and enforcement actions.
(5) Licensee commitments documented in USNRC safety evaluations or licensee event reports.

Design Basis Design basis is the body of plant-specific design bases information defined by 10CFR50.2.

Design-Basis Events As defined in 10CFR50.49(b)(1)(ii), design-basis events include normal operating conditions, anticipated operating transients, design-basis accidents, external events, and natural phenomena that the plant was designed to with stand.

Degraded Condition An SSC condition in which any loss of quality or functional capability occurs.

Nonconforming Condition An SSC condition in which there is failure to meet requirements of licensee commitments. The following are some examples of nonconforming conditions:

(1) A failure to conform to one or more applicable Codes or Standards specified in the FSAR.
(2) As-built or as-modified equipment that does not meet FSAR design requirements.
(3) Operating experience or engineering reviews that demonstrate a design inadequacy.
(4) Documentation required by USNRC requirements, such as 10CFR50.49, that is deficient or unavailable.

Full Qualification Full qualification constitutes conforming to all aspects of the current licensing basis, including Codes and Standards, Design Criteria, and commitments.

Active Components Those components that perform a mechanical motion to accomplish their assigned safety functions.

7.10 NOMENCLATURE

A_g = area of gross section of linear support member
A_p = pipe cross-sectional (metal) area
b = actual width of stiffened and unstiffened compression elements
b_f = flange width of rolled beam or plate girder, in.
B_1 = pressure stress index from NB-3683 [19]
B_2, C_2 = moment stress indices from NB-3683 [19]
C_m = coefficient applied to the bending term in the interaction equation and dependent upon column curvature caused by applied moments
D = pipe outside diameter
E = modulus of elasticity of steel, ksi
f_a = computed axial stress, ksi
f_b = computed bending stress, ksi
f_t = bolt tensile stress, ksi
f_v = bolt shear stress, ksi
F_{tb} = allowable bolt tensile stress at temperaure, ksi
F_{vbl} = allowable bolt shear stress at temperature, ksi
F_e = Euler stress divided by factor of safety, ksi
F_a = axial stress permitted in the absence of bending moment
F_b = bending stress permitted in the absence of axial force
F_s = allowable related to strength in combined compression bending
F_t = tensile stress
F_{to} = allowable tensile stress in a concrete expansion anchor
F_v = shear stress
F_{vo} = allowable shear stress in a concrete expansion anchor
F_w = stress in a fillet weld
i = stress intensification factor
K = effective length factor
K_{la} = material fracture toughness based on crack arrest
K_{lc} = material fracture toughness based on fracture initiation
l = for beams, distance between the cross section braced against twist or lateral displacement of the compression flange, in.
l = for columns, actual unbraced length of member, in., and unsupported length of lacing bar, in.
M_A = sustained moment
M_D = amplitude of the moment for Level D (all dynamic loads)
M_{sl} = amplitude of the moment for Level D/faulted condition (reversing dynamic loads only)
M_{sm} = range of the moment from Level D/faulted seismic anchor motion
P = design pressure
P_{cl} = maximum compressive allowable load of a linear support member
$P_{\max}$ = pressure for Level D/faulted condition that is coincident with loads being evaluated
P_a = allowable working pressure or rated pressure for each piping component as determined by the pressure design section of the Construction Code or Code of Record
P_{sm} = amplitude of the axial force from Level D/faulted seismic anchor motion
r_b = radius of gyration about axis of concurrent bending, in.
S_{cr} = critical buckling load
S_h = ASME design stress allowable, Classes 2 and 3
S_m = ASME design stress intensity allowable, Class 1
S_u = specified minimum tensile strength at temperature
S_y = specified minimum yield strength at temperature
t_f = flange thickness
t = wall-thickness
Z = pipe section modulus

7.11 ACKNOWLEDGEMENT

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CHAPTER

8

FLUIDS[1]

Frederick J. Moody

8.1 INTRODUCTION

This chapter presents a brief summary of force predictions from fluid phenomena and behavior, both of which are significant to the formulations and criteria employed in the ASME Boiler and Pressure Vessel (B&PV) Code. It focuses on the nature of fluid forces imposed on vessels and piping systems from the standpoint of designers, who need guidelines for both the design and operational recommendations of fluid transport systems.

Fluid forces are the result of pressure and shear phenomena, caused by energy transfer at pumps or turbines, or by disturbances resulting from such sources as valve operation, pipe rupture, vapor void collapse, and the motion of the frame to which the system in question is anchored. A fluid disturbance generally occurs over a predictable time period; the fluid may respond simultaneously (bulk flow response) or in a propagation sense (waterhammer response), depending on the system geometry. The nature of bulk flow and waterhammer responses are significantly different, making it essential for one to identify the specific fluid response before calculating the resulting forces.

Most of the forces of concern in boiler and piping design are generated from pressure and shear within internal flow systems. However, fluid forces are also of significant concern in external flow systems, where structures are submerged in fluids.

Fluid forces result from both stationary and moving fluids, both of which are considered in this chapter. If stationary, the fluid forces are hydrostatic exerting forces based on gravity and fluid depth; if exerted by motion, however, the fluid can exert either steady or accelerative forces.

8.2 THE NATURE OF FLUID FORCES

Fluid forces need to be predicted to create safe boiler and piping designs. System material strength, geometric properties, and operational specifications can be formulated when the expected fluid forces are known. A fluid can only exert pressure or shear forces on a structural surface. Local pressure forces in stationary or moving fluids act normal to the surface, whereas local shear forces of moving fluids act tangentially to the surface.

A buoyant force results from hydrostatic pressure acting on surfaces. For example, a submerged pipe has higher hydrostatic pressure on the bottom than on the top; therefore, it is exposed to a net upward force of the surrounding fluid whether the fluid is stationary or moving.

Pressure forces exerted by moving fluids result from fluid momentum changes in space and / or time. Whenever fluid flows around a corner, its momentum change is consistent with the pressure forces exerted on the containing walls. Lift forces on submerged structures are created by the lower pressure on one side relative to a higher pressure on the other side.

Shear forces caused by fluid friction lead to drag forces on containing surfaces. Also, fluid flow past certain structural geometries can separate from the structure, leaving a region of low-pressure, nearly stagnant fluid (known as a *wake*) behind the structure, thereby creating another pressure force known as *form drag*. For example, the fluid forces exerted on a partially closed gate-valve curtain are the result of form drag.

Although the momentum change resulting from a change in steady fluid-flow direction (e.g., the flow around an elbow) is associated with pressure forces, the momentum changes resulting from unsteady flow acceleration or deceleration (e.g., from valve operation) also lead to pressure forces.

Basic formulations resulting in fluid forces are considered in the following paragraphs.

8.2.1 Hydrostatic Forces

A stationary fluid has no pressure gradient in the x, z plane normal to the vertical acceleration vector (gravity in most cases). However, a pressure gradient does exist in the vertical y direction. Vertical pressure variation in a stationary fluid is determined by the so-called hydrostatic pressure differential equation, which follows.

$$\frac{dP}{dy} = -\rho g = -\gamma \tag{8.1}$$

where

ρ = the fluid density
g = the acceleration of gravity
γ = the fluid specific weight

It is clear from the negative sign in equation (8.1) that pressure decreases as y increases (moving upward in the fluid) and pressure increases as y decreases (moving downward in the fluid).

The hydrostatic pressure force magnitude exerted on a submerged plane surface is obtained from the product of pressure at the area centroid ($\overline{P}$) and the area (A), or

$$F = \overline{P}A \tag{8.2}$$

[1]Frederick J. Moody, author of this chapter has stated that there are no revisions for this edition. – Editor

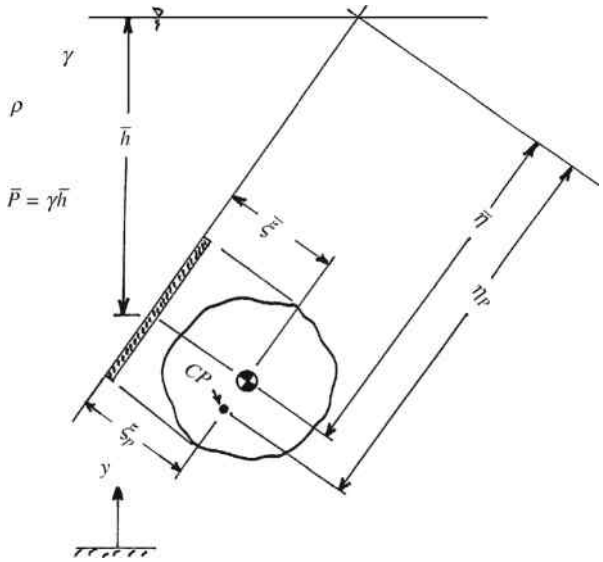


FIGURE 8.1 GEOMETRY OF SUBMERGED FLAT SURFACE

The direction of force in the foregoing equation is normal to the area plane. However, if F is to be the magnitude of a single resultant vector, its point of application corresponds to the center of pressure (CP) expressed by the following coordinates:

$$\eta_p = \bar{\eta} + \frac{I_{\xi\xi}}{\bar{\eta} A} \tag{8.3}$$

and

$$\xi_p = \bar{\xi} + \frac{I_{\xi\eta}}{\bar{\eta} A} \tag{8.4}$$

where

$\xi, \eta =$ the coordinates shown in Fig. 8.1

The horizontal hydrostatic pressure force component on a submerged curved surface is obtained as the horizontal force on the curved area projection A_x on a vertical plane, as shown in Fig. 8.2. Equations (8.2)–(8.4) yield the following:

$$F_{\text{horizontal}} = \bar{P} A_x \tag{8.5}$$

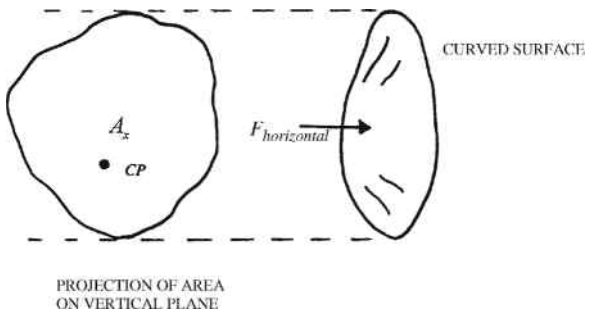


FIGURE 8.2 HORIZONTAL FORCE ON CURVED SURFACE

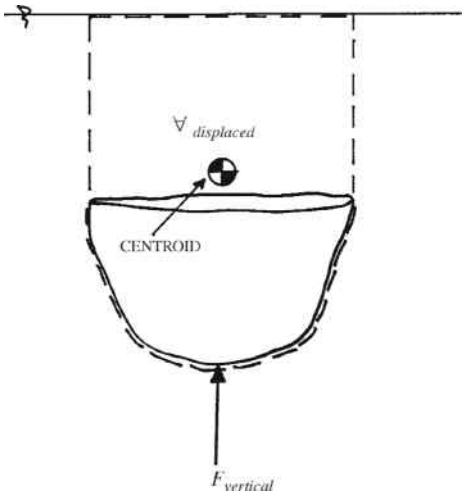


FIGURE 8.3 VERTICAL FORCE ON CURVED SURFACE

The line of action is through the CP of the projected area.

The vertical force on a submerged curved surface is obtained by integrating the pressure obtained from equation (8.1) on the surface area projected on a horizontal plane. This process yields the following:

$$F_{\text{vertical}} = \gamma \forall_{\text{displaced}} \tag{8.6}$$

where

$\forall_{\text{displaced}} =$ is the volume inside the dashed lines

The volume would be swept out by moving the submerged surface upward vertically until it crosses the liquid horizontal surface or its continuation, as shown in Fig. 8.3. The line of action passes through the centroid of $\forall_{\text{displaced}}$.

These basic hydrostatic force relationships make it possible to predict forces on boundaries of static fluid systems.

8.2.2 Pressure and Shear Forces from Fluid Motion

Pressure in moving fluids is generally obtained from the momentum equation, written for incompressible liquid as the following:

$$\frac{\partial \mathrm{V}}{\partial t} + \mathrm{V} \cdot \nabla \mathrm{V} + \frac{1}{\rho}\nabla P + g\mathbf{j} = \upsilon \nabla^2 \mathrm{V} \tag{8.7}$$

For compressible fluids, the left side remains the same, but the viscous term to the right of equation (8.7) contains additional components. The velocity is often coupled with the equation of mass conservation, given by the following:

$$\frac{\partial \rho}{\partial t} + \mathrm{V} \cdot \nabla \rho + \rho \nabla \cdot \mathrm{V} = 0 \tag{8.8}$$

that reduces to

$$\nabla \cdot V = 0 \tag{8.9}$$

for incompressible flow.

Disturbance sources generally cause localized changes in pressure or velocity, yielding a time- and space-dependent pressure field and the resulting pressure forces. Usually the shear forces are small relative to pressure forces; however, they are obtained from the velocity gradient normal to the surface of concern. They are usually written as follows:

$$F_{\text{shear}} = \tau_{\text{wall}} A = \mu \frac{\partial u}{\partial y} A \tag{8.10}$$

where

τ_{wall} = the wall shear stress
u = the velocity component parallel to the surface
y = the normal coordinate
A = the area

Equation (8.10) generally applies to laminar or turbulent flows with appropriate modifications in the turbulent viscosity term.

Fluid flow in pipes and other flow passages is usually predicted from one-dimensional flow theory. Pressure and velocity are related by the momentum equation, given as follows:

$$\frac{\partial v}{\partial t} + V\frac{\partial V}{\partial x} + \frac{1}{\rho}\frac{\partial P}{\partial x} + \frac{f}{D}\frac{V}{2}|V| + g\sin\theta = 0 \tag{8.11}$$

where

f = the Darcy friction factor
θ = the angle of the flow passage with the horizontal

The mass conservation principle for a flexible, nonuniform flow passage is given by the following:

$$\frac{\partial \rho}{\partial t} + V\frac{\partial \rho}{\partial x} + \rho\frac{\partial V}{\partial x} + \frac{\rho}{A}\left(\frac{\partial A}{\partial t} + V\frac{\partial A}{\partial x}\right) = 0 \tag{8.12}$$

Equation (8.12) is often written in terms of pressure derivatives instead of density derivatives by incorporating the sound speed, which follows:

$$C = \sqrt{\left(\frac{\partial P}{\partial \rho}\right)} \tag{8.13}$$

that yields

$$\frac{\partial P}{\partial t} + V\frac{\partial P}{\partial x} + \rho C^2\frac{\partial V}{\partial x} + \frac{\rho C^2}{A}\left(\frac{\partial A}{\partial t} + V\frac{\partial A}{\partial x}\right) = 0 \tag{8.14}$$

If the pipe area changes significantly with pressure, the pipe-wall dynamics are employed for an additional formulation of flow area in terms of pressure and pipe-wall mechanical properties.

Equations (8.7), (8.8), (8.11), and (8.14) can be simplified for flow systems that are dominated by either propagative flow or bulk flow. Solutions for time- and space-dependent pressure and velocity are often obtained for fluid regions connected to other fluid regions through nozzles or other boundaries. To provide behavioral coupling between fluid properties in connected regions, the Bernoulli equation, which follows, can be employed.

$$\frac{\partial \phi}{\partial t} + \frac{V^2}{2} + \int\frac{dp}{\rho} + gy = f(t) \tag{8.15}$$

The Bernoulli equation is obtained from the momentum equation (8.4) for an inviscid fluid. Most pipe flow applications disregard the unsteady term $\partial\phi/\partial t$ and consider instead the function $f(t)$ = constant. When the flow is incompressible or slightly compressed, the integral simply becomes p/ρ, leading to the following steady, incompressible form:

$$\frac{V^2}{2} + \frac{P}{\rho} + gy = \text{constant} \tag{8.16}$$

8.3 DISTURBANCE SOURCES

Fluid disturbances occur at boundaries of the fluid region to be analyzed. For example, valves, pipe ruptures, area transitions, pumps, branches, and vapor column collapse are localized disturbance sources adjacent to fluid columns in piping systems. Submerged explosions, bubble expansion or collapse, vortex shedding, and movement of mechanical structures impose disturbances on the surrounding fluids in which they are submerged.

Most disturbances are exerted in the form of pressure or velocity transients. A controlled moving piston imposes a local velocity disturbance associated with a local pressure disturbance and based on the fact that fluid movement works in harmony with a pressure gradient. A valve opening or closure causes a local pressure and velocity response, based on the classical relationship between valve pressure loss and the square of the velocity.

Other fluid disturbances come from heating or cooling at the boundaries. A hot fluid front entering a cold pipe undergoes heat transfer with the pipe walls, often creating significant thermal stress. Such thermal boundary conditions are not considered in this section, however, for it is devoted to pressure and velocity disturbances.

Most fluid disturbances cause unbalanced forces acting on pipe or vessel walls. The magnitude and transient characteristics of these forces determine the required strength properties of the vessel or piping as well as the supporting member structures, the latter including wall anchors or dashpots. Once fluid disturbances are known, the resulting fluid transient behavior and associated forces can be predicted. Many fluid disturbances, formulated as common boundary conditions in terms of pressure and / or velocity, are discussed in the following paragraphs.

8.3.1 Motor- or Manually Operated Valves

Motor- or manually operated valves (MOVs) have slow opening or closure characteristics relative to most other valves. The valve sketched in Fig. 8.4 shows a partially open valve with a flow area (A_v) in a pipe of flow area (A). The pressure loss across such a valve is expressed in terms of flow velocity in the pipe (V), as follows.

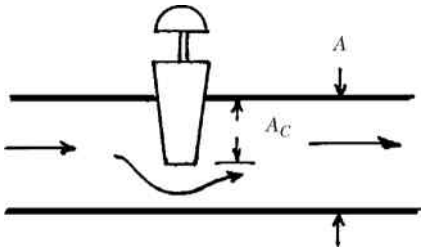


FIGURE 8.4 MOTOR- OR MANUALLY OPERATED VALVE

$$\Delta P_L = P_1 - P_2 = K_{v(t)} \frac{V^2}{2} \rho \tag{8.17}$$

where

$K_v(t)$ = the valve pressure loss coefficient (generally expressed as a function of A_v and A)

If the flow is single-phase liquid, an approximate expression for $K_v(t)$ is given by the following:

$$K_v(t) = \left(\frac{A}{C_c A_v(t)} - 1 \right)^2 \tag{8.18}$$

The contraction coefficient, C_c, is the ratio of the vena-contracta area to the valve area (A_v); the range is from about 0.6 for a sharp, orifice-type valve flow area to 1.0 for a smooth, rounded entrance. If the fluid is a gas or an otherwise compressible mixture such as a bubbly liquid–gas mixture, the pressure loss of equation (8.17) is modified by an expansion factor. If critical or choked flow of a compressible mixture occurs in the valve, equation (8.17) would be replaced by an expression for the critical flow rate, which depends only on upstream conditions.

Some valve pressure loss properties are given by the manufacturer in terms of a flow coefficient, defined by the following:

$$C_f = \frac{Q}{\sqrt{\Delta P_L}} \tag{8.19}$$

where

Q = the volume flow rate of fluid

Figures 8.5 and 8.6 give a typical flow coefficient and the resulting loss coefficient for a typical globe valve.

8.3.2 Safety/Relief Valves

Figure 8.7 shows cutaway views of a typical safety/relief valve (SRV) in the closed and open conditions. To provide pressure relief from a vessel, these valves generally are designed to open quickly, thereby permitting a sudden flow of steam or other compressible fluid that is choked in the valve minimum flow area. If the upstream stagnation pressure and density are P_0 and ρ_0, the critical mass flow rate through the valve is given by the following:

$$\dot{m} = A_{v G_c} \tag{8.20}$$

in which the critical mass flux for gas is predicted from the following:

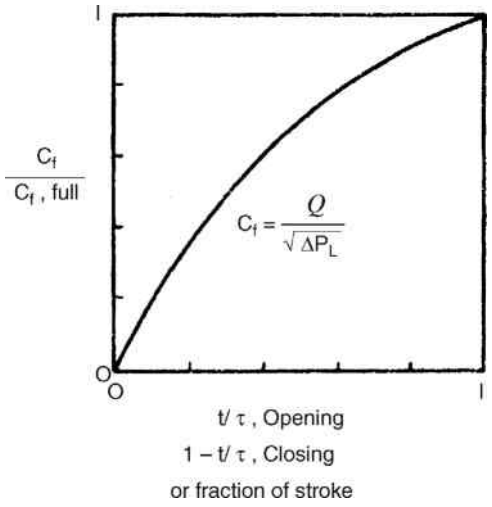


FIGURE 8.5 FLOW COEFFICIENT: TYPICAL GLOBE VALVE

$$G_c = \sqrt{k P_o \rho_o} \left(\frac{2}{k+1} \right)^{(k+1)/2(k-1)} \tag{8.21}$$

The rapid opening time, in the order of tens of milliseconds, is often fast enough to create moving shock waves in the downstream discharge piping and also associated reaction forces capable of damaging pipe penetrations if the supports are not designed for the loads.

8.3.3 Check Valve Closure

Check valves are designed to allow flow in one direction only. If a flow reversal is imposed, a check valve closes. Figure 8.8 shows a swing-check valve in the open position with forward flow. Flow reversal usually cannot cause the valve to swing shut immediately; the flow already has a reverse velocity when full closure occurs. The impact of water column stoppage on a mechanical surface and the additional impact of the metal swing against its stop can cause valve failure. Indeed, most waterhammer failures reported in the energy industry are associated with swing-check valves. If the reversed liquid velocity at the instant

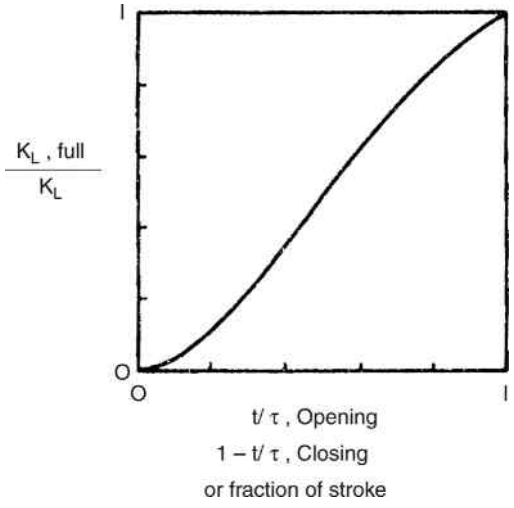


FIGURE 8.6 LOSS COEFFICIENT: TYPICAL GLOBE VALVE

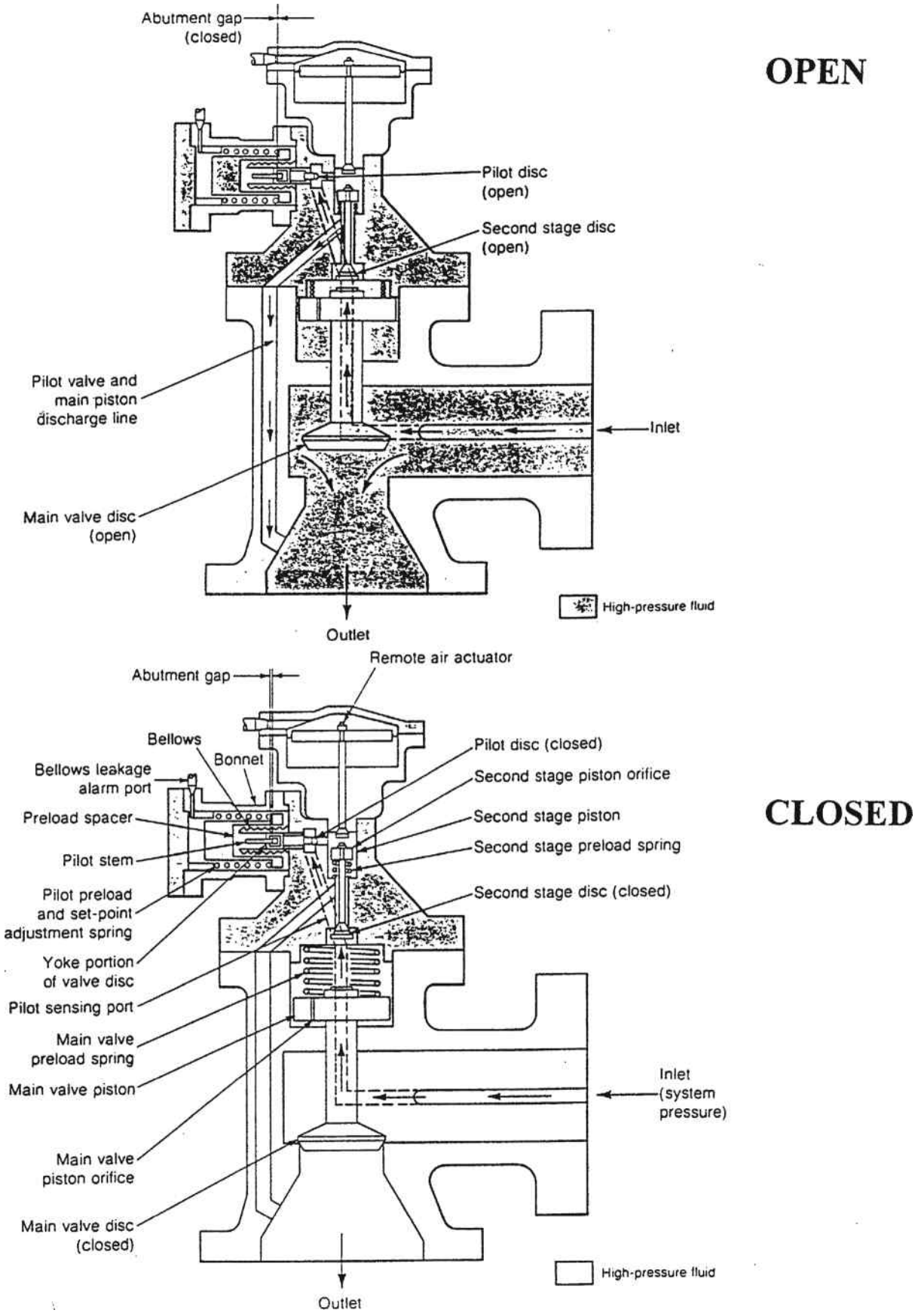


FIGURE 8.7 CUTAWAY VIEWS: SAFETY/RELIEF VALVE

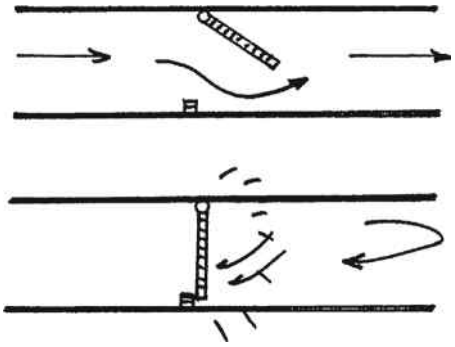


FIGURE 8.8 SWING-CHECK VALVE SCHEMATIC

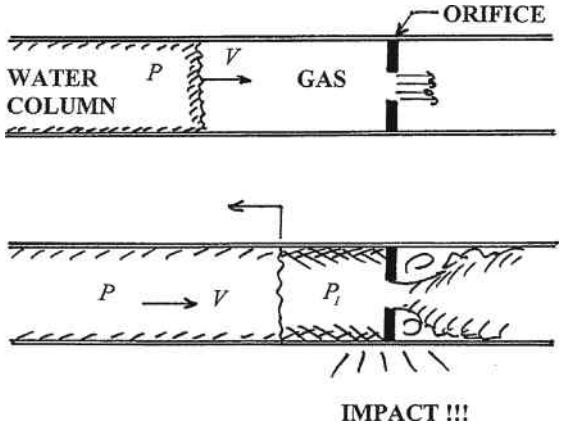


FIGURE 8.9 LIQUID COLUMN IMPACT AT AREA CONTRACTION

of full valve closure is V, the impact pressure is given by the Joukowski equation, as follows:

$$\Delta P = \rho C V \tag{8.22}$$

8.3.4 Pipe Rupture

Although the sudden rupture of a high-pressure pipe is a failure that must be avoided, it happens often enough to be included in design considerations. The rapid discharge from both ends of a pipe rupture cause pressure disturbances to be propagated through other parts of the piping system. Pipe sections often are braced to permit weld failures without serious pipe whipping problems, which could lead to other pipe ruptures. However, the decompression waves and the subsequent thrust forces exerted from pipe rupture discharges can cause significant forces on other pipes, junctions, and penetrations.

The sudden rupture of a pipe containing nonflashing liquid will undergo fluid discharge at a velocity increase ΔV, obtained from the Joukowski equation in the following form:

$$\Delta V = \frac{\Delta P}{\rho C} \tag{8.23}$$

in which ΔP is the decompression amplitude that travels through the piping system at sonic speed (C), creating a force on each pipe section with which it comes into contact. When the steady discharge is reached, the only surviving force is the jet-thrust force acting on the ruptured pipe end.

8.3.5 Liquid Column Impact at Area Contraction

There are some cases in which a liquid column, traveling at velocity (V), suddenly encounters an orifice or a partially open valve—the consequence of which is a suddenly applied pressure at the valve propagating through the liquid column. Figure 8.9 shows the liquid column arriving at an orifice, followed by the suddenly formed impact region. The impact pressure difference ($P_1 - P$) also can be obtained from equation (8.22) in terms of the velocity reduction.

8.3.6 Liquid Column Separation

If a valve suddenly closes on a flowing liquid column, pressure increase on the upstream side corresponds to equation (8.22). However, liquid on the downstream side keeps moving, creating a vacuum between the closed valve–liquid interface. The vacuum pressure is equal to vapor pressure at the liquid temperature, and the voided space is filled with vapor. Higher downstream pressure acting on the separated liquid column causes it to decelerate, reversing its motion. It finally collapses the vapor space and thus impacts the closed valve. (Figure 8.10 shows the process in steps.) If pipe friction is not important, the separated water column will arrive again at the valve with the same velocity it had immediately after valve closure. Again, the impact pressure corresponds to equation (8.22).

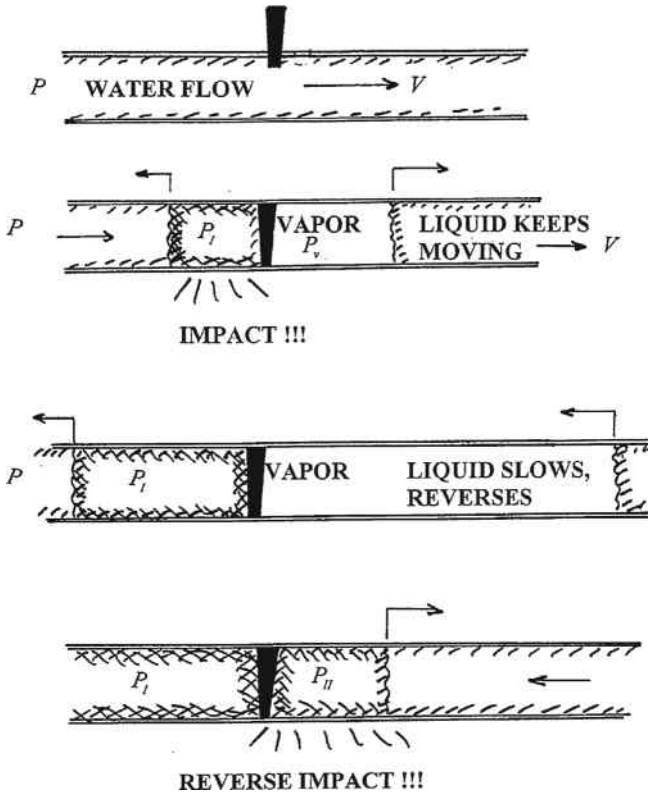


FIGURE 8.10 LIQUID COLUMN SEPARATION

8.3.7 Condensation-Induced Waterhammer

If cool liquid is introduced into a pipe that contains vapor, the vapor will condense rapidly and create a low pressure. Higher pressure at the far ends of the water columns causes both columns to accelerate toward each other, the result of which is that, upon arrival of the water columns, a sudden impact pressure is created. This impact pressure propagates through the piping system—a process illustrated in Fig. 8.11.

8.3.8 Centrifugal Pumps

Fluid disturbances are imposed by centrifugal pumps during start-up, coastdown, and even during steady operation via the rotating impeller vanes. A pump start-up or coastdown causes fluid acceleration or deceleration and resulting forces in all connected pipe segments. The high-frequency velocity or pressure pulses created by the vanes passing the discharge plenum are usually of low amplitude, although the imposed frequency may be such that eigenfrequencies are excited in connecting piping.

8.3.9 Pipe Movement

If a straight pipe segment undergoes motion in the direction of its axis, the contained liquid will respond as if a piston at either end were causing the flow to accelerate. Pressure imposed will be related to the velocity of the pipe by equation (8.22).

8.3.10 Positive Displacement Pumps

Figure 8.12 shows a positive-displacement pump schematic and the resulting discharge velocity pulsations of a triplex pump.

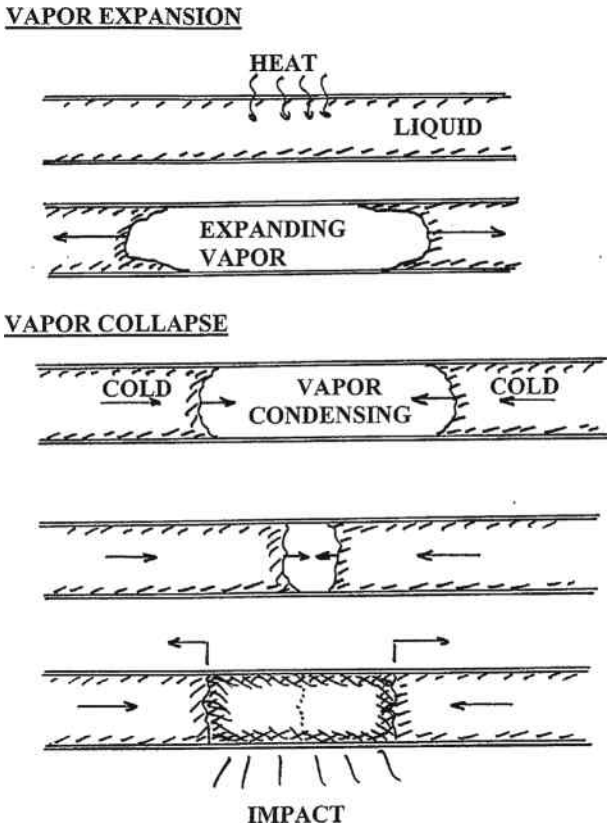


FIGURE 8.11 CONDENSATION-INDUCED WATERHAMMER

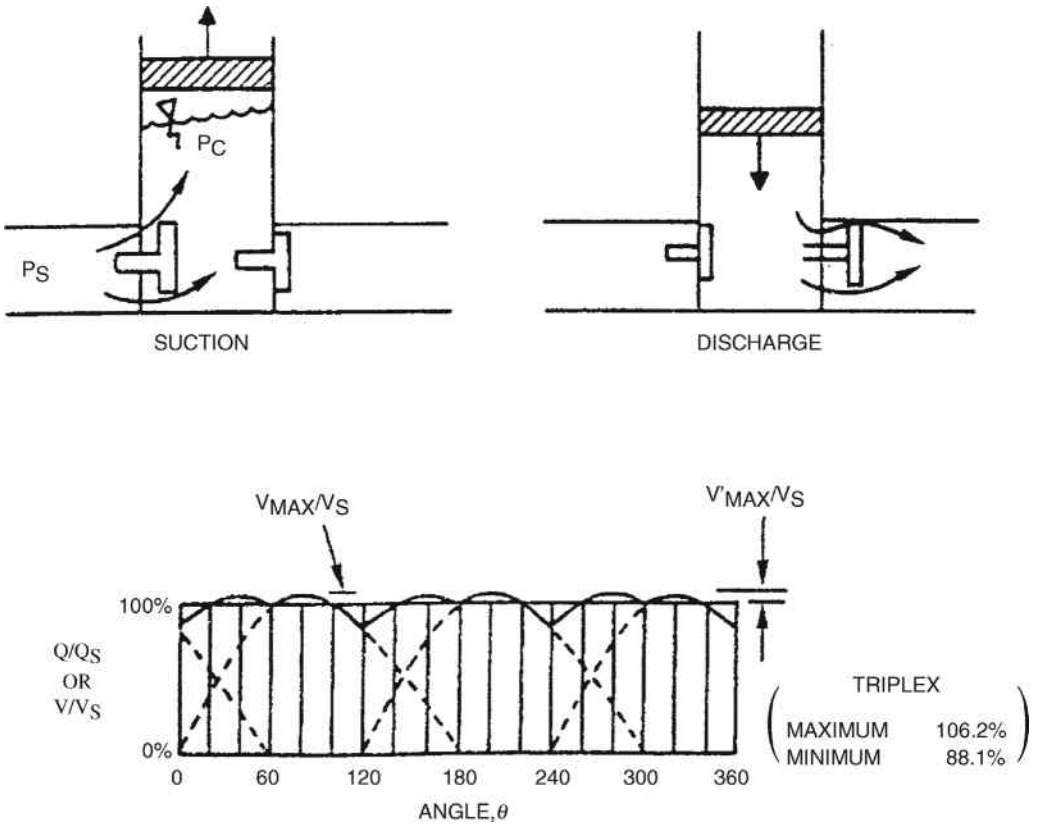


FIGURE 8.12 POSITIVE-DISPLACEMENT PUMP SCHEMATIC

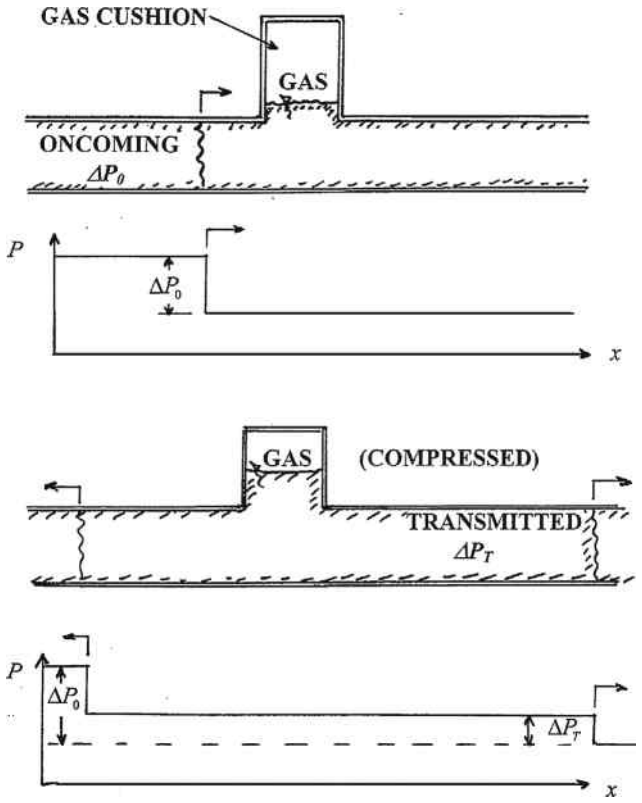


FIGURE 8.13 GAS CUSHION

The pulsating velocity creates a pulsating pressure disturbance, which propagates through the associating piping.

8.3.11 Gas Cushion

A device sometimes used to reduce pressure disturbances in piping systems is like a surge tank with a compressible gas cushion. Figure 8.13 shows such a device attached to a pipe with an oncoming pressure disturbance. When the pressure disturbance reaches the gas cushion, it is compressed, absorbing much of the arriving energy, so that the transmitted pressure disturbance is less.

8.3.12 Vortex Shedding

When an object is submerged in a flowing stream, flow instabilities may occur, creating vortices that detach periodically from opposite sides of the structure. The formation and detachment of a vortex creates a pressure disturbance on the object. If the vortex detachment or shedding frequency corresponds to one of the eigenfrequencies of the structure, a forced oscillation can result, creating significant forces. Figure 8.14 shows the vortex-shedding frequency for uniform flow past a cylinder in terms of the Reynolds and Strouhal numbers.

8.3.13 Bulk Flow and Propagative Flow Modeling in Pipes

Bulk flow describes the fluid response when all of the fluid particles undergo simultaneous motion. For example, the start-up flow acceleration of a centrifugal pump causes all the fluid particles in a relatively short pipe segment to have the same acceleration until the steady flow is achieved.

Propagative flow describes the fluid response when a pressure or velocity disturbance moves through the fluid at a speed of propagation; examples include the sound velocity or the velocity of a shock wave. All of the fluid particles do not respond simultaneously, for they remain undisturbed until the disturbance reaches them. For example, the instantaneous closure of a valve on a steadily flowing liquid in a relatively long pipe creates a sudden impact pressure at the valve curtain, which travels through the pipe at sound speed. Those fluid particles nearest the valve are immediately disturbed, whereas those particles at the most distant end of the pipe are not disturbed until the pressure wave arrives.

The fluid flow equations are reduced significantly for either bulk flow or propagative flow problems. If a fluid response is dominated by bulk flow, serious errors in the fluid behavior prediction can result if the equations for propagative flow are employed. The same is true if a fluid response is dominated by propagative flow and the equations for bulk flow are used to predict transient properties. Errors associated with applying the wrong equations can be eliminated by performing a simple upfront test to determine if a problem is dominated by either bulk or propagative flow.

Figure 8.15 shows a fluid region with a dominant length (L), which could be the length of a pipe segment or the diameter of a fluid tank. A disturbance is shown at the left side of the fluid region, which is propagating at speed (S). The disturbance has an associated disturbance time (t_d) that could be the opening time or closing time of a valve, the start-up time of a centrifugal pump, or another pressure or velocity disturbance for which a characteristic time of application can be obtained. The time required for the disturbance to advance through the entire fluid region of concern is the propagation time (t_p), expressed as the following:

$$t_p = \frac{L}{S} \tag{8.24}$$

If the disturbance time (t_d) is long relative to the propagation time (t_p), the disturbed property changes minimally as the entire fluid region begins to respond. Continuous changes in the disturbed property are slow enough to permit the state of the entire fluid region to follow within a small increment of the quasi-steady response. Incremental disturbances are successively transmitted throughout the fluid region. An observer might conclude that the disturbance is slow enough that the entire fluid region responds simultaneously (or nearly so) in a bulk flow mode. If, however, the disturbance application is completed before it can be transmitted through the fluid region, an observer might conclude that the disturbance is completed while only part of the fluid region has responded in a propagation mode. A simple test for determining if a fluid system is dominated by a bulk or propagative flow response is the following:

$$t_p \ll t_d \text{ Bulk Flow Dominated; If}$$

$$\text{Otherwise, Propagative Flow Dominated} \tag{8.25}$$

Flow in pipe segments of uniform area is generally dominated by either bulk or propagative flow. It is possible that in some piping systems, bulk flow dominates in shorter pipe segments and

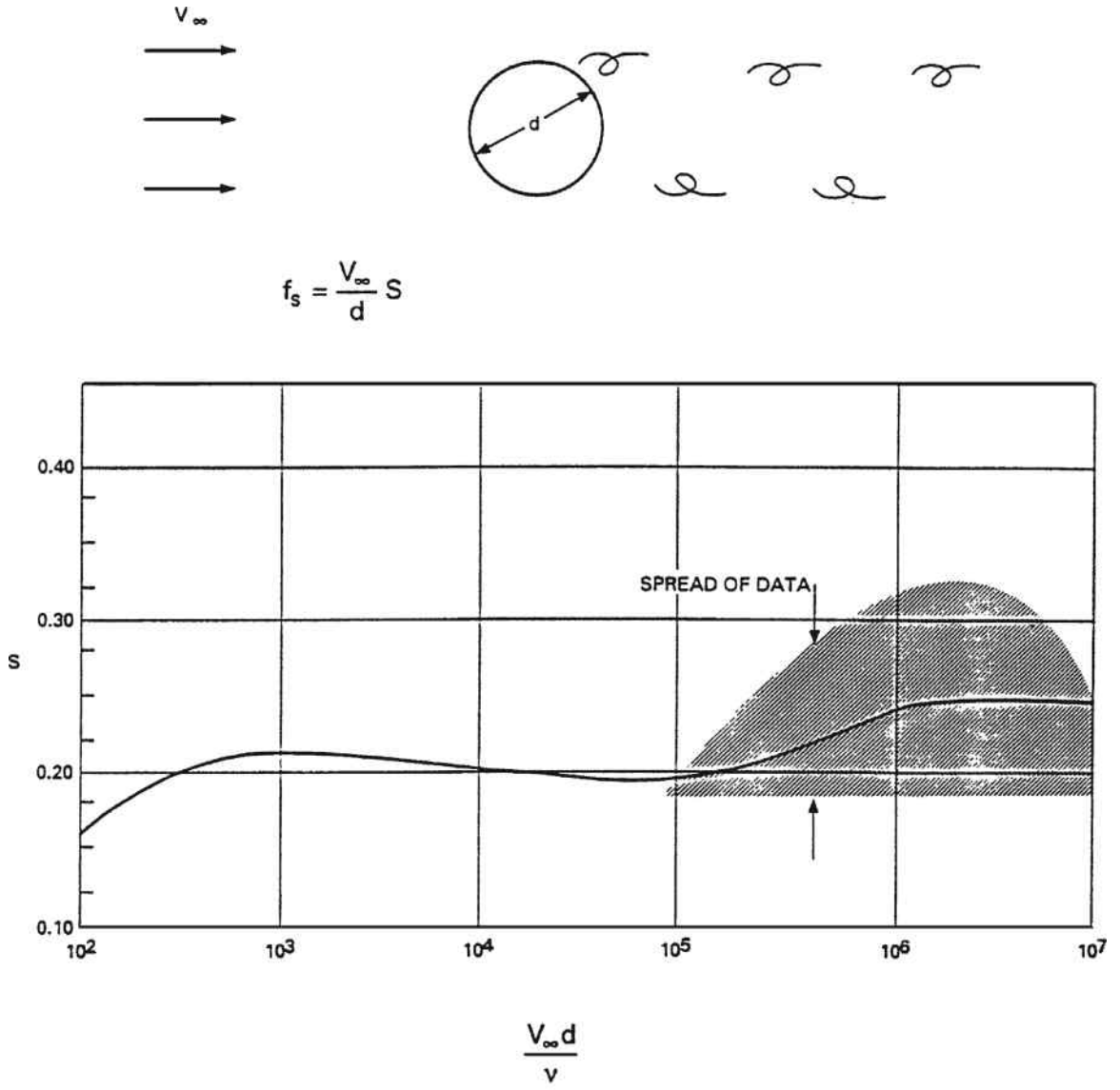


FIGURE 8.14 VORTEX-SHEDDING FREQUENCY

propagative flow dominates in longer segments. Moreover, some disturbances may cause bulk flow response during one interval and propagative flow during another interval, both of which could occur during the constant stem velocity closure of a valve. The valve flow area may need to be reduced to 10–20% of its full open condition before the actual flow becomes strongly affected. Flow reduction during the first 80–90% of the valve stroke could disturb the flow in a bulk flow mode, whereas the more rapid flow reduction during the last part of closure could cause a propagative disturbance.

When a flow transient in a uniform pipe is dominated by bulk flow, equation (8.14) reduces to the following:

$$\frac{\partial V}{\partial x} = 0 \tag{8.26}$$

Hence, equation (8.11) becomes the following:

$$\frac{\partial V}{\partial t} + \frac{1}{\rho}\frac{\partial P}{\partial x} + \frac{f}{D}\frac{V}{2}|V| + g\sin\theta = 0 \tag{8.27}$$

A solution of equation (8.27) can be obtained by ordinary differential equation techniques.

When a fluid transient in a uniform pipe of negligible friction is dominated by propagative flow, equations (8.14) and (8.11) reduce to following:

$$\frac{\partial P}{\partial x} + \rho C^2 \frac{\partial V}{\partial x} = 0 \tag{8.28}$$

and also

$$\frac{\partial V}{\partial t} + \frac{1}{\rho}\frac{\partial P}{\partial x} = 0 \tag{8.29}$$

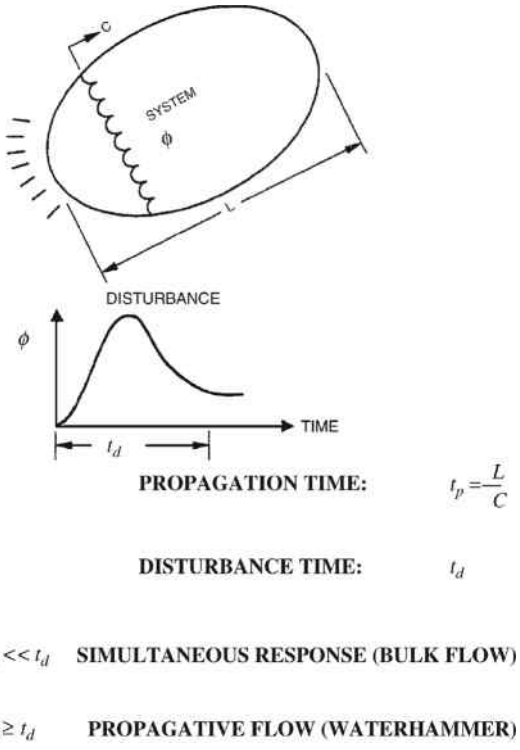


FIGURE 8.15 FLUID REGION: BULK OR PROPAGATIVE FLOW

A solution to equations (8.28) and (8.29) can be obtained by a rotation of the axes or transforms.

It can be shown that if a propagative disturbance is imposed on an established steady flow, the solution can be expressed as the superposition of the propagative solution and a quasi-steady flow, which corresponds to each instant of the disturbance. That is, the full transient solution can be separated into a propagative solution that is decoupled from a steady flow solution.

Occasionally, a fluid system and disturbance are not clearly dominated by bulk or propagative flow. Solutions for such cases can be obtained by applying the method of characteristics to the full governing equations.

8.4 ESTIMATING FLUID-FLOW FORCES IN PIPES

If a piping system consists of numerous straight segments joined by elbows, tees, or branches, the reaction force of fluid on any segment of flow area (A) and length (L) can be expressed from the momentum principle as follows:

$$F = -A\frac{d}{dt}\int_0^L \rho V\, dx \tag{8.30}$$

Equation (8.30) applies to either bulk or propagative flows. The bulk flow velocity is given functionally as $V(t)$; it can be removed from the integral prior to differentiation with respect to time. If the flow is propagative, $V = V(x, t)$. For relatively constant density, the time derivative can be taken under the integral and $\partial V/\partial t$ can be replaced by $-(1/\rho)\partial P/\partial x$; consequently, F becomes the following:

$$F = A[P(L, t) - P(0, t)] \tag{8.31}$$

8.5 FLUID FORCES ON SUBMERGED STRUCTURES

Significant forces can be exerted by fluid motion past submerged structures. Three important phenomena contributing to these forces are *fluid acceleration, form drag*, and such periodic flow instabilities as those associated with vortex shedding.

A fluid motion starting from a zero velocity field will first impose pressure gradients around a structure because of local acceleration components. The associated force is often referred to as *acceleration drag*. Continued increase of the velocity field can cause boundary layer separation from the structure and the development of a low-pressure wake on the downstream side. The resulting forces on the structure are called *standard drag*. The onset of oscillatory flow properties is the result of instabilities caused by interaction of the fluid stream with the boundary layer. Alternate periodic vortex shedding from opposite sides of the structure cause an *oscillating lift force*. Although the magnitude of forces from vortex shedding is not great, the shedding frequency often corresponds to natural eigenfrequencies of the structure, causing largeamplitude structural response and stresses. This is of particular concern in the design of heat exchangers with flow across tube bundles. The so-called turbulent buffeting from local turbulent flow bursts impinging on tubes creates another load that leads to vibration.

8.5.1 Acceleration Drag Force

Figure 8.16 shows a submerged structure in a rightward-accelerating flow. The fluid density is constant, its velocity is $U_\infty(t)$, and its acceleration is given as $U_\infty(t)$. The structure of mass (M_s), volume ($\forall_s$), and length (L) is moving at velocity $U_s(t)$. The fluid force, in the absense of viscous forces or wakes, is expressed as an integration of pressure around the structure boundary, or as the following:

$$F = \oint PL\, dy \tag{8.32}$$

Pressure (P) can be determined from equation (8.15) in terms of a velocity potential ϕ, which can be expressed for the general case shown in Fig. 8.16 as the following:

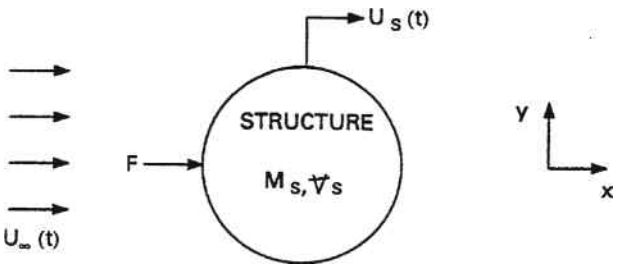


FIGURE 8.16 ACCELERATING FLUID PAST STRUCTURE

$$\phi(x, y, t) = U_\infty(t)x + [U_x(t) - U_s(t)]\zeta(x, y) \tag{8.33}$$

in which $\zeta(x, y)$ is a function that gives the velocity potential associated with the structural geometry when the structure is moving through stationary fluid. It follows that the force of equation (8.32) becomes the following:

$$F = -\rho L[\dot{U}_\infty(t) \oint x\, dy + [\dot{U}_\infty(t)\dot{U}_s(t)] \oint \zeta(x, y)\, dy] \tag{8.34}$$

Both line integrals are obtained by traversing the structure surface with fluid on the left. Hence the numerical value of both integrals is negative.

If the structure is stationary, the resulting force would be as follows:

$$F_\infty = -\rho L\dot{U}_\infty(t)\left[\oint x\, dy + \oint \zeta(x, y)\, dy \right] \tag{8.35}$$

The first term of equation (8.35) involves the mass of liquid that would occupy a volume equal to that of the structure, so that

$$-\rho L \oint x\, dy = \rho \forall_s \tag{8.36}$$

The second integral of equation (8.35) can be expressed in terms of the classical hydrodynamic or virtual mass, as follows:

$$M_h = -\rho L \oint \zeta(x, y)\, dy \tag{8.37}$$

It follows that

$$F_\infty = \rho\left[\forall_s + \frac{M_h}{\rho} \right]\dot{U}_\infty(t) \tag{8.38}$$

If the fluid is stationary and the structure is moving, the force of equation (8.34) becomes the following:

$$F_s = \rho L\dot{U}_s(t) \oint \zeta(x, y)\, dy = -M_h\dot{U}_s(t) \tag{8.39}$$

The fluid force exerted by moving fluid on a moving structure is obtained from equations (8.34), (8.38), and (8.39) as follows:

$$F = F_\infty + F_s \tag{8.40}$$

The structural dynamic response is governed by Newton's law in which the total force (F) is applied to the structural mass (M_s), or

$$F = F_\infty + F_s = M_s\dot{U}_s(t) \tag{8.41}$$

Rearranging,

$$F_\infty = M_s\dot{U}_s(t) - F_s = (M_s + M_h)\dot{U}_s(t) \tag{8.42}$$

Equation (8.42) shows that the structural response in an accelerating flow can be predicted from a computational method in which the fluid and structural motions are decoupled. That is, the force (F_∞) can be obtained for the known fluid acceleration past a stationary structure; then, it can be applied to a dry structure with mass that is equal to its actual mass plus the corresponding hydrodynamic mass.

8.5.2 Standard Drag Force

When steady fluid flow is achieved, the force exerted on a submerged structure is given by the following:

$$F_{ss} = C_D A_p \frac{U_\infty^2}{2}\rho \tag{8.43}$$

where

C_D = a drag coefficient for the given structure and Reynolds flow number
A_p = the structural area projected on a plane normal to the flow velocity

8.6 FLUID—STRUCTURE INTERACTION

Time-dependent fluid pressure forces on submerged structural components have caused destructive mechanical vibrations that have been observed at a number of facilities, including power plants, chemical processing plants, and throughout industrial processes which include direct contact of flowing fluids and flexible structures. The most convincing way of studying such phenomena involves the design and operation of a full size, instrumented facility, in which a multitude of measurements can be obtained. When a fluid-structure interaction (FSI) is outside design preferences, either mechanical, material, or operational modifications can be imposed and tested to ensure acceptable behavior. Some applications can be reduced to geometrically scaled test facilities in which various multipliers are applied to measurements in order to display expected full size behavior. However, there are scale model limitations that need to be considered before attempting to design a scale model test.

Subscale tests are often the best choice for studying a system with a single dominant unsteady component, like either the transient fluid flow in a rigid structural flow path, or the dynamics of the structure in the absence of transient fluid forces. However, it becomes increasingly difficult to use subscale models when two or more systems, with interaction, are to be studied together. The main difficulty is that each system has a characteristic response time, whose ratio with all other system response times must be identical in both the full size and subscale model. Each system to be studied in a single subscale test imposes additional constraints to the modeling laws. This does not mean that a subscale model can never be designed to study full size coupled systems. It simply means that the modeling constraints become more restrictive as more systems are included, and it might be highly impractical or impossible to satisfy all the constraints simultaneously.

The prospect of obtaining useful information from the subscale test of a given component like a jet pump, valve internals, or steam generator tubes, is unlikely, whereas a full size test at operating conditions is expected to provide information that will enable an accurate interpretation of the fluid and structure

phenomena which could cause structural interaction and possible damage. If the dominant scaling laws for the fluid and all associated components cannot be satisfied, any attempt to build, run, and interpret results from a subscale test facility would be a risk of time, effort, and cost, because the different scale could either introduce dissimilar effects, or exclude pertinent physical effects. Such a test could also introduce unique behavior that is nonrepresentative of the full size system. For cases where the dominant scaling laws can be satisfied, a subscale test can provide useful information.

Acoustic effects, vortex shedding or shear layer instability, and the fundamental component vibration modes characterize response times, which must maintain the same ratios in both the full size and scale model systems. A geometrically similar subscale test system should preserve the response from the full size system if both the fluid and structural component transient response times all differ by the same factor. That is, consider a $\frac{1}{2}$ size geometric scale model. All lengths are half of the full size system. Suppose that the dominant mechanical vibration period for this scale model decreased to $\frac{1}{2}$ the full size period (2 times the full size frequency). The corresponding response time of an acoustic excitation pressure wave would also have to be decreased by a factor of $\frac{1}{2}$. Use of the same fluid in both full and scale model systems, with the same value of sound speed, would cause an acoustic response time reduction of maintaining the correct ratio of time scales in the full and scaled systems.

Suppose that acoustic effects were weak, and structural excitation came from shear layer instability, like vortex shedding at the famous Tacoma Narrows Bridge. The shear layer instability response time is proportional to the length scale and inversely proportional to the velocity. In a $\frac{1}{2}$ scale model, the shear layer instability and structural vibration time scale ratios would be maintained in subscale and full size systems if the fluid velocity was equal in both systems. Use of a different fluid in the scale model could require a different velocity.

If the vane passing frequency of a pump played a strong role in a coupled fluid structure system, new similarity problems could be introduced. Suppose again that a $\frac{1}{2}$ geometrically similar scale model is to be used, where structural vibration response times also are $\frac{1}{2}$ that of the full size system. Vane frequency pulsations would have to be imposed twice as often as that in full size. However, since unsteady forces exerted on structural components depend on fluid velocity, the scale model fluid velocity might have to be controlled, perhaps by an outflow valve from the scaled system.

One additional item that could discourage a subscale test involves the possibility of cavitation at subscale that would not occur in the full size system. If it is necessary to have the same water velocity in both the full and scaled systems, the Bernoulli pressure reduction would be about the same in each. If water at atmospheric pressure and 100°F has a velocity of 100 fps, the velocity head pressure reduction would be about 70 psi. Such a pressure reduction, or even part of it, could easily reach the saturation pressure, introducing vapor bubbles, which would also undergo subsequent collapse in a subscale test.

It is possible that subscale tests could reveal some useful fluid *or* structural behavior insights. Studying a coupled fluid–structure system in a reduced, geometrically similar facility, has various pitfalls that need careful examination. When singular phenomena is to be studied, subscale model testing is often the most efficient, economic method. However, when several coupled phenomena are to be combined in a single test, the need to maintain time scale ratios for all important phenomena implies that a full size system at full size structural and fluid parameters, may be the most likely success path.

8.6.1 Analysis for Scale-Modeling Fluid-Structure-Interaction

Liquid flow dynamics in a pipe flow system can be modeled by the multi-dimensional mass conservation and momentum equations, given by

mass conservation:

$$\frac{\partial P}{\partial t} + V \cdot \nabla P + \frac{\rho C^2}{g_0} \nabla \cdot V = 0 \tag{8.44}$$

momentum:

$$\frac{\partial V}{\partial t} + V \cdot \nabla V + \frac{g_0}{\rho} \nabla P + b = \frac{g_0}{\rho} \nabla \cdot \Gamma \tag{8.45}$$

where V is velocity, P is pressure, ρ is the constant density, C is the constant sound speed, and Γ is the shear stress dyadic, given by

$$\Gamma = \sum_j \sum_i n_i t_{ij} n_j; \quad ij = x, y, z \tag{8.46}$$

and

$$\tau_{i,j} = \mu \left[\left(2 + \frac{\zeta}{\mu} \right) \left(\frac{\partial u}{\partial x}, \frac{\partial v}{\partial y}, \frac{\partial w}{\partial z} \right) - \frac{2}{3} \nabla \cdot V \right]; \quad i, j = xx, yy, zz \tag{8.47}$$

$$\tau_{i,j} = \mu \left(1 + \frac{\zeta}{\mu} \right) \left[\left(\frac{\partial u}{\partial y} + \frac{\partial v}{\partial x} \right), \left(\frac{\partial v}{\partial z} + \frac{\partial w}{\partial y} \right), \left(\frac{\partial w}{\partial x} + \frac{\partial u}{\partial z} \right) \right];$$

$$i, j = xy = yx, yz = zy, zx = xz \tag{8.48}$$

The body force acceleration vector **b** can be a function of time, **b**(t), if the structure is moving and the fluid reference frame is attached to the structure. When normal gravity acts, **b** is given by $g\mathbf{n}_y$.

When boundary conditions and initial conditions are specified, Eqs. (8.44) and (8.45) can be used to predict the fluid behavior.

Suppose that one structural component is a pipe, comprising a uniform cylindrical cantilever of diameter D, wall thickness δ, and total length L_s, firmly supported at one end for the purpose of including a simple structural dynamics formulation, and showing how it is associated with the fluid system. The governing equation for a cantilever deflection η, with its undisturbed, longitudinal axis in the x_s direction, is given by

$$\frac{\partial^2 \eta}{\partial t^2} + \left(\frac{g_0 EI}{\rho_s A} \right) \frac{\partial^4 \eta}{\partial x_s^4} = \frac{g_0}{\rho_s A} F'(x, t) \tag{8.49}$$

where E is Young's modulus, ρ_s is the structural density, A is the structure cross-sectional area,

$$A = \pi D \delta \tag{8.50}$$

I is the cross-sectional area moment of inertia,

$$I = \frac{1}{8}\pi D^3 \delta \tag{8.51}$$

and F' is the force per unit length, written in terms of pressure on the wall as

$$F'(x, t) = \frac{dF(x, t)}{dx} = [P(x, y, z, t) - P_i]\pi D \tag{8.52}$$

8.6.2 Normalized Variables

The dependent and independent variables are normalized so that their value ranges between 0.0 and 1.0, that is, their order of magnitude is 1.0, designated by the notation **O**(1). The normalization is accomplished by writing for the fluid,

$$\mathbf{V}^* = \frac{\mathbf{V} - \mathbf{V}_i}{\delta V} \quad t^* = \frac{t}{\delta t} \quad \mathbf{\Gamma}^* = \frac{L}{\mu \delta V}\mathbf{\Gamma} \tag{8.53}$$

$$x^* = \frac{x}{L} \quad y^* = \frac{y}{L} \quad z^* = \frac{z}{l} \tag{8.54}$$

$$P^* = \frac{P - P_i}{\delta P} \quad \nabla^* = L\nabla \quad \mathbf{b}^* = \frac{\mathbf{b}}{g} \tag{8.55}$$

and for the structure,

$$\eta^* = \frac{\eta}{\eta_0} \quad x_s{}^* = \frac{x_s}{L_s} \quad t_s{}^* = \frac{t}{\delta t_s} \tag{8.56}$$

where L is a reference length, δt is the response time, δV is the expected change or range in velocity, and δP is the expected change in pressure for the phenomena to be analyzed. Substituting Eqs. (8.53), (8.54), and (8.55) into (8.44) and (8.45) results in the normalized fluid flow equations,

$$\frac{\partial P^*}{\partial t^*} + \pi_1\left(\mathrm{V} + \frac{V_i}{\delta V}\right)\cdot \nabla^* P^* + \pi_2 \nabla^* \cdot \mathrm{V}^* = 0 \tag{8.57}$$

and

$$\frac{\partial \mathbf{V}^*}{\partial t^*} + \pi_1\left(\mathbf{V}^* + \frac{\mathbf{V}_i}{\delta V}\right)\cdot \nabla^* \mathbf{V}^* + \pi_3 \nabla^* P^* + \pi_4 \mathbf{b}^* = \pi_5 \nabla^* \mathbf{\Gamma}^* \tag{8.58}$$

The structural dynamics expressed by Eqs. (8.49)–(8.52) are normalized with the variables of (8.56) and the pressure of (8.55) to give

$$\frac{\partial^2 \eta^*}{\partial t^{*2}} + \pi_6 \frac{\partial^4 \eta^*}{\partial {x_s}^{*4}} = \pi_7 P^*(x^*, y^*, z^*, t^*) \tag{8.59}$$

The non-dimensional groups of Eqs. (8.57), (8.58), and (8.59) are given by

$$\pi_1 = \frac{\delta V \delta t}{L} \tag{8.60}$$

$$\pi_2 = \frac{\rho C^2}{g_0}\frac{\delta V}{\delta P}\frac{\delta t}{L} \tag{8.61}$$

$$\pi_3 = \frac{g_0 \delta P \delta t}{\rho L \delta V} \tag{8.62}$$

$$\pi_4 = \frac{g \delta t}{\delta V} \tag{8.63}$$

$$\pi_5 = \frac{g_0 \mu}{\rho}\frac{\delta t}{L^2} = \frac{v \delta t}{L^2} \tag{8.64}$$

$$\pi_6 = \frac{\delta t_s^2 g_0 EI}{\rho_s A L_s^4} = \frac{1}{8}\left(\frac{g_0 E}{\rho_s}\right)\left(\frac{\delta t_s D}{L_s^2}\right)^2 = \frac{1}{8}\left(\frac{C_s \delta t_s D}{L_s^2}\right)^2 \tag{8.65}$$

$$\pi_7 = \frac{g_0 \delta t_s^2 \delta P}{\rho_s \eta_s \delta}\left(\frac{C_s \delta t_s D}{L_s^2}\right) = 8\pi_6 \tag{8.66}$$

where the sound speed in the structural material,

$$C_s = \sqrt{\frac{g_o E}{\rho_s}} \tag{8.67}$$

has been employed with Eqs. (8.65) and (8.66).

The kinematic viscosity, v, has been introduced into Eq. (8.64). If some of the non-dimensional groups have small magnitudes relative to **O**(1) for a system component or operation mode, that term in the governing equations can be neglected, thus simplifying the problem to be solved mathematically. If one non-dimensional group is associated with a phenomenon that is causing a problem with vibration or other undesirable response, parameters appearing in that group possibly can be changed to reduce the magnitude of the phenomenon and its importance. If the calculated result is acceptable, the full size system design or operation mode could be adjusted accordingly to avoid or reduce the problem.

If it is desirable to build a subscale model of a full size system, the dominant non-dimensional groups must have the same numerical value in both scales in order to preserve representative behavior. Time and space should be scaled according to the normalized x, y, z, and t in Eqs. (8.53) and (8.54).

8.6.3 Acoustic Disturbances

If it is desirable to study the possible excitation of acoustic resonances in the system, a reasonable time interval is the acoustic transit time,

$$\delta t = \frac{L}{C} \tag{8.68}$$

and the pressure and velocity disturbances are related by

$$\delta P = \frac{\rho C \delta V}{g_0} \tag{8.69}$$

for which

$$\pi_1 = \frac{\delta V}{C} \approx 0 \tag{8.70}$$

$$\pi_2 = 1.0 \tag{8.71}$$

$$\pi_3 = 1.0 \tag{8.72}$$

$$\pi_4 = \frac{gL}{C\delta V} \approx 0 \tag{8.73}$$

$$\pi_5 = \frac{v}{LC} \approx 0 \tag{8.74}$$

The simplified governing equations are, therefore,

$$\frac{\delta P}{\delta t} + \frac{\rho C^2}{g_0}\nabla \cdot \mathrm{V} = 0 \tag{8.75}$$

$$\frac{\delta \mathrm{V}}{\delta t} + \frac{g_0}{\rho}\nabla_P = 0 \tag{8.76}$$

which are recognized as the multi-dimensional waterhammer or acoustic equations.

8.6.4 Incompressible, Non-Acoustic Flows

If acoustic effects were not important, but vortex shedding or shear layer instabilities generated the unsteady exciting forces, the reference time interval is of the order of

$$\delta t = \frac{D}{V} \tag{8.77}$$

where d is the dimension associated with the vortex, such as the diameter of a cavity, and V is the fluid velocity across the cavity. The associated pressure amplitude for velocity V in incompressible flow is

$$\delta P = \rho \frac{V^2}{2g_0} \tag{8.78}$$

The corresponding π groups become

$$\pi_1 = 1 \tag{8.79}$$

$$\pi_2 = 2\frac{C}{V} \tag{8.80}$$

$$\pi_3 = \frac{1}{2} \tag{8.81}$$

$$\pi_4 = \frac{gD}{V^2} \approx 0 \tag{8.82}$$

$$\pi_5 = \frac{v}{DV} \approx 0 \tag{8.83}$$

for which the governing fluid equations become

$$\nabla \cdot \mathrm{V} = 0 \tag{8.84}$$

and

$$\frac{\delta \mathrm{V}}{\delta t} + \frac{g_0}{\rho}\nabla P + \mathrm{by} = 0 \tag{8.85}$$

8.6.5 Structural Response

An expression for the free end vibration amplitude is chosen as the steady deflection for a uniform load F_0', which is given by

$$\eta_0 = \frac{1}{8}L_s^4\frac{F'_0}{EI}\frac{1}{8}L_s^4\left(\frac{\delta P \pi D}{EI}\right) = \frac{L_s^4 \delta P}{ED^2\delta} \tag{8.86}$$

If the fundamental cantilever vibration period or inverse frequency was needed from Eq. (8.59), the right hand side forcing function could be set to zero, and nondimensional group π_6 could be set equal to 1.0 to obtain

$$\delta t_s = L_s^2\sqrt{\frac{\rho_s A}{g_o EI}} = \frac{L_s^2}{D}\sqrt{\frac{8\rho_s}{g_o E}} = \sqrt{8}\,\frac{L_s^2}{DC_s} \tag{8.87}$$

for which π_7 becomes

$$\pi_7 = 8 \tag{8.88}$$

8.6.6 Ratios of Time Scales

The nondimensional time $t^* = t/\delta t$ must be the same at all scales to ensure similarity. That means that the normalizing time scales, δt, for each phenomenon to be included in a subscale test, must have the same ratio as in the full size system. That is, if the acoustic, incompressible, structural, and pump vane passing time responses were all important, then the ratios

$$\delta t_{\text{acoustic}}/\delta t_{\text{structure}} \quad \delta t_{\text{acoustic}}/\delta t_{\text{incomp}} \quad \delta t_{\text{acoustic}}/\delta t_{\text{pump.VP}} \tag{8.89}$$

simultaneously would have to be identical in both the full size and subscale systems. The vane passing pulse time can be expressed by

$$\delta t_{\text{pump,VP}} = \frac{60}{(RPM)}\frac{1}{N} \tag{8.90}$$

where *RPM* is the pump rotational speed in revolutions per minute, the factor 60 changes the *RPM* to revolutions per second, and N is the number of vanes, each vane passing the cutwater giving a pressure pulse. Equation (8.90) is, then, the time for a single pulse of a vane passing, or in time units of seconds, the *seconds per pulse*.

It follows that the ratios of Eq. (8.90) lead to the subscale/full-size requirements,

$$\frac{C_{\text{sub}}}{C_{\text{full}}} = \frac{C_{\text{structure, sub}}}{C_{\text{structure, full}}} \tag{8.91}$$

$$\frac{V_{\text{sub}}}{V_{\text{full}}} = \frac{C_{\text{sub}}}{C_{\text{full}}} \tag{8.92}$$

and

$$\frac{N_{\text{sub}}(RPM)_{\text{sub}}}{N_{\text{full}}(RPM)_{\text{full}}} = \left(\frac{L_{\text{full}}}{L_{\text{sub}}}\right)\left(\frac{C_{\text{sub}}}{C_{\text{full}}}\right) \tag{8.93}$$

Suppose that the subscale and full size structural materials were identical so that $C_{\text{structure,sub}}$ and $C_{\text{structure,full}}$ were identical. Equation (8.91) shows that for this condition, the fluid sound speeds C_{sub} and C_{full} would have to be the same in both the

subscale and full size systems. Suppose that the full size sound speed at 1000 psia and 545ºF is about

$$C_{\text{full}} \approx 3767 \text{ fps} \tag{8.94}$$

whereas at subscale model conditions of about 1.0 *atm*. and 100°F,

$$C_{\text{sub}} \approx 5126 \text{ fps} \tag{8.95}$$

A 25% difference in the sound speeds would be intolerable for subscale similarity, unless a liquid could be found with the full size system sound speed at atmospheric conditions.

Equation (8.92) shows that if identical fluid sound speed were achieved, the fluid velocity would have to be equal in both the subscale and full size systems, or

$$V_{\text{sub}} = V_{\text{full}} \tag{8.96}$$

The condition of equal velocities at both scales is probably achievable, but if the pump vane passing pulsations plays an important role, it would be necessary to have

$$N_{\text{sub}}(RPM)_{\text{full}} = \left(\frac{L_{\text{full}}}{L_{\text{sub}}}\right) N_{\text{full}}(RPM)_{\text{full}} \tag{8.97}$$

That is, either the *RPM* or the number of vanes, *N*, or both would have to be increased in subscale to achieve similarity with the full size system. Whether or not this condition would result in achieving a subscale fluid velocity equal to that in full size, as required by Eq. (8.96), would depend on the pump characteristics. If a subscale pump were run, according to Eq. (8.97), at a speed increased above the full size pump by the geometric scaling factor, Eq. (8.97) would be satisfied only if the pump discharge velocity was proportional to the ratio (L_{sub} / L_{full}). That is, a subscale pump, run at the same speed as the full size pump, would have a smaller discharge velocity. If running the subscale pump at faster speed satisfied both Eqs. (8.96) and (8.97), then the acoustic/pump time scale ratio would be satisfied.

8.6.7 Cavitation?

If a subscale test were performed at full size fluid velocity, it is likely that cavitation bubbles would form and subsequently collapse, distorting the measured results. If the full size pipe discharge velocity was about 100 fps, the corresponding Bernoulli pressure effect of Eq. (8.79) for water at 62 lbm/ft^3 is about 70 psi. If the secondary flow entered the pipe at one atmosphere, the high velocity of the flow would create an aspiration pressure reduction up to 70 psi, which could easily reduce the water pressure to its saturation value of about 1.0 psia. Therefore, even if the model laws described earlier could be accommodated, a cavitation effect could be introduced that would not be present in the full size system.

8.6.8 Conclusions

Single system phenomena can often be studied in subscale model tests if the associated model laws are satisfied both in the testing and upscaling the results to predict the full size behavior. When a system contains two or more subsystems, each subsystem introduces its own set of model laws that must be accommodated simultaneously in order to obtain subscaled test results that are similar to, and can be scaled up to predict the full size system behavior. The requirement of maintaining identical time response ratios for all the combined phenomena introduces scale modeling constraints that can be difficult if not impossible to achieve with available resources. When it is shown that similarity cannot be achieved in a subscale model, the best choice is to test in a full size facility.

The phenomena of importance that appear in many fluid-structure systems are the fluid acoustics for pressure wave propagation, the fluid incompressible aspects for vibration sources like vortex shedding or shear layer instability, the structural dynamics, and pump pulsation disturbances. This analysis shows that in order to achieve similar subscale test results in a geometrically scaled model, it is necessary to have:

equal sound speeds in the liquid;
equal liquid velocities
equal structural state properties (density, Young's modulus)
higher pump pulsation frequency (increased by the scale factor)

Each of these constraints appears to be difficult to satisfy, and satisfying them simultaneously could be impractical. Furthermore, the unwanted introduction of cavitation needs to be considered in every scale model simulation.

8.7 VESSEL STEAM PIPE RUPTURE FORCE ON VESSEL INTERNALS

A postulated steam pipe rupture in a water-moderated nuclear power plant would cause a sonic discharge from the rupture and the formation of a large-amplitude step decompression, which would travel through the pipe to the reactor vessel. When the decompression arrived at the reactor, it would propagate into the vessel where it would exert decompression forces on the internal steam dryer and other surfaces. The magnitude of the decompression can be 40 bars or more when first beginning in the steam line. If the initial magnitude entered the vessel as a step, even though attenuated by expanding, damage could occur to the dryer components. However, solution of the propagation equations show that a step decompression in a compressible fluid spread as it travels so that its arrival at the vessel is a ramp disturbance in time rather than a step. This feature causes a decompression force of smaller impulse to be exerted on vessel internal structures. This section presents an analytical model for examining conservative decompression forces on a flat wall structure (like a dryer surface) inside a reactor caused by a steam line rupture. It shows that longer steam line lengths and greater distances between the vessel wall and the dryer surface result in smaller transient load magnitudes. Also, smaller dryer surface dimensions cause the dryer force duration to be decreased.

It is expected that steam compressibility effects are important for the decompression transient in the region between the pipe rupture and vessel. The decompression propagates toward the vessel, spreading as it travels. When it reaches the vessel, the vessel discharge velocity increases over a time interval, which determines the magnitude of the resulting decompression reaching the dryer. It will be useful to know important parameter effects on the applied decompression load.

Since pressure disturbances inside the vessel are expected to be a relatively small fraction of the total pressure, acoustic theory is employed to determine pressure forces exerted on the dryer. The pressure field is modeled by an array of acoustic point sources, with the primary source at the steam line attachment to the vessel. Other image sources are arranged to maintain symmetry of the dryer and vessel wall solid surfaces. Therefore, the predicted disturbance, which arrives at the dryer opposite the steam line, is a series of decompression steps, corresponding to the arrival of separate disturbances from each image source.

The analysis shows the effect of various parameters on predicted dryer loads. It is seen that the load is reduced for a longer steam line, or greater distance between the dryer surface and the steam line/vessel attachment. Example calculations are included.

8.7.1 Nomenclature

a, b	Dryer dimensions, Fig. 8.28
C	Sound speed
$f(V)$	Function in Eq. (8.106)
F_R, F_L	Wave functions, Eqs. (8.127) and (8.128)
g_0	Newton's constant
$H_s(\ )$	Heaviside step function
k	Ratio of specific heats
k	Constant in Eq. (8.149)
L	Pipe length, break to vessel
n	Number of sources
P	Pressure
P_d*	Normalized pressure on dryer
Q	Volume flow rate
R	Pipe, sphere radii
r	Radius
t	Time
V	Velocity
x	Distance on pipe
$\Delta V/\Delta t$	Velocity rate
$(\ )_i$	Initial value
$(\ )$*	Value in discharge plane

8.7.2 Compressible or Acoustic Theory for Transient Steam Flows?

A disturbance which changes the local velocity of a compressible gas flow in a pipe also causes a change in the gas pressure. Small disturbances usually can be treated by acoustic theory, whereas large disturbances introduce stronger compressibility effects. When disturbances predicted by compressibility effects are more than about 10% of the pressure disturbances predicted by acoustic theory, it is good practice to employ compressible flow models. The following considerations can help determine when acoustic theory is reasonable for predicting pressure transients in gas flows, and when compressible flow models are preferred.

Consider the ideal gas flow in the uniform, frictionless pipe of Fig. 8.17 with initial pressure P_i, velocity V_i, density ρ_i, and sound speed C_i.

A valve partially closes or opens at the right end of the pipe, causing (1) a velocity decrease with a corresponding pressure increase, or (2) a velocity increase with a corresponding pressure decrease. Each case is treated separately, corresponding to the leftward propagation of compressive and decompressive disturbances.

(1) *Compressive Disturbance Propagation*

Velocity $V < V_i$ Flow velocity is suddenly reduced by partial or full valve closure (see Fig. 8.17).

The acoustic pressure formulation for this case gives [3]

$$P - P_i = \frac{\rho_i C_i}{g_0}(V_i - V) \tag{8.98}$$

The sound speed for gas,

$$C_i = \sqrt{k g_0 \frac{P_i}{\rho_i}} \tag{8.99}$$

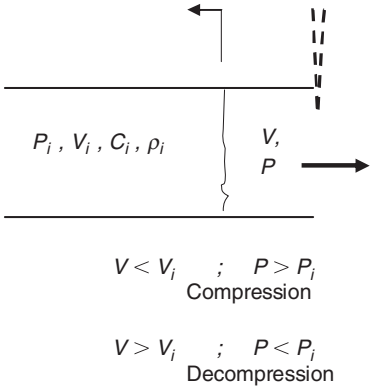


FIGURE 8.17 DISTURBANCE PROPAGATING IN COMPRESSIBLE FLUID

is used in Eq. (8.98) to write

$$\frac{P - P_i}{P_i} = k\left(\frac{V_i - V}{C_i}\right) \text{ acoustic} \tag{8.100}$$

If the compressible flow equations are written for a sudden, partial valve closure, the resulting normal shock relationship between pressure and velocity is given by [3,5]

$$k\left(\frac{V_i - V}{C_i}\right) = \left(\frac{P - P_i}{P_i}\right)\left[\left(\frac{k+1}{2k}\right)\left(\frac{P - P_i}{P_i}\right) + 1\right]^{-\frac{1}{2}}$$

compressibility effects (8.101)

Equations (8.100) and (8.101) are graphed in Fig. 8.18. It is seen that for compressive disturbances, predictions which include compressibility effects depart about 10% from acoustic predictions when the pressure disturbance is about $(P - P_i)/P_i \oplus 0.30$, or 30% of the base pressure.

(2) *Decompressive Disturbance Propagation*

Velocity $V > V_i$ Flow velocity is suddenly increased, e.g., by a valve partial opening or pipe rupture (see Fig. 1).

Although similar to Eq. (8.100), the acoustic pressure for this case is given by

$$\frac{P_i - P}{P_i} = k\left(\frac{V - V_i}{C_i}\right) \tag{8.102}$$

Riemann's equations for propagation of a decompression [3] give the pressure/velocity relationship for a pressure wave moving leftward in the pipe of Fig. 8.17 as

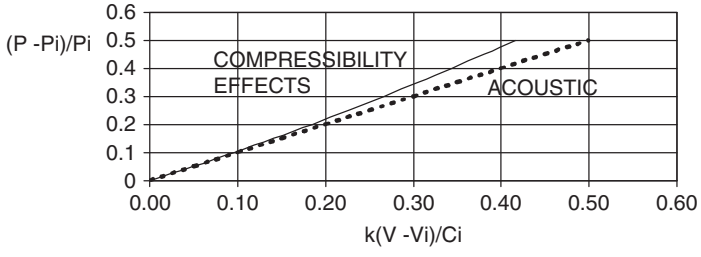


FIGURE 8.18 COMPRESSIBILITY EFFECTS, COMPRESSION

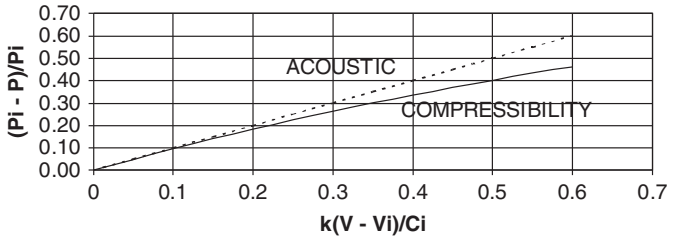


FIGURE 8.19 COMPRESSIBILITY EFFECTS, DECOMPRESSION

$$\frac{P_i - P}{P_i} = 1 - \left[1 - \left(\frac{k-1}{2k}\right)k\left(\frac{V - V_i}{C_i}\right)\right]^{\frac{2k}{(k-1)}} \tag{8.103}$$

Equations (8.102) and (8.103) are graphed in Fig. 8.19, showing that for decompressive disturbances, predictions which include compressibility effects depart about 10% from acoustic predictions when the pressure disturbance is about $(P_i - P)/P \approx 0.25$, or about 25% of the base pressure.

8.7.3 General Solution, Compressible Flow Transient In Pipe

Transient compressible gas flow in a uniform, horizontal, unheated, frictionless pipe, like that shown in Fig. 8.20, is governed by the mass and momentum principles for one-dimensional flow in the forms,

$$\frac{\partial P}{\partial t} + V\frac{\partial P}{\partial x} + \frac{\rho C^2}{go}\frac{\partial V}{\partial x} = 0 \tag{8.104}$$

$$\frac{\partial V}{\partial t} + V\frac{\partial V}{\partial x} + \frac{g_0}{\rho}\frac{\partial P}{\partial x} = 0 \tag{8.105}$$

Riemann's solution for disturbance propagation is [3]

$$x = (V \pm C)t + f(V) \tag{8.106}$$

with solutions for density, sound speed, and velocity given by

$$\rho = \rho_i\left(\frac{P}{P_i}\right)^{1/k} \tag{8.107}$$

$$C = \sqrt{kg_0\frac{P}{\rho}} = \sqrt{kg_0\frac{P_i}{\rho_i}}\sqrt{\left(\frac{P}{P_i}\right)^{\frac{(k-1)}{k}}} = C_i\left(\frac{P}{P_i}\right)^{\frac{(k-1)}{2k}} \tag{8.108}$$

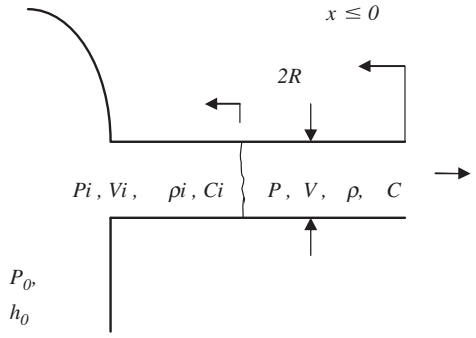


FIGURE 8.20 COMPRESSIBLE FLOW TRANSIENT IN PIPE

$$V = V_i \pm \frac{2C_i}{k-1}\left[\left(\frac{P}{P_i}\right)^{\frac{k-1}{2k}} - 1\right] \tag{8.109}$$

$$C = C_i \pm \frac{k-1}{2}\left(V - V_i\right) \tag{8.110}$$

Velocity V is considered positive to the right, C is the sound speed, P is the pressure, ρ is the density, subscript i is the initial value, and function $f(V)$ is determined from a known boundary condition. The + sign corresponds to rightward propagation from the origin with $x > 0$, and the − sign corresponds to leftward propagation with $x < 0$.

8.7.4 Pipe Rupture Boundary Condition

If there is an initial rightward steam flow in the pipe at velocity V_i, an instantaneous, full pipe rupture that completely opened the pipe would reach discharge flow properties obtained from Eqs. (8.108), (8.109), and (8.110) for leftward propagation by setting the discharge velocity V in Eq. (8.110) equal to the local sonic velocity C, giving the maximum discharge velocity V^* in the form

$$\frac{V}{C_i} = \frac{C}{C_i} = \frac{V^*}{C_i} = \frac{V_i}{C_i} + \left(\frac{2}{k+1}\right)\left(1 - \frac{V_i}{C_i}\right) \tag{8.111}$$

leftward traveling disturbance

at discharge pressure P^*, obtained from Eqs. (8.109) and (8.111) as

$$\frac{P}{P_i} = \frac{P^*}{P_i} = \left[\left(\frac{k-1}{k+1}\right)\frac{V_i}{C_i} + \frac{2}{k+1}\right]^{\frac{2k}{k-1}}$$

leftward traveling disturbance (8.112)

The discharge velocity and pressure of Eqs. (8.111) and (8.112) are shown in Fig. 8.21 for $k = 1.3$. If there is no initial velocity V_i, the discharge velocity and pressure of Eqs. (8.111) and (8.112) reduce to

$$\frac{V^*}{C_i} = \frac{2}{k+1}; \quad V_i = 0 \tag{8.113}$$

$$\frac{P^*}{P_i} = \left(\frac{2}{k+1}\right)^{\frac{2k}{k-1}}; \quad V_i = 0 \tag{8.114}$$

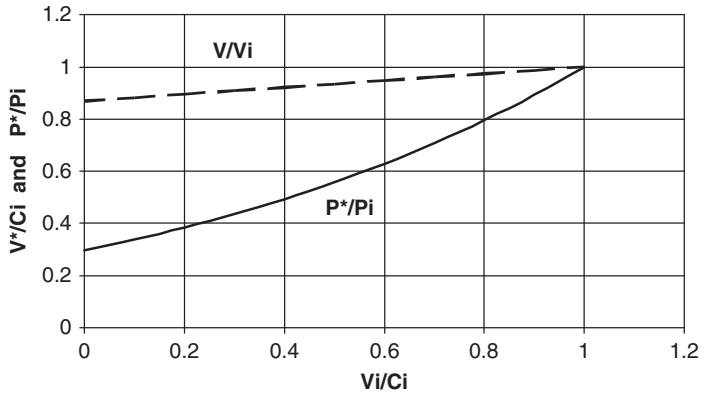


FIGURE 8.21 DISCHARGE PRESSURE AND VELOCITY, PIPE RUPTURE

8.7.5 The Function $f(V)$

Figure 8.20 shows a steam line, attached to a vessel at the left end, with a rupture opening at the right end. The rupture location is considered $x = 0$ for this case with the vessel attachment at $x = -L$. The rupture boundary condition is described by Eq. (8.111), which reduces to Eq. (8.113) for $V_i = 0$, or zero initial flow rate. However, prior to applying the discharge boundary condition, it can be seen that the initial disturbance travels into the oncoming steam flow at the initial sonic speed C_i, less the initial steam velocity V_i, traveling leftward a distance x in time t according to

$$x = -(C_i - V_i)t \tag{8.115}$$

If x of Eq. (8.115) is substituted into Eq. (8.106) for the left-traveling disturbance front propagation, where the velocity is V_i and the sonic speed is C_i, it follows that

$$x = -(C_i - V_i)t = (V_i - C_i)t + f(V_i) \tag{8.116}$$

Eq. (8.116) shows that $f(V_i)$ must be zero, and therefore,

$$f(V) = 0; \text{ sudden pipe rupture} \tag{8.117}$$

Equation (8.106) is next written at any value of x, using $f(V) = 0$, and also C from Eq. (8.110), giving

$$x = \left[\left(\frac{k+1}{2}\right)V - C_i - \left(\frac{k-1}{2}\right)V_i\right]t \tag{8.118}$$

or, rearranging in non-dimensional form,

$$\frac{x}{L} = \left[\left(\frac{k+1}{2}\right)\frac{V}{C_i} - \left(\frac{k-1}{2}\right)\frac{V_i}{C_i} - 1\right]\frac{C_i t}{L} \tag{8.119}$$

Equation (8.119) describes the expansion fan of Fig. 8.22 for $V_i/C_i = 0$. originating at $x/L = 0$, with straight lines of constant V/C_i propagating to the left on different slopes. Other expansion fans could be constructed for values of V_i/C_i up to 1.0, which would be a fan collapsed into a single vertical line at the discharge plane with initial flow properties on its left side. Equation (8.119) shows that as long as there are no reflected waves, the velocity at any x never reaches a steady state value at any time t, but always continues to approach the value given by Eq. (8.111), which is achieved only at the rupture location. That is because the full rupture velocity is sonic, which does not permit P^* or V^* to propagate into the discharging flow.

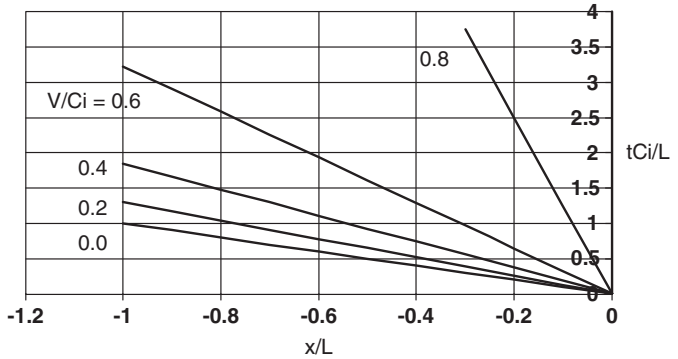


FIGURE 8.22 EXPANSION FAN

Eq. (8.119) can also be written as

$$\frac{C_i t}{L} = \frac{(x/L)}{\left[\left(\frac{k+1}{2}\right)\frac{V}{C_i} - \left(\frac{k-1}{2}\right)\frac{V_i}{C_i} - 1\right]}$$

$$\frac{C_i t}{L} \geq \left(\frac{-\frac{x}{L}}{1 - \frac{V_i}{C_i}}\right) \tag{8.120}$$

The restriction on time noted in Eq. (8.120) implies that at an arbitrary location x/L, the solution does not apply until the disturbance front $V/C_i = V_i/C_i$ has had time to propagate from the rupture through the distance x. For the vessel at $x = -L$, the arriving velocity of Eq. (8.120) becomes

$$\frac{V(-L,t)}{C_i} = \left(\frac{k-1}{k+1}\right)\frac{V_i}{C_i} + \left(\frac{2}{k+1}\right)\left(1 - \frac{1}{\left(\frac{C_i t}{L}\right)}\right)$$

$$\frac{C_i t}{L} \geq \frac{1}{1 - \frac{V_i}{C_i}} \tag{8.121}$$

The corresponding pressure at $x = -L$ is obtained from Eq. (8.109) as

$$\frac{P(-L,t)}{P_i} = \left[1 - \left(\frac{k-1}{2}\right)\left(\frac{V(-L,t)}{C_i} - \frac{V_i}{C_i}\right)\right]^{\frac{2k}{k-1}} \tag{8.122}$$

Both the arriving velocity and pressure transient predictions at the vessel for a sudden pipe rupture are shown in Figs. 8.23 and 8.24 for a range of initial flow Mach numbers, V_i/C_i.

8.7.6 Steam Discharge Velocity From Vessel

When the decompression arrives at the vessel steam line attachment, the decreasing pressure will cause steam flow acceleration from the vessel into the steam line, which will result in the propagation of decompression forces onto vessel internal surfaces. In order to apply the vessel constant pressure boundary condition near the steam line attachment, it is first necessary to express the arriving velocity disturbance. Although the arriving velocity of Eq. (8.121) decays with a reciprocal time function,

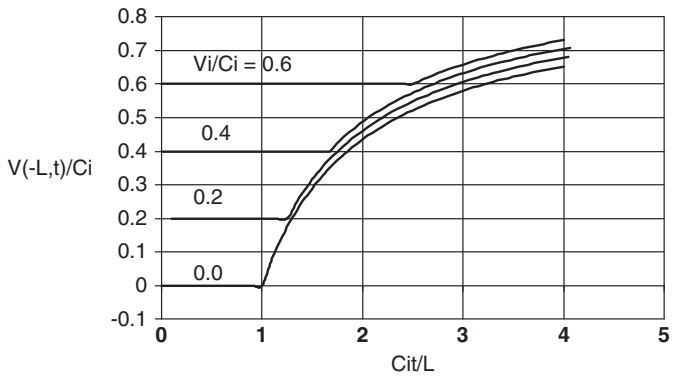


FIGURE 8.23 VELOCITY ARRIVING AT VESSEL

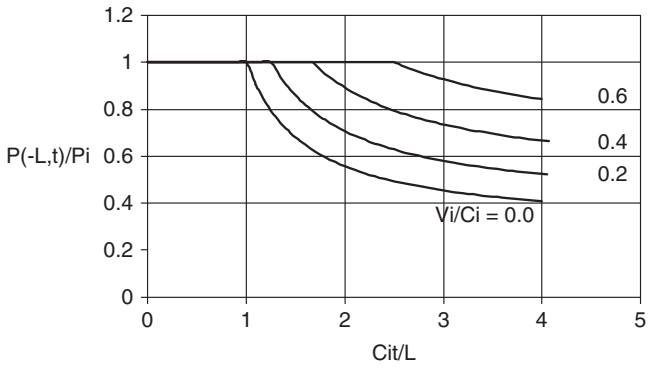


FIGURE 8.24 PRESSURE ARRIVING AT VESSEL

it is conservative and much simpler to use the initial velocity rate $(dV/dt)_i$ and obtain a corresponding vessel steam discharge rate for initial pressure loads. The simplified arriving decompression is given by

$$V = V_i + \frac{\Delta V}{\Delta t}\left(t - \frac{L}{C_i - V_i}\right) \tag{8.123}$$

which applies after the disturbance arrives at the vessel. The initial velocity rate $\Delta V/\Delta t$ at $x = -L$ is obtained from Eq. (8.121) as

$$\frac{dV(-L,t)}{dt} = \frac{C_i^2}{L}\left(\frac{2}{k+1}\right)\left[\left(\frac{k+1}{2}\right)\frac{V}{C_i} - \left(\frac{k-1}{2}\right)\frac{V_i}{C_i} - 1\right]^2 \tag{8.124}$$

When the decompression first arrives at the vessel, Eqs. (8.121) and (8.124) give the initial velocity rate as

$$\frac{\Delta V}{\Delta t} = \left.\frac{dV(-L,t)}{dt}\right|_i = \left(\frac{2}{k+1}\right)\frac{(C_i - V_i)^2}{L} \text{ initial arrival} \tag{8.125}$$

which ultimately decays to the steady velocity rate,

$$\left.\frac{dV(-L,t)}{dt}\right|_{t\to\infty} = 0 \text{ steady state} \tag{8.126}$$

Therefore, the initial velocity rate of Eq. (8.125) is employed for decompression loads. Note that for a longer steam line length L, Eq. (8.125) gives a smaller $\Delta V/\Delta t$.

A general solution to the linear acoustic equations, namely Eqs. (8.104) and (8.105) without the nonlinear terms $V\partial P/\partial x$ and $V\partial V/\partial x$, and with $\rho = \rho_i$ and $C = C_i$, is given by

$$P(x,t) = F_L\left(t + \frac{x}{C}\right) + F_R\left(t - \frac{x}{C}\right) \tag{8.127}$$

and

$$V(x,t) = -\frac{g_0}{\rho C}\left[F_L\left(t + \frac{x}{C}\right) - F_R\left(t - \frac{x}{C}\right)\right] \tag{8.128}$$

The initial velocity and pressure in the steam line are V_i and P_i, for which the corresponding functions shown in Fig. 8.25 are

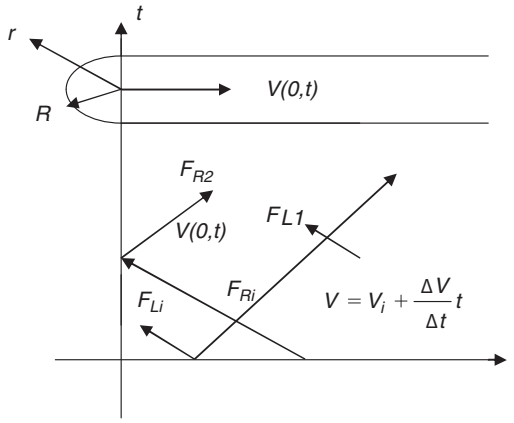


FIGURE 8.25 ACOUSTIC POINT SOURCE

$$F_{Li} = \frac{1}{2}\left(P_i - \frac{\rho C V_i}{g_0}\right) \tag{8.129}$$

and

$$F_{Ri} = \frac{1}{2}\left(P_i + \frac{\rho C V_i}{g_0}\right) \tag{8.130}$$

The arriving disturbance of Eq. (8.123) is used in Eq. (8.128) to express F_{L1} as

$$F_{L1} = -\frac{\rho C}{g_0}\left(V_i + \frac{\Delta V}{\Delta t}\left[t - \frac{L}{C_i - V_i}\right]\right) + \frac{1}{2}\left(P_i + \frac{\rho C V_i}{g_0}\right) \tag{8.131}$$

Upon arrival at the vessel boundary, a velocity $V(-L,t)$ will be reflected back into the steam line, having the form

$$V(-L,t) = -\frac{g_0}{\rho C}\left[\frac{1}{2}\left(P_i - \frac{\rho C V_i}{g_0}\right) - \frac{\rho C \Delta V}{g_0\ \Delta t}\left(t - \frac{L}{C_i - V_i}\right) - F_{R2}\right] \tag{8.132}$$

where the function F_{R2} is unknown. Pressure at the pipe attachment also can be expressed from Eqs. (8.127) and (8.131) with $F_R = F_{R2}$, resulting in

$$P(-L,t) = -\frac{\rho C}{g_0}\left(V_i + \frac{\Delta V}{\Delta t}\left[t - \frac{L}{C_i - V_i}\right]\right) + \frac{1}{2}\left(P_i + \frac{\rho C V_i}{g_0}\right) + F_{R2} \tag{8.133}$$

One more equation is needed to obtain the three unknowns $V(-L,t)$, $P(-L,t)$, and F_{R2} in Eqs. (8.132) and (8.133), which comes from the velocity and pressure field solutions inside the vessel. Propagation inside the vessel will be approximated from the superposition of point acoustic sources with spherical symmetry. The corresponding spherical acoustic equations are [3,4]:

DEs:
$$\frac{\partial P}{\partial t} + \frac{\rho C^2}{g_0}\frac{1}{r^2}\frac{\partial}{\partial r}(r^2 V_r) = 0 \tag{8.134}$$

$$\frac{\partial V_r}{\partial t} + \frac{g_0}{\rho}\frac{\partial P}{\partial r} = 0 \tag{8.135}$$

where the velocity disturbance from its steady flow value is $V_r(r,t)$. Conditions for an initially undisturbed flow are

ICs
$$P(r, 0) = P_0 \tag{8.136}$$
$$V_r(r, 0) = 0 \tag{8.137}$$

One boundary condition for the point source at the steam line attachment, using the hemispherical volume of Fig. 8.25 is

BC:
$$\frac{4\pi R^2}{2} V_r(R, t) = \pi R^2 V(0, t) = \frac{Q(t)}{2} \tag{8.138}$$

where $Q(t)$ is the volume flow rate crossing the spherical boundary, and

$$V_r(\infty, t) = 0 \tag{8.139}$$

The reason that Eq. (8.138) gives half the source strength $Q(t)/2$ is that it is for the hemisphere, and a point source produces or absorbs fluid uniformly in both hemispheres. Solutions to the spherical acoustic equations for pressure and velocity are given by

$$V_r(r,t) = \frac{1}{4\pi r}\left[\frac{1}{C}\frac{dQ}{dt}\left(t - \frac{r}{C}\right) + \frac{1}{r}Q\left(t - \frac{r}{C}\right)\right]H_s\left(t - \frac{r}{C}\right) \tag{8.140}$$

and

$$P(r,t) - P_0 = \frac{1}{4\pi r}\frac{\rho}{g_0}\frac{dQ}{dt}\left(t - \frac{r}{C}\right)H_x\left(t - \frac{r}{C}\right) \tag{8.141}$$

Continuity across the hemisphere $r = R$ and the pipe entrance is written as

$$\frac{4\pi R^2}{2} V_r(R, t) = \pi R^2 V(0, t) \text{ or } 2V_r(R, t) = V(0, t) \tag{8.142}$$

Equations (8.132), (8.140), and (8.142) are combined to give

$$\left(\frac{\rho}{2\pi R g_0}\right)\frac{dQ}{dt} + \left(\frac{\rho C}{2\pi R^2 g_0}\right)Q =$$
$$-\frac{1}{2}\left(P_i - \frac{\rho C V_i}{g_0}\right) + \left(\frac{\rho C \Delta V}{g_0\ \Delta t}\right)\left(t - \frac{L}{C_i - V_i}\right) + F_{R2} \tag{8.143}$$

Also, combining Eq. (8.141) with Eq. (8.133),

$$\left(\frac{\rho}{4\pi R g_0}\right)\frac{dQ}{dt} = \frac{1}{2}\left(P_i - \frac{\rho C V_i}{g_0}\right)$$
$$-\left(\frac{\rho C \Delta V}{g_0\ \Delta t}\right)\left(t - \frac{L}{V_i - V_i}\right) + F_{R2} \tag{8.144}$$

Eliminating F_{R2} from Eqs. (8.143) and (8.144) gives a differential equation in $Q(t)$, with a solution in the form

$$Q(t) = 4\pi R^2 \frac{\Delta V}{\Delta t}\left(t - \frac{L}{C_i - V_i}\right)$$
$$+ (\text{const}) \exp\left(-2\frac{C\left[t - \dfrac{L}{C_i - V_i}\right]}{R}\right) + \text{const} \tag{8.145}$$

The exponential quickly dies out, and the constant does not play a role in the decompression disturbance imposed on the dryer. Recognizing that F_{R2} is generally a function of time, it can be shown from Eqs. (8.132), (8.144), and (8.145) with the last two terms neglected that

$$\frac{dV(-L, t)}{dt} = 2\frac{\Delta V}{\Delta t} = 2\left(\frac{2}{k + 1}\right)\frac{(C_i - V_i)^2}{L} \tag{8.146}$$

or that the vessel steam discharge acceleration is twice the acceleration associated with the initial arriving velocity rate of Eq. (8.125). The initial volume flow rate of steam from the vessel is

$$Q_i = \pi R^2 V_i \tag{8.147}$$

and during the steam flow acceleration of Eq. (8.146), the volume discharge rate is

$$Q_v = Q_i + \left(2\frac{\Delta V}{\Delta t}\right)(\pi R^2)\left(t - \frac{L}{C_i - V_i}\right) t \geq \frac{L}{C_i - V_i} \tag{8.148}$$

The suddenly imposed volume rate of Eq. (8.148) is next used as the disturbance source for an acoustic pressure field inside the vessel, which results in decompression forces on internal surfaces.

8.7.7 Decompression Loads on the Steam Dryer

Figure 8.26 shows the steam line of radius R attached to the vessel with discharge flow coming through an imaginary hemispherical surface, shown dotted. The initially undisturbed volume flow rate corresponds to that of Eq. (8.147), whereas Eq. (8.148) gives the volume flow rate when the decompression arrives.

The vessel acoustic disturbance is approximated by a three-dimensional acoustic source (or sink), surrounded by fluid on all sides, which would involve a uniform volume flow rate from every direction, with equal amounts coming from both right and left half planes. Therefore, the volume flow rate of such a point source Q_s would be *twice* that for discharge from the vessel Q_v. Beginning a new time scale t, at the time of disturbance arrival,

$$Q_s = 2Q_v = \left(4\pi R^2 \frac{\Delta V}{\Delta t}\right)t = \kappa t; \quad \kappa = 4\pi R^2 \frac{\Delta V}{\Delta t} \tag{8.149}$$

It is necessary to obtain the acoustic pressure field associated with this point source.

A single spherical acoustic source is shown in Fig. 8.27, where V_r is the disturbed velocity, $V_{\text{radial}} - V_{\text{undisturbed}}$, not the absolute velocity. The full acoustic problem is specified by

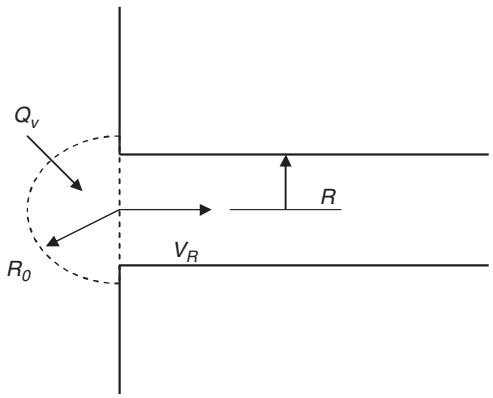


FIGURE 8.26 MODEL FOR FLOW INTO STEAM LINE FROM VESSEL

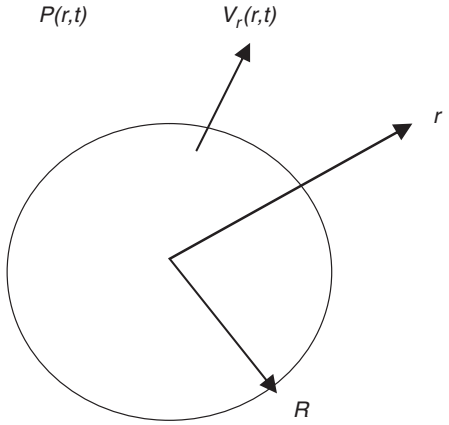


FIGURE 8.27 SPHERICAL POINT SOURCE

DEs:
$$\frac{\partial P}{\partial t} + \frac{\rho C^2}{g_0}\frac{1}{r^2}\frac{\partial}{\partial r}(r^2 V_r) = 0 \tag{8.150}$$

$$\frac{\partial V_r}{\partial t} + \frac{g_0}{\rho}\frac{\partial P}{\partial r} = 0 \tag{8.151}$$

ICs
$$P(r,0) = P_\infty \tag{8.152}$$

$$V_r(r,0) = 0 \tag{8.153}$$

BCs
$$4\pi r^2 V_r(r,t)\big|_{r\to 0} = \kappa t \text{ ramp volume rate} \tag{8.154}$$

$$V_r(\infty,t) = 0 \tag{8.155}$$

A solution for pressure is given by

$$\frac{P(r,t) - P_\infty}{P_\infty} = \left(\frac{\rho\kappa}{4\pi g_0 P_\infty}\right)\frac{1}{r}H_s\left(\frac{Ct}{r} - 1\right) \tag{8.156}$$

where H_s is the Heaviside step function (zero for negative values of its argument and +1 for positive values). Since flow is inward in Fig. 8.27 toward the center, the source is a negative source, or a sink with $\kappa < 0$. Rewriting with κ from Eq. (8.149),

$$P_d^* = \frac{P(r,t) - P_\infty}{\left(\frac{\rho R\,\Delta V}{g_0\,\Delta t}\right)} = \frac{R}{r}H_s\left(\frac{CtR}{R\,r} - 1\right) \tag{8.157}$$

It is interesting to note that for a point acoustic source with a linearly increasing volume flow rate, pressure increases as a *step* at any location r when the pressure disturbance arrives at a time $t = r/C$. If there are multiple acoustic sources at various locations, the pressure at any common location will be additive at the different times of disturbance arrival, determined from Eq. (8.157).

8.7.8 Example Calculation

Figure 8.28 shows the steam line source, 1, from which the first acoustic decompression spreads to the dryer, a distance b away. The dryer solid wall geometry is maintained by placing an equal image source 2 as shown, whose velocity field cancels the velocity field of source 1 at the dryer boundary, and whose pressure field adds to that of source 1. The pressure disturbance from source 2 will arrive at the vessel wall, and in order to maintain that solid boundary, another image source 3 is needed at a distance $2b$ from source 1. An additional symmetric source 4 is needed as shown to further maintain the dryer boundary when the disturbance from source 3 arrives at the dryer, etc.

The dryer may rest on a structure, which approximates a flow blockage at the vessel wall, as shown by the horizontal "shelf." The steam region for this case is idealized as a rectangular geometry with two vertical walls and a closed horizontal bottom, which requires image sources 1′, 2′, 3′, 4′, as shown, where distance a is the length of the "shelf" below and parallel to the centerline of the steam line.

All of the sources begin propagating simultaneously, but their various disturbances reach any distance r according to Eq. (8.157). For the geometry given, at a point on the dryer $r = b$, directly opposite the steam line attachment to the vessel, the summation from all sources can be expressed by the summations,

$$P_d^* = \frac{P(b,t) - P_\infty}{\left(\frac{\rho R\,\Delta V}{g_0\,\Delta t}\right)} = 2\sum_{n=1,2,3,\cdot} \frac{R}{nb}H_s\left(\frac{Ct}{R} - \frac{nb}{R}\right)$$
$$+ 2\sum_{n=1,2,3,\cdot\cdot}\left\{\begin{array}{l}\dfrac{R}{nb}\dfrac{1}{\sqrt{1+\left(\frac{2a}{nb}\right)^2}} \\ \times H_s\left(\dfrac{Ct}{R} - \dfrac{nb}{R}\sqrt{1+\left(\frac{2a}{nb}\right)^2}\right)\end{array}\right\} \tag{8.158}$$

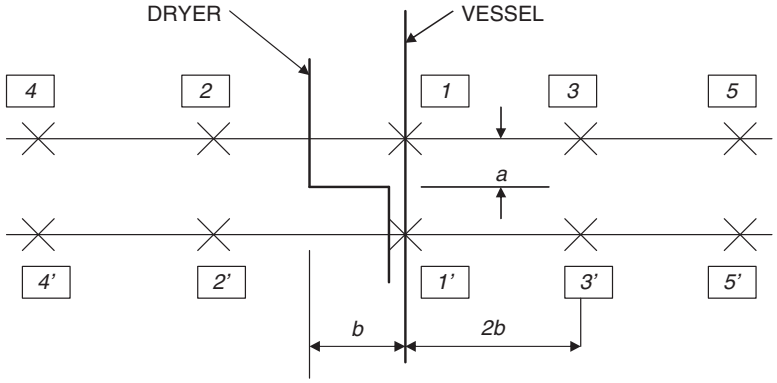


FIGURE 8.28 SOURCE IMAGES FOR DECOMPRESSION PROPAGATION BETWEEN VESSEL WALL AND DRYER

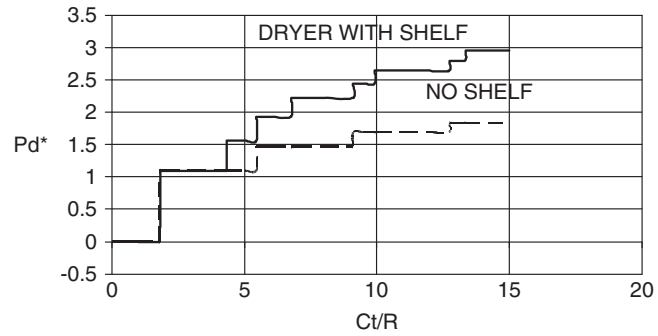


FIGURE 8.29 NORMALIZED DRYER PRESSURE OPPOSITE STEAMLINE, A/R = 2, B/R = 1.8

Figures 8.29 and 8.30 give normalized pressure profiles from Eq. (8.158) for a value of $a/R = 2$ and values of $b/R = 1.8$ and 2.4, respectively, to show the effect of dryer distance from the vessel inside wall. Note too that the normalized pressure P_d* contains $\Delta V/\Delta t$ from Eq. (8.125), which is inversely proportional to the distance L from the steam line rupture to the vessel. A distance twice as long would cause the pressure load to be reduced by a factor of 2.0.

The solid lines include the "shelf," whereas the dotted lines are for cases without a "shelf." *Recall that the pressure is actually a decompression shown as a positive value*. The decompression will reach a maximum value when it is either relieved by reflection from the dryer boundary or from the steam line. Since the physical length, and therefore the round trip acoustic wave transit time, between the vessel and venturi is much longer than that of the dryer half width *W/2*, a reflection from the dryer outer edge would return first to begin relieving the decompression buildup on the dryer in an approximate time

$$\left(\frac{Ct}{R}\right)_{\max imum} \approx \frac{2(W/2)}{R} \tag{8.159}$$

Although the pressures of Figs. 8.29 and 8.30 continue to increase in time, they represent about 10 ms total time. Pressure relief for a typical dryer would occur at a time of $Ct/R \approx 11$.

8.8 SHOCK REFLECTION AT THE INTERFACE OF A BUBBLY LIQUID

The reflection of a shock wave at a gas/liquid interface in a pipe is a phenomena that is considered in the design of nuclear fuel reprocessing plants. The transmitted and reflected shock pressures at a pure liquid interface can be six or more times as large as the initial shock, and creates proportionally large loads on the piping. Calculations show that the magnitude of the transmitted and reflected shocks from the interface of a bubbly mixture is close to the same magnitude as if reflection occurred from a pure liquid interface, until the mixture void fraction is increased to nearly 90%, at which the mixture is becoming a froth.

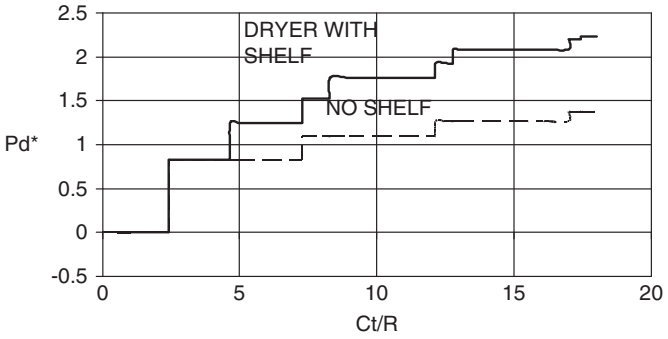


FIGURE 8.30 NORMALIZED DRYER PRESSURE OPPOSITE STEAMLINE, A/R = 2, B/R = 2.4

Explosive gas mixtures in pipes can sometimes cause a detonation shock to propagate and reflect from a downstream liquid surface. Reaction forces exerted on piping components by the initial detonation shock must be considered, but shock reflection and transmission at the interface of a stationary liquid column can result in significantly higher forces. Some viscous or gel-like liquid columns may contain gas bubbles, which are expected to absorb shock impact energy. This analytical model is included to provide simple estimates transmitted shock properties when an oncoming shock in gas arrives and reflects from the interface of a liquid column, which may or may not contain suspended gas bubbles.

A simplified model is employed throughout, beginning with a brief summary of the normal moving shock equations in perfect gas, followed by the waterhammer equations for treating the limiting case of a shock in gas reflecting from a pure liquid. Then state equations for a mixture of perfect gas bubbles in an incompressible liquid are summarized. These state equations are employed in the moving shock equations to predict the transmitted shock properties after an oncoming shock in gas reflects from a bubbly gas/liquid mixture interface.

It is expected that after the oncoming shock in gas reflects from the mixture interface, a shock will reflect back into the gas, and a shock of equal magnitude will propagate forward into the mixture. Between the two shocks moving away from each other, the pressures and fluid velocities should be the same, both in the gas and in the mixture, although the shock speeds, one in the gas and the other in the bubbly mixture, are expected to be different. Forces exerted on the piping sections through which each shock moves will be determined by pressures and velocities upstream and downstream of both shocks, and force durations will be determined by the shock speeds through various section. The emphasis in this section, however, is primarily on the transmitted shock properties.

8.8.1 Nomenclature

A	Pipe flow area
C	Sound speed
e	Specific internal energy
f	Function defined by Eq. (8.182)
g_0	Newton's constant ($F = Ma/g_0$)
h_0	Stagnation enthalpy
h	Static enthalpy
k	Ratio of specific heats, gas
$\dot{m}$	Mass flow rate
P	Pressure
S	Shock speed
T	Temperature
V	Velocity
x	Gas mass fraction
α	Gas volume fraction
ρ	Density
$(\ )_g$	Gas
$(\ )_L$	Liquid
$(\ )_R$	Reflected
$(\ )_x$	Undisturbed
$(\ )_y$	Oncoming shock

$( )_z$ Reflected or transmitted
$( )_m$ Bubbly mixture

8.8.2 Moving Normal Shock Summary

Figure 8.31 shows a normal shock moving in a uniform flow passage of area A. Its speed S, and both upstream and downstream velocities V_y and V_x are relative to the lab frame. Fluid velocity ahead of the shock (undisturbed) is designated by subscript x, and behind the shock (shocked) is designated by subscript y. Corresponding densities ρ, static pressures P, static enthalpies h, and stagnation enthalpies h_0 also have similar designations.

The dotted control volume around the shock is so thin that mass, momentum, and energy storage terms inside are negligible. Therefore, the mass, momentum, and energy principles for the moving shock can be written as

$$\text{Mass: } \dot{m} = \rho_x (S - V_x) A = \rho_y (S - V_y) A \tag{8.160}$$

$$\text{Momentum: } \dot{m}(V_y - V_x) = g_o(P_y - P_x)A \tag{8.161}$$

$$\text{Energy: } \dot{m}(h_{0y} - h_{0x}) + (P_x - P_y)AS = 0 \tag{8.162}$$

The constant g_0 is Newton's constant, ($F = Ma/g_0$). The gravitational potential energy is neglected and the stagnation enthalpy is written as

$$h_0 = h + \frac{V^2}{2g_0} \tag{8.163}$$

so that intermediate forms of Eqs. (8.160), (8.161), and (8.162) are

$$\text{Mass: } \rho_y(S - V_y) - \rho_x(S - V_x) = 0 \tag{8.164}$$

$$\text{Momentum: } \rho_x(S - V_x)^2 - \rho_y(S - V_y)^2 = g_0(P_y - P_x) \tag{8.165}$$

$$\text{Energy: } h_x - h_y + \frac{1}{2}(P_y - P_x)\left(\frac{1}{\rho_y} + \frac{1}{\rho_x}\right) = 0 \tag{8.166}$$

Equations (8.164), (8.165), and (8.166) apply to any simple compressible fluid.

8.8.3 Moving Shock in a Perfect Gas

Useful state equations for a perfect gas are summarized below [4]:

$$P = \rho RT \text{ state equation} \tag{8.167}$$

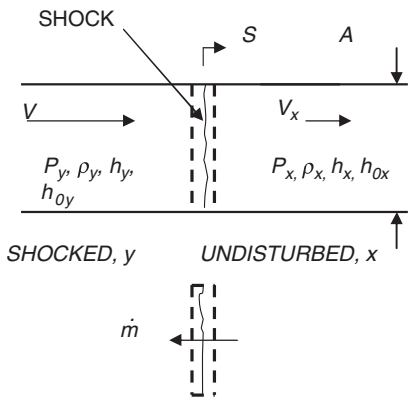


FIGURE 8.31 MOVING NORMAL SHOCK IN FLOW PASSAGE

$$C = \sqrt{kg_0RT} = \sqrt{kg_0P/\rho} \text{ sound speed} \tag{8.168}$$

$$\frac{P}{\rho^k} = \text{const isentropic state change} \tag{8.169}$$

$$e = c_vT = \frac{1}{k-1}\frac{P}{\rho} \text{ internal energy} \tag{8.170}$$

$$h = e + \frac{P}{\rho} = c_pT = \frac{k}{k-1}\frac{P}{\rho} \text{ static enthalpy} \tag{8.171}$$

$$k = \frac{c_p}{c_v} \text{ ratio of specific heats} \tag{8.172}$$

Equations (8.167) – (8.172) are used to obtain the following useful forms for moving normal shocks from Eqs. (8.164), (8.165), and (8.166):

$$\frac{V_y - V_x}{C_x} = \left(\frac{P_y}{P_x} - 1\right)\sqrt{\frac{\left(\frac{2}{k(k-1)}\right)}{\left(\frac{k+1}{k-1}\frac{P_y}{P_x} + 1\right)}} \tag{8.173}$$

$$\frac{S - V_x}{C_x} = \sqrt{\left(\frac{k+1}{2k}\right)\frac{P_y}{P_x} + \left(\frac{k-1}{2k}\right)} \tag{8.174}$$

and

$$\frac{\rho_y}{\rho_x} = \frac{\left(\frac{k+1}{k-1}\frac{P_y}{P_x} + 1\right)}{\left(\frac{k+1}{k-1} + \frac{P_y}{P_x}\right)} \tag{8.175}$$

A known shock pressure ratio P_y/P_x determines the density ratio ρ_y/ρ_x so that the sound speed ratio is

$$\frac{C_y}{C_x} = \sqrt{\frac{P_y\rho_x}{P_x\rho_y}} \tag{8.176}$$

8.8.4 Shock Reflection From a Flexible Interface

The flexible interface considered is either a liquid or other substance (such as mixture of liquid containing homogeneously distributed gas bubbles with a known void fraction). Since the arrival of a normal shock wave at such an interface must conserve mass, momentum, and energy in both substances, the resulting impact properties are influenced by both sets of conservation principles.

Figure 8.32 shows the shock reflecting from a flexible interface in the flow passage. The same equations developed from Fig. 8.31 can be used for the reflected shock. The reflected shock velocity S_R has the same sign as S. However, the other terms undergo the following changes:

$$V_y \rightarrow -V_z$$
$$V_x \rightarrow -V_y$$
$$P_y \rightarrow P_z$$
$$\rho_y \rightarrow \rho_z$$
$$C_y \rightarrow C_z$$
$$P_x \rightarrow P_y$$
$$\rho_x \rightarrow \rho_y$$
$$C_x \rightarrow C_y$$

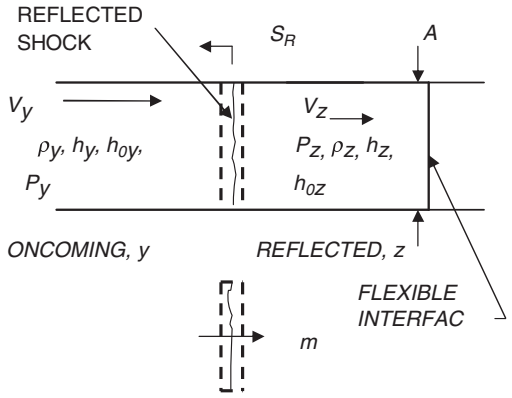


FIGURE 8.32 SHOCK REFLECTING FROM FLEXIBLE INTERFACE

It follows that the reflected shock equations for Fig. 8.32 are

$$\frac{-V_z + V_y}{C_y} = \left(\frac{P_z}{P_y} - 1\right)\sqrt{\frac{\left(\frac{2}{k(k-1)}\right)}{\left(\frac{k+1}{k-1}\frac{P_z}{P_y} + 1\right)}} \tag{8.177}$$

$$\frac{S_R + V_y}{C_y} = \sqrt{\left(\frac{k+1}{2k}\right)\frac{P_z}{P_y} + \left(\frac{k-1}{2k}\right)} \tag{8.178}$$

$$\frac{\rho_z}{\rho_y} = \frac{\left(\frac{k+1}{k-1}\frac{P_z}{P_y} + 1\right)}{\left(\frac{k+1}{k-1} + \frac{P_z}{P_y}\right)} \tag{8.179}$$

and

$$\frac{C_z}{C_y} = \sqrt{\frac{P_z \rho_y}{P_y \rho_z}} \tag{8.180}$$

8.8.5 Shock Reflection From a Rigid Interface

If the interface is rigid, velocity $V_z = 0$ in Eq. (8.177), since the moving gas behind the oncoming shock will come to a complete stop. If P_z/P_y is expressed from Eq. (8.177) in terms of V_y/C_y, and Eqs. (8.173), (8.175), and (8.176) are used to express V_y/C_x and C_y/C_x in terms of the oncoming shock pressure P_y/P_x, it follows that the reflected pressure from a rigid interface can be obtained from

$$\frac{P_z}{P_x} = \frac{P_y 1}{P_x 2}\left\{\begin{array}{l}\left[2 + \dfrac{k(k+1)}{2}f^2\right] \\ + \sqrt{\left[2 + \dfrac{k(k+1)}{2}f^2\right]^2 - 4\left[1 - \dfrac{k(k-1)}{2}f^2\right]}\end{array}\right\} \tag{8.181}$$

where

$$f = \frac{(V_y/C_x)}{(C_y/C_x)} \tag{8.182}$$

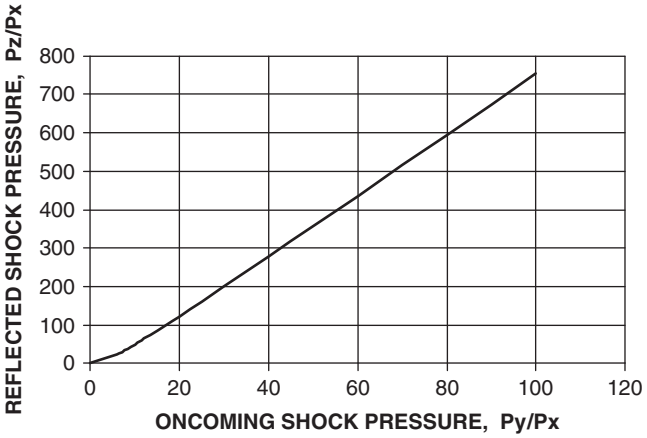


FIGURE 8.33 REFLECTED SHOCK, RIGID SURFACE

Figure 8.33 gives the reflected pressure at a rigid interface for arriving shocks of various magnitudes. The limit for large P_y/P_x can be shown to be

$$\left.\frac{P_z}{P_x}\right|_{\frac{P_y}{P_x}\to\infty} = \left(\frac{3k-1}{k-1}\right)\frac{P_y}{P_x} \tag{8.183}$$

or $8(P_y/P_x)$ for air with $k = 1.4$. The reflected pressure from a rigid interface in liquid is only twice the oncoming value of the oncoming pressure disturbance, based on waterhammer theory.

8.8.6 Shock Tranmission at a Pure Liquid Interface

If the interface belongs to a pure liquid (slightly compressible fluid) and pressures are not likely to exceed several hundred atmospheres (some references suggest 1200 atmospheres), then classical waterhammer theory can be employed for predicting pressure and velocity propagation with minimal error. Figure 8.34 shows the interface condition of Fig. 2 in more detail between a gas and slightly compressible fluid where waterhammer applies. Both the fluids have a common pressure P_z and velocity V_z,

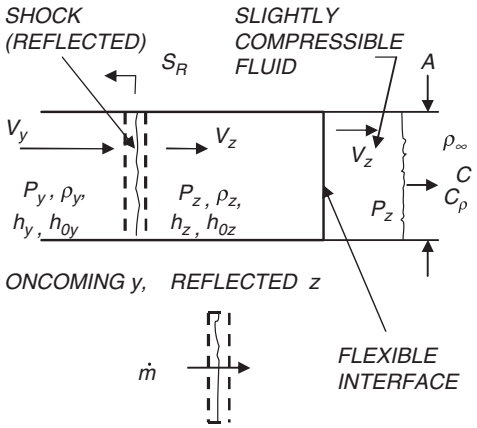


FIGURE 8.34 SHOCK REFLECTING FROM SLIGHTLY COMPRESSIBLE FLUID

which are expressed for the gas from Eq. (8.177), and for the liquid by the waterhammer equation,

$$P_z - P_\infty = \frac{\rho C}{g_0} V_z \tag{8.184}$$

Equations (18) and (24) are combined to obtain, for $P_\infty = P_x$,

$$\left(\frac{g_0 P_x}{\rho C C_x}\right)\left(\frac{P_z}{P_x} - 1\right) =$$

$$\left(\frac{V_y}{C_x}\right) - \left(\frac{C_y}{C_x}\right)\left[\left(\frac{P_z}{P_x}\right)\left(\frac{P_x}{P_y}\right) - 1\right]\sqrt{\frac{\dfrac{2}{k(k-1)}}{\left(\dfrac{k+1}{k-1}\right)\left(\dfrac{P_z}{P_x}\right)\left(\dfrac{P_x}{P_y}\right)+1}} \tag{8.185}$$

Again using Eqs. (8.173) – (8.176) for V_y/C_x and C_y/C_x, Eq. (8.185) was used to obtain the reflected and transmitted pressure P_z/P_x, shown in Fig. 8.35, for oncoming shocks of various strengths P_y/P_x in atmospheric air, arriving at a water interface.

Comparison with Fig. 8.33 shows that the reflected shock magnitude from a water interface is nearly the same as if the interface was rigid. The difference is that for the liquid interface, a pressure wave of the same magnitude P_z in Fig. 8.35 will be transmitted through the liquid at sonic velocity C_L, exerting transient forces on the pipe segments encountered.

Bubbly Liquid/Gas Mixture If the liquid in the previous analysis is replaced by a homogeneous mixture of incompressible liquid containing ideal gas bubbles with a gas mass fraction x_m, or void fraction α_m, the mixture density can be expressed by

$$\rho_m = \frac{1}{\dfrac{x_m}{\rho_{gm}} + \dfrac{(1 - x_m)}{\rho_L}} = \alpha_m \rho_{gm} + (1 - \alpha_m)\rho_L \tag{8.186}$$

Note that when such a bubbly mixture pressure varies, both the void fraction α_m and gas density ρ_m vary, whereas the gas mass fraction x_m and liquid density ρ_L remain constant. The mixture enthalpy is

$$h_m = x_m h_{gm} + (1 - x_m)h_L \tag{8.187}$$

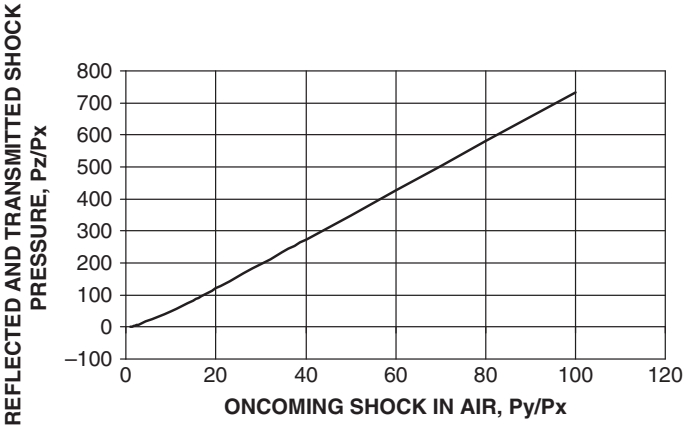


FIGURE 8.35 REFLECTED AND TRANSMITTED SHOCK PRESSURE AT AIR/ WATER INTERFACE

where

$$h_{gm} = \frac{k}{k-1}\frac{P_m}{\rho_{gm}} \tag{8.188}$$

and

$$h_L = e_L + \frac{P_m}{\rho_L} \tag{8.189}$$

Since the system being considered is adiabatic, the internal energy e_L of the incompressible liquid remains constant during compression. Also, isentropic state changes for the gas are expressed by

$$\frac{P_m}{\rho_{gm}^k} = const \tag{8.190}$$

so that the gas sound speed is given by

$$C_{gm} = \sqrt{g_0\left(\frac{\partial P_m}{\partial \rho_{gm}}\right)_s} = \sqrt{k g_0 \frac{P_m}{\rho_{gm}}} \tag{8.191}$$

Sound speed in the bubbly mixture is given by [1]

$$\frac{C_m}{C_{gm}} = \frac{1}{C_{gm}}\sqrt{g_0\left(\frac{\partial P_m}{\rho_m}\right)_s}$$

$$= \frac{\dfrac{\rho_{gm}}{\rho_m}\sqrt{1 - \dfrac{\rho_{gm}}{\rho_L}}}{\sqrt{\left(\dfrac{\rho_{gm}}{\rho_m}\right)\left[1 - \left(\dfrac{\rho_{gm} C_{gm}}{\rho_L\ C_L}\right)^2\right] - \left[\dfrac{\rho_{gm}}{\rho_L} - \left(\dfrac{\rho_{gm} C_{gm}}{\rho_L\ C_L}\right)^2\right]}} \tag{8.192}$$

where sound speed in the liquid, C_L, is constant. It follows from Eqs. (8.163), (8.164), (8.165), and (8.186) through Eq. (8.192) that the moving shock equations in a bubbly mixture of noncondensible gas and incompressible liquid are given by

$$\frac{\rho_{ym}}{\rho_{xm}} = \frac{\left(\dfrac{k+1}{k-1}\dfrac{P_{ym}}{P_{xm}} + 1\right)}{\left[\left(\dfrac{k+1}{k-1} + \dfrac{P_{ym}}{P_{xm}}\right) + 2\dfrac{(1-x)}{(k-1)}\left(\dfrac{\rho_{xm}}{\rho_L}\right)\left(\dfrac{P_{ym}}{P_{xm}} - 1\right)\right]} \tag{8.193}$$

$$\frac{V_{ym} - V_{xm}}{C_{gxm}} = \sqrt{\frac{\left(\dfrac{1}{k}\right)\left(\dfrac{\rho_{gxm}}{\rho_{xm}}\right)\left(\dfrac{\rho_{ym}}{\rho_{xm}} - 1\right)\left(\dfrac{P_{ym}}{P_{xm}} - 1\right)}{\left(\dfrac{\rho_{ym}}{\rho_{xm}}\right)}} \tag{8.194}$$

$$\frac{S_m - V_{xm}}{C_{gxm}} = \sqrt{\frac{\left(\dfrac{1}{k}\right)\left(\dfrac{\rho_{gxm}}{\rho_{xm}}\right)\left(\dfrac{\rho_{ym}}{\rho_{xm}}\right)\left(\dfrac{P_{ym}}{P_{xm}} - 1\right)}{\left(\dfrac{\rho_{ym}}{\rho_{xm}} - 1\right)}} \tag{8.195}$$

where

$$\frac{\rho_{gxm}}{\rho_{xm}} = x_m + (1 - x_m)\left(\frac{\rho_{gxm}}{\rho_L}\right) \tag{8.196}$$

and

$$\frac{\rho_L}{\rho_{xm}} = x_m\left(\frac{\rho_L}{\rho_{gxm}}\right) + (1 - x_m) \tag{8.197}$$

A known transmitted shock pressure in the mixture, P_{ym}/P_{xm}, determines the density ratio of Eq. (8.193) for the known

mixture properties of Eq. (8.197). Mixture velocity and shock speed of Eqs. (8.194) and (8.195) also are determined from the transmitted shock pressure P_{ym}/P_{xm}. However, the magnitude of the transmitted shock pressure P_{ym}/P_{xm} must first be determined by simultaneous solution with the reflected shock.

8.8.7 Shock Reflection From Bubbly Liquid Mixture

The reflected shock properties in gas, given by Eqs. (8.177) (8.180), remain the same for shock arrival at the interface of a bubbly liquid mixture. However, the transmitted properties will correspond to a shock with properties described by Eqs. (8.193) − (8.197).

The bubbly liquid is initially at pressure $P_x = P_{xm}$ with gas sound speed $C_{gx} = C_{gxm}$. Also, $V_{xm} = 0$, and the propagating shock pressure and velocity in the mixture will be equal to the reflected shock properties in the gas, that is, $P_z = P_{ym} = P_{zm}$ and $V_z = V_{ym} = V_{zm}$ so that Eq. (8.194) is written as

$$\frac{V_{zm}}{C_{gxm}} = \sqrt{\frac{\left(\frac{1}{k}\right)\left(\frac{\rho_{gxm}}{\rho_{xm}}\right)\left(\frac{\rho_{zm}}{\rho_{xm}} - 1\right)\left(\frac{P_{zm}}{P_{xm}} - 1\right)}{\left(\frac{\rho_{zm}}{\rho_{xm}}\right)}} \tag{8.198}$$

where the density behind the transmitted shock, based on Eq. (8.193), corresponds to

$$\frac{\rho_{zm}}{\rho_{xm}} = \frac{\left(\frac{k+1}{k-1}\frac{P_{zm}}{P_{xm}} + 1\right)}{\left[\left(\frac{k+1}{k-1} + \frac{P_{zm}}{P_{xm}}\right) + 2\frac{(1-x)}{(k-1)}\left(\frac{\rho_{xm}}{\rho_L}\right)\left(\frac{P_{zm}}{P_{xm}} - 1\right)\right]} \tag{8.199}$$

The reflected shock pressure and velocity $P_z/P_y = P_{zm}/P_y$ and $V_z/C_y = V_{zm}/C_y$ of Eq. (8.177) apply to the gas (subscript z stands for reflected properties in the gas and transmitted properties in the mixture, and subscript y stands for the oncoming shock in the gas). Equating V_{zm} from Eqs. (8.177) and (8.194), noting that C_x in the undisturbed gas is equal to C_{gxm} in the undisturbed bubbly mixture ($C_x = C_{gxm}$), and retaining the oncoming shock pressure, velocity, and sound speed P_y/P_x, V_y/C_x, and C_y/C_x, the shock pressure transmitted to the bubbly mixture can be obtained from a solution to

$$\frac{V_{zm}}{C_{gxm}} = \frac{V_y}{C_x} - \left(\frac{\left(\frac{P_{zm}}{P_{xm}}\right)}{\left(\frac{P_y}{P_x}\right)} - 1\right)\left(\frac{C_y}{C_x}\right)\sqrt{\frac{\left(\frac{2}{k(k-1)}\right)}{\left(\frac{k+1}{k-1}\right)\left(\frac{P_{zm}}{P_{xm}}\right)\left(\frac{P_x}{P_y}\right) + 1}}$$

$$= \sqrt{\frac{\left(\frac{1}{k}\right)\left(\frac{\rho_{gxm}}{\rho_{xm}}\right)\left(\frac{P_{zm}}{P_{xm}} - 1\right)\left(\frac{\rho_{zm}}{\rho_{xm}} - 1\right)}{\left(\frac{\rho_{zm}}{\rho_{xm}}\right)}} \tag{8.200}$$

When a solution for the transmitted shock pressure P_{zm}/P_{xm} is determined from Eq. (8.200) for a known value of the oncoming shock pressure P_y/P_x, the middle or right term of Eq. (8.200) can be used to obtain the mixture velocity V_{zm}/C_{gxm} behind the transmitted shock. Also, Eq. (8.199) can be used to obtain the corresponding density ratio across the transmitted shock, and the shock speed from Eq. (8.195) would be given by

$$\frac{S_m}{C_{gxm}} = \sqrt{\frac{\left(\frac{1}{k}\right)\left(\frac{\rho_{gxm}}{\rho_{xm}}\right)\left(\frac{\rho_{zm}}{\rho_{xm}}\right)\left(\frac{P_{zm}}{P_{xm}} - 1\right)}{\left(\frac{\rho_{zm}}{\rho_{xm}} - 1\right)}} \tag{8.201}$$

Several useful properties are given in Table 8.1 for example computations.

Figure 8.36 gives the transmitted and reflected pressure P_{zm}/P_{xm} (where the undisturbed initial pressures P_{xm} and P_x are equal) for a range of oncoming shock pressures P_y/P_x at several gas mass fractions x_m. Note that the bubbly mixture with a void fraction of about 90% still transmits a shock pressure five times the oncoming shock magnitude. That is, bubbles generally are not effective in reducing transmitted shock pressures, unless they approach more than 99%, which is like a froth, and that simply becomes a straight transmission of a shock from gas into another gas region.

Figures 8.37, 8.38, and 8.39 give the corresponding mixture density ρ_{zm}/ρ_{xm} and velocity V_{zm}/C_{gxm} behind the shock, and shock speed S_m/C_{gxm}. Computations similar to the ones represented by Figs. 8.36, 8.37, 8.38, and 8.39 would be useful in determining the dynamic loads applied to piping systems exposed to moving shocks transmitted at bubbly liquid interfaces.

TABLE 8.1
EXAMPLE PROPERTIES, UNDISTURBED AIR AND WATER

$P(bar)$	$\rho_g(kg/m^3)$	$\rho_L(kg/m^3)$	$C_g(m/s)$	$C_L(m/s)$	x_m	α	C_m/C_g
1	1.2	1000	343	1524	0.00001	(0.008)	0.383
					0.0001	(0.08)	0.130
					0.001	(0.45)	0.070
					0.01	(0.89)	0.112
					0.1	(0.99)	0.320
					1.0	(1.00)	1.000

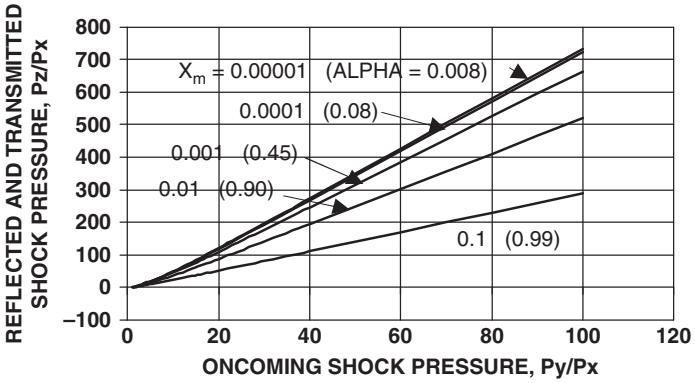


FIGURE 8.36 TRANSMITTED AND REFLECTED SHOCK PRESSURE, BUBBLY MIXTURE

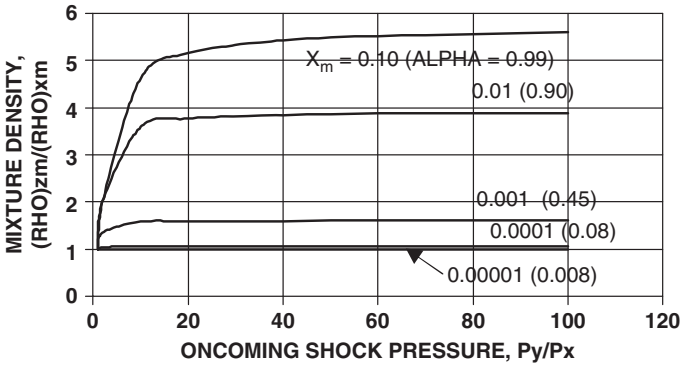


FIGURE 8.37 BUBBLE MIXTURE DENSITY BEHIND SHOCK

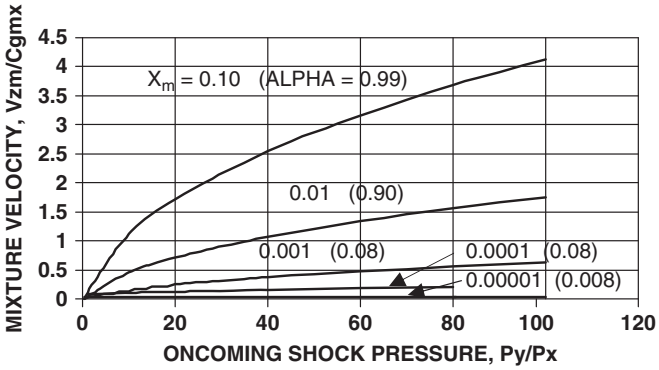


FIGURE 8.38 BUBBLY MIXTURE VELOCITY BEHIND TRANSMITTED SHOCK

Equation (8.192) was written for the shocked state in the bubbly mixture, $(\ )_{zm}$, and the density relationship of Eq. (26) was also employed in various forms to express the mixture sound speed C_{zm}/C_{gxm} behind the transmitted shock in the bubbly mixture. Results are given in Fig. 8.40.

8.8.8 Important Observations

A reflected normal shock from a rigid interface can be much higher than a reflected waterhammer wave, according to Eq. (8.183). Reflection from a pure liquid interface is almost of the same magnitude as reflection from a rigid interface. Furthermore, even a bubbly mixture of gas and liquid with a 45% gas volume content transmits almost 90% of the rigid interface reflection magnitude. The shock speed and sound speed in the bubbly mixture are strongly affected by void fraction, being high at low and high void fractions, and low at the mid-range of void fraction. Although bubbles do not affect the transmitted shock magnitude strongly, they do affect the moving shock speed, and would have the general effect of increasing the force application time interval on straight pipe sections between elbows.

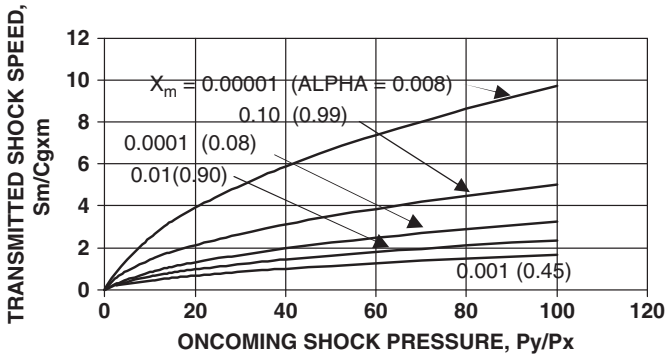


FIGURE 8.39 TRANSMITTED SHOCK SPEED IN BUBBLY MIXTURE

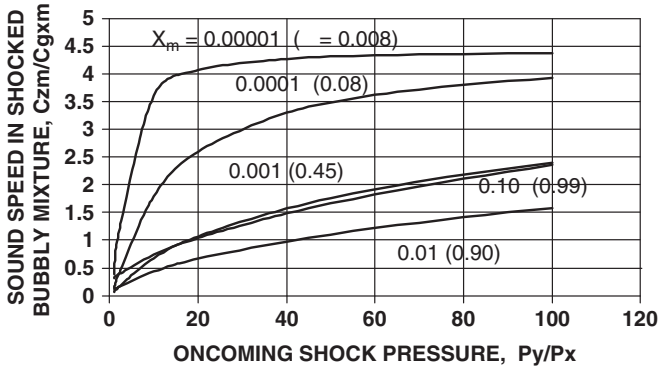


FIGURE 8.40 SOUND SPEED IN BUBBLY MIXTURE BEHIND TRANSMITTED SHOCK

8.9 SUMMARY

This chapter described basic fluid-flow phenomena and the applications used to predict forces exerted on pipes and structures. Specific flow field solutions were too numerous to include here. Although many analytical solutions are available, an increasing number of fluid forces exerted in a complex piping system are predicted by sophisticated computer models. Once force magnitudes and both time- and space-dependencies are determined, they are incorporated in rigorous structural models to predict system dynamic response and associated stresses. Such results lead to design guidelines for the mitigation or prevention of potential failures.

Progress continues to be made in analyzing coupled fluid and structure motions under the title of fluid-structure interaction (FSI). That is, when forces are exerted on a structure by the fluid, any structure motion will affect the fluid motion and also affect the forces. The analytical demands for modeling both fluid and structural motion with coupling at the moving structural boundaries are significant computational challenges. However, current predictive methods often make use of the fact that exact coupled solutions can be obtained for decoupled fluid and structural motions, as shown by the interpretation of Eq. (8.42). When fluid and structural decoupling is not obvious, or when complete computer modeling or representative experimental results are not available, conservative decoupling is employed to provide design rules that ensure sufficient design factors.

8.10 REFERENCES

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CHAPTER

9

BOLTED-FLANGE JOINTS AND CONNECTIONS

William J. Koves

9.1 INTRODUCTION

Although flanged joints are essential components in nearly all pressurized systems, they are also one of the most complex. Many factors are involved in determining the successful design and operation of a bolted flange joint in service—namely, the interaction between the bolting, flange, and gasket, as well as important nonlinear variables such as friction and gasket properties. Safety considerations are, of course, extremely important; just as the Pressure Vessel and Piping Codes were developed with safety in mind, so, too, were the rules for bolted flange joints. The Code Bolted-Flange Joint Design Rules provide a method for sizing the flange and bolts to be structurally adequate for the specified design conditions; however, the rules do not address assembly and special requirements, nor do they guarantee a leak-tight joint for all transient operating conditions. The latter issue is discussed further in the sections on tightness-based design and flange-joint assembly.

The purpose of this chapter is to provide the background and basis for the Bolted-Flange Joint Design Rules contained in the ASME Codes and to present how the rules are applied.

9.2 CODES ADDRESSING FLANGE DESIGN

All pressurized systems must address the joining of components. The following are some major Codes used by the industry to address the design of flanged joints. Each is discussed briefly in Section 9.3.

(a) Pressure Vessel Codes
  (1) ASME Section VIII, Division 1 (See ref. [1].)
  (2) ASME Section VIII, Division 2
  (3) ASME Section VIII, Division 3
  (4) ASME Section I
  (5) ASME Section III

(b) Piping Codes
  (1) ASME B3l.3, *Process Piping*
  (2) ASME B3l.1, *Power Piping*
  (3) ASME B3l.8, *Gas-Transmission Piping*
  (4) ASME B31.4, *Liquid-Transmission Piping*

9.2.1 Jurisdictional Requirements

Codes are standards that are accepted and required by the local jurisdictions. The ASME Pressure Vessel Codes, such as Section VIII, Divisions 1 and 2, are referenced in most U.S. states. The ASME Piping Codes are referenced in many states, although not as extensively as the Pressure Vessel Codes. Adherence to both the Pressure Vessel and the Piping Codes becomes law when such adherence is required by the local jurisdiction. Any contractual requirements are in addition to the jurisdictional requirements. Thus, even if a facility or plant is constructed outside of the United States and the local jurisdiction does not require construction in accordance with an ASME Code, any contractual requirements could still require ASME Code compliance.

9.2.2 Applicability of Flange Standards

Flange standards, such as ASME B16.5 and B16.47, are not Codes and become mandatory only when referenced by the governing Design Code, such as the ASME sections in the foregoing list. However, these are standards developed in accordance with the American National Standards Institute (ANSI) procedures and constitute industry-accepted standards based on consensus and public review, as opposed to standards developed by Manufacturers or trade organizations.

9.3 FLANGE DESIGN FOR PRESSURE VESSELS

This section outlines each of the aforementioned ASME Code sections that address flange design. Pertinent paragraph references are provided for each Code section in addition to a brief description of the requirements contained in the referenced paragraphs. Specific design formulas are provided wherever they differ from (or are in addition to) the ASME flange design methodology described in Section 9.6.l.

9.3.1 ASME Section VIII, Division 1

This Division of the ASME Code allows the use of flanges in accordance with listed standards. For the design of special flanges, it provides design rules.

UG-44 This paragraph permits the use of flanges in accordance with the following standards at their listed pressure–temperature ratings:

(1) ASME/ANSI B16.5, Pipe Flanges and Flanged Fittings
(2) ASME/ANSI B16.42, Ductile Iron Pipe Flanges and Flanged Fittings
(3) ASME/ANSI B16.47, Large-Diameter Steel Flanges, NPS 26 through NPS 60

TABLE 9.1 YEAR OF ACCEPTABLE EDITION OF REFERENCED STANDARDS IN DIVISION 1 (*Source*: Table U-3, Section VIII, Division I, 2011a Addenda of the ASME B&PV Code)

Title	Number	Year
Seat Tightness of Pressure Relief Valves	API Std. 527	1991 (R 2007)
Unified Inch Screw Threads (UN and UNR Thread Form)	ASME B1.1	Latest edition
Pipe Threads, General Purpose (Inch)	ANSI/ASME B1.20.1	Latest edition
Cast Iron Pipe Flanges and Flanged Fittings, Classes 25, 125, 250, and 800	ASME/ANSI B16.1	2005
Pipe Flanges and Flanged fittings	ASME B16.5	2009
Factory-Made Wrought Steel Buttwelding Fittings	ASME B16.9	Latest edition
Forged Fittings, Socket-Welding and Threaded	ASME B16.11	Latest edition
Cast Bronze Threaded Fittings Classes 125 and 250	ANSI/ASME B16.15	Latest edition
Metallic Gaskets for Pipe Flanges – Ring-Joint, Spiral Wound and Jacketed	ASME B16.20	Latest edition
Cast Copper Alloy Pipe Flanges and Flanged Fittings, Class 150, 300, 400, 600, 900, 1500, and 2500	ASME B16.24	2006
Ductile Iron Pipe Flanges and Flanged Fittings, Class 150 and 300	ASME/ANSI B16.42	1998 (R 2006)
Large Diameter Steel Flanges, NPS 26 Through NPS 60	ASME B16.47	2006
Square and Hex Nuts (Inch Series)	ASME/ANSI B18.2.2	Latest edition
Welded and Seamless Wrought Steel Pipe	ANSI/ASME B36.10M	Latest edition
Pressure Relief Devices	ASME PTC 25	2010

Table U-3 This table, given here in part as Table 9.1, provides the date of the accepted edition for all referenced standards. Note that the date approved by ASME in Table U-3 may not correspond with the latest edition of the standard. In fact, there is always a lag from the time that a standard is published to the time that the Code edition containing date of the latest edition of the standard is published. The Code Committee must first review the new standard and vote an approval of it before it is issued. There have been instances in which the latest edition of ASME B16.5 was not approved by the Code Committee and the older editions remained listed until the next revision of ASME B16.5. The reader is cautioned that when significant rating changes occur in the standard, that failure to adhere to the correct listed data could result in the incorrect flange class specified for the system. This was the case between 1996 and 1999, in which the 1988 edition of ASME B16.5 continued to be referenced well after the 1996 edition was published.

Note that the 2011a Addenda of Section VIII Division 1 started referencing the "Latest Edition" for certain ASME Standards. The exceptions are standards that include pressure–temperature ratings, including the Flange Standards such as B16.5.

UG-11(a)(2) This paragraph allows the rerating of standard flanges to the design requirements of UG-34 for blind flanges or to Appendix 2 for raised-face flanges. This means that if the design rules of UG-34 or Appendix 2 provides a greater flange rating than that specified in ASME B16.5, the greater rating may be used. Note that, quite often, the ASME B16.5 Standard flanges do not meet the ASME special-design rules.

UG-22 This paragraph states that external loads must be considered in addition to pressure and temperature ratings. The Code requires the consideration of external loads; however, it provides no guidance on the subject, leaving the designer to establish a design in accordance with paragraph U-2(g) that is equivalently safe. A later section discusses this subject in detail.

UG-34 This paragraph addresses the design rules for unstayed flat heads (blind flanges). Blind flanges or flat heads are designed as flat plates under pressure, with edge moments from the bolt and gasket reactions.

Appendix 2 This appendix addresses the design rules for bolted flange connections with ring-type gaskets. Ring-type gaskets are shaped like circular rings, and there is a wide range of construction types, including spiral-wound, sheet, corrugated metal, metal grooved or profiled, jacketed, solid-metal, oval, and hexagonal. The flange facings are raised-face or ring-joint where they only contact the gasket.

Appendix 24 This appendix addresses the design rules for clamp connections. Clamp connections, including the type commonly called the *Greyloc style flange*, require gaskets that are pressure-energized or gaskets that contain low-seating stress.

Appendix Y This appendix addresses flat-face flanges with metal-to-metal contact outside the bolt circle. These flanges are intended for use with self-sealing or low seating–stress gaskets, such as O–ring–type gaskets.

Appendix S This appendix addresses the design considerations including thermal effects for bolted flange connections. It discusses flange assembly bolt stress explaining why it is necessary to assemble a flange to bolt stress levels in excess of the Code-allowable bolt stress, and it provides a formula for "typical" bolt stress levels achieved by manual tightening. The nonmandatory requirements on flange rigidity have been moved to the mandatory requirements in Appendix 2. When a dual set of allowable stress values are listed for a material, the lower values are recommended in flange design. As the mechanisms and material properties contributing to flange leakage are complex, they are discussed further in a later section.

Section II, Part D The allowable stresses for flanges, necks, and bolting are contained in Section II, Part D. Note that in 1999 the Code revised its allowable stress basis from a design factor of 4.0 to a design factor of 3.5. This new allowable stress basis also applies to flanges, although the original Code Case did not allow the use of the increased allowable stresses for flanges. Note that the bolting allowable stress values did not change.

9.3.2 ASME Section VIII, Division 2

ASME Section VIII, Division 2 contains Alternative rules for pressure vessel design. Division 2 allows higher allowable design stress than Division 1, however it requires tighter quality control and engineering design requirements. This division was entirely rewritten for the 2007 Edition to include modern analysis methods and to take better advantage of material strength. The Division 2 allowable stresses below the creep range are based on the lesser of the specified minimum tensile strength at room temperature divided by 2.4 or the specified minimum yield strength divided by 1.5.

Allowable stress values are also provided above the temperature where creep strength governs design. Division 2 pressure vessels are typically specified for high pressure applications where the higher design allowable stresses provide economic advantage over Division 1, in addition to the quality advantages. Flanges may be designed by analysis, in accordance with Part 5, considering all operating conditions and utilizing the applicable allowable stress values, or designed by the formulas provided in Part 4. However, the basic formulas and stress limits for flange design in accordance with Part 4 are essentially the same as Division 1, however the allowable stresses differ.

The Division 2 approach to flange design is very similar to Division 1 in that referenced standards are allowed and special design rules are provided for non-standard flanges. However, Division 1 only provides a design by formula approach, whereas Division 2 allows either design by analysis or design by formula. The following lists the pertinent paragraph references addressing flange design.

4.1.11.1 Lists ASME B16.5, B16.24 and B16.47 to be acceptable flange standards for use in Division 2. Paragraph 4.16.1.3 recommends these standards for connections to external piping.

4.1.11.3 Provides criteria for the design of forged nozzle long weld neck flanges.

4.6 Provides design rules for flat (unstayed) heads, both circular and non-circular (e.g. manway covers and blind flanges).

Part 4 Paragraph 4.16 of Part 4 provides rules for the Design of Bolted Flange Connections with Ring Type Gaskets. (Note: the design methodology is essentially the same as ASME Section VIII Division 1, Appendix 2). Flange types include the integral weld neck type, as well as the loose type including slip-on and lap joint type flanges.

However, the allowable stress values for flange design, including bolts, differs from Division 1. External forces and moments are also included in the design basis, which is not currently addressed in Division 1.

Part 5 When analysis by Part 5 is required, including fatigue, the analysis rules and allowable stresses of Division 2, Part 5 apply. However, paragraph 5.7.1 requires that the number and cross-sectional area of the bolts required to resist the design pressure be determined in accordance with the design by formula procedure of 4.16, and the Division 2 Bolting allowable stresses specified in Part 3. The actual service stresses in bolts, due to preload, pressure, and differential expansion, may exceed the allowable bolt stresses given in the applicable Section II, Part D tables. The maximum membrane stress intensity in the bolts shall not exceed two times the Part 3 allowable stress, and the maximum membrane plus bending stress intensity is limited to three times the Part 3 allowable stress. See paragraph 5.7.2 for additional discussion on the allowable maximum service stress limits in bolts. When the bolts are tightened by means that result in residual torsion, the stress due to torsion must be considered in the determination of the equivalent stress in equation 5.1.

The flange stresses are evaluated by the Part 5 rules. The flange stresses due to internal pressure, external primary loads, and the minimum gasket stress required to maintain a seal, as defined by the Code gasket "m" factor, should be classified as primary. Actual flange service stresses, produced by the combination of cold pre-load, pressure, external loads, including those due to restrained thermal growth, and differential thermal expansion, should be classified as primary plus secondary. Flange stresses are predominantly bending and primary bending stresses are limited to 1.5 S while primary plus secondary bending stresses are limited to 3S (S is the applicable Division 2 allowable stress). See paragraph 5.1.1.3 for a discussion of when the allowable stress values from Annex 3.A are governed by time dependent properties.

9.3.3 ASME Section VIII Division 3

Although ASME Section VIII, Division 3 (*High-Pressure Vessels*) is intended for use at pressures generally greater than 10,000 psi, this limit is neither a minimum requirement for Division 3 nor a maximum limit for Divisions 1 or 2. ASME B16.5 flanges are not referenced because the intended pressure ratings are well above those included in the standard. Flange connections are generally of a special design.

KD-601 This paragraph requires a complete stress analysis of all components that contribute to the strength and sealing capabilities of the closure.

KD-621 This paragraph states that the required bolting area shall be such that the primary membrane stress intensity at the thread-root diameter shall be limited to the yield stress divided by 1.8 unless the bolt shank is less than 0.9 times the thread-root diameter, in which case the limit shall be the yield stress divided by 1.5.

Primary-plus-secondary membrane stress intensity in the bolts shall not exceed 0.75 times yield. Primary-plus-secondary membrane plus bending stress intensity shall not exceed yield.

Appendix G This is a nonmandatory appendix covering the design rules for clamp connections. This type of connector carries the axial pressure thrust by shear and bending in the external clamp. Pressure-energized or low seating–load gaskets are recommended, and the hub faces should be in metal-to-metal contact outside of the gasket-seal diameter. This appendix is similar to Appendix 24 of Section VIII, Division 1, and it is based on the same technical analysis.

9.3.4 ASME Section I

ASME Section I (*Power Boilers*) does not address flange design to the same extent as Section VIII. The use of flanges in accordance with the listed standards is allowed; however, no rules are provided for nonstandard flanges.

PG-3 This paragraph discusses referenced standards. It allows the use of Code-referenced standards and refers to Appendix A-360 for specific editions of these referenced standards.

Appendix A-360 Table A-360 of this appendix lists the following standards and reference dates:

(1) B16.5—2009
(2) B16.1—2005
(3) B16.20—2007
(4) B16.42—1998 (for Ductile Iron)

Table A-361 This table contains the maximum allowable working pressure (MAWP) for B16.5 flanges—specifically, the MAWP for steam service at saturation temperature and the MAWP for boilerfeed- and blowoff-line service.

PG-31 This paragraph discusses unstayed flat heads and covers and provides design rules for flat heads and blind flanges. Gasket-seating requirements require the design-bolt load *W* to be based on the average of the required and actual bolt areas. The operating case requires that the flange be designed for the pressure thrust plus the required gasket force for tightness. However, no guidance is provided for the required force for tightness. It is assumed that the required operating gasket force Appendix 2 of Section VIII, Division 1 would be acceptable.

PG-59.1.1.2 In this paragraph, bolted joints, including Van Stone (lap joint) flanges, are allowed for the attachment of piping to boiler outlets.

PG-42.1 This paragraph discusses the applicable ASME Standards. It requires flanges (except those supplied as miscellaneous pressure parts under PG-11) to be in accordance with the listed standards in PG-42.1.

PG-42.4.4 This paragraph allows the use of ASME B16.5 pressure–temperature ratings.

PG-42.4.5 This paragraph states that when the pressure–temperature requirements exceed those given in ASME B16.5, the Code requirements are met if the bolting and flange thicknesses are increased so that the flange rotation and flange stresses are less than or equal to those of the nearest B16.5 pressure-rating class.

PG-42.4.7 This paragraph provides limitations for slip-on flanges.

PG-42.4.8 This paragraph provides limitations for socket-welded flanges. It is a general paragraph that allows the use of ASME Section VIII, Division 1 rules for design of nonstandard flanges and also references the use of ASME B16.5 flanges within their pressure–temperature ratings.

9.3.5 ASME Section III

The Section III rules contain provisions for design by the use of referenced standards and provisions for design-by-analysis and design-by-formula approaches similar to those of Section VIII. Section III, Class 1 uses a design-by-analysis approach, whereas Section III, Classes 2 and 3 (including Classes 2 and 3 allowable stresses) use the Appendix XI design-by-formula approach. The design-by-formula approach is similar to that of Section VIII, Division 1 except that external moments are included with an error, in the author's opinion; the longitudinal membrane stress from pressure is added to the hub-bending stress; an additional bolt-stress calculation is added; and the allowable stress limits differ.

9.3.5.1 Section III, Class 1 Components The following is a tabulation of the significant paragraph references that address flange design in Section III, Class 1 components, including both vessels and piping.

NB-3132 This paragraph requires that standard products comply with the listed standards in Table NB-3132-1. The listed standards include B16.5 (for flanges); however, these flanges are not exempted from the stress analysis requirements. For example, if a fatigue analysis is required, a standard B16.5 flange would also be required to meet the fatigue requirements.

NB-3200 Design by analysis is required for thermal loads and cyclic fatigue analysis. Class 1allowable stresses apply. See NB-3222.4 for components that do not require a fatigue analysis.

NB-3222 This paragraph provides the following equation that addresses flange stress limits for pressure + gasket compression + bolt loads + piping loads:

$$P_L + P_b + P_e + Q < 3S_m$$

Note: The P_e classification for external loads from restrained differential expansion (such as from attached piping) does not apply to vessels.

NB-3226 This paragraph addresses testing. Primary stress limits are imposed to limit the potential for yielding and deforming the vessel during pressure testing.

$$\text{For} \quad \begin{matrix} P_m < 0.67S_Y \\ P_m + P_b < 1.35S_Y \end{matrix}$$

Bending limits are reduced when the membrane limit exceeds, $.67S_y$

NB-3227.4 This paragraph addresses triaxial stress limits. The Code limits the sum of principal stresses to less than $4S_m$, where S_m is the basis Code-allowable stress.

$$\sigma_1 + \sigma_2 + \sigma_3 < 4S_m$$

Triaxial stress limits are imposed to limit the hydrostatic stress and guard against the potential for brittle fractures caused by constraint. This situation can arise in heavy-wall vessels at locations of geometric discontinuity.

9.3.5.2 Section III, Class 1 Bolting

NB-3230 The required bolt area shall be in accordance with Appendix E (based on m, y, and pressure similar to Section VIII). Allowable stresses shall be in accordance with Section II, Part D, Subpart 1, Table 4 for Section III, Class 1—same for Section VIII, Division 2, Appendix 4 (Design by Analysis).

NB-3232 This paragraph addresses Levels A, B, and C stress limits. Bolt-operating-service stresses may exceed S_m; however, the maximum membrane stress is limited to $2S_m$, and the membrane plus bending stress is limited to $3S_m$.

NB-3232.3 This paragraph addresses fatigue analysis of bolts.

(1) Tensile strength <100 ksi:

$K_T >$ = 4 (unless demonstrated by analysis or test data)

(2) Tensile strength > 100 ksi:

$$K_T > = 4$$

The maximum stress intensity from membrane plus bending $<2.7S_m$ (if the higher curve in I-9.4 is used). The threads shall be V-type with a root radius > = 0.003 in. and the ratio to the shank diameter > = 0.06.

9.3.5.3 ASME Section III Class 1 Piping The following paragraph references apply to flange design for ASME Section III, Class 1 piping systems.

NB-3647 This paragraph addresses pressure design. It allows the use of pressure–temperature ratings of listed standards. Therefore, ASME B16.5 flanges may be used within their pressure–temperature ratings without additional analysis. Nonstandard flanges are designed in accordance with Appendix XI (similar to Section VIII) using Classes 2 and 3 allowable stresses.

NB-3658 This paragraph provides limits on the external bending moments on flange joints during operation based on the flange yield strength and the bolt area. Bending and torsion are considered separately. The technical basis for this requirement is the allowable stress limits for bolts. In accordance with NB-3232, the bolt membrane stress is allowed to be as high as $2S_m$, considering all of the operating stresses on the joint. If the bolts are assumed to react to the externally applied moment, and half of the allowable bolt stress of 25,000 psi is available for moment loading, the following equation can be derived:

$$M_{fs} < = 3{,}125(S_y/36{,}000)C \times A_b$$

The yield-strength ratio (S_y/ 36,000) compensates for the effect of temperature on the flange-allowable stress.

An example is a 12 in. SA105 carbon-steel, Class 600, B16.5 flange, where the

bolt-circle diameter, C = 19.25 in.
number of bolts = 20

bolt diameter = $1\frac{1}{4}$ in.
bolt-root area = 0.929 in.^{2}
flange yield strength, S_y = 36,000 psi
$A_b = 20 \times 0.929 = 18.58$ in.^{2}

The maximum bending moment for service loads is as follows:

M_{fs} = 3,125 (36,000/36,000)(19.25)(18.58)
M_{fs} = 1,117,700 in.-lb

9.3.5.4 Section III, Class 2 Vessels

NC-3262.1 This paragraph states that flanges to external piping shall be in accordance with ASME B16.5.

NC-3262.2 This paragraph states that slip-on flanges in accordance with ASME B16.5 are acceptable if the following conditions are met:

(1) the specified minimum tensile strength is < = 80 ksi;
(2) the percent of elongation > = 12%; and
(3) the neck thickness < =1.25 in.

NC-3262.3 This paragraph states that flanges not in accordance with ASME B16.5 shall meet the bolted-flange rules of Appendix XI (similar to Section VIII).

NC-3262.4 This paragraph states that the studded connection–thread engagement length > the bolt diameter.

9.3.5.5 Section III, Class 2 Piping

NC-3658.1 This paragraph states that design for flanges in Class 2 piping systems shall be in accordance with Appendix XI except for standard flanges meeting the requirements given here. External moments are accounted for by using an equivalent pressure in the calculation of H, as defined in Appendix XI, and the pressure used in the equation for H is replaced by a total equivalent pressure, P, where

$$P' = P + P_{eq}$$
$$P_{eq} = 16M/\pi G^3 \text{ (psi)}$$
$$P = \text{design pressure (psi)}$$
$$G = \text{gasket diameter (in)}$$

The total end thrust from pressure is H. When the total equivalent pressure is used to compute H, the bending moment is treated as though it were an equivalent axial force acting on the flange. (Note: This is not the same as what is commonly called the *equivalent-pressure method.*) The equivalent axial force is the force that produces an axial stress in the pipe equal to the maximum stress from the bending moment. The author feels that the Code should have required the calculation of both H and H_D in Appendix XI to use the total equivalent pressure.

NC-3658.2 This paragraph addresses standard flanges for low pressure (less than 100 psi) and low temperature (less than 200°F). Such flanges are acceptable if the moments are limited to the following:

$$M < = A_b CS/4$$
$$C = \text{the bolt circle diameter (in)}$$
$$S = \text{the bolt allowable (psi)}$$

NC-3658.3 This paragraph addresses ASME B16.5 flanges with high-strength bolting, in which the allowable bolt stress > = 20,000 psi. Standard flanges are acceptable for Levels A and B operating loads if the external moments (where bending and torsion are each considered separately) are limited to the following:

$$M_{fs} < = 3{,}125(S_y/36{,}000)C \times A_b$$

Refer to the discussion in Section 9.3.5.3 on NB-3658 for the basis and an example problem.

9.4 FLANGE DESIGN FOR PIPING

A summary of the flange-design requirements contained in the Piping Design Codes is presented.

9.4.1 ASME B31.3, *Process Piping*

Similar to Section VIII, ASME B31.3 listed Standards are accepted and design rules are provided for nonstandard flanges. There are three design options:

(a) Paragraph 302.2.1: This paragraph allows the use of flanges in accordance with approved Standards listed in Table 326.1. The approved edition dates are in Appendix E. The "Latest Edition" is now specified for ASME flange standards. Note that this differs from the BPV Codes for vessels that lists an approved date that may lag the Latest Edition. The extension of pressure–temperature ratings by Code Rules is allowed as well.
(b) Paragraph 304.7.2: Flanges not in accordance with a listed standard or the design rules of ASME Section VIII, Division 1 shall be qualified in accordance with paragraph 304.7.2. This paragraph is for the qualification of unlisted components and requires calculations supported by one of the following:
  (1) extensive successful experience;
  (2) physical testing; or
  (3) detailed stress analysis, such as finite-element analysis, in accordance with ASME Section VIII, Division 2.
(c) Paragraph 304.5: Design in accordance with ASME Section VIII, Division 1, using allowable stresses in ASME B31.3.

F312 This paragraph recommends that external loads and the application of thermal insulation be considered in design. ASME B31.3 does not provide any guidance on the analysis for external loads; that is left to the designer. (External loads are addressed further in a later section.) External thermal insulation must be considered in design because the designer may have taken advantage of the temperature reduction and corresponding increase in allowable stress for uninsulated flanges (see the following entry on paragraph 301.3.2). Insulating those components could put them over their pressuretemperature rating.

301.3.2 This paragraph allows temperature reduction for uninsulated flanges. The Code allows the following reductions in temperature (as a percentage of the fluid temperature) for the design of flange joints that are not insulated during operation:

(1) 90% for weld neck and slip-on;
(2) 85% for lap joint; and
(3) 80% for bolting.

For example: If the process fluid is l,000°F and the flange joint is uninsulated, the weld neck flange may be designed for 900°F and the bolts for 800°F without the need to perform any detailed heat-transfer calculations. Field data indicate that the foregoing reductions are conservative for high-temperature applications.

The Code also allows the use of field measurements on similar flanges in comparable operating conditions and the use of detailed heat-transfer calculations.

302.2.4 This paragraph allows pressuretemperature variations over the design by as much as 33% if they are approved by the Owner. This section of the Code contains provisions to exceed the pressuretemperature design conditions of piping components for short-term events. Infrequent high-temperature operating conditions, such as a regeneration case, are allowed if the conditions occur within specified time limits. This means that although flange joints may also be subjected to these increased conditions, the flange rating is not required to be increased. The designer must ensure that the flange, bolting, and gasket materials are suitable for the higher-temperature conditions, as well as ensure the tightness of the joint.

306.4 This paragraph provides rules and limitations for the design of laps for lap-joint flanges.

Appendix L This appendix discusses flange pressure–temperature ratings for aluminum. Flanges may be designed in accordance with ASME B16.5 dimensions for the classes specified in this appendix. Note that Appendix L is based on Code Case 141, which provided the pressure–temperature rating basis before the flanges were incorporated into the Code. Class 150, 300, and 600 ratings are given for 3003-H112 and 6061-T6 aluminum alloys for Group 1A gaskets in ASME B16.5.

These ratings, however, have been the source of some controversy. In 1994, the ASME B31.3 *Process Piping* Code Committee surveyed members and Users on field problems with aluminum flanges. The survey did not uncover any significant problems with aluminum flanges that were designed in accordance with ASME B16.5 dimensions and ratings. The primary use of aluminum flanges has been in cryogenic service because of the good ductility of aluminum at low temperature. The concern is that aluminum contains approximately one-third the elastic modulus of steel—a condition that results in about three times the flange rotation for the same flange design and bolt stress. Aluminum has more than three times the thermal conductivity, four to five times the thermal diffusivity, and nearly two times the thermal expansion of carbon steel, making the aluminum flange more sensitive to temperature changes. The conclusion of the Code Committee was that the Appendix L pressure–temperature ratings were adequate. Nevertheless, designers should be aware of the sensitivity of aluminum flanges to temperature change and greater rotation.

Chapter IX (High-Pressure Piping) Special design rules are provided for piping designed for pressure in excess of ASME B16.5, Class 2500 pressure ratings. This piping may be used with pressure vessels designed in accordance with ASME Section VIII, Division 3.

K304.5.1 Flanges may be designed in accordance with Section VIII, Division 2, Appendix 3 (2006 Edition. This section will be updated to reference the 2007 Edition of Division 2) or to Section VIII, Division 3, Article KD-6. Section VIII, Division 3 requires a complete stress analysis of the flange closure, including displacements on the seal, and does not provide formulas for other than clamp-type connections.

Alternatively, flanges may be qualified by meeting the requirements of paragraph K304.7.2 for unlisted components and elements. K304.7.2 requires that the design be based on calculations consistent with the design philosophy of Chapter IX, substantiated by either extensive, successful service experience or performance testing for both static-pressure design and fatigue strength at the intended operating conditions. Interpolation between previously qualified components is acceptable if it is supported by analysis.

9.4.2 ASME B31.1, *Power Piping*

Similar to ASME B31.3, listed standards in ASME B31.1 are accepted and design rules are provided for nonstandard flanges. There are three design options:

(a) Design by the use of referenced standards in Table 126.1 with the approved edition and addenda dates given in Appendix F.
(b) Special design in accordance with Section VIII, Division 1.
(c) The design of flanges not in accordance with listed standards in Table 126.1 and of a design not covered by the rules of Section VIII, Division 1 may be qualified by the provisions of paragraph 104.7.2. This paragraph is for the qualification of unlisted components that have geometries not conforming to the Section VIII, Division 1 rules—odd-shaped flanges and proprietary designs, for example—and require calculations supported by one of the following:
  (1) extensive successful experience;
  (2) physical testing; or
  (3) detailed numerical calculations, such as finite-element analysis.

104.5 In this paragraph, flanges $<$ = 24 NPS (nominal pipe size) in accordance with ASME B16.1 and B16.5 are allowed to be used within their listed ratings, except that ASME B16.5 slip-on flanges are limited to Class 300.

Users are cautioned for flanges NPS $>$ 24 using the ASME B16.47 flange standard since there is the option to select either series A or series B dimensional standards and they are not compatible.

The design of nonstandard flanges shall be in accordance with Section VIII, Division 1 using flange-allowable stresses from ASME B31.1 and bolting-allowable stress basis from Section VIII, Division 1. The rules of Section VIII, Division 1 are used for design, and the requirements of ASME B31.1 are used for fabrication, assembly, inspection, and testing.

108.5 This paragraph provides bolting requirements, including nuts, washers, and threading. Bolting, including studs, nuts, and washers, shall be of forged or rolled material and designed in accordance with standards listed in Table 126.1. Threading shall be of the coarse-thread series except that alloy-steel bolting $1\frac{1}{8}$ in. and larger shall be of the 8-pitch-thread series.

Table 112 This table provides flange bolting, facing, and gasket requirements.

9.4.3 ASME B31.8, *Gas-Transmission Piping*

Flange design is by referenced standards with reference dates as shown in Appendix A.

831.2 This paragraph permits the following:

(1) Lapped flanges in accordance with ASME B16.5.
(2) Slip-on flanges in accordance with ASME B16.5. (Rectangular flanges may be substituted for hubbed flanges if calculated in accordance with ASME Section VIII.)
(3) Weld-neck flanges in accordance with ASME B16.5 or MSS SP-44.
(4) Contact faces shall be in accordance with MSS SP-6 except that ANSI B16.24 shall be used for nonferrous flanges.

(5) Guidance on external moments has been added to the Notes to Table E1:

External moment to produce leakage may be estimated from the following equation.

ML = (C/4)(Sb Ab – P Ap)
Ab = Total bolt area (in^2)
Ap = Pressure thrust area to outside of gasket contact (in^2)
C = Bolt Circle Diameter (in)
P = Internal Pressure (psi)
Sb = Bolt stress (psi)

9.4.4 ASME B31.4, *Liquid-Transmission Piping*

Design is allowed in accordance with the listed standards in Table 426.1.

9.4.5 This paragraph

(1) allows listed standards to be used;
(2) allows design in accordance with Section VIII, Division 1; and
(3) requires the use of Section VIII, Division 1 to validate the use of rectangular slip-on flanges.

9.5 FLANGE STANDARDS

The most commonly used flange standards referenced by the ASME are ASME B16.5, used for flanges less than 24 in. nominal pipe size (NPS), and B16.47, used for the larger-sized flanges.

9.5.1 ASME B16.5, *Steel Pipe Flanges and Flanged Fittings*

ASME B16.5 addresses flanged fittings of NPS $\frac{1}{2}$ in. –24 in. Flange classes 150, 300, 400, 600, 900, 1500, and 2500 are also addressed. (Note: Class 400 is not commonly used in the industry and deleting the class from the standard has been discussed by the committee.) ASME B16.5 provides dimensional standards for individual flange classes and pressure versus temperature-rating tables for the classes covered. In addition, the standard specifies the materials used for the flanges and bolts, and it includes fabrication requirements such as dimensions, tolerances, and weld-bevel details.

Because the flange-joint design is also dependent on the bolts and gasket, ASME B16.5 therefore includes requirements for the allowed bolting as well as gasket types and dimensional requirements. Flanges that are addressed include weld-neck, slip-on, lapped, threaded, socket-welding, and blind types. Flange facings include raised-face, ring-joint, male–female, and tongue-and-groove types.

Limitations are as follows:

(1) Threaded and socket-welding flanges are not recommended at temperatures above 500°F or below −50°F.
(2) External forces and moments are not considered in the pressure ratings.
(3) Caution must be used for Class 150 flange joints at temperatures >400°F, and Class 300 and greater joints at temperatures >750°F.
(4) Ratings are for use with specified gaskets.
(5) Bolting-temperature limits shall be in accordance with the governing Code. The temperature limits in the Pressure Vessel or Piping Codes for the specified bolts may be less than the maximum temperature listed in the rating tables of ASME B16.5.
(6) Alloy-steel-stud bolts, threaded at full length with a nut at each end, are recommended for high-temperature service. Threading for alloy-steel bolting shall be in accordance with ANSI B1.1, with nominal diameters 1 in. and smaller of the coarse-thread series and $1\frac{1}{8}$ in. and larger of the 8-pitch-thread series. Bolts shall have a Class 2A thread; nuts, Class 2B thread.

9.5.2 ASME B16.47, *Large-Diameter Steel Flanges*

ASME B16.47 addresses flanges of NPS 26 in. 60 in. Series A includes MSS SP-44 in Classes 150, 300, 400, 600, and 900; Series B includes API 605 in Classes 75, 150, 300, 400, 600, and 900.

9.5.3 Gaskets

The ASME Pressure Vessel and Piping Codes do not provide specific guidance on how to select the correct gasket for a specific application; doing so is the responsibility of the User. The flange standards, such as ASME B16.5 and B16.47, are based on certain gasket types and dimensions as specified in the standard. Some gasket-design issues are as follows:

(1) Gasket type and characteristics—density, flexibility, creep, suitability for the process and temperature, and so forth.
(2) Gasket properties for design—PVRC gasket constants and ASTM Standard tests.
(3) Reference to a dimensional standard, such as ASME B16.21, is Recommended.
(4) Ring joint gasket materials shall conform to ASME B16.20. Materials for other gaskets shall be in accordance with ASME B16.5 ANNEX C.

9.6 FLANGE-DESIGN METHODS

9.6.1 ASME Design Methodology

The design-by-formula approach used by the ASME Codes is based on the same methodology for all of the ASME Code sections that provide specific design rules for raised-face flanges. ASME Section VIII, Division 1, Appendix 2 provides the basis that is described in more detail in the following section. ASME Section VIII, Division 2 and ASME Section III, Appendix XI also provide detailed design rules, but because they are nearly identical to Division 1, the discussion of the Division 1 rules also applies to the other Code sections. The differences between the Code sections are noted in other sections of this chapter.

The technical-basis and design-rule discussions initially focus on raised-face flanges, as they are the type most commonly used. Flanges with metal-to-metal contact outside of the bolt circle, as well as clamp-type flanges, are also discussed in a later section. The three flange designs are each based on independent design methods requiring individual discussion.

9.6.1.1 Historical Background and Technical Basis The historical summary and bibliography on the methodology used to design bolted-flange joints is given by Blach and Bazergui [2]. The earliest methods in bolted-flange design used beam-flexure approaches; however, in 1927 Professors Waters and Taylor developed the first “exact” method for the analysis of bolted-flange joints by using plate theory and beam on an elastic foundation

analysis of flanges [3]. Waters, Rossheim, Wesstrom and Williams took on the task for the development of the critical design method for taper-hub Flanges. A condensed version of the method was published in 1937 [4] and was later published as a technical bulletin from Taylor Forge in 1949, and was later reprinted by the Pressure Vessel Research Council (PVRC) as a classic in flange design known as the *red book.* The Waters et al. method, which included taper-hub flanges, was adopted by the ASME Codes and Standards as the technical basis and the standard method for bolted-flange-joint design. Figure 9.1 illustrates the analysis considered by the Waters, et al. method. The flange ring is modeled as an annular plate, using Kirchoff's plate bending equations, and the hub elements by thin shell theory. The gasket factors m and y first appeared in the 1942 ASME Code. Some basis for the Code m-and y-gasket factors was contained in an article written by Rossheim and Markl in 1943 [5]. The authors recognized that the m-factor for gasket stress (required to maintain a seal under operating pressure) increased as the initial bolt load decreased, for which reason they proposed an empirical equation relating m and y: $y = 180(2m = 1)^2$. Although many of the m-and y-factors in the Code today agree with their simplified empirical equation, it was recognized that more research was required to develop appropriate gasket factors. Because an improvement was needed, a program was initiated by the PVRC in 1974 [6] to study the problem. The conclusion was that an improved methodology was needed over the existing m-and y-gasket factors and that a better understanding of gasket-joint behavior was also needed. The test program that followed led to the methodology known today as the *PVRC method* that is currently under consideration as an alternate method to flange design in the ASME Boiler and Pressure Vessel (B&PV) Code. The new methodology introduces the concept of joint tightness, thereby recognizing that all joints have some predetermined leak rate that can be determined by design.

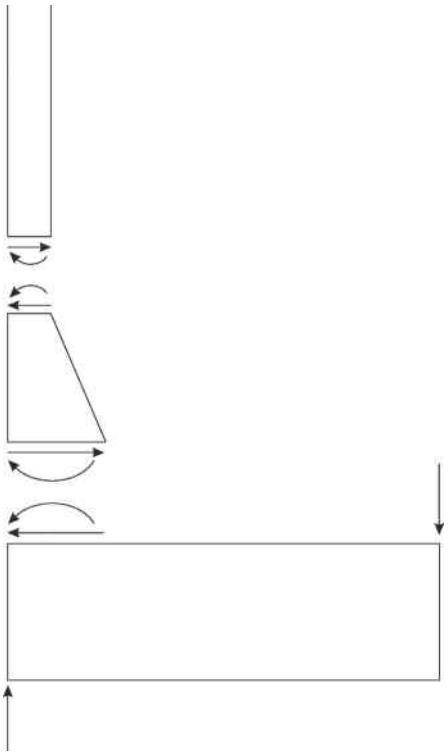


FIG. 9.1 FLANGE DISCONTINUITY ANALYSIS

9.6.1.2 Scope and Design Philosophy The scope of the ASME flange design rules contained in Section VIII, Division 1, Appendix 2 is for bolted-flange connections with ring-type gaskets located entirely within the bolt circle. The raised-face-flange design is intended to avoid contact of the flanges outside of the bolt circle. Appendix Y addresses flanges with metal-to-metal contact outside of the bolt circle; in this chapter, Section 9.6.1.4 discusses flat-face flanges with full-face gaskets.

The current Code methodology includes the following features:

(1) The rules are not applicable to integral tubesheets.
(2) The external loads must be addressed independently, as Appendix 2 does not provide specific design requirements.
(3) The gasket-seating requirements must be met.
(4) The operating case requires maintenance of a minimum gasket stress.
(5) The methods not based on actual loads, for which design loads are used to proportion the flange.
(6) The external loads not explicitly included.

9.6.1.3 Flange Types The flanges addressed by the ASME include raised-face and ring-joint flanges using ring-type gaskets, flanges with metal-to-metal contact outside of the bolt circle, and clamp-type connections. The raised-face and ring-joint flanges addressed by the ASME include weld-neck (integral), slip-on, lap-joint, threaded, reversed, optional, flat-head, noncircular, and split-ring types. The most recent Code addenda includes both integral-type and loose ring–type reverse flanges. Design rules for the specific flange types are discussed in the following sections.

9.6.1.3.1 Raised-Face and Ring-Joint Flanges Using Ring-Type Gaskets Raised-face flanges have a facing surface, upon which the gasket sits, extends $\frac{1}{16}$ to $\frac{1}{8}$ inch beyond the face of the flange ring to ensure that the flange rings do not contact one another (other than at the gasket face) from the bolt-clamping forces. This, in turn, ensures that no metal-to-metal contact outside of the bolt circle occurs. Flanges with metal-to-metal contact outside of the bolt circle are covered in a later section.

The rules and nomenclature of Section VIII, Division 1, Appendix 2 will be followed in the forthcoming sections because the rules in Section VIII, Division 2, Appendix 3 and in Section III, Appendix XI all have the same basis.

The flanges discussed in this section include weld-neck (integral), slip-on, lap-joint, threaded, reversed, optional, flat-head, noncircular, and split-ring types. The following nomenclature, moment arms, gasket-effective-seating width, flange forces, and parameters apply to all flange types. The details of the specific flange types are discussed in later sections.

One important design issue is how corrosion allowance is addressed by the ASME Code. All design calculations are done in the corroded condition, and corrosion allowance is added on after the design is complete.

The geometry nomenclature is as follows:

B = the inside diameter of the flange (note that if $B < 20g_1$, an optional value for B may be used)
A = the outside diameter of the flange
C = the bolt-circle diameter
G = the diameter of the gasket-load reaction
g_0 = the thickness of the hub at the small end
g_1 = the thickness of the hub at the back of the flange
R = the radial distance from the bolt circle to the point of intersection. Of the hub and back of the flange, it is $R = 0.5 (C - B) - g_1$.

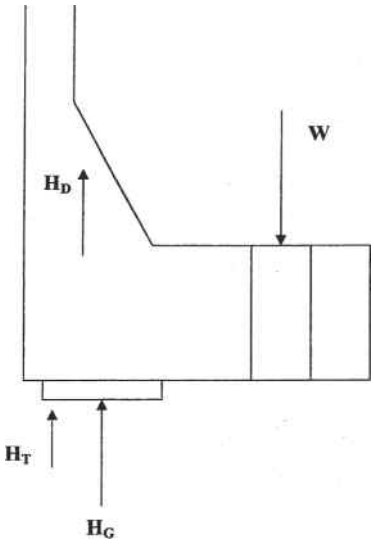


FIG. 9.2 FORCES ACTING ON A FLANGE JOINT

(*a*) *Moment Arms for Flange Loads* As illustrated in Figs. 9.2 and 9.3, the forces acting on a flange result from internal pressure and the gasket-reaction force. These applied forces, multiplied by moment arms, create a twisting moment on the flange, causing it to rotate outward. The moment arms for the various flange types are summarized in Table 9.2. Recall that the Code approach uses total moment in the design equations rather than moment per unit length of circumference, as the flange is an axisymmetric structure. The diameter appears in the denominators of the stress equations to convert the total moment into a moment per unit length.

(*b*) *Effective Gasket-Seating Width* Because of flange rotation, the actual gasket stress is greater than the nominal. The "effective" width of the gasket, *b*, is calculated in accordance with Table 2-5.2 of Section VIII, Division 1, Appendix 2 (given here as Table 9.3) for the various flange facings that may be used. The determination of *b* for the most common type gasket (sketch 1a) applicable to sheet-type, jacketed, or spiral-wound gaskets is as follows:

N = the nominal gasket contact width
$b_o = 0.5N$

$$\text{If } b_o <= 0.25 \text{ in., then } b = b_o$$
$$\text{If } b_o > 0.25 \text{ in., then } b = .5\sqrt{b_o}$$

(*c*) *Gasket-Load Reaction* Because of flange rotation, the gasket-load reaction may not act at the center of the gasket. The Code provides rules to determine the effective diameter where the gasket-reaction force acts.

If $b_o <= 0.25$ in., then G = the mean diameter of the gasket face
If $b_o > 0.25$ in., then G = the outside diameter of gasket contact face less $2b$

TABLE 9.2 THE MOMENT ARM

Flange Type	h_D	h_T	h_G
Integral	$R + .5g_1$	$.5(R + g_1 + h_g)$	$.5(C - G)$
Loose	$.5(C - B)$	$.5(h_D + h_G)$	$.5(C - G)$
Lap Joint	$.5(C - B)$	$.5(C - G)$	$.5(C - G)$

Note: All dimensions in corroded condition

(*d*) *Forces* Refer to Figs. 9.2 and 9.3 for the forces acting on a flange joint. The flange must resist both internal pressure and gasket-reaction forces. External loads are not directly addressed by the ASME.

P = the internal pressure
W = the flange-design-bolt load
= W_{m1} (for operating conditions)
= $0.5 \times (A_m + A_b) \times S_a$ (for gasket seating; it provides for abuse)
H_D = the hydrostatic end force
= $0.785B^2P$
H = the total hydrostatic end force
= $0.785G^2P$
$H_T = H - H_D$
H_G = the gasket load
= $W - H$

(*e*) *Required Bolt Loads* The required bolt loads are determined from the force required to react the axial thrust from internal pressure and the gasket-reaction forces. Two cases must be considered in design: *gasket-seating* and *operating* cases. The gasket-seating case is based on a required initial cold-bolt-up gasket stress to "seat" or compress the gasket to a level sufficient to make a seal. The gasket-seating stress, *y*, is based on a gasket-effective width, *b*, and is a function of the gasket type from Table 2-5.1 of Section VIII, Division 1, Appendix 2, given here as Table 9.4.

During operation, the application of internal pressure causes the gasket to unload; therefore, a minimum gasket stress is required during operation. The Code requires that a gasket stress equal to a factor *m* multiplied by the internal pressure be maintained on the gasket during operation. The gasket width over which this gasket stress is assumed to act is equal to 2*b*. Note, however, that in actual application the gasket stresses and associated bolt stresses typically exceed these design values—a matter discussed further in Section 9.9.1 on Appendix S.

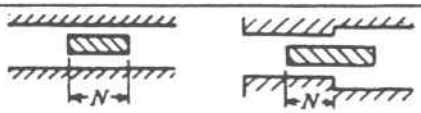
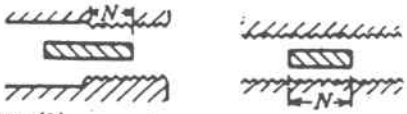
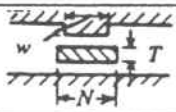
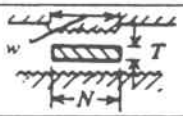
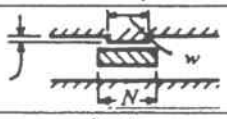
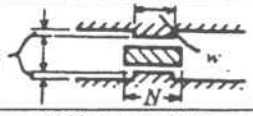
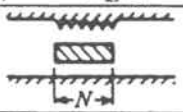
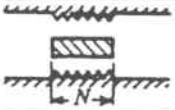
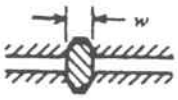
y = the gasket-seating stress
W_{m2} = the minimum required bolt load for gasket seating
= $3.14bG_y$
m = the gasket-operating factor
W_{m1} = the minimum required bolt load during operation
= $H + H_p$
= $0.785G^2P + (2b)(3.14G_mP)$

(*f*) *Required Bolt Area*

S_a = the allowable bolt stress, *a*, 70°F
S_b = the allowable bolt stress at the design temperature
A_{m1} = the required bolt area for the operating case
= W_{m1}/S_b
A_{m2} = the required bolt area for gasket seating
= W_{m2}/S_a

The required bolt area, A_m, is the greater of A_{m1} and A_{m2}, and A_b = the actual bolt area selected. This bolt area is based on the root area of the threads. (Note that this is not the same as the "stress area," which is typically greater.) The coarse-thread series is used below $1\frac{1}{8}$ in. bolt diameter; the 8-pitch-thread series, $1\frac{1}{8}$ in. and greater. Table 9.5, taken from the Taylor Forge modern flange design publication [17], can be used to determine bolt areas. Table 9.5, also gives some minimum recommended dimensions for bolt spacing; radial distance, *R*, from the bolt circle to the outside diameter of the large end of the hub; and edge distance from the bolt circle to the outside diameter of the flange.

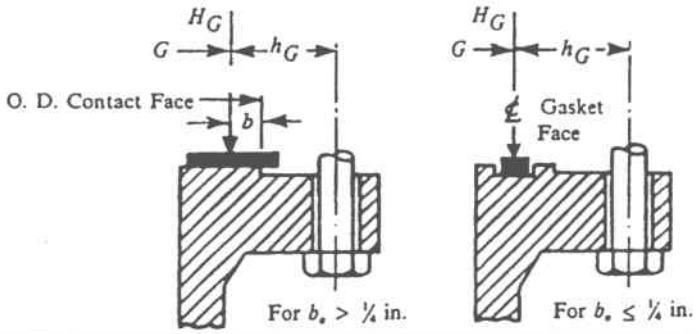
TABLE 9.3 EFFECTIVE GASKET WIDTH [Note (1)] (*Source*: Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

Facing Sketch (Exaggerated)	Basic Gasket Seating Width b_o	
	Column I	Column II
(1a) 	$\frac{N}{2}$	$\frac{N}{2}$
(1b)  See Note (1)		
(1c)  $w \le N$	$\frac{w+T}{2}$; $\left(\frac{w+N}{4}\text{ max}\right)$	$\frac{w+T}{2}$; $\left(\frac{w+N}{4}\text{ max}\right)$
(1d)  See Note (1) $w \le N$		
(2)  1/64 in. nubbin $w \le N/2$	$\frac{w+N}{4}$	$\frac{w+3N}{8}$
(3)  1/64 in. nubbin $w \le N/2$	$\frac{N}{4}$	$\frac{3N}{8}$
(4)  See Note (1)	$\frac{3N}{8}$	$\frac{7N}{16}$
(5)  See Note (1)	$\frac{N}{4}$	$\frac{3N}{8}$
(6) 	$\frac{w}{8}$	..

Effective Gasket Seating Width, b

$b = b_o$, when $b_o \le 1/4$ in.; $b = 0.5\sqrt{b_o}$, when $b_o > 1/4$ in.

Location of Gasket Load Reaction



NOTE:
(1) Where serrations do not exceed 1/64 in. depth and 1/32 in. width spacing, sketches (1b) and (1d) shall be used.
(2) The gasket factors listed only apply to flanged joints in which the gasket is contained entirely within the inner edges of the bolt holes.

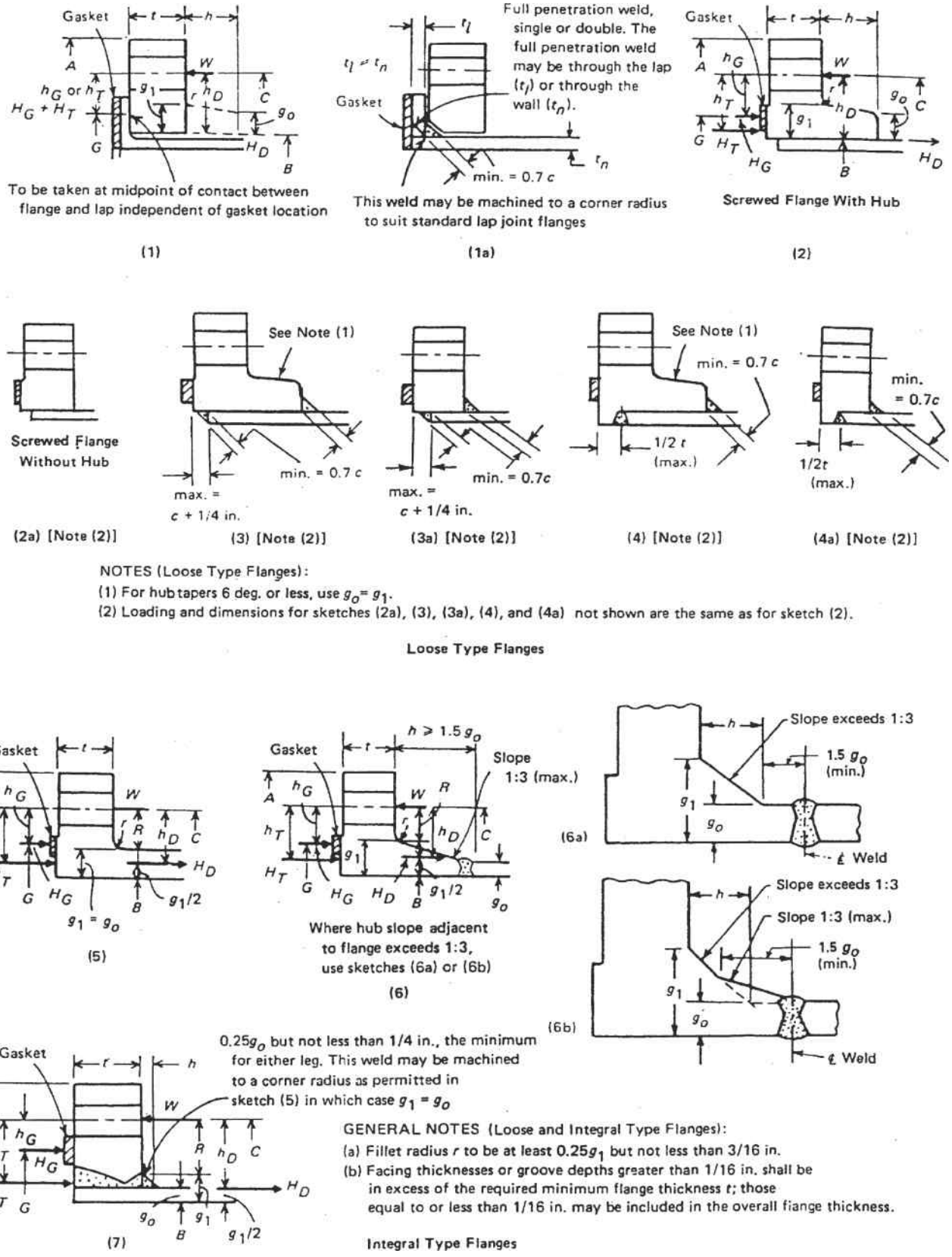
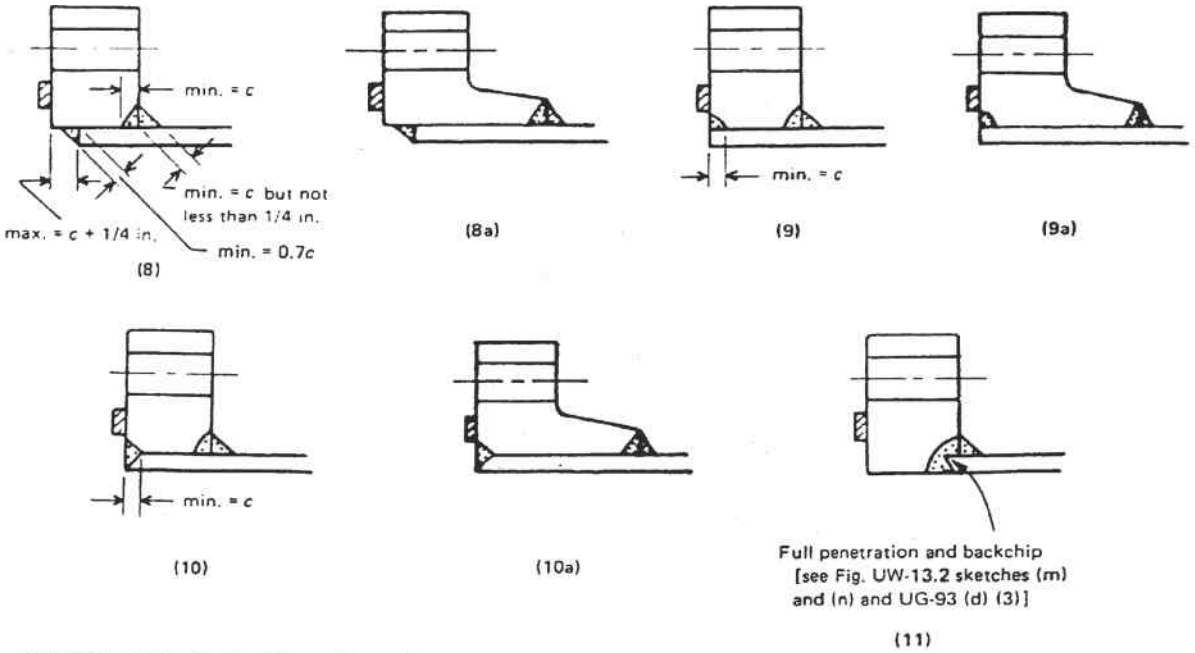


FIG. 9.3 TYPES OF FLANGES (*Source*: Fig. 2-4, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)



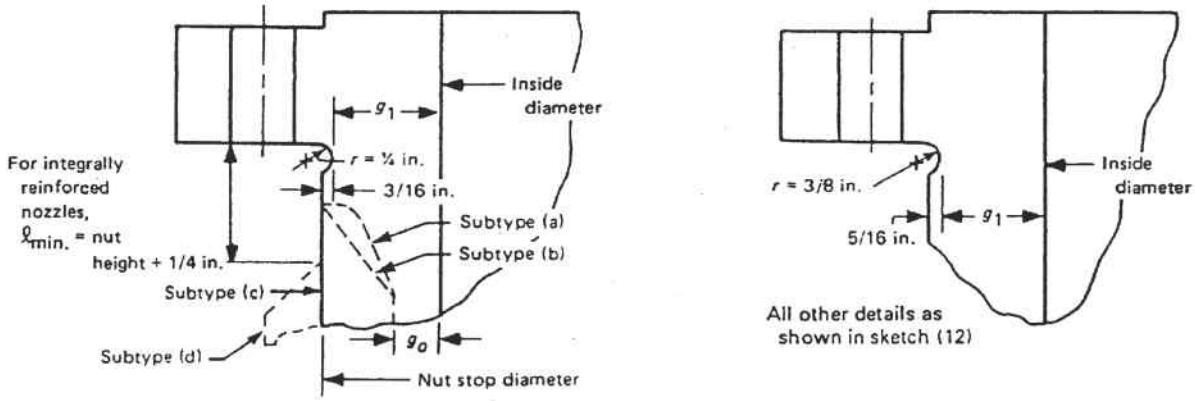
GENERAL NOTES (Optional Type Flanges):

(a) Optional type flanges may be calculated as either loose or integral type. See 2-4.

(b) Loadings and dimensions not shown in sketches (8), (8a), (9), (9a), (10), and (10a) are the same as shown in sketch (2) when the flange is calculated as a loose type flange and as shown in sketch (7) when the flange is calculated as an integral type flange.

(c) The groove and fillet welds between the flange back face and the shell given in sketch (8) also apply to sketches (8a), (9), (9a), (10), and (10a).

Optional Type Flanges



GENERAL NOTE (Flanges With Nut Stops):

For subtypes (a) and (b), g_o is the thickness of the hub at the small end. For subtypes (c) and (d), $g_o = g_1$.

Flanges With Nut Stops

FIG. 9.3 (CONTINUED)

These dimensions, based on accessibility of a standard wrench, are practical guidelines for use in design.

(*g*) *Flange Moments* The procedure for the determination of flange stresses is to first calculate the forces acting on the flange, followed by the flange moments created by those forces. Then, the moments are used to compute stress in the flange components based on axial symmetry. Note that total forces and moments are used rather than distributed forces per unit circumference; it is the final stress calculation that accounts for the difference. The flange moments are shown as follows:

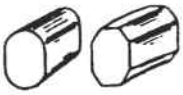
For the gasket-seating case:

$$W = 0.5(A_m + A_b)S_a \quad \text{(lb)}$$
$$M_o = 0.5W(C - G) \quad \text{(in.-lb)}$$

TABLE 9.4 GASKET MATERIALS AND CONTACT FACINGS (GASKET FACTORS *m* FOR OPERATING CONDITIONS AND MINIMUM DESIGN SEATING STRESS, *y*) [Note (1)]
(*Source*: Table 2-5.1, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

Gasket Material	Gasket Factor *m*	Min. Design Seating Stress *y*, psi	Sketches	Facing Sketch and Column in Table 2-5.2
Self-energizing types (O rings, metallic, elastomer, other gasket types considered as self-sealing)	0	0	...	...
Elastomers without fabric or high percent of asbestos fiber:				
Below 75A Shore Durometer	0.50	0		(1a),(1b),(1c),(1d), (4),(5); Column II
75A or higher Shore Durometer	1.00	200		
Asbestos with suitable binder for operating conditions:				
1/8 in. thick	2.00	1600		(1a),(1b),(1c),(1d), (4),(5); Column II
1/16 in. thick	2.75	3700		
1/32 in. thick	3.50	6500		
Elastomers with cotton fabric insertion	1.25	400		(1a),(1b),(1c),(1d), (4),(5); Column II
Elastomers with asbestos fabric insertion (with or without wire reinforcement):				
3-ply	2.25	2200		
2-ply	2.50	2900		(1a),(1b),(1c),(1d), (4),(5); Column II
1-ply	2.75	3700		
Vegetable fiber	1.75	1100		(1a),(1b),(1c),(1d), (4)(5); Column II
Spiral-wound metal, asbestos filled:				
Carbon	2.50	10,000		(1a),(1b); Column II
Stainless, Monel, and nickel-base alloys	3.00	10,000		
Corrugated metal, asbestos inserted, or corrugated metal, jacketed asbestos filled:				
Soft aluminum	2.50	2900		
Soft copper or brass	2.75	3700		
Iron or soft steel	3.00	4500		(1a),(1b); Column II
Monel or 4%–6% chrome	3.25	5500		
Stainless steels and nickel-base alloys	3.50	6500		

TABLE 9.4 (CONTINUED)

Gasket Material	Gasket Factor *m*	Min. Design Seating Stress *y*, psi	Sketches	Facing Sketch and Column in Table 2-5.2
Corrugated metal:				
Soft aluminum	2.75	3700		(1a),(1b),(1c),(1d); Column II
Soft copper or brass	3.00	4500		
Iron or soft steel	3.25	5500		
Monel or 4%–6% chrome	3.50	6500		
Stainless steels and nickel-base alloys	3.75	7600		
Flat metal, jacketed asbestos filled:				
Soft aluminum	3.25	5500		(1a),(1b),(1c),[2] (1d)[2];(2)[2]; Column II
Soft copper or brass	3.50	6500		
Iron or soft steel	3.75	7600		
Monel	3.50	8000		
4%–6% chrome	3.75	9000		
Stainless steels and nickel-base alloys	3.75	9000		
Grooved metal:				
Soft aluminum	3.25	5500		(1a),(1b),(1c),(1d), (2),(3); Column II
Soft copper or brass	3.50	6500		
Iron or soft metal	3.75	7600		
Monel or 4%–6% chrome	3.75	9000		
Stainless steels and nickel-base alloys	4.25	10,100		
Solid flat metal:				
Soft aluminum	4.00	8800		(1a),(1b),(1c),(1d), (2),(3),(4),(5); Column I
Soft copper or brass	4.75	13,000		
Iron or soft steel	5.50	18,000		
Monel or 4%–6% chrome	6.00	21,800		
Stainless steels and nickel-base alloys	6.50	26,000		
Ring joint:				
Iron or soft steel	5.50	18,000		(6); Column I
Monel or 4%–6% chrome	6.00	21,800		
Stainless steels and nickel-base alloys	6.50	26,000		

NOTES:
(1) This Table gives a list of many commonly used gasket materials and contact facings with suggested design values of *m* and *y* that have generally proved satisfactory in actual service when using effective gasket seating width *b* given in Table 2-5.2. The design values and other details given in this Table are suggested only and are not mandatory.
(2) The surface of a gasket having a lap should not be against the nubbin.

For the operating case:

$$M_o = H_D h_D + H_T h_T + H_G h_G$$

When the bolt spacing exceeds $2a + t$, multiply M_O by the bolt spacing correction factor B_{SC} for calculating flange stress

$$B_{SC} = \sqrt{\frac{B_s}{2a + t}}$$

where,

B_S = Bolt spacing
a = Bolt diameter
t = Flange thickness

(*h*) *Flange Parameters* The flange-geometry parameters must be determined to compute stresses from the applied moments for a given geometry. The solution for flange stresses is based on relationships with significant dimensionless parameters, as shown below. Figures 9.3–9.9 are reproductions of Figures from

TABLE 9.5 BOLT AREA AND SPACING (*Source*: Ref. [17])

Bolt Size a	Threads Per Inch	Root Area Sq. In.	Bolt Spacing	Radial Distance R	Edge Distance E
1/2	13	.126	1 1/4	13/16	5/8
5/8	11	.202	1 1/2	15/16	3/4
3/4	10	.302	1 3/4	1 1/8	1 3/16
7/8	9	.419	2 1/16	1 1/4	1 5/16
1	8	.551	2 1/4	1 3/8	1 1/16
1 1/8	8	.728	2 1/2	1 1/2	1 1/8
1 1/4	8	.929	2 13/16	1 ¾	1 1/4
1 3/8	8	1.155	3 1/16	1 7/8	1 3/8
1 1/2	8	1.405	3 1/4	2	1 1/2
1 5/8	8	1.680	3 1/2	2 1/8	1 5/8
1 3/4	8	1.980	3 3/4	2 1/4	1 3/4
1 7/8	8	2.304	4	2 3/8	1 7/8
2	8	2.652	4 1/4	2 1/2	2
2 1/4	8	3.423	4 3/4	2 3/4	2 1/4
2 1/2	8	4.292	5 1/4	3 1/16	2 3/8
2 3/4	8	5.259	5 3/4	3 3/8	2 5/8
3	8	6.324	6 1/4	3 5/8	2 7/8

Appendix 2 of Section VIII, Division 1 that are appropriate to this discussion. Note that the Figures of Section VIII, Division 2 and Section III, Appendix XI are identical except in numbering.

(*i*) *All Flanges* The following parameters are to be computed for all flange types. The appropriate additional parameters for specific flange types are presented in later sections. The steps are as follows:

(1) compute $K = AB$;
(2) determine T, U, Y, and Z from Fig. 9.4; and
(3) compute g_1/g_o, h/h_o, and h_o

Note that for a straight-neck integral flange without a hub, set $g_1 = g_o$ for the determination of flange parameters.

9.6.1.3.2 Integral Flanges The preceding flange parameters apply to all flange types. The specific figures for integral flanges are outlined with the following steps:

(1) Determine F from Fig. 9.5, V from Fig. 9.7, and f from Fig. 9.6 ($f >= 1.0$). (Note: f is the ratio of the bending stress at the small end of the hub, at g_o, to the bending stress at the large end of the hub, at g_1.)

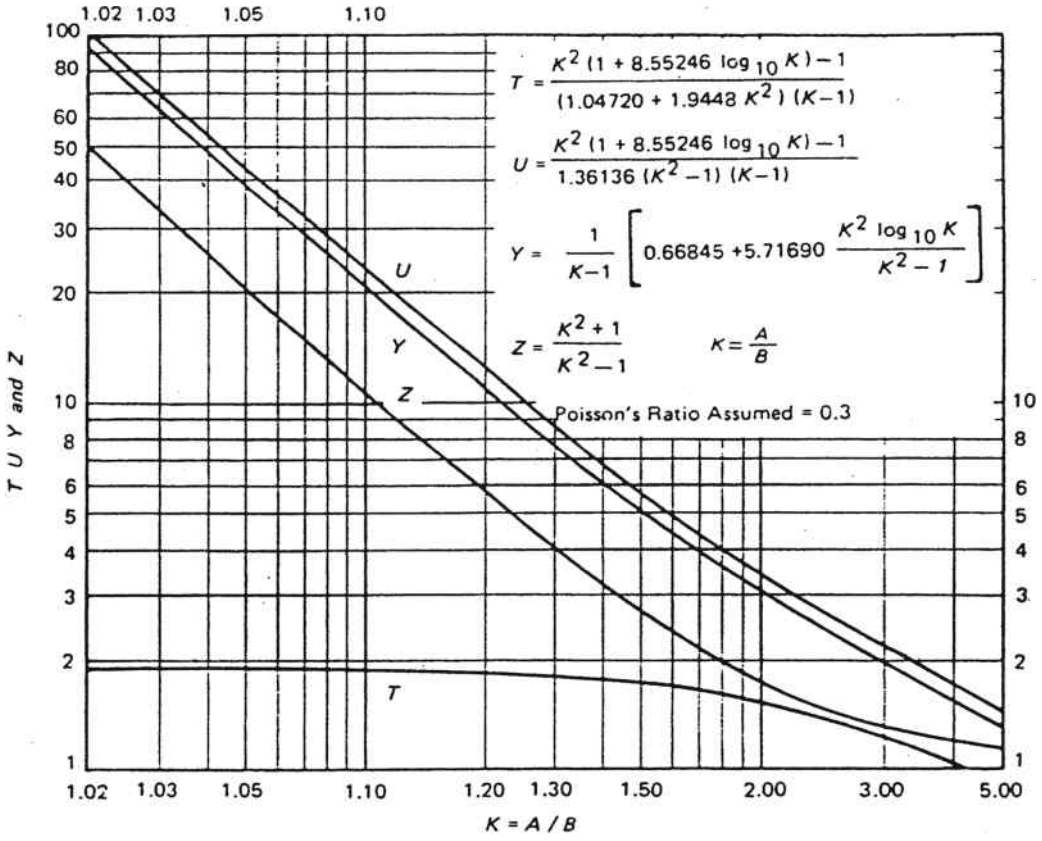


FIG. 9.4 VALUES OF *T, U, Y,* AND *Z* (TERMS INVOLVING *K*) (*Source*: Fig. 2-7.1, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

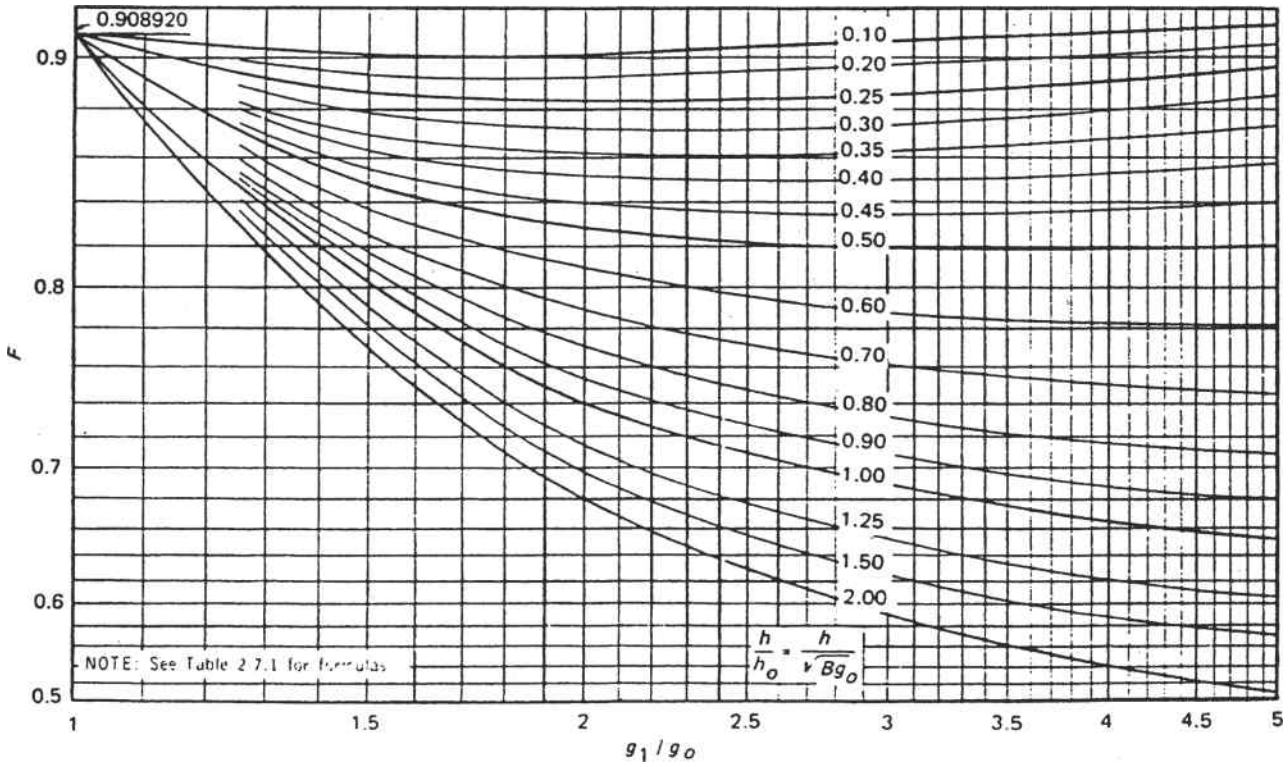


FIG. 9.5 VALUES OF *F* (INTEGRAL FLANGE FACTORS) (*Source*: Fig. 2-7.2, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

(2) Compute

$$d = \frac{U}{V} h_o g_o^2$$
$$e = \frac{F}{h_o}$$
$$L = \frac{te + 1}{T} + \frac{t^3}{d}$$

where

t = the flange thickness

9.6.1.3.3 Loose Flanges Loose flanges include those that are not considered integral, such as slip-on, lap-joint, and threaded types. Loose flanges either have no direct connection to the nozzle neck (as in a lap-joint flange) or have a method of attachment that is not considered to give the same mechanical strength as the integral weld necktype design (as in a slip-on flange, which is only fillet-welded to the neck). Figure 2-4 of Section VIII, Division 1, Appendix 2 (given here as Fig. 9.3) illustrates the attachment details for loose flanges.

The parameters for loose flanges, and the figures from which they are obtained, are outlined as follows:

(1) *FL* from Fig. 9.8, *VL* from Fig. 9.9, and $f = 1.0$.
(2) Compute the following:

$$d = \frac{U}{V_L} h_o g_o^2$$
$$e = \frac{F_L}{h_o}$$
$$L = \frac{te + 1}{T} + \frac{t^3}{d}$$

9.6.1.3.4 Slip-on Flanges Slip-on flanges are designed to slide over the outside diameter of the attached nozzle neck and then be attached by fillet welding at both ends of the flange. Sketches (3) and (3a) of Fig. 2-4 of Section VIII, Division 1, Appendix 2 (given here as Fig. 9.3) illustrate the attachment details for slip-on flanges. The axial-thrust load from internal pressure is assumed to shear into the flange ring through the fillet welds and to act at the inside diameter of the flange ring. A minimum fillet weld size of 0.7 times the nozzle-neck thickness, measured through the throat of the weld, is required. When the nozzle-neck thickness is greater than two times the thickness required for internal pressure, that value may be used for the nozzle-neck thickness in the calculation of the minimum size required for a fillet weld. However, it may not be less than $\frac{1}{4}$ in. (See definitions of c and t_x in Appendix 2 nomenclature.)

9.6.1.3.5 Socket-Welding Flanges Socket-welding flanges are designed to slide over the outside diameter of the attached nozzle neck into a socket machined into the inside diameter of the flange ring. The flange is then attached by welding at both its ends.

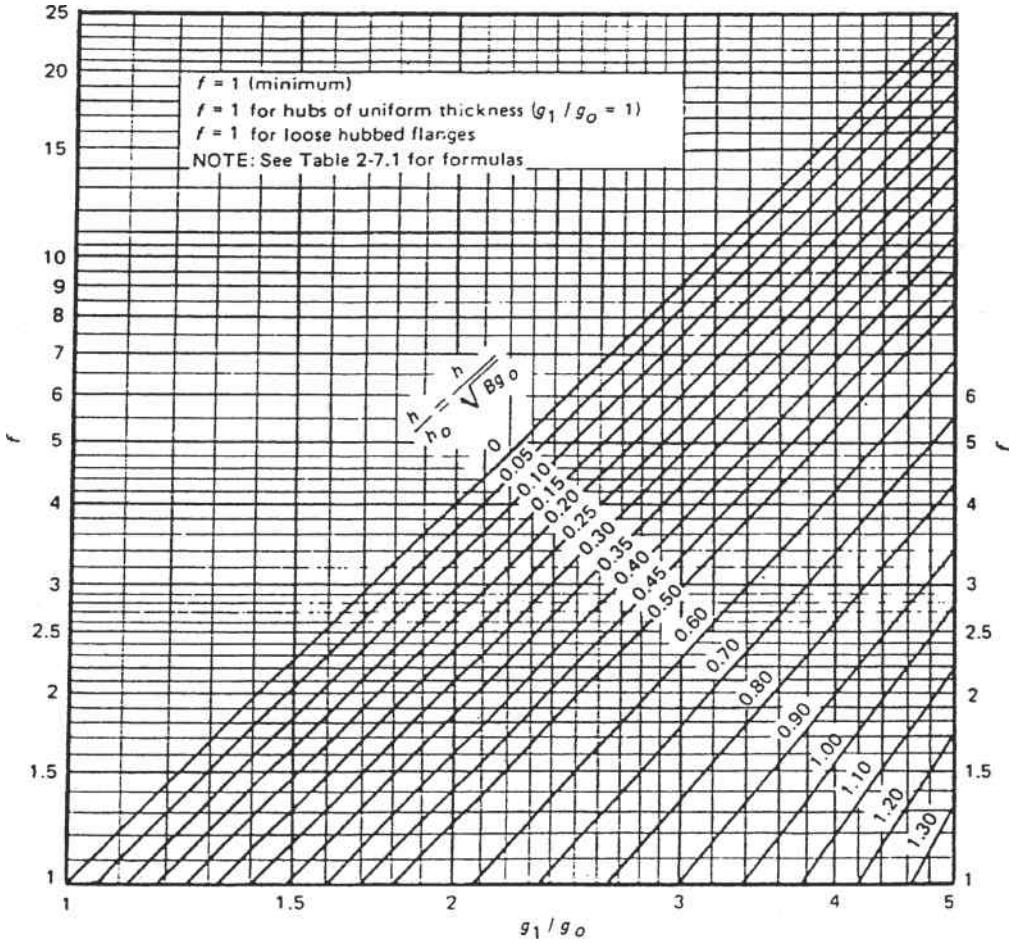


FIG. 9.6 VALUES OF *f* (HUB STRESS CORRECTION FACTOR) (*Source*: Fig. 2-76, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

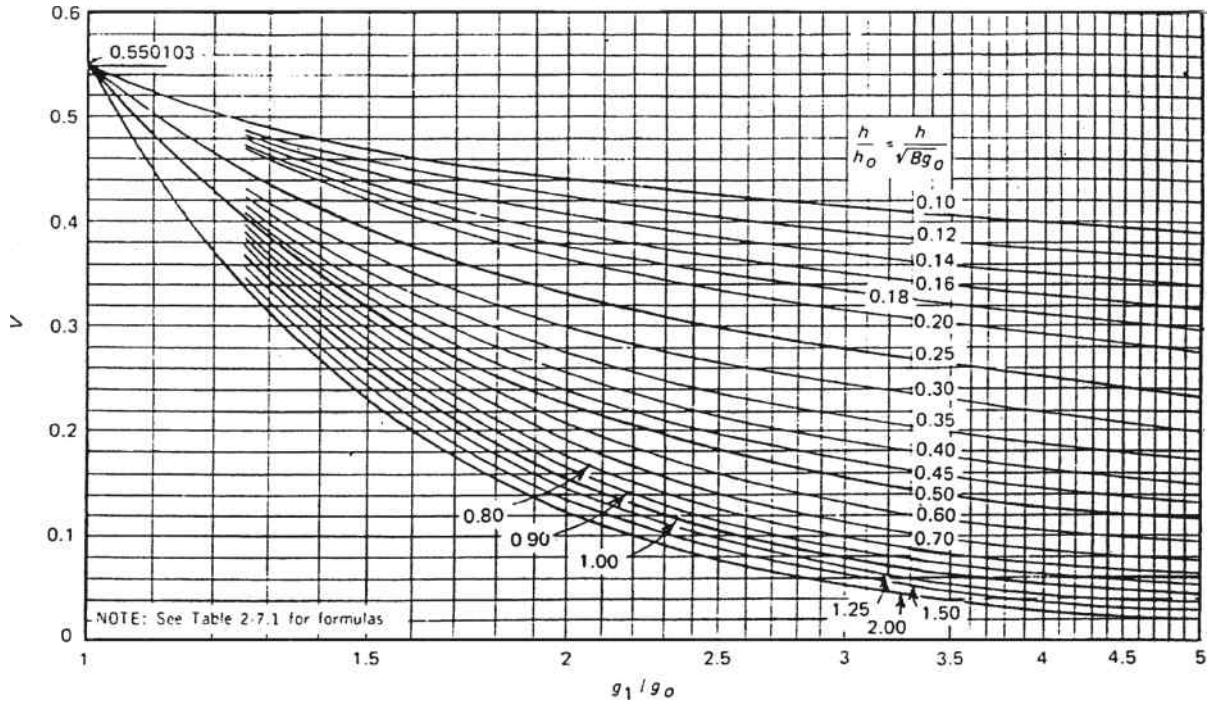


FIG. 9.7 VALUES OF *V* (INTEGRAL FLANGE FACTORS) (*Source*: Fig. 2-7.3, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

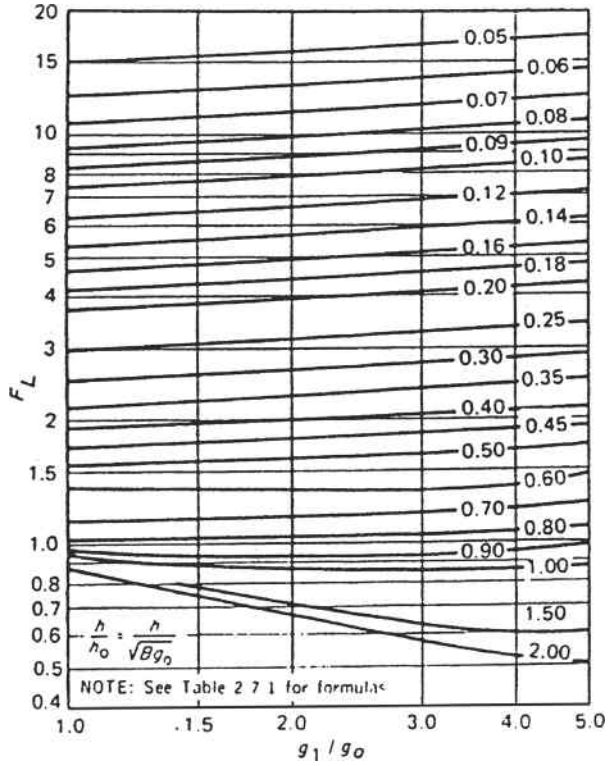


FIG. 9.8 VALUES OF F_L (LOOSE HUB FLANGE FACTORS) (*Source*: Fig. 2-7.4, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

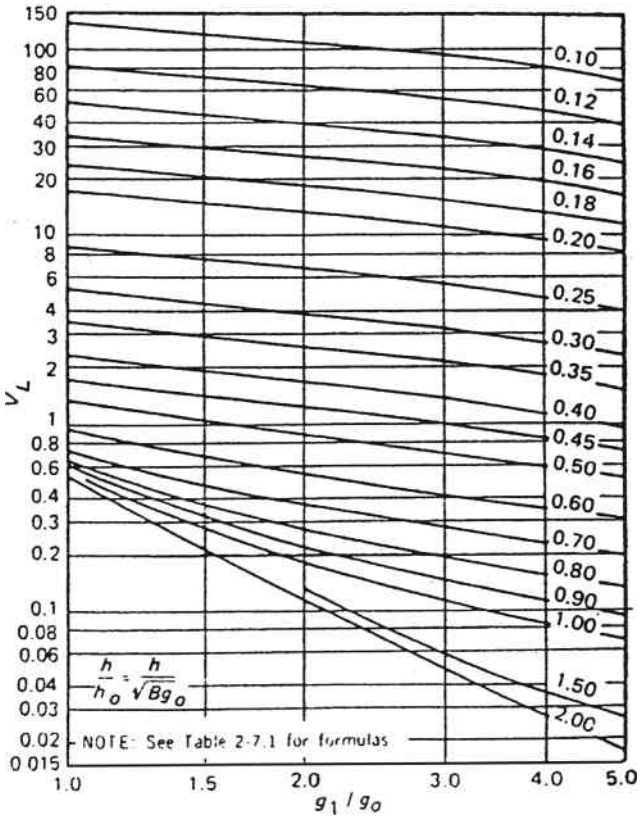


FIG. 9.9 VALUES OF V_L (LOOSE HUB FLANGE FACTORS) (*Source*: Fig. 2-7.5, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

Sketches (4) and (4a) of Fig. 2-4 of Section VIII, Division 1, Appendix 2 illustrate the attachment details for socket-welding flanges. The axial-thrust load from internal pressure is assumed to shear into the flange ring through the welds and to act at the inside diameter of the flange-ring socket. A minimum fillet weld size of 0.7 times the nozzle-neck thickness, measured through the throat of the weld, is required. When the nozzle-neck thickness is greater than two times the thickness required for internal pressure, that value may be used for the nozzle-neck thickness in the calculation of the minimum size required for a fillet weld. However, it may not be less than $\frac{1}{4}$ in. A groove weld is required at the butt end of the socket.

9.6.1.3.6 Lap-Joint Flanges Lap-joint flanges are designed to slide over the outside diameter of the attached nozzle neck containing a forged or fabricated lap. The flange is not attached to the nozzle neck. Sketches (1) and (2) of Fig. 2-4 of Section VIII, Division 1, Appendix 2 illustrate the attachment details for lap-joint flanges. The axial-thrust load from internal pressure is assumed to transmit into the flange ring through contact with the lap. The gasket-reaction force is assumed to act at the midpoint of contact between the flange ring and the lap independent of the gasket location.

9.6.1.3.7 Threaded Flanges Threaded flanges are designed as loose flanges, the same as with slip-on flanges. The Code rules for loose flanges assume that the neck offers no resistance to rotation of the flange ring and does not add to the stiffness of the joint. The axial-pressure-thrust load is assumed to transfer from the neck to the flange ring by shear through the threads and to act at the inside diameter of the flange. The moment arms for computing the flange moments are given in Table 2-6 of the Code (given here as Table 9.2).

From a practical standpoint, heavy-wall neck should be used to accommodate the threads. Threaded flanges are generally used in the smaller sizes.

9.6.1.3.8 Flange Stresses The following equations are used for the calculation of flange stresses for both integral and loose types, with and without hubs.

(*a*) *Integral Flanges and Loose Flanges with Hubs*

The longitudinal-hub stress:

$$S_H = \frac{fM_o}{Lg_1^2B}$$

Note that neither Section VIII, Division 1 nor Section VIII, Division 2 includes the nozzle-neck axial-pressure stress in the calculation for the longitudinal-hub stress. However, Section III, Appendix IX does include the longitudinal-pressure stress at the large end of the hub. The preceding equation calculates stress at the greater of the stresses at either the large or the small end of the hub by the use of the factor f. When the stress at the small end is greater, the factor f is greater than 1.0; when f is less than 1.0, it is set equal to 1.0, and the stress at the large end of the hub governs.

The radial-flange stress:

$$S_R = \frac{(1.33t_e + 1)M_o}{Lt^2B}$$

The tangential-flange stress:

$$S_T = \frac{YM_o}{t^2B} - ZS_R$$

(*b*) *Loose Flanges without Hubs*

$$S_T = \frac{YM_o}{t^2B}$$

$$S_R = 0 \quad S_H = 0$$

The allowable stresses:

S_f = allowable stress for the flange at the design temperature for the operating case and ambient temperature for the gasket-seating case
S_n = allowable stress for the nozzle neck at the applicable temperature

The longitudinal-hub stress:

integral: $S_H < 1.5S_f$ and $2.5S_n$
cast iron: $S_H < S_f$
optional or ring integral: $S_H < 1.5S_f$ or $1.5S_n$

The tangential-flange stress:

$$S_T < S_f$$

The radial-flange stress:

$$S_R < S_f$$

The combined stresses:

$$(S_H + S_R)/2 < S_f$$

$$(S_H + S_T)/2 < S_f$$

The allowable shear stresses are as follows:
For loose or optional slip-on flanges:

$$\text{shear stress in attachment welds} < 0.8\,S_n$$

For lap-joint flanges:

$$\text{shear stress in lap} < 0.8S_n$$

In addition to the flange and bolting allowable stress limits, flange rigidity is an additional requirement to control leakage. The Flange Rigidity Factors, J, are given in Table 2-14 and shown below for the various flange types.

Integral Type Flanges: $J = (52.14\ M_o\ V)/(LE\ g_o^2\ h_o\ K_I) \leq 1.0$

Loose Type Flanges with hubs: $J = (52.14\ M_o\ V_L)/(LE\ g_o^2\ h_o\ K_L) \leq 1.0$

Loose Type Flanges without hubs: $J = (109.4\ M_o)/(Et^3\ K_L \ln(K)) \leq 1.0$

Where:

$K_I = .3$
$K_L = .2$

These rigidity limits effectively limit the flange rotation for the required design moments to .3 degrees for an integral flange and .2 degrees for a loose flange.

Example Check the flange stresses and required bolt area for the following integral-weld-neck flange design in which both flanges are identical:

The design pressure: $P = 414$ psi
The design temperature: $T = 500$ F
The flange material: SA105
The bolting material: SA193–B7
The inside diameter: $B = 32$ in.
The outside diameter: $A = 39.125$ in.
The bolt circle: $C = 37.00$ in.
The flange thickness: $t = 2.0$ in.
The hub length: $h = 2.75$ in.
The hub thickness (small end): $g_o = 0.5$ in.
The hub thickness (large end): $g_1 = 1.125$ in.

The gasket: spiral-wound, graphite-filled, and has an outer ring 35.5 in. (O.D.) × 33.5 in. (I.D.)

$m = 3.0$
$y = 10{,}000$

Note: The *m* and *y* values given in Table 2-5.1 of Section VIII, Division 1, Appendix 2 are nonmandatory, and many are based on the use of asbestos filler. The Code would allow the use of Manufacturer-recommended values; however, for consistency, this example will use the Table 2-5.1 values.

bolting: 36 − 1 in. diameter bolts ($n = 36$)
bolt area: $A_b = 36(0.551) = 19.836$ in.^{2} (root area from Table 9.2)
Code-allowable stress values:
S_a = the allowable bolt stress at 70°F
S_{fa} = the allowable flange stress at 70°F
S_b = the allowable bolt stress at the design temperature
S_f = the allowable flange stress at the design temperature
Flange, gasket-seating: $S_{fa} = 20{,}000$ psi
operating-case: $S_f = 19{,}600$ psi
Neck, gasket-seating: $S_{fa} = 20{,}000$ psi
operating-case: $S_f = 19{,}600$ psi
Bolts, gasket-seating (70°F): $S_a = 25{,}000$ psi
operating-case (500°F): $S_b = 25{,}000$ psi

Note: Do not be confused by the fact that the Code uses both the terms *operating condition* and *design condition*. The operating condition is evaluated at the design pressure for allowable stresses determined at the design temperature.

Compute the gasket-reaction location and effective width:

$$N = 0.5 \times (35.5 - 33.5) = 1.0\text{ in.}$$

From Table 2-5.2 (or Table 9.3 here):

$b_o = N/2 = 1.0/2 = 0.5$ in.
$b = 0.5 \times \sqrt{b_o}$
$= 0.5 \times \sqrt{0.5} = 0.3536$
G = the gasket O.D. $- 2 \times b$ (since $b_o > 0.25$ in.)
$= 35.5 - 2 \times 0.3536 = 34.793$ in.

Compute the required bolt loads:

y = the gasket-seating stress = 10,000 psi
W_{m2} = the minimum required bolt load for gasket seating
$= 3.14bGy$
$= 3.14 \times 0.3536 \times 34.793 \times 10{,}000 = 386{,}300$ lb
m = the gasket-operating factor = 3.0
W_{m1} = the minimum required bolt load during operation
$H = 0.785G^2P$
$= 0.785(34.793^2)414 = 393{,}420$
$H_P = (2b)(3.14GmP)$

$= 2(0.3536)3.14(34.793)3.0(414) = 95{,}960$

$W_{m1} = H + H_p$

$= 393{,}420 + 95{,}960$

$W_{m1} = 489{,}380$ lb

$H_D = 0.785B^2P = 0.785(32.0^2)414$

$= 332{,}790$ lb

$H_T = H - H_D = 393{,}420 - 332{,}790$

$= 60{,}630$ lb

Compute the required bolt area:

A_{m1} = the required bolt area for operating case

$= W_{m1}/S_b$

$A_{m1} = 489{,}380/25{,}000 = 19.575$ in.^{2}

A_{m2} = the required bolt area for gasket seating

$= W_{m2}/S_a$

$= 386{,}300/25{,}000 = 15.452$ in.^{2}

The required bolt area, A_m, is the greater of A_{m1} or A_{m2}; therefore, $A_m = 19.575$ in.^{2}. The actual bolt area is based on 36 − 1 in. diameter bolts. The root area, from Table 9.5, is 0.551 in.^{2} per bolt.

A_b = the actual bolt area selected

$= 36(0.551) = 19.836$ in.^{2}

W = the flange-design bolt load

$= W_{m1}$ (for operating conditions)

W(operating) $= Wm_1 = 489{,}380$ lb

W(gasket seating) $= 0.5 \times (A_m + A_b) \times S_a$

(for gasket seating; it provides for abuse)

$= 0.5 \times (19.575 + 19.836)25{,}000$

$= 492{,}630$ lb

The flange moments:

Gasket Seating: $M_o = 0.5W(C - G)$ (in.-lb)

$= 0.5(492{,}630)(37.0 - 34.793) = 543{,}620$

Operating: $M_o = H_D h_D + H_T H_T + H_G h_G$ (in.-lb)

$R = 0.5 \times (C - B) - g_I = 0.5(37 - 32) - 1.125 = 1.375$

$h_D = R + 0.5_{g1} = 1.375 + 0.5(1.125) = 1.9375$

$h_G = 0.5 \times (C - G) = 0.5(37 - 34.793) = 1.104$

$h_T = 0.5 \times (R + g_1 + h_G) = 0.5 \times (1.375 + 1.125 + 1.104)$

$= 1.802$

$M_o = (332{,}790)1.9375 + (60{,}630)1.802 + (95{,}960)1.104$

$= 859{,}920$

Determine the flange parameters from the figures or by calculation from the equations in Table 2-7.1 of the Code. This example will refer to the figures.

Compute:

$$K = A/B$$

$$K = 39.125/32.0 = 1.223$$

Determine T, U, Y, and Z from Fig. 2-7.1 of Section VIII, Division 1, given here as Fig. 9.4:

$T = 1.83$

$U = 10.74$

$Y = 9.773$

$Z = 5.041$

$h_o = \sqrt{B \times g_o} = \sqrt{32.0 \times 0.5}$

$h_o = 4.0$

Compute g_1/g_o and h/h_o:

$$g_1/g_o = 1.125/0.5 = 2.25$$

$$h/h_o = 2.75/4 = 0.6875$$

Determine F from Fig. 9.5, F 1.0 = 0.777; V from Fig. 9.7, $V = 0.1616$; and f from Fig. 9.6, $f <$ ($f = 0.922$ from the equations in Table 2-7.1 of the Code).

Recall that f is the ratio of the bending stress at the small end of the hub (at g_o) to the bending stress at the large end of the hub (at g_1). Because f is less than 1.0, the large end of hub governs, and $f = 1.0$ is used in the calculation of stress.

Compute the parameters d, e, and L

$$d = \frac{U}{V} h_o g_o^2 = \frac{10.74}{0.1616} \times 4 \times 0.5^2 = 66.48$$

$$e = \frac{F}{h_o} = \frac{0.777}{4} = 0.194$$

$$L = \frac{te + 1}{T} + \frac{t^3}{d} = \frac{2.0 \times 0.194 + 1}{1.83} + \frac{2.0^3}{66.48} = 0.879$$

(*c*) *Flange Stresses*

Calculate the flange stresses for both the operating moment and the gasket-seating moment.

Operating condition ($M_o = 859{,}920$):

The longitudinal-hub stress:

$$S_H = \frac{f \times M_o}{L \times g_1^2 \times B} = \frac{1.0 \times 859{,}920}{0.879 \times 1.125^2 \times 32.0} = 24{,}150$$

The radial-flange stress:

$$S_R = \frac{(1.33 \times t \times e + 1) \times M_o}{L \times t^2 \times B} = \frac{(1.33 \times 2.0 \times 0.194 + 1) \times 859{,}920}{0.879 \times 2.0^2 \times 32.0} = 11.590$$

The tangential-flange stress:

$$S_T = \frac{YM_o}{t^2 B} - ZS_R = \frac{9.773 \times 859{,}920}{2.0^2 \times 32.0} - 5.041 \times 11{,}590 = 7{,}230$$

The combined stresses:

$0.5(S_H + S_R) = 0.5(24{,}150 + 11{,}590) = 17{,}870$ psi

$0.5(S_H + S_T) = 0.5(24{,}150 + 7{,}230) = 15{,}690$ psi

Similarly, for the gasket-seating condition:

$S_H = 15{,}270$ psi

$S_R = 7{,}330$ psi

$S_T = 4{,}570$ psi

$0.5(S_H + S_R) = 11{,}300$ psi

$0.5(S_H + S_T) = 9{,}900$ psi

The allowable stresses:

$S_H < 1.5\ S_f = 1.5(19{,}600) = 29{,}400$ psi (operating case)

$= 1.5(20000) = 30000$ psi (gasket-seating case)

S_R, S_T, $0.5(S_H + S_R)$, $0.5(S_H + S_T) < 19{,}600$ psi (operating)
$< 20{,}000$ psi (gasket-seating)

The flange rigidity requirement:

$J = (52.14\ M_o\ V)/(LE\ g_o^2\ h_o\ K_I)$

Operating Case, $E = 27\ E6$

$J = (52.14\ (859920)\ .1616)/(.8792\ (27\ E6)\ .52\ (4)\ (.3))$
$J = 1.02 > 1.0$ Exceeds Limit

Gasket Seating Case, $E = 29.2\ E6$

$J = (52.14\ (543620)\ .1616)/(.8792\ (29.2\ E6)\ .52\ (4)\ (.3))$
$J = 0.60 < 1.0$ O.K.

The flange stresses are within the allowable stress limits for the specified design conditions. Note that the bolt stress for the operating condition governs. However the flange rigidity requirement is not met and the maximum allowable working pressure must be reduced to 404 psi.

(*d*) *Optional Flanges* These flanges are similar in design to slip-on flanges in that they have a flange ring, with or without a hub, welded to the outside of a pipe or nozzle neck. The optional-flange designs and weld details are shown in sketches (8) and (11) of Fig. 2-4 of Section VIII, Division 1, Appendix 2 (Figure 9.3 here). They are generally of the type that slips over the outside diameter of the nozzle neck, with the exception of Fig. 2-4, sketch (11) of the Code, where the neck is welded to the back of the ring. The primary difference between an optional flange and a slip-on flange is the weld detail, as illustrated in the details in Fig. 2-4. The optional flange details are closer to integral construction in that they require a weld bevel into the flange, compared with a simple fillet weld for slip-on flanges.

Optional Flanges may be designed as integral flanges or, for simplicity, designed as loose flanges if none of the following values is exceeded:

$$g_o = \frac{5}{8}\ \text{in.}$$
$$B/g_o = 300$$
$$P = 300\ \text{psi}$$
$$\text{the operating temperature} = 700°\text{F}$$

9.6.1.3.9 Reverse Flanges Reverse flanges, shown in Figs. 2-13.1 and 2-13.2 of the Code (given here as Figs. 9.10 and 9.11, respectively), are reducing flanges used to change the line size. Before the 1999 addenda of the 1998 edition, only the integral reverse flange was covered. Currently, however, the Code coverage includes loose reverse flanges. The derivation of Code formulas used for the design of reverse flanges is in Waters and Schneider [7].

Loads from internal pressure are determined similar to conventional flanges in Section 9.6.1.3.1. Moments are similarly computed, but the moment terms may be positive or negative.

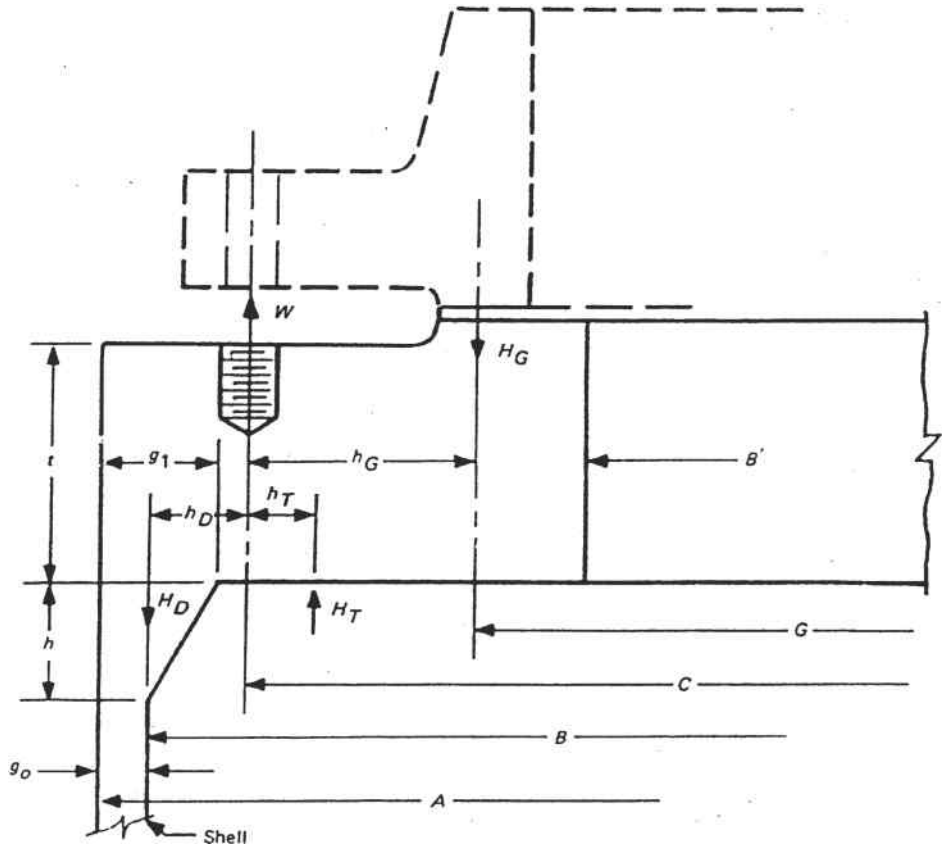


FIG. 9.10 REVERSE FLANGE (*Source*: Fig. 2-13.1, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

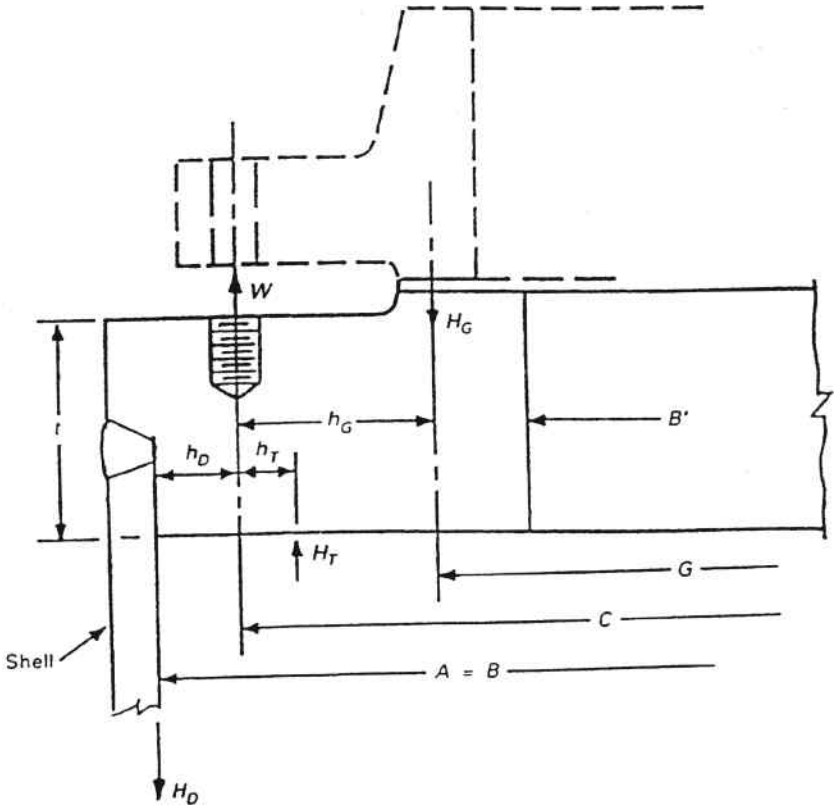


FIG. 9.11 LOOSE RING-TYPE REVERSE FLANGE (*Source*: Fig. 2-13.2, Section VIII, Division 1, Appendix 2 of the ASME B&PV Code)

The absolute value is used for the moment used to compute stress.

The gasket-seating moment:

$$M_o = Wh_G$$

The operating moment:

$$M_o = ABS[H_D h_D + H_T h_T + H_G h_G]$$

Positive forces act *down* in Figs. 9.10 and 9.11 and positive moment arms act to the *right* of the bolt circle (H_T and h_D are negative as shown).

(*a*) *Stresses in Reverse Flanges* Flange parameters are modified as follows:

$$h_{or} = \sqrt{AG_o}$$
$$U_r = \alpha_r U$$
$$Y_r = \alpha_r Y$$
$$T_r = \frac{Z + 0.3}{Z - 0.3}\alpha_r T$$

where

$$\alpha_r = [1 + 0.668(K + 1)/Y]/K^2$$

Stress equations are provided for both the inside and outside diameters.

9.6.1.3.10 Flat-Flanged Heads and Blind Flange Paragraph UG-34 discusses the rules for unstayed flat heads and covers. A stayed head is one that has stay rods to add support to the head. Therefore, these rules are for heads that are self-supporting across the span to the gasket-reaction location.

The design rules of UG-34 cover both circular and noncircular heads. Noncircular heads are addressed by modifying the circular-head equation by a factor that accounts for the noncircular geometry (to be discussed in this section). These design rules are also referenced by the Piping Codes for the design of blind flanges.

The design rules are based on the elasticity solution for a flat-circular plate with simply supported edge conditions, and, in addition, they limit the maximum bending stress in the plate to the Code-allowable stress. The edge moment from the bolt and gasket reactions is superimposed. Formulas are based on stress, not deflection, and flange rotation considerations may require a greater thickness.

The design equations for flat heads are as follows:

d = the diameter to the gasket-reaction location (G as defined in Appendix 2), for noncircular heads in the short span, in.
D = the diameter to the gasket-reaction location (G as defined in Appendix 2), for noncircular heads in the long span, in.
E = the weld joint efficiency
h_G = the moment arm from the centerline of the bolts to the gasket-reaction location (See Appendix 2, Table 2-5.2 or Table 9.2), in.
P = the internal design pressure, psi
S = the Code-allowable stress, psi
W = the total bolt load from equations (3) and (4) of Appendix 2, 2-5(e), lb

$C = 0.3$ for the blind flange with a ring gasket inside the bolt circle (attachment factor from Fig. UG-34 of the Code)

The required thickness, t, for circular flat heads:

$$t = d \times \sqrt{(C \times P/(S \times E) + 1.9 \times W \times h_G/(S \times E \times d^3)}$$

The required thickness, t, for noncircular flat heads:

$$t = d \times \sqrt{(Z \times C \times P/(S \times E) + 6 \times W \times h_G/(S \times E \times L \times d^3)}$$

$$Z = 3.4 - \frac{2.4 \times d}{D}$$

Note that, similar to the Appendix 2 rules for flanges, the required thickness is calculated for both the operating case and the cold-bolt-up (gasket-seating) cases; the greater thickness will govern.

Example Calculate the required thickness for a 24 in. (nominal diameter) manway with the following design conditions:

The design pressure: $P = 600$ psi
The design temperature: $T = 500$°F
The flange material: SA105
The weld joint efficiency: $E = 1.0$
The bolting material: SA193 − B7
The geometry: matches ASME B16.5, Class 300
The inside diameter: $B = 23.25$ in.
The outside diameter: $A = 36.0$ in.
The bolt circle: $BC = 32.00$ in.

The gasket: spiral-wound graphite-filled, and has an outer ring 27 in. O.D. × 24.75 in. I.D.

$m = 3.0$
$y = 10{,}000$

Note: The m and y values given in Table 2-5.1 of Section VIII, Division 1, Appendix 2 are nonmandatory, and many are based on the use of asbestos filler. The Code would allow the use of Manufacturer-recommended values; however, for consistency, this example will use the Table 2-5.1 values.

The Code-allowable stress values:

S_a = the allowable bolt stress at 70°F
S_{fa} = the allowable flange stress at 70°F
S_b = the allowable bolt stress at the design temperature
S_f = the allowable flange stress at the design temperature
Flange, gasket-seating: $S_{fa} = 20{,}000$ psi
operating-case: $S_f = 19{,}600$ psi
Bolts, gasket-seating (70°F): $S_a = 25{,}000$ psi
operating-case (500°F): $S_b = 25{,}000$ psi

Note: Do not be confused by the fact that the Code uses both the terms *operating condition* and *design condition.* The operating condition is evaluated at the design pressure for allowable stresses determined at the design temperature.

Compute the gasket-reaction location and effective width:

$$N = 0.5 \times (27.0 - 24.75) = 1.125 \text{ in.}$$

From Table 2-5.2:

$$b_o = N/2 = 1.125/2 = 0.5625 \text{ in.}$$
$$b = 0.5 \times \sqrt{b_o} = 0.5 \times \sqrt{0.5625} = 0.375$$

G = the gasket O.D. $- 2 \times b$ (since $b_o > 0.25$ in.)
$= 27.0 - 2 \times 0.375 = 26.25$ in.

Therefore, $d = 26.25$ in.:

$$h_g = 0.5(BC - G) = 0.5(32 - 26.25) = 2.875$$

Compute the required bolt loads:

y = the gasket-seating stress = 10,000 psi
W_{m2} = the minimum required bolt load for gasket seating
$= 3.14bGy$
$= 3.14 \times 0.375 \times 26.25 \times 10{,}000 = 309{,}090$ lb
m = the gasket operating factor = 3.0
W_{m1} = the minimum required bolt load during operation
$= H + H_p$
$= 0.785G^2P + (2b)(3.14GmP)$
$= 0.785(26.25^2)600 + 2(0.375)3.14(26.25)3.0(600)$
$= 435{,}820$ lb

Compute the required bolt area:

A_{m1} = the required bolt area for operating case
$= W_{m1}/S_b$
$= 435{,}822/25{,}000 = 17.433$ in.^{2}
A_{m2} = the required bolt area for gasket seating
$= W_{m2}/S_b$
$= 309{,}094/25{,}000 = 12.364$ in.^{2}

The required bolt area, A_m, is the greater of A_{m1} or A_{m2}; therefore, $A_m = 17.433$ in.^{2}. The actual bolt area is based on 24 − 1.5 in. diameter bolts. The root area, from Table 9.5, is 1.405 in.^{2} per bolt.

A_b = the actual bolt area selected
$= 24(1.405) = 33.72$ in.^{2}
W = the flange design bolt load
$= W_{m1}$ (for operating conditions)
W(operating) $= W_{m1} = 435{,}820$ lb
$= 0.5 \times (A_m + A_b) = S_a$
(for gasket seating; it provides for abuse)
W(gasket seating) $= 0.5 \times (17.433 + 33.72)25{,}000$
$= 639{,}410$ lb

Compute the required head thickness:

$$t = d \times \sqrt{(C \times P/(S \times E) + 1.9 \times W \times h_G/(S \times E \times d^3)}$$

The operating case ($S = Sf = 19{,}600$ and $W = 435{,}820$):

$$t = 26.25 \times [(0.3 \times 600)/(19{,}600 \times 1.0) + 1.9 \times 435{,}820 \times 2.875/(19{,}600 \times 1.0 \times 26.25^3)]^{1/2}$$
$$t = 3.310 \text{ in.}$$

The cold-bolt-up case ($P = 0$, $S = S_{fa} = 20{,}000$, and $W = 639{,}410$):

$$t = 26.25 \times \sqrt{1.9 \times 639{,}410 \times 2.875/(20{,}000 \times 1.0 \times 26.25^3)}$$
$$t = 2.579$$

Therefore, the operating case governs and the minimum required thickness = 3.31 in. With corrosion allowance included, the minimum required thickness = 3.31 + 0.125 = 3.435. Use a design thickness of 3.5 in.

9.6.1.3.11 Flange Design for External Pressure The significant difference between the design for external pressure and that

for internal pressure is that external pressure increases the gasket compression. The following list summarizes the differences:

(1) The gasket seating is same as for internal pressure.
(2) The operating-case moments are computed about the gasket reaction location without consideration of the bolt load.
(3) The stress equations and allowable stresses are the same as for internal pressure.

(*a*) *Gasket Seating* (*Cold-Bolt-Up*)
The minimum required total cold-bolt load:

$$W_{m2} = 3.14bGy$$

The minimum required total bolt area:

$$A_{m2} = W_{m2}/S_a$$

The design bolt load:

$$W = 0.5(A_{m2} + A_b)S_a$$

The design moment:

$$M_o = Wh_G$$

(*b*) *Operating Case*

P_e = the external design pressure (positive number), psi
$H_D = 0.785B^2P_e$
$H = 0.785G^2P_e$
$H_t = H - H_D$

The design operating moment:

$$M_o = H_D(h_D - h_G) + H_T(h_T - h_G)$$

9.6.1.3.12 Noncircular Flanges with Circular Bore The following conservative design approach is used if the flange's outside diameter is noncircular:

(1) The flange outside diameter, *A*, for parameter calculations is the largest concentric diameter *inscribed entirely* within the outside edges of the flange.
(2) The moments are based on a bolt circle located at the *outermost* bolt holes.

9.6.1.3.13 Loose Split-Ring Flanges Split-ring flanges are of the loose lap-joint type and are used when it is necessary to remove the flange. Split flanges are designed the same as solid flanges except that the design moment is increased to compensate for the lack of circumferential continuity.

(1) Single-split flanges shall be designed using 200% of the design moment for a solid flange.
(2) If two split rings are used and assembled with splits 90 deg. apart, 75% of the solid flange design moment shall be applied to each split-ring flange independently.

9.6.1.4 Flanges with Metal-to-Metal Contact Outside the Bolt Circle (Appendix Y Flanges) Appendix Y of Section VIII, Division 1 covers flat-face flanges with metal-to-metal contact outside the bolt circle. This type of flange is used where O-ring–type gaskets are appropriate; a thinner flange pair results from the reduced bending moments on the flange. The metal-to-metal contact creates a reaction force that counteracts the moment on the flange from the axial-pressure-thrust force, reduces moments on the flange, and requires a thinner flange than what would result from an Appendix 2 analysis. The Appendix Y analysis is based on the following:

(a) Rules for self-sealing gaskets.
(b) Both identical and nonidentical flange pairs.
(c) Methodology as follows:
  (1) flanges are continuous annular plates;
  (2) flexural characteristics can be approximated by beam theory;
  (3) theory of rigid-body rotation is applied for nonidentical flange pairs; and
  (4) tangential contact is assumed *outside* the bolt circle.
(d) The theoretical basis for Appendix Y is contained in reference [18] by R. W. Schneider.

The analysis approach is based on determining the reaction force at the point of metal-to-metal contact, H_C, by considering the elastic interaction between bolt elongation and flange deflection, which is a function of the stiffness of the elements of the flange assembly and the initial bolt prestress. However, if the analysis assumes that the metal-to-metal tangential contact point is at the flange's outside diameter, no special bolting requirements are necessary to assemble the flange joint.

The first step in the analysis is to determine the classification and category for the flange assembly; doing so determines the set of required design equations. The flange classification and category is defined as follows:

(*a*) *Flange Classification*

Class 1: identical flange pairs
Class 2: nonidentical flanges where the I.D. of the reducing flange $> C/2$
Class 3: nonidentical flanges where the I.D. of the reducing flange $< C/2$

(*b*) *Flange Categories*

Within each class are three categories:

Category I: integral
Category II: loose with hub
Category III: loose or optional without hub

The allowable flange-design stresses:

S_b = the Code-allowable design stress for the bolts
S_f = the Code-allowable design stress for the flange

The operating bolt stress:

$$\sigma_b < = S_b$$

The longitudinal-hub stress:

$$S_H < = 1.5S_f \quad \text{and} \quad 2.5S_n$$
$$< = S_f \quad \text{(for cast iron)}$$

The radial stress:

$$S_R < = S_f$$

The tangential stress:

$$S_T < = S_f$$

The combined stresses:

$$(S_H + S_R)/2 < = S_f$$
$$(S_H + S_T)/2 < = S_f$$

The stress at the center of the reducing flange:

$$S_R \quad \text{and} \quad S_T < = S_f$$

(*c*) *Procedure for the Design of Appendix Y Flanges*

First determine the class and category, then,

(1) Assume metal-to-metal contact point h_c (see Fig. 9.12):

$$h_{c\ \max} = (A - C)/2 \quad \text{(for no spacer)}$$

Note: It is conservative and often reasonable to assume $h_c = h_{c\ \max}$.

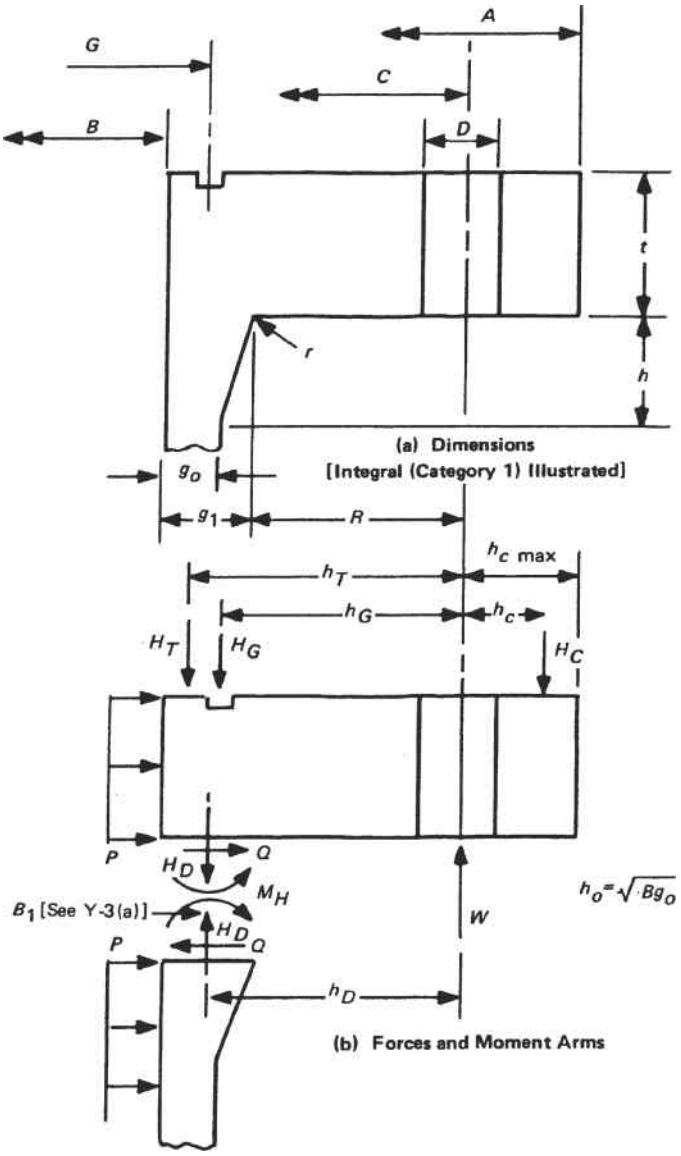


FIG. 9.12 FLANGE DIMENSIONS AND FORCES (*Source*: Fig. Y-3.2, Section VIII, Division 1, Appendix Y of the ASME B&PV Code)

(2) Compute the contact force, H_c:

$$H_c = (M_p + M_s)/h_c$$

(3) Compute the operating bolt load:

$$W_{m1} = H + H_G + H_C$$

(4) Compute the operating bolt stress:

$$\alpha_b = W_{m1}/A_b$$

(5) Is the operating bolt stress < the allowable?
(6) Compute the bolt prestress, S_i
(7) Is S_i reasonable and $< S_b$?
(8) Compute the flange stresses

Example Check the flange stresses and required bolt area for the following integral-weld-neck flange design where both flanges are identical. (Note: The geometry is identical to the example in Section 9.6.1.3.8.)

The design pressure: $P = 414$ psi
The design temperature: $T = 500$°F
The flange material: SA105
The bolting material: SA193–B7
The inside diameter: $B = 32$ in.
The outside diameter: $A = 39.125$ in.
The bolt circle: $C = 37.00$ in.
The flange thickness: $t = 2.0$ in.
The hub length: $h = 2.75$ in.
The hub thickness (small end): $g_o = 0.5$ in.
The hub thickness (large end): $g_1 = 1.125$ in.
The gasket: an elastomer O-ring at $G = 33.888$ in.
The bolting: 36 − 1 in. diameter bolts ($n = 36$)
The bolt area: $A_b = 36(0.551) = 19.836$ in.^{2} (root area is from Table 9.5)

Because the flange design is integral and both flanges in the flange pair are identical, the flange assembly is classified as Class 1, Category 1. In accordance with Table Y-6.1, the following equations from Appendix Y apply to this design: (5a), (7)–(13), (14a), (15a), and (16a).

Calculate the bolt-circle-aspect ratio:

$$AR = nD/(3.14C)$$

Where the bolt-hole diameter, D, is equal to the bolt diameter + 0.125 in.:

$$AR = 36(1.125)/[(3.14)(37)] = .348$$

Calculate the bolt-hole-flexibility factor, which accounts for the increase in bending flexibility from the presence of bolt holes in the flange. The effect of the bolt holes on flange rigidity is not addressed for Appendix 2 flanges without metal-to-metal contact outside the bolt circle.

$$r_B = \frac{1}{n} \times \left(\frac{4}{\sqrt{1 - AR^2}} \tan^{-1} \sqrt{\frac{1 + AR}{1 - AR}} - \pi - 2 \times AR) \right)$$
$$= \frac{1}{36} \times \left(\frac{4}{\sqrt{1 - 0.348^2}} \tan^{-1} \sqrt{\frac{1 + 0.348}{1 - 0.348}} - \pi - 2 \times 0.348 \right)$$
$$= 0.00757$$

Calculate the integral-flange factors from Appendix 2:

$$\begin{aligned} h_o &= \sqrt{B \times g_o} \\ &= \sqrt{32 \times 0.5} \\ &= 4.0 \\ h/h_o &= 2.75/4.0 = 0.6875 \\ g_1/g_o &= 1.125/0.5 = 2.25 \\ K &= A/B = 39.125/32 \\ &= 1.223 \\ F \text{ (from Fig. 2-7.2)} &= 0.777 \\ V \text{ (from Fig. 2-7.3)} &= 0.162 \\ f \text{ (from Fig. 2-7.6)} &< 1.0; \text{ therefore, use } f = 1.0 \\ Z \text{ (from Fig. 2-7.1)} &= 5.041 \\ F' \text{ [from Eqn. (5a)]} &= g_o^2(h_o + Ft)/V \\ &= 0.5^2(4 + 0.777 \times 2.0)/0.162 \\ &= 8.592 \end{aligned}$$

$$\begin{aligned} \text{Because } f < 1.0,\ B_1 &= B + g_1: \\ B_1 &= 32 + 1.125 = 33.125 \end{aligned}$$

The shape factor:

$$\begin{aligned} \beta &= (C + B_1/2 \times B_1) \\ &= \frac{37 + 33.125}{2 \times 33.125} = 1.0585 \end{aligned}$$

The moment arms (see also Appendix 2, Table 2-6):

$$\begin{aligned} R &= (C - B)/2 - g_1 \\ &= (37 - 32)/2 - 1.125 = 1.375 \\ h_D &= R + 0.5g_1 \\ &= 1.375 + 0.5(1.125) = 1.9375 \\ h_G &= (C - G)/2 \\ &= (37 - 33.888)/2 = 1.556 \\ h_T &= (R + g_1 + h_G)/2 \\ &= (1.375 + 1.125 + 1.556)/2 = 2.028 \end{aligned}$$

Assume the maximum value for h_C:

$$\begin{aligned} h_C = H_{C\,\max} &= (A - C)/2 \\ &= (39.125 - 37)/2 = 1.0625 \end{aligned}$$

The shape factor:

$$\begin{aligned} a &= (A + C)/(2B_1) \\ &= (39.125 + 37)/(2 \times 33.125) = 1.149 \\ J_S &= \frac{1}{B_1}\left(\frac{2 \times h_D}{\beta} + \frac{h_C}{a}\right) + \pi \times r_B \\ &= 0.1622 \\ J_P &= \frac{1}{B_1} \times \left(\frac{h_D}{\beta} + \frac{h_C}{a}\right) + \pi \times r_B \\ &= 0.107 \\ H &= 0.785G^2P \\ &= 0.785(33.888)^2 414 = 373{,}220 \\ H_D &= 0.785B^2P \\ &= 0.785(32)^2 414 = 332{,}790 \\ H_G &= 0 \quad \text{(the self-sealing O-ring)} \end{aligned}$$

$$\begin{aligned} H_T &= H - H_D \\ &= 373{,}220 - 332{,}790 = 40{,}430 \\ H_P &= 2b(3.14)GmP \\ &= 0 \quad \text{(the self-sealing O-ring, } m = 0) \\ M_P &= H_D h_D + H_T h_T + H_G h_G \\ &= 332{,}790(1.9375) + 40{,}430(2.028) + 0 \\ &= 726{,}770 \end{aligned}$$

The moment from the flange hub interaction:

$$\begin{aligned} M_S &= -\frac{J_P \times F' \times M_P}{t^3 + J_S \times F'} \\ &= -71{,}000 \\ E\theta_B &= \frac{5.46}{\pi \times t^3}(J_S \times M_S + J_P \times M_P) \\ &= 14{,}380 \\ H_C &= (M_P + M_S)/h_C \\ &= 617{,}102 \\ W_{m1} &= H + H_G + H_C \\ &= 990{,}320 \end{aligned}$$

The operating-bolt stress:

$$\begin{aligned} \sigma_b &= \frac{W_{m1}}{A_b} \\ &= 49{,}925 \text{ psi} \end{aligned}$$

However, this is greater than the allowable bolt stress, S_b = 25,000 psi; therefore, the bolt area must be increased.
The design prestress in bolts:

$$S_i = \sigma_b - \frac{1.15 \times h_c^2 \times (M_P \times M_S)}{a \times t^3 \times l \times r_E \times B_1}$$

$$l = 2t + t_s + 0.5d_b = 2(2) + 0 + 0.5(1) = 4.5 \text{ in.}$$

$$r_E = \text{modulus ratio} = 1.0$$

$$S_i = 56{,}672 - \frac{1.15 \times 1.0625^2 \times (726{,}768 - 71{,}097)}{1.149 \times 2^3 \times 4.5 \times 1.0 \times 33.125} = 49{,}300$$

The radial flange stress at the bolt circle (the allowable stress = 19,600 psi):

$$\begin{aligned} S_R &= \frac{6 \times (M_P + M_S)}{t^2 \times (\pi \times C - n \times D)} \\ &= \frac{6 \times (655{,}671)}{2^2 \times (\pi \times 37 - 36 \times 1 \times 1.125)} = 12{,}990 \end{aligned}$$

The radial flange stress at the inside diameter (the allowable stress = 19,600 psi):

$$\begin{aligned} S_R &= -\left(\frac{2 \times F \times t}{h_o + F \times t} + 6\right) \times \frac{M_S}{\pi \times B_1 \times t^2} \\ &= -\left(\frac{2 \times 0.7769 \times 2}{4 + 0.7769 \times 2} + 6\right) \times \frac{-71{,}097}{\pi \times 33.125 \times 2^2} = 1{,}120 \end{aligned}$$

The tangential flange stress at the inside diameter (the allowable stress = 19,600 psi):

$$S_T = \frac{t \times E \times \theta_B}{B_1} + \left(\frac{2 \times F \times t \times Z}{h_o + F \times t} - 1.8\right) \times \frac{M_S}{\pi \times B_1 \times t^2}$$
$$= \frac{2 \times 19{,}392}{33.125} + \left(\frac{2 \times 0.7769 \times 2 \times 5.0413}{4 + 0.7769 \times 2} - 1.8\right) \times \frac{-77{,}097}{\pi \times 33.125 \times 2^2} = 690$$

The longitudinal-hub stress (the allowable stress = 1.5 × 19,600 = 29,400 psi):

$$S_H = \frac{h_o \times E\theta_B \times f}{0.91 \times (g_1/g_0)^2 \times B_1 \times V}$$
$$= \frac{4 \times 14{,}381 \times 1.0}{0.91 \times (1.125/0.5)^2 \times 33.125 \times 0.1616} = 2{,}333$$

The combined stresses (the allowable stress = 19,600 psi):

$(S_H + S_R)/2 = 7{,}660$ psi (at the bolt circle)
$(S_H + S_R)/2 = 1{,}730$ psi (at the inside diameter)
$(S_H + S_T)/2 = 1{,}510$ psi (at the inside diameter)

The flange stresses are low; they are below the allowable stress limits, with the radial stress at the bolt circle governing the design. Therefore, the same flange geometry as that used for the Section VIII, Division 1, Appendix 2 example shown in Section 9.6.1.3.8 would require more bolt area but less flange thickness when used as a flat-face Appendix Y flange with an O-ring gasket. Note: This design was used for comparison, not as an optimum design.

9.6.1.5 Design Rules for Clamp Connections Clamp connectors carry the axial end thrust through the clamp. The bolts are used to draw the clamp together to maintain metal contact. Typically, pressure-energized gaskets are used. The clamp design is illustrated in Fig. 9.13; clamp-lug configurations are illustrated in Fig. 9.14. Some issues considered in the design of clamp connectors in accordance with Section VIII, Division 1, Appendix 24 of the ASME Code are as follows:

(1) Section VIII, Division 1, Appendix 24 and Section VIII, Division 3, Appendix G each contain design rules for clamp connections. This lower-profile design has advantages for higher design pressures.
(2) Appendix 24 applies to clamp designs whether or not they use a wedge action during assembly.
(3) Designs with clamping surfaces parallel to the hub faces are acceptable and designed for a total clamping angle of 10 deg.
(4) The use of either pressure-energized or low-seating load gaskets is recommended.
(5) Hub forces shall have metal-to-metal contact outside the gasket-seal diameter.
(6) Friction between the hub and clamp is considered in design. Friction resists the bolt forces compressing the flange-seating faces during cold-bolt-up; however, it also resists the pressure thrust attempting to open the flange faces during operation.
(7) The clamp-hub taper angle shall not be greater than 40 deg., and for the calculation of the operating-bolt load, the difference between the clamp-hub taper angle and the friction angle shall not be less than 5 deg.
(8) The friction angle used in the calculation of the gasket-seating and assembly-bolt loads shall not be less than 5 deg. The friction angle shall be determined by the Manufacturer and be based on test results for both assembly and operating conditions.
(9) Clamps shall be provided with a bolt retainer that will hold the clamps together independently in case of a bolting failure, or else two or more bolts per lug shall be used.
(10) Hubs and clamps shall not be machined from the plate and shall be given a normalizing or full-annealing heat treatment when the thickness of the hub neck exceeds 3 in.

The design methodology is as follows:
The total hydrostatic end force:

$$H = 0.785G^2P$$

The total axial-gasket-seating load:

$$H_m = 3.14bGy$$

or the required load for self-energized gaskets.
The operating gasket compressive load:

$$H_p = 2b \times 3.14GmP.$$

Note that for self energized gaskets $H_p = 0$, unless the retaining load is significant.

Bolting requirements are for the total bolt area per clamp lug. Typically there are two bolts per clamp lug. The bolts pull the clamps together in the tranverse or circumferential direction, and the tapered clamp faces draw the flange faces together in the axial direction. Similar to Appendix 2 flange-joint design, both a gasket seating and an operating case are considered in design. However, a third assembly case is required to ensure that the flange faces are properly preloaded. The friction force works against you during gasket seating by resisting the bolting forces and works for you during operation by resisting joint separation.

The minimum initial bolt load for gasket seating:

$$W_{m2} = 0.637 \times H_m \times \tan(\phi + \mu)$$

where

ϕ = the clamp-hub taper angle
μ = the friction angle

The required bolt load for the operating condition:

$$W_{m1} = 0.637 \times (H + H_p) \times \tan(\phi - \mu)$$

The required initial assembly-bolt load to ensure that the flange faces are preloaded sufficiently to prevent joint separation during operation:

$$W_{m3} = 0.637 \times (H + H_p) \times \tan(\phi + \mu)$$

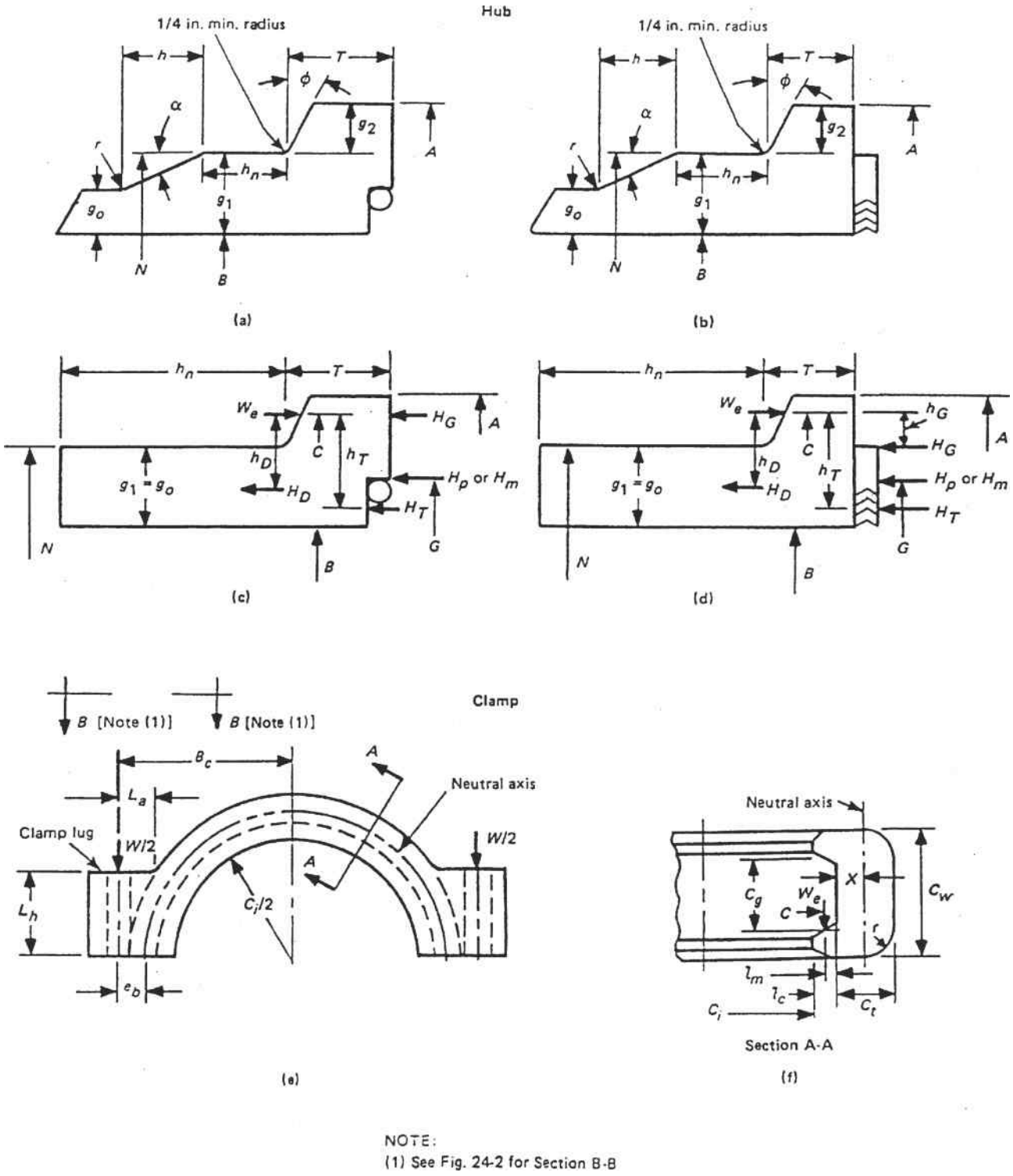


FIG. 9.13 TYPICAL HUB AND CLAMP (*Source*: Fig. 24-1, Section VIII, Division 1, Appendix 24 of the ASME B&PV Code)

The required bolt area per lug, A_{mL}, is the greater of A_{m1}, A_{m2}, or A_{m3}:

$A_{m1} = W_{m1}/2S_b$

$A_{m2} = W_{m2}/2S_a$

$A_{m3} = W_{m3}/2S_a$

A_{bL} = actual root bolt area per lug (in^2)

S_a = the allowable bolt stress at room temperature, psi

S_b = the allowable bolt stress at the design temperature, psi

The design-bolt loads are as follows:

Operating condition: $W = W_{m1}$

Assembly condition: $W = (A_{mL} + A_{bL})S_a$

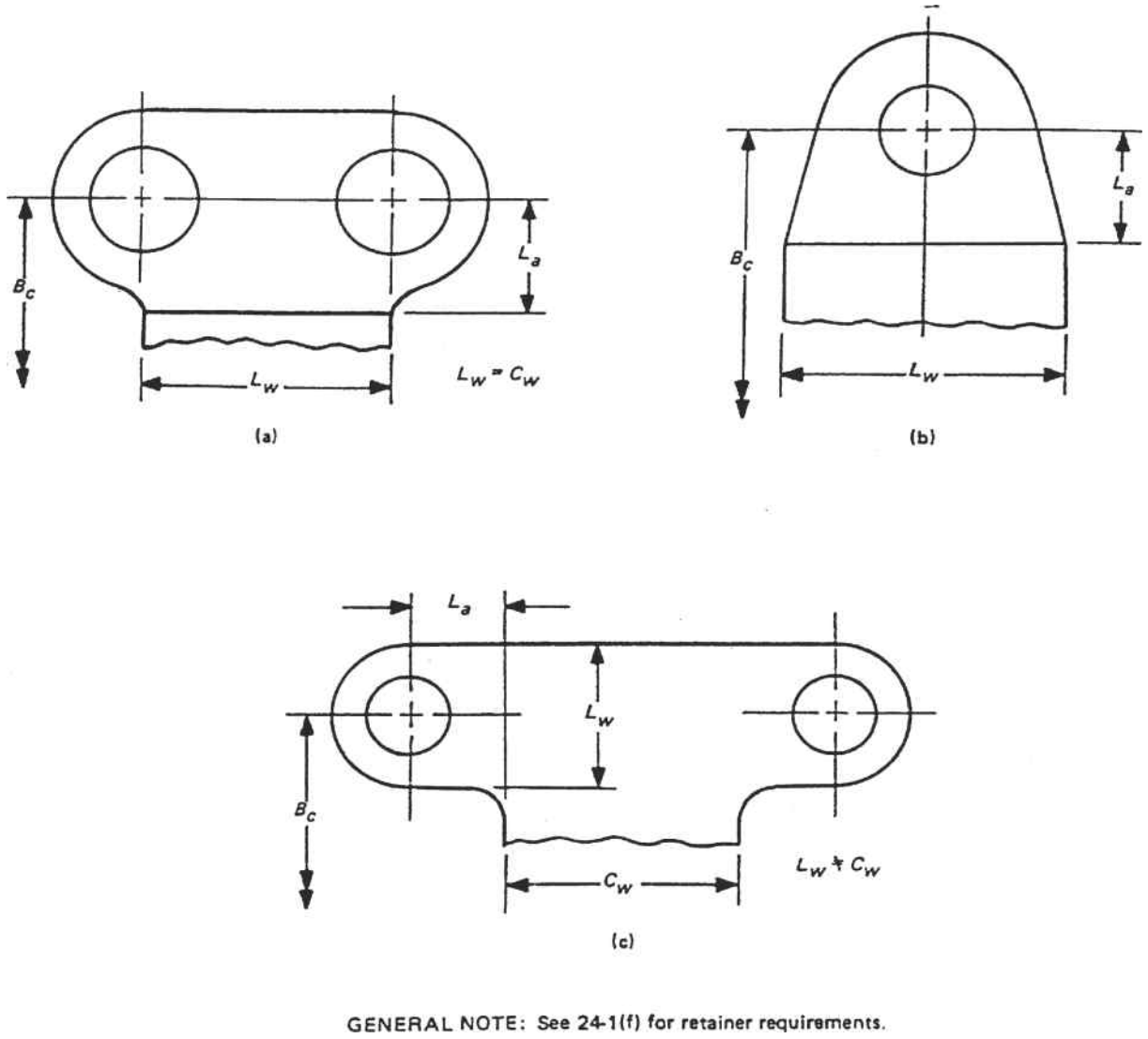


FIG. 9.14 TYPICAL CLAMP-LUG CONFIGURATIONS (*Source*: Fig. 24-2, Section VIII, Division 1, Appendix 24 of the ASME B&PV Code)

Hub moments are calculated by the equations in Appendix 24 for the operating condition. The operating-design moment is the sum of six individual moments. The assembly-design moment is based on the assembly-design-bolt load shown in the preceding equations.

$$M_o = \frac{0.785 \times W \times (C - G)}{\tan(\phi + \mu)}$$

The stress calculation includes the longitudinal-hub stress, S_1; the hoop-hub stress, S_2; the hub-axial-shear stress, S_3; and the hub-radial-shear stress, S_4.

S_1 = the sum of the axial-pressure stress and the bending stress from the reaction moment at the hub neck
S_2 = the Lamé equation for the hoop stress in a thick-walled cylinder
S_3 = the axial-shear stress from the respective design-bolt loads
S_4 = the radial-shear stress from the reaction-shear force at the hub neck

9.6.1.6 Flange Design for Full-Face Gaskets Design rules for flat-face flanges with full-face gaskets are not specifically addressed by the ASME. The following summarizes where in the various Code Sections this flange design would apply.

(1) Section VIII, Division 1, paragraph U(2)(g).
(2) ASME B31.3, paragraph 304.7.2.
(3) ASME B31.1, paragraph 104.7.
(4) Section III, NB-3200 (Design by Analysis).
(5) Section VIII, Division 2, Appendix 4 (Design by Analysis).

Although the ASME B&PV Code does not provide specific formulas for the design of flat-face flanges with full-face gaskets, a variety of methods have been published and used by designers over the years. Although the focus of this chapter is on ASME Code flange design, for which reason detailed formulas are not present, an overview of such methods is presented in the following paragraphs. (Chapter 11 of a book titled *Gaskets and Gasketed Joints* [8] presents a more detailed discussion of bolted flanged connections with full-face gaskets.)

The *Taylor Forge method* is a method that has been used for many years. In fact, it is recommended in Section of the ASME B&PV Code, *Fiber-Reinforced Plastic Pressure Vessels*, that the method be used for the analysis of nonstandard fiber-reinforced plastic (FRP) flanges. Test data have shown this method to be very conservative; it is this conservatism that has led to the other methods discussed later in this chapter. The Taylor Forge method uses the same analytical solution as that used for flanges without contact outside the bolt circle (e.g., Section VIII, Division 1, Appendix 2) and derives a counteracting moment acting on the flange.

In the Taylor Forge method,

(1) The gasket is decomposed into two rings: one inside the bolt circle and the other outside.
(2) Gasket-reaction forces are split between two rings based on the area.
(3) Moments and flange stresses are computed in the same manner as for Appendix 2 flanges.

An indication of this method's marked conservatism is noted during flange rotation, when the outer gasket ring is loaded higher than the inner ring. The Taylor Forge method does not account for this effect; indeed, the required flange thickness may be thicker than necessary.

The *Blach method* is an improvement of the Taylor Forge method. Blach [Reference 8, Chapter 11] suggests using an assumption on gasket-stress distribution different from the uniform stress assumed by the Taylor Forge method. The conservatism in the Taylor Forge method can be reduced by assuming a gasket-stress distribution that increases toward the outside diameter. Two assumptions can be made based on the relative flange stiffness:

(1) thicker (stiffer) flanges with soft gaskets use triangular distribution, and
(2) thinner (flexible) flanges with harder gaskets use parabolic distribution.

9.6.1.7 Rectangular Flanges Flanges of rectangular geometry are not addressed by the ASME B&PV Code. The special design provisions of paragraph U(2)(g) in Division 1 or 304.7.2 in ASME B31.3 apply. References that address the design of rectangular flanges are discussed in the following paragraphs.

(*a*) A design method for rectangular flanges is presented by Mahajan in *Pressure Vessel Design* [9]. The rectangular flat-cover plate is designed the same as that in Section VIII, Division 1 by using the Code *Z*-factor.

B_s = the bolt spacing (maximum bolt spacing = $B_{s\,\max}$)
d = the nominal bolt diameter
$B_{s\,\max} = 2d + (6t/m + 0.5)$

Loads W and bolt areas A are per bolt; the rest of the nomenclature is the same as that of Section VIII, Division 1.

The bolt load for the gasket seating:

$$W_{m2} = B_s b y$$

The bolt load for the operating condition:

$W_{m1} = 0.5GB_S P + 2bB_S mP$
$A_m = > W_{m2}/S_a$ or W_{m1}/S_b
A_b = the actual bolt area
$W_m = 0.5(A_m + A_b)/S_a$

The plate parameter, Z:

$$Z = 3.4 - 2.4G/G_1 \quad (Z < = 2.5)$$

The flat-cover-plate thickness:

$$t_C = G\sqrt{\frac{ZCP}{S_C} + \frac{6Wh_G}{S_C B_S G^2}}$$

S_C = the cover-plate allowable stress

9.6.1.8 Header Flange Design It is recommended that one deviate from Mahajan's procedure for the header-flange design if full-penetration welds are assumed (if not, the section modulus should be modified accordingly).

$W = W_m$ for the cold-bolt-up case (compare with cold allowables)
$W = W_{m1}$ for the operating case (allowables at the design temperature)

Assuming that $G_1 \gg G$ and the corners add little support to the mid-span bending:

$$M = WX$$

The radial flange stress, S_R:

$$S_R = 6M/(B_s t^2) < = S_a$$

The longitudinal-bending stress in the header side plates (note: flat side plates must also meet ASME Section VIII rules for rectangular vessels):

$$M_H = Wh_H$$
$$S_L = 6M_H/[B_S(t_H)^2] < = 1.5S_a$$

Note that the allowable stress basis follows the Section VIII, Division 1 approach and is conservative. The Section VIII, Division 2, Appendix 4 approach can be applied in certain applications with more rigorous analysis.

Flange rotation and tangential stress must also be considered. The header-flange ring rotates from the distributed bolt load and pressure rotation of the sidewall.

If the side plates are overstressed or have excessive rotation, then gusset plates between the side plates and flange should be considered.

Chapter 10 of *Gaskets and Gasketed Joints* [8] is titled "Bolted Flange Connections for Noncircular Pressure Vessels," by A. E. Blach. The approach is limited to a rectangular flange that is nearly square with an aspect ratio of less than 1.5. The method treats the flange as an equivalent circular flange and follows the ASME Section VIII, Division 1, Appendix 2 rules. The flange width is taken as the same as the rectangular flange; however, the minimum span of the rectangle is "modified" to an equivalent diameter. Note *that* this approach should not be used for other than small diameter flanges to limit span length.

The equivalent I.D., B:

$$B = d\sqrt{Z}$$

where

d = the short span of the rectangular opening
Z = the factor from ASME Section VIII, Division 1

9.7 DESIGN FOR EXTERNAL LOADS

The flange joint is a complex, statically redundant, nonlinear, three-dimensional structural system [10]. There are many variables that affect the behavior of a bolted joint, for which the reader is referred to a book by Bickford [11] that discusses the subject. This section addresses on aspect of the bolted joint design: the linear behavior of flanged joints under pressure and external loads. Because of the complexity of a flange–joint system, pressure vessel and piping design engineers use a variety of simplified approaches to evaluate the adequacy of flanged joints under external loads. Some traditional approaches used in the past are discussed in the following paragraphs.

(*a*) *Guidelines* General guidelines, more commonly referred to as *rules of thumb*, were normally expressed in terms of a maximum force or moment as a function of diameter and were used to determine if loads resulting from external piping were excessive. Although these rules of thumb were simple to apply, they were also inaccurate. Nevertheless, these rules are still used to limit loads on pressure vessel nozzles or on rotating equipment, such as pumps and compressors.

(*b*) *Bolt-Stress Limits* The maximum force per bolt, resulting from pressure and external loads, was computed; it neglected the gasket reaction and was limited to a prescribed allowable. A variation of this method is found in the ASME B31 Mechanical Design Committee (MDC) document, and more recently, in ASME B31.8. The maximum external moment to avoid leakage is given by the following equation:

$$M_L = \left(\frac{C}{4}\right)(S_b A_b - P A_P)$$

where

S_B = the bolt stress, psi
A_b = the total bolt area, in.^{2}
P = the internal pressure, psi
A_p = the area to outside of gasket contact, in.^{2}
M_L = the moment to produce flange leakage, in.-lb
C = the bolt-circle diameter, in.

(*c*) *The Equivalent-Pressure Method* The *equivalent-pressure method* is the most common method of accounting for external loads. It is simple to apply and directionally more accurate than the rules of thumb. However, the method still lacks the accuracy necessary to properly evaluate the adequacy of a flange joint under external loads.

The equivalent pressure is computed as the pressure that gives the same maximum longitudinal stress in the flange neck as the applied external forces. The equivalent pressure for an applied force, F_A, and moment, M, is given by the following equation, where G is the gasket diameter and consistent units are used.

$$P_{\text{eq}} = \frac{16}{\pi G^3} M + \frac{4}{\pi G^2} F_A$$

The equivalent pressure is added to the design pressure; then, the flange adequacy for the total pressure is determined by either one of the following approaches:

(1) comparison with the ASME B16.5 flange ratings, or
(2) computation in accordance with the ASME Section VIII design rules.

Although the ASME Section VIII computation is the more accurate approach, the results are still conservative because the design requires an artificially high pressure.

(*d*) *Equivalent-Axial-Force Method* A relatively simple but effective method is to compute the maximum axial stress in the flange neck that results from bending and axial forces. The flange is analyzed by using the ASME procedure and adding an axial, axisymmetric force equivalent to the maximum longitudinal stress that is distributed 360 deg. around the flange. Moments can be converted into an equivalent axial force, on the basis of gasket diameter, by the following equation:

$$F_{\text{eq}} = \frac{4M}{G}$$

This method gives reasonable answers and has been effectively employed [12], [13].

(*e*) *Gasket Reaction* Another approach is to look at the reaction forces on the gasket alone, assuming that the bolt stress remains unchanged with external loads [12]. The validity of this assumption on the bolt stress is, of course, dependent on the stiffness of the gasket relative to the bolts. The shift in neutral axis is computed on the basis of the loading and unloading properties of the gasket.

The problem with this method is that it is really applicable only to flange joints under low internal pressures. If the pressures are high, the compression side never overcomes the reduction in gasket stress that arises from pressure, and the gasket stress remains on the same unloading gasket curve. Blach and Liguo [14] compute the gasket reaction, assuming that the bolts carry the tensile portion and the gasket carries compression and ignoring preload and unloading of the gasket and bolts.

(*f*) *Finite-Element Method* The *finite-element method* has the capability of analyzing a flange joint under pressure and external loads by either a full three-dimensional model or an axisymmetric model with moment loads applied as a single harmonic term. Nonlinear gasket properties and thermal effects can also be included. It is one of the most accurate methods, but it is also the most time-consuming.

(*g*) *Recommended Approach* The most efficient approach for evaluating leakage is to evaluate the flange as a structural system. The flexibility of the flange gaskets and bolts must be modeled to accurately predict the gasket and bolt loads resulting from pressure and external loads. The flange can be analyzed by using the shell-and-plate theory solution presented in ref. [4], which is consistent with the current ASME Code approach. The effect of axial loads on a flange joint can be handled the same way as the axial-pressure thrust term in the current ASME method. The axial force is simply added to the axial-pressure-thrust force, and the ASME design procedure is followed for the computation of flange moments. Using the ASME nomenclature,

$$H_D = 0.785 B^2 P + F_A$$

where

F_A = the axial applied force, lb
P = the design pressure, psi
B = the inside diameter of flange, in.
H_D = the axial force in the flange neck, lb

External moments are more difficult to handle. The loading is not axisymmetric and cannot be addressed as easily as the axial forces. However, the ASME design approach assumes axisymmetric

behavior. Therefore, the problem is to evaluate the effect of external-moment loading on the flange joint and develop a correction to be applied to the axisymmetric analysis. This is addressed by analytically solving for the forces acting on a ring flange, as a result of an external moment; then comparing it with the axisymmetric force solution [10].

An external applied moment is assumed to create a linear stress distribution in the flange neck. This moment can be reduced to a linear-distributed load. Therefore, a moment correction factor, F_M, can be defined that adjusts for the torsional resistance of the flange to external-moment loads. Using the relationship between the shear and elastic moduli, $G = E/2(1 + \nu)$, gives the following:

$$F_M = \frac{1}{1 + \dfrac{J}{2(1 + \nu)I}}$$

The greater the torsional resistance, relative to the bending resistance, the less the induced circumferential bending stress and corresponding flange rotation as a result of the external moment.

The preceding equation is an exact solution for compact-ring flanges, where bending is primarily carried by the ring. When circumferential bending or flange rotation limits the design, the equation may be applied directly. Finite-element analysis of loose-ring flanges subjected to both an axisymmetric axial force and a harmonically varying force agree with the preceding equation. Note that the correction can be significant; for example, a rectangular ring flange may be in error by a factor of two or more.

Using the terminology of Section VIII, Division 1, external moments and forces can be included in the design by defining the operating design moment as follows:

$$H_D = 0.785B^2P + F_A + 4F_M M_E/G$$
$$H_G = (2b)(3.14GmP)$$
$$H_T = 0.785(G^2 - B^2)P$$
$$M_o = H_D h_D + H_T h_T + H_G h_G \quad \text{(in.-lb)}$$

Note that this is the approach used by the latest edition of section VIII Division 2.

9.8 TIGHTNESS-BASED DESIGN

The ASME Code *m*-and *y*-factors are empirically based rather than founded on theory, which would allow the prediction of leakage as a function of gasket stress. Tightness-based design methods recognize that all flange joints leak; hence the objective to provide a flange-joint design with a leak rate within acceptable limits for the fluid service. Recent developments in tightness-based design have occurred in the United States, Europe and Japan.

Note that this approach has been the subject of debate by the Code bodies, delaying the addition of new rules in the Code. The details of the method have changed however the basic approach is the same as previous editions of this chapter.

9.8.1 The Pressure Vessel Research Council Method

The new Pressure Vessel Research Council (PVRC) approach [15] developed from an approximately fifteen-year period of research to develop new gasket constants. The research led to the creation of three gasket constants that provide a reasonable representation of the leakage characteristics of a typical flange joint's gasket with a loading history. An understanding of the methodology requires knowing several new definitions, which are summarized in the following paragraphs.

The tightness parameter, T_p, is the internal gage pressure in atmospheres that is required to produce a standard leak rate per unit-gasket diameter. This parameter is dimensionless because pressure is normalized by atmospheric pressure and the leak rate is normalized by a standard leak rate. The tightness parameter is a function of the gasket stress as well as the gasket stress history.

$$T_p = (P/P^*)(L^*/L)^{0.5}$$

where

P^* = the atmospheric pressure
L^* = the standard leak rate, 1 mg He/sec/150 mm diameter
P = the gage pressure
L = the leak rate, mg He/sec/mm diameter

9.8.1.1 Gasket Constants Three gasket constants can define the history of gasket stress as a function of the tightness parameter. Figure 9.15 illustrates the relationship between the gasket constants. The methodology assumes a linear relationship between the log of gasket stress and the log of the tightness parameter—a relationship that changes depending on whether the gasket is loaded or unloaded. The gasket tightness as a function of stress level is history-dependent. The physical significance of the gasket constants is as follows:

a = Slope of the log-gasket stress versus the log-tightness parameter during gasket loading
G_b = Intercept of the log–log plot of gasket loading stress versus the tightness-parameter line at a tightness parameter of 1.0
G_s = Intercept of gasket unloading stress versus the tightness-parameter line, on a log–log plot, at a tightness parameter of 1.0

The greater the initial gasket stress, the greater the tightness for the same stress level after gasket unloading in operation. Therefore, the new correlations reinforce the long-held importance of initial gasket prestress. The three gasket constants G_s, G_b and a replace constants *m* and *y*.

9.8.1.2 Minimum Required Tightness

$$T_{p\ \min} = 0.1243(T_c)P$$

where

T_c = the tightness class factor based on a target-allowable leak rate

Therefore, $T_{p\ \min}$ is the minimum tightness required during operation to maintain leakage to within the target allowable. Tightness is determined by the combination of gasket prestress and operating-gasket-stress levels.

9.8.1.3 Minimum Required Cold-Bolt-Up Gasket Stress

$$S_{ya} = (G_b)(T_{pa})^a$$

where,

T_{pa} = assembly tightness

9.8.1.4 Minimum Required Operating-Gasket Stress

$$S_{m1} = G_S(T_{p\ \min})^k$$
$$k = \log(S_{ya}/Gs)/\log(T_{pa})$$

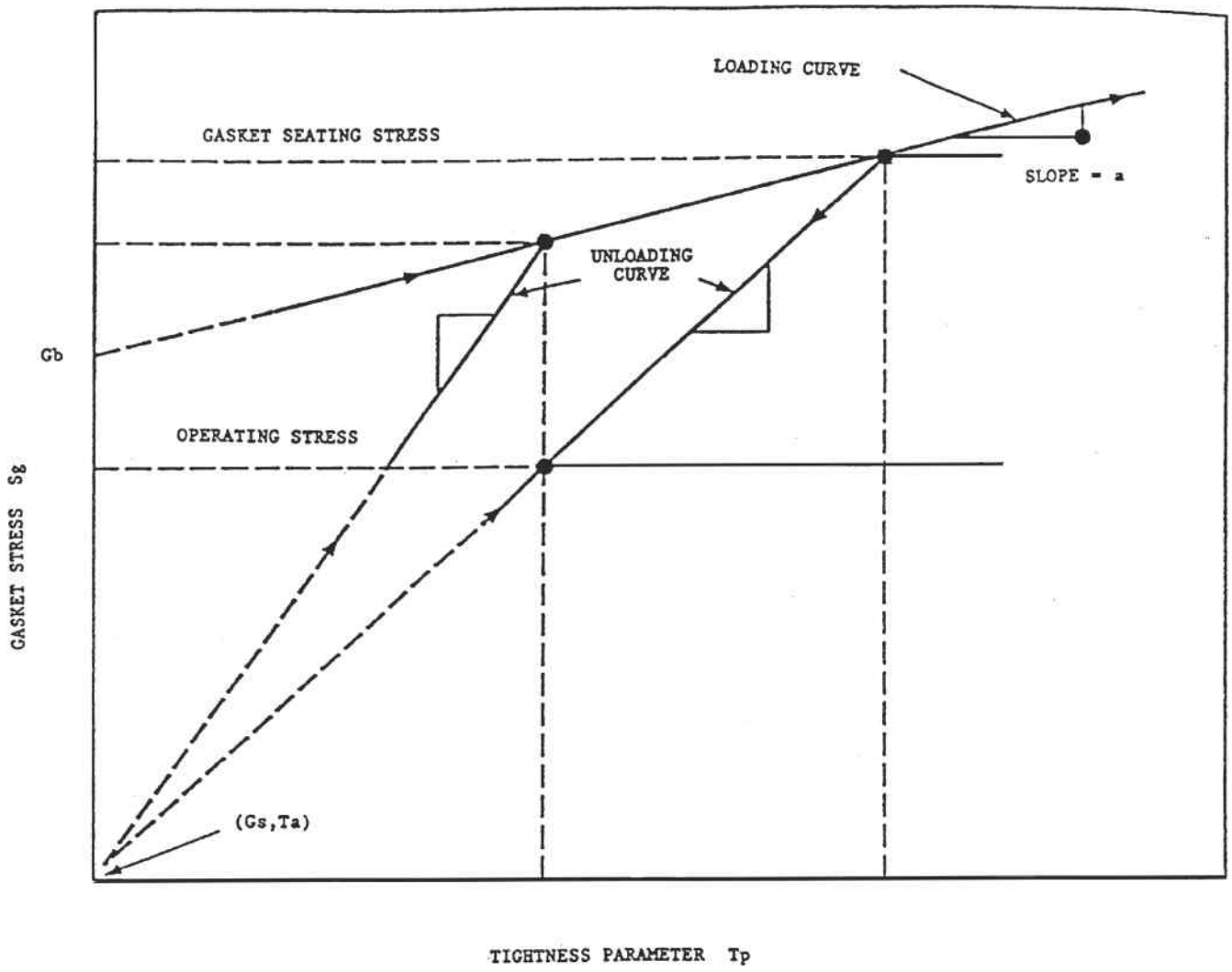


FIG. 9.15 GASKET STRESS VERSUS TIGHTNESS PARAMETER

where, at the optimum pre-load:

S_{m1} = operating gasket stress equal to the initial cold-bolt-up gasket stress minus the amount that the gasket is unloaded from the axial-pressure thrust and external loads.

Therefore, it is an iterative procedure to solve for the required initial gasket stress to achieve the required tightness during operation.

9.8.2 New Proposed ASME Flange Design Rules

Reader caution: These rules are not yet approved and the details are under development and review. The ASME B&PV Code is currently in the process of adopting a new set of design rules for flange design. The current intention is that the new rules will initially enter the Code as a nonmandatory appendix. Mandatory Appendix 2 in Section VIII, Division 1 will remain as is; however, design in accordance with the new appendix will be permitted. The new proposed ASME flange design rules are based on the PVRC research program. The concept of tightness is introduced to the Code and the three new gasket constants a, G_b, and G_s will replace the use of m and y factors in the new flange-design appendix.

The designer may be required to select a service class which corresponds to a theoretical tightness and leak rate. This is still under discussion but the concept is: the higher the service class, the greater the required bolting and the thicker the flange design. The proposed service classes are shown in Table 9.6. The current proposal is to use a default value of $T_c = 1.0$. other values may be used based on experience and user agreement.

The concept of bolting efficiency has also been discussed for inclusion in the Code. It is well known that controlled tensioning or direct measurement of bolt strain provides a more reliable gasket prestress than uncontrolled torquing of the bolts. The design concept would be that bolting-assembly efficiency would penalize flange designs that do not use controlled torque or bolt tensioning as shown in Table 9.7.

External loads from forces and moments will also be included. The proposed methodology is as described in Section 9.7. The flange stresses during assembly and operation will more closely represent actual flange joint behavior than the current rules.

TABLE 9.6 TIGHTNESS FACTORS FOR SERVICE CLASS

Service Class	Tc	Leak Rate LbHe/hr/in Diameter	Leak Rate mgHe/sec/ mm diameter
Mild	0.1	1/25	1/5
Normal	1	1/2500	1/500
Critical	3	1/22500	1/4500

TABLE 9.7 ASSEMBLY EFFICIENCY

Assembly Efficiency η	Bolt Preload Control Method	Bolt Load Variation from Mean
0.75	Manual or power wrench	Over 50%
0.85	Accurately applied torque	30 to 50%
0.95	Simultaneous multiple Application of direct Tension to three or More bolts	10 to 30%
1.0	Direct measurement of Stud stress or strain or the Simultaneous hydraulic Tensioning of all bolts	10% or less

Elastic interaction equations have also been proposed, considering the elastic stiffness of the bolts, gasket and flange to compute the operating gasket stress.

The variation is gasket stress between bolts is addressed by a bolt spacing reduction factor, γ, on gasket stress. The methodology is as discussed in paragraph 9.9.2.3.

Effects such as thermal differentials, gasket stress–strain, and creep behavior are considered in a simplified approach. The design methodology is described in the following paragraphs:

Select a tightness class and factor, T_c, from Table 9.6, and select an assembly method for the flange and establish h from Table 9.7.

Compute the required minimum tightness during operation, $T_{P\,\min}$:

$$T_{P\,\min} = 0.1243(T_c)P$$

The required assembly tightness, T_{Pa}, is between $T_{P\,\min}$ and $T_{P\,\max}$.

Where $T_{P\,\max}$ is a specified tightness limit.

The design-gasket stress (to seat the gasket during initial assembly):

$$S_{ya} = (G_b)(T_{pa})^a$$

The minimum required operating-gasket stress:

$$S_{m1} = G_s(T_{p\,\min})^k$$

$$k = \log(S_{ya}/G_s)/\log(T_{pa})$$

$$S_{m\gamma} = \{A_b\eta\gamma S_{bg} - [PA_i + F_A + 4QM_E/G + \Delta T + \Delta C + U_s]\}/ + (A_g + A_p)$$

Compute the bolt loads:

$$\text{BU2} = PA_I + S_{M1}(A_g/\eta\gamma + A_p) + F_A + (4M_E)/G$$

$$\text{BU1} = \text{BU2} + \Delta T + \Delta C$$

where

F_A = the applied axial load
M_E = the external bending moment
A_I = the pressurized area = $0.785G^2$
A_g = the gasket contact area based on n_o
ΔT = bolt load loss due to temperature differentials
ΔC = bolt load loss due to gasket creep
U_s = gasket load partion taken by compression stop
S_{bg} = allowable bolt stress at the gasket seating temperature
S_{bo} = allowable bolt stress at the operating temperature

The required bolt area is the greater of A_{m1} and A_{m2}.

$$A_{m1} = \text{BU1}/(2.0S_{bg})$$

$$A_{m2} = \text{BU2}/S_{bo}$$

Compute the flange moments for the determination of flange stresses as follows:

The operating case:

$$M_{o1} = H_Dh_D + H_Th_T + H_Gh_G$$
$$M_{o2} = 4M_EF_M[h_D/(C - 2h_D)] + F_A(h_D) + (\Delta T + \Delta C)\,h_g$$
$$M_o = M_{o1} + M_{o2}$$

where

F_M = the moment correction factor = $[2(1 + v)I]/[I_P + 2(1 + v)I]$
I = the flange bending moment of inertia
I_P = the flange polar moment of inertia

H_D, h_D, etc., are the same as defined in Section 9.6.1.3.8 for Section VIII, Division 1, Appendix 2.

The gasket-seating (assembly) moment:

$$M_i = .5(2S_{bo}\,A_b + S_{m1}A_p)(C - G)$$

Calculating flange stresses is by use of the same equations as those of Section VIII, Division 1, Appendix 2 flange stresses.

Future design considerations include gasket creep, thermal effects and flange interaction analysis.

9.9 FLANGE-JOINT ASSEMBLY

The ASME Code design requirements in Appendices 2 and Y are based on structural integrity and safety of the design to adequately contain pressure. These design rules do not address the assembly of the bolted flange joint. A typical flange joint must be bolted up to bolt stress levels well above the Code-allowable design stresses to achieve and maintain tightness during service. Appendix S of Section VIII, Division 1 provides guidance to the designer on some practical considerations of the design and assembly of flange joints.

ASME PCC-1 provides guidance on bolted joint flange assembly.

9.9.1 ASME Appendix S: Design Considerations for Bolted Flange Connections

Appendix S of Section VIII, Division 1 is a nonmandatory appendix that addresses the assembly of bolted flange joints. The rules of Appendices 2 and Y of Division 1 provide design rules and equations to size the flange-joint member and to determine the required bolt area. However, in an actual flange joint designed to Code rules, bolt stresses may exceed the Code-allowable bolt-stress levels to achieve a leak-tight joint. Obviously, higher bolt stresses are required to pass a hydrostatic test only because of the higher pressures. Other practical considerations include the need for higher initial bolt stresses to accommodate the loss of bolt preload caused by gasket creep or nonrecoverable deformation during operation.

Appendix S provides a correlation for expected bolt stress to be achieved for manual bolting. The typical bolt stress for manually tightened bolts is given by the following empirical equation:

$$S = 45{,}000/d$$

S = the nominal bolt stress, psi
d = the nominal bolt diameter, in.

ASME Section II Part D lists two sets of allowance stress values for the austenitic alloys, due to the relatively low yield strength values for these materials. However, when more than one set of allowable stress values are listed for a material, it is recommended to use the power values for flange design since displacement is a concern for flange design.

9.9.2 Bolting and Gasket Considerations

During tightening, bolt stresses are influenced by the tightening of adjacent bolts from elastic deflections of the flange assembly. This effect is called *elastic interaction.* Bibel [16] discusses this in more detail.

Elastic interaction has the greatest and least effect on the first and last bolts tightened, respectively.

9.9.2.1 Variables Affecting Elastic Interaction

(1) The bolting pattern, method and sequence.
(2) The gasket type and filler.
(3) The relative stiffness of the bolts compared to the flange gasket system.

9.9.2.2 Variables Affecting Gasket Tightness during Operation

(1) The elastic interaction during assembly.
(2) The target bolt-stress assembly.
(3) The flange-assembly procedure.
(4) The flange insulation.
(5) The thermal gradients and transients.
(6) The bolt and flange yield strength.
(7) The gasket relaxation.
(8) The gasket stress–strain properties.
(9) The gasket thermal degradation and stress limits.
(10) The surface finish.
(11) The overcompression of spiral-wound gaskets.

9.9.2.3 Bolt-Spacing Requirements Bolt spacing in an important consideration in flange design. The bolts must be spaced close enough together to maintain nearly uniform gasket pressure between them. However, certain minimum spacing requirements must be maintained to allow for tightening of the bolts by torquing or tensioners. Table 9.5 provides spacing requirements for manual wrenching.

Taylor Forge's "Modern Flange Design" [18] publication recommends the following equation, recognizing the importance of gasket compressibility that varies inversely with the gasket parameter, *m.*

$$\text{Bolt spacing (max)} = 2d + 6t/(m + 0.5)$$

where

d = the bolt diameter
t = the flange thickness

Koves [20] developed an analytical solution for the gasket-pressure distribution between bolts based on a beam with an elastic-foundation analysis. This was an improvement on Roberts 1950 [19] numerical super position approach and validated by 3-D flange element analysis.

The allowable bolt spacing is determined by the required minimum gasket stress mid way between bolts ($\sigma_{L/2}$) divided by the maximum stress under the bolts (σ_0) and is a unique function of the parameter [βL]. Table 1 provides some target values of [βL] for specific allowable values of $\sigma_{L/2}/\sigma_0$. The maximum allowable bolt spacing to meet a given stress ratio limit is given by the following equation.

Bolt Spacing Limit = [βL]/β

Where the parameter

$$\beta = \sqrt[4]{\frac{E_g \cdot b_g}{2 \cdot t_g \cdot E_f \cdot I}}$$

Nomenclature:

B = Flange ID, mm (in)
b_g = Gasket effective width, mm, (in)
E_f = Elastic Modulus of Flange, MPa (ksi)
E_g = Elastic Modulus of Gasket, MPa (ksi)
g_0 = Small end of hub; mm (in)
h_o = ASME Code Appendix 2 hub parameter, mm (in)
I = Effective bending moment of inertia of flange, mm^4 (in^4)
L = Bolt Spacing, mm (in)
P = Bolt Load, N (lbs)
t_g = Gasket thickness, mm (in)
t = Flange thickness, mm (in)

The effective bending moment of inertia, I, of the flange can be determined from the plate and shell theory flange stiffness solution used by ASME by equating the flange rotation of a compact ring with the flange rotation given by the ASME Appendix 2 equations.

For an Integral or loose flange without a hub:

$$I = (1/24)\, B t^3 \ln(K)$$

For an Integral flange with a hub:

$$I = .0874\, (L\, g_0^2\, h_0\, B)/V$$

For a Loose flange with a hub:

$$I = .0874\, (L\, g_0^2\, h_0\, B)/V_L$$

Table 1

Stress Ratio $\sigma_{L/2}/\sigma_0$	[βL]
.95	1.494
.9	1.795
.85	2.009
.8	2.183
.75	2.336
0	4.735

Table 1 may be used with the equations above to establish maximum allowable bolt spacing for a given flange design and gasket. Stiffer gaskets with more flexible flanges will require smaller bolt

spacing limits. Notice how quickly the gasket stress between bolts falls off for higher values of [βL]. The procedure is as follows: First select an acceptable value of reduction in gasket stress, $\sigma_{L/2}/\sigma_0$, then determine parameter [βL] from Table 1 and divide by β, to get the allowable bolt spacing L. For example, if $\sigma_{L/2}/\sigma_0 = .95$ is desired for leak tightness, then the required bolt spacing equals $1.494/\beta$. Note that gasket stress-strain characteristics are typically non-linear, however they can be reasonably represented as an effective elastic modulus over the range of gasket stress of interest.

9.10 FUTURE CODE REQUIREMENTS

The ASME Codes and Standards are constantly evolving, adding technology as it is developed. Section 9.8 describes the methodology proposed for the ASME Code flange design rules to address leakage. This fills a need to provide a more rational approach to establish gasket factors for assembly and operation. However, the proposed gasket factors do not provide all of the important data needed to establish joint tightness. Section 9.7 describes design methods for external forces and moments, not currently covered by ASME Section VIII Division 1. Some recommendations for future additions to the Code are addressed below.

Replacing the current Code m and y values with the new tightness based gasket constants will be a step in the right direction. However, they only describe the behavior of a 4 inch NPS gasket at room temperature with uniform gasket stress. There are many other variables involved in a successful flange design in the field. The following lists some of the gasket properties that are important in evaluating a design.

(a) The stress-strain loading and unloading characteristics of a gasket.
(b) The gasket stress-strain and tightness properties as a function of temperature.
(c) The time dependent creep relaxation properties of a gasket.
(d) The degradation of gasket properties over time.
(e) Gasket tightness in the presence of radial shear.
(f) The effect of gasket width on tightness.
(g) The effect of non-uniform gasket stress on tightness.
(h) The effect of gasket stress-strain history on tightness.
(i) The gasket stress limits and tightness at high stress levels.
(j) Gasket tightness under external forces and moments.

The flange design determines the gasket loading based on the flange stiffness and loading history. Thermal loads play a significant roll in actual flange joint behavior in operating plants, however current Code rules only address primary pressure loads. The following lists some flange design issues important in design.

(a) The flange rigidity.
(b) Flange rotation due to pressure (axial and radial components).
(c) Flange thermal rotation.
(d) Transient and steady state thermal differential temperatures.
(e) Effect of flange local yielding.
(f) Flange and bolt creep effects.
(g) Flange and bolt stress-strain properties.
(h) Flange design for external forces and moments.

Flange assembly is also an essential piece of the design requirements for a flange joint. Assembly stress is limited by flange distortion or gasket overstress, but must be adequate to maintain minimum tightness requirements and compensate for loss of gasket stress during operation.

Code requirements in the future should better represent actual flange joint behavior by addressing the gasket and flange design issues outlined above. The new proposed ASME Section VIII, Division 1, Appendix BFJ addresses a few of the issues above, but many important issues need resolution. The potential inclusion of the effects of gasket creep, thermal differentials and flange joint interaction in Appendix BFJ would help address some critical issues.

9.11 ACKNOWLEDGMENTS

Many reference sources were used for this chapter, but wherever material was directly reproduced, the source was the ASME B&PV Code Section VIII, Division 1.

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CHAPTER

10

THE EVOLUTION OF U.S. TRANSPORTATION REGULATIONS FOR RADIOACTIVE MATERIALS — AN UPDATED RETROSPECTIVE

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The discussion in this Chapter is a highly condensed version of the information presented previously in Chapter 52 of the 2nd Edition of the *Companion Guide to the ASME Boiler & Pressure Vessel Code* [1]. The full text of the previous Chapter 52, i.e., *Development of U.S. Regulations for the Transportation of Radioactive Materials — A Look Back over the Past 40 Years*, could not be reproduced here. Therefore, this Chapter offers a high-level overview of the information presented previously, including all of the appropriate references.

For the most part, the material that was not included in this version of Chapter 10 is available in the public domain. Due to the sheer volume of the information, readers interested in the preamble-only versions of the material referenced in this Chapter are redirected to Reference [1]. Readers interested in the full-text versions of the material referenced in this Chapter are redirected to the appropriate *Federal Register* and/or U.S. Nuclear Regulatory Commission (NRC) websites. Because some of the material dates back to pre-website times, readers interested in the full-text versions of some of the references may have to rely on the services of their local libraries.

10.1 INTRODUCTION

The discussion in this Chapter is a relatively straightforward, chronological description of the development of U.S. transportation regulations for radioactive materials over the past 40 years. Although primarily based on the development of U.S. regulations for the shipment of what is now known as *Type B* quantities of radioactive materials, the information presented details the interactions between a number of U.S. governmental agencies, commissions, and departments, and the International Atomic Energy Agency (IAEA).

For the most part, the information that follows was taken directly from the *Federal Register*, between 1958 and 2004, which, within the boundaries of the U.S., is considered law — or at least policy — at the federal level. Starting in 1978, however, the information also takes a look at a series of what are called *Guidance Documents*, including Regulatory Guides (i.e., Reg. Guides), NUREGs, and NUREG/CRs.* Developed originally by the U.S. Atomic Energy Agency (AEC), and later adapted by the NRC, the NUREGs and NUREG/CRs cited in this Chapter clearly specify a preferred methodology that can be used to meet the regulatory requirements of Title 10 of the Code of Federal Regulations, Part 71 (10 CFR Part 71, or, more simply, 10 CFR 71). As is appropriate for the discussion in this Chapter, the methodology preferred by the NRC, not as law but as guidance, was adapted directly from the requirements of the ASME's *Boiler & Pressure Vessel Code*.

The information is provided with little embellishment. By taking the information directly from the *Federal Register*, and from the NUREGs and NUREG/CRs that were developed at the time, it becomes a story that tells itself. The information is self-consistent, and it provides many of the details behind the numerous policy decisions that led to the development of the U.S. regulations, as they were in their time, and as they are now.

10.2 BACKGROUND

In 1958, at the request of the Economic and Social Council of the United Nations, the IAEA undertook the development of international regulations for the safe transportation of radioactive materials. The initial regulations published by the IAEA in 1961 were recommended to member states as the basis for national regulations and for application to international transportation. That began the process, in the United States, of a series of revisions to

*As is noted by their descriptions, Reg. Guides and NUREGs are guidance documents developed by the NRC, whereas NUREG/CRs are guidance documents developed for the NRC by NRC contractors. The primary difference between the three types of documents is that Reg. Guides specify NRC *policy*, NUREGs make recommendations speaking for the NRC, and NUREG/CRs make recommendations speaking for NRC contractors.

the U.S. regulations governing the transportation of radioactive materials.

In the hierarchical structure of the U.S. transportation regulations for hazardous materials, the Department of Transportation (DOT) sits at the top. DOT is responsible for the transportation of all hazardous materials within the physical boundaries of the United States. DOT is also responsible for the transportation of all hazardous materials into and out of the United States. In that capacity, the DOT functions as the *Competent Authority* for the United States in all regulatory matters dealing with the transportation of hazardous materials of any kind on a national and international basis.

From a regulatory standpoint, however, radioactive materials are considered to be a subset of hazardous materials. Termed *Class 7* materials in DOT's regulatory language, radioactive materials are currently subdivided into two additional subcategories: Type A quantities and Type B quantities, based on the relative hazard of the radionuclide(s) in question, and the total amount of the activity being shipped in a given package. Although the DOT generally defers to the NRC on technical matters dealing with the transportation of radioactive materials, the regulatory requirements for the transportation of Type A (i.e., relatively small) quantities of radioactive material fall under the purview of DOT regulations (in Title 49 of the Code of Federal Regulations, Parts 173–178, i.e., 49 CFR 173–178); whereas regulatory requirements for the transportation of Type B (i.e., relatively large) quantities of radioactive material fall under the purview of NRC regulations, in 10 CFR 71. But, whether it is a Type A package under the purview of the DOT, or a Type B package under the purview of the NRC, the one major subtheme that is constantly at work is the consistency between the regulations of the United States and those of the IAEA.

In this Chapter, we look at the development of the regulations, the policies, and the recommendations, for the transportation of radioactive material. Although the primary focus is on the development of the regulations for Type B shipping containers (10 CFR 71), we also, out of necessity, take an occasional look at the development of some of the regulations that fall under the purview of the DOT (49 CFR 173–178). Along the way, we also delve into a second major subtheme: compliance with the requirements of the ASME Boiler & Pressure Vessel Code, used as a metric to quantify the U.S. regulatory requirements.

10.3 TITLE 10, CODE OF FEDERAL REGULATIONS, PART 71 (10 CFR 71)

The first, real version of what we would now recognize as 10 CFR 71 was published in the *Federal Register* on July 22, 1966 [2]. That version would become the cornerstone, because it combined the existing regulatory requirements from the older version of 10 CFR 71 [3] with a recently proposed revision to 10 CFR 71 [4] and the proposed regulatory requirements from a then proposed 10 CFR 72 [5,6]. It also went on to describe the initial framework that separated the regulatory jurisdiction of the Atomic Energy Commission[†] from the Interstate Commerce Commission.[‡] It went on to describe the origins of the development of what we now refer to as "specification packages," and it provided a direct linkage between the U.S. regulations for the transportation of radioactive materials and those of the IAEA [7].

10.3.1 10 CFR 71 — 1965 Proposed Rule

Prior to looking at the 1966 Final Rule, however, an examination of its immediate predecessor becomes worthwhile. Published as a *Proposed Rule Making* on December 21, 1965 [8], the proposed rule clearly outlines the framework for what would become the Final Rule:

> "The regulations of the Atomic Energy Commission, Parts 30, 40, and 70 of Title 10, code of Federal Regulations (10 CFR), require that before the Commission approves an application for license to receive, possess, use, or transfer byproduct, source, or special nuclear material, it must determine that the applicant's proposed program is adequate to protect health and minimize danger to life and property.
> "In 1958, the Commission adopted 10 CFR Part 71, 'Regulations To Protect Against Accidental Conditions of Criticality in the Shipment of Special Nuclear Material.' This regulation established procedures for approval of transport of special nuclear material, but set only limited standards. Certain small shipments under specified conditions were made exempt from the licensing requirement.
> "In 1960 and again in 1961, the Atomic Energy Commission published for public comment its proposed 10 CFR Part 72, 'Protection Against Radiation in the Shipment of Irradiated Fuel Elements,' to regulate the increasing number of shipments of irradiated solid nuclear fuel. That proposed regulation has never been adopted by the Commission as an effective regulation, although its previsions [*sic*] have been used as licensing criteria since their publication.
> "On March 5, 1963, the Commission published a proposed revision of Part 71 (28 F.R. 2134), incorporating standards developed as the result of licensing experience as well as from the Commission's experience as a shipper of special nuclear material. In that proposed revision, the concept of different classes of packages of special nuclear material was introduced. This concept, which has been developed by the International Atomic Energy Agency at that time, is intended to distinguish among classes of packages according to the degree of control which must be exercised in transport in order to avoid criticality.
> "Public response to the proposed revision of Part 71 to a large extent suggested that (1) the regulation should emphasize performance standards, insofar as possible, rather than detailed design specifications for shipping containers and shipping procedures, and (2) the method of shipment to satisfy those performance standards should be left to the ingenuity of the shippers. It was suggested that the detailed standards proposed might impair the growth of the industry and development of improved safety concepts and that the standards were already outdated and were in some cases inapplicable, inadequate, or overly restrictive. The comments indicated that licensing requirements based on performance standards would allow needed flexibility to develop improved shipping methods. It was also suggested that the regulatory relationship between the Atomic Energy Commission and the Interstate Commerce Commission be made clear.
> "As a result of the numerous public comments and further study, the notice of proposed rule making issued on March 5,

[†] The Atomic Energy Commission would later be subdivided into the Nuclear Regulatory Commission (NRC) and the Energy Resource and Development Agency (ERDA). ERDA would later become the Department of Energy (DOE).

[‡] The Interstate Commerce Commission would later become the Department of Transportation (DOT).

1963, is withdrawn, and is superseded by this notice. The revision of 10 CFR Part 71 here proposed has deleted the detailed design standards of that proposal, and emphasizes performance standards to determine the adequacy of proposed shipping methods. The performance standards of this proposed revision are compatible with those developed by the International Atomic Energy Agency during the past few years.

"In response to public comments received on the proposed Part 72 dealing with the transport of irradiated fuel elements, and to provide flexibility of approach in that rapidly growing field, a revision was also undertaken of Part 72. As in Part 71, the requirements have, as far as possible, been modified into performance standards. Since the nuclear safety requirements of Part 71 are applicable to the shipment of irradiated as well as unirradiated special nuclear material, the two Atomic Energy Commission transport regulations, Parts 71 and 72 have been combined into a single document in the interest of clarity and to avoid duplication. The notice of proposed rule making issued on September 23, 1961, 10 CFR 72 (26 F.R. 8982), and a minor amendment issued March 5, 1963 (28 F.R. 2142), are withdrawn and superseded by this notice.

"A proposed amendment dated March 5, 1963, to 10 CFR Part 40, 'Licensing of Source Material,' would have provided transport control over certain large masses of source material which, when shipped in combination with materials having unusual moderating properties, might present a possibility of accidental criticality (28 F.R. 2111). Public comments on this proposed amendment questioned the level at which control would be imposed, and questioned the practical need for any control at all. Upon further consideration, the Commission determined that there is no practical need for the proposed control at this time. Accordingly, the notice of proposed rule making issued on March 5, 1963, to 10 CFR Part 40 (28 F.R. 2111) is withdrawn.

"Since 1948 shipments of radioactive material in interstate and foreign commerce have been regulated by the Interstate Commerce Commission under the Transportation of Explosives and other Dangerous Articles Act (18 U.S.C. 831–835). The Atomic Energy Commission has provided a safety evaluation of the same shipments in some cases, both as part of its regulation of the activities of its licensees and its control of its own shipments. To coordinate these efforts under a proposed agreement between the two agencies, the Atomic Energy Commission would adopt standards for the transport of large quantities of licensed radioactive material, as specified in the regulation, as well as the transport of all fissile material because of the additional potential hazard of criticality. The Commission would issue regulations applicable to its licensees, and would apply the same standards in rendering technical advice to the Interstate Commerce Commission for shipments requiring their approval. In regulating the transport of radioactive materials, the Interstate Commerce Commission would take into account the authority to ship granted by the Commission to its licensees and contractors, and the technical advice rendered to the Interstate Commerce Commission by the Commission.

"In summary, the revised Part 71 contains: (1) The substance of the earlier Part 71 which covered the shipment of unirradiated fissile materials, as revised to emphasize performance standards, (2) standards and requirements for the shipment of irradiated fissile materials, and (3) standards and procedures for the shipment of 'large quantities' of licensed material.

"Persons specifically licensed to receive, possess, use, or transfer source material have been included in the scope of this regulation because it is intended that any source material be considered in the evaluation of a package or shipment which also contains byproduct and special nuclear material in sufficient quantities that the standards of Part 71 apply. It is recognized that the exemption provisions of the proposed § 71.5 would probably apply to most, if not all, packages or shipments of source material per se.

"A 'large quantity' of licensed material is defined in the regulation in terms of the 'transport group' of the radionuclide in question (which is based on relative potential hazard in transport), and in terms of 'special form' of the licensed material. A 'special form' is a nondispersible form, so that there is no need for further consideration of the hazard of ingestion of the material by a human being. The criteria used to determine whether the material is in 'special form' are given in the definition of 'special form' in § 71.4(s), and depend upon the inherent properties of the material and the properties of a capsule in which it may be transported. It is anticipated that, under proposed regulations now being developed, responsibility for determining 'special form' by virtue of the inherent properties of the material will remain with the shipper. When 'special form' is based on encapsulation, it is anticipated that approval of the capsule design and properties will be required by the Interstate Commerce Commission.

"The proposed § 71.6(c) includes a general license for the transport of fissile material and large quantities of licensed material in 'specification packages' as they are and will be authorized in the regulations of the Interstate Commerce Commission for that purpose. At present, the Interstate Commerce Commission regulations (49 CFR Part 78) contain a number of 'specification containers' but these are authorized only for small quantities of nonfissile radioactive material (§ 73.393 of 49 CFR Part 73). It is anticipated that the Interstate Commerce Commission will soon publish some specifications for packages for use in the transport of fissile materials and large quantities of radioactive materials, at which time such 'specification packages' may be used, in accordance with § 71.6(c), without further approval by the Atomic Energy Commission. The Atomic Energy Commission will review and approve 'specification containers' before they are listed by the Interstate Commerce Commission.[§]

"The proposed new Part 71 is divided into four subparts:

"Subpart A, 'General Provisions,' imposes the requirement of a license for certain shipments of licensed material (including fissile material). It specifies the quantities and methods of transport which are exempt and those which are under a general license. Exemption and general license provisions are applicable to shipments which are not dependent for safety on an individual packaging evaluation other than that provided under the regulations of the Interstate Commerce Commission.

[§] Author's Note: The emphasis here on 'specification packages' will continue to show up, repeatedly, through this Chapter. Also note that, by regulation, these so-called *specification packages* could be used ". . . without further approval by the . . . Commission."

"Subpart B, 'License Applications,' specifies the information which must be submitted to the Commission for specific licensing of any method of shipment not authorized under Subpart A.
"Subpart C, 'Package Standards,' specifies the standards which a package must meet for the shipment of fissile material or a large quantity of licensed material, and certain special requirements for the transport of Fissile Class II and Fissile Class III shipments.
"Subpart D, 'Operating Procedures,' specifies the general package determinations and shipping precautions required in order to assure the effectiveness of approved shipping methods.
"In order to provide reasonable assurance of adequate radiation shielding, containment of the radioactive material, and absence of nuclear criticality during transport, the performance of the package and the control exercised over it during transport must be evaluated for normal transport conditions and for potential accident conditions. To avoid inconsistencies involved in guarding against every conceivable condition which could be encountered in transport, Part 71 specifies the transport conditions against which a shipping system must be evaluated. It specifies a set of 'normal conditions of transport' intended to represent conditions which may normally occur during transport. Packages must be designed to withstand these normal conditions. The regulation further specifies a set of 'hypothetical accident conditions' consisting of a 30-foot drop onto a flat surface, followed by a 40-inch drop onto a 6-inch diameter steel bar, followed by exposure to an environment at a temperature of 1475°F for 30 minutes, followed by immersion in water. The hypothetical accident conditions prescribed in the regulation are not intended to represent any one accident, but are so chosen that satisfactory performance of a package exposed to them may be considered to give reasonable assurance of satisfactory performance in accidents likely to occur in transportation.
"A package is not expected to withstand without damage the hypothetical accident conditions specified. The extent of allowable damage to a package depends on the effect of that damage on the containment, shielding, and nuclear safety characteristics of the package. It is expected that, in accordance with the Interstate Commerce Commission, Coast Guard, or Federal Aviation Agency regulations, any package which is damaged in transport would not be carried further in normal transport until any necessary repairs were made.
"The 'Package Standards' in Subpart C, in prescribing the performance standards for a single package and for a permissible array of packages, require that a 'sample package' be subjected, by test or other assessment, to the specified transport tests and conditions. The 'sample package' must fairly represent the actual package to be introduced into transport. In some cases of Fissile Class III shipments, where the entire shipment is to be controlled during transport, the 'sample package' may be considered to be the entire shipment together with the transporting vehicle. It is the intent of these regulations that any analytical treatment which has a reasonable degree of certainty may be employed to predict the performance of a package under the specified test conditions. The results of subjecting a package to the test conditions might be determined by engineering analysis, by physical testing of prototype packages or of scale model packages, by testing of package components, or by any other method as long as a reasonable degree of certainty is established for the results. A great deal of effort has gone into the establishment of the test conditions to make it possible to use calculative methods of solution. It is hoped that good calculative methods will be developed so as to avoid, at least to some extent, the performance of physical tests which otherwise would be necessary . . . .
"In addition to the standards which determine if a package performs adequately when subjected to the normal and accident conditions of transport, there are certain design requirements directed to structural integrity, temperature, radiation shielding, and other general design features of a package. The design requirements directed toward package lifting and tiedown systems are intended to assure that such devices are not torn from the package during use, and that stresses delivered to the package through the lifting or tiedown systems would not damage the package.
"The proposed § 71.13, 'Limited exemption for transport of special nuclear material' would require that every licensee now authorized to transport fissile material file a consolidated application for a superseding license. Information and procedures developed by applicants in past years, and embodied in license applications which have in turn been incorporated by reference in existing licenses, will in most cases require reevaluation. Moreover, many licenses have been the subject of numerous amendments which have incorporated by reference material in previous applications. It is the view of the Commission that issuance of new licenses based on consolidated applications, submitted in accordance with the technical standards of the proposed Part 71, will contribute significantly to the effective administration of these licenses, and ultimately to nuclear safety. The Commission has determined from its review that the continued use of certain existing packages (casks) now used for the transport of irradiated nuclear fuel does not constitute an undue risk to the health and safety of the public. The proposed § 71.42 therefore exempts from the package standards existing packages which have been approved since 1961 under the criteria of proposed Part 72.
"The proposed § 71.14, 'Limited exemption for transport of large quantities of licensed material' would provide a period of time for licensees to obtain approval of shipping procedures before the requirements of Part 71 come into effect. The Commission proposes to evaluate, on an individual basis, licensed material packages which have been constructed prior to the effective date of the regulation using the package standards of Part 71. Loss of shielding resulting from the puncture test followed by the thermal test will not be considered, in itself, ground for disapproval of such a package which meets all the other standards of Part 71.
"Notice is hereby given that adoption of the following rules is contemplated. All interested persons who desire to submit written comments and suggestions for consideration in connection with the proposed rules should send them in triplicate . . . within 60 days after publication of this notice in the FEDERAL REGISTER.[**] Comments received after that period will be

[**] Author's Note: Normally, the preferred format for the term *Federal Register* would be in italics. In this case, however, the format shown, i.e., FEDERAL REGISTER, was provided by the U.S. Government Printing Office. This will show up again, repeatedly, throughout the remainder of this Chapter.

considered if it is practical to do so, but assurance of consideration cannot be given except as to comments filed within the period specified. . . ." [8]

10.3.2 10 CFR 71 — 1966 Final Rule

The July 22, 1966 version of 10 CFR Part 71 was published as the final regulation, with the differences between the proposed rule and the final rule described appropriately in the preamble:

"The regulations of the Atomic Energy Agency (AEC), 10 CFR Parts 30, 40, and 70, require that before the AEC approves an application for license to receive, possess, use or transfer byproduct, source, or special nuclear material, it must determine that the applicant's proposed program is adequate to protect health and minimize danger to life and property.

"In 1958, the AEC adopted 10 CFR Part 71, 'Regulations to Protect Against Accidental Conditions of Criticality in the Shipment of Special Nuclear Material.' This regulation established procedures for approval of transport of special nuclear material, but set only limited standards. Certain small shipments under specified conditions were exempted from the licensing requirement.

"On March 5, 1963, the AEC published a proposed revision of Part 71 (28 F.R. 2134), incorporating many detailed specifications regarding acceptable shipping methods. Public response to that proposed revision suggested that the detailed standards proposed might impair the growth of the industry and development of improved safety concepts and that the regulation should emphasize performance standards rather than detailed design standards. Proposed Part 72, 'Protection Against Radiation in the Shipment of Irradiated Fuel Elements' (26 F.R. 8982, 28 F.R. 2142), which proposed standards and procedures for packaging and transport of irradiated solid nuclear fuel, elicited a similar public response.

"On December 21, 1965, the AEC published for comment a proposed revision of Part 71 (30 F.R. 15748). The proposed revision combined the standards for unirradiated and irradiated fissile material previously proposed separately as Parts 71 and 72, and added standards and procedures for the shipment of large quantities of licensed material. It emphasized performance standards to determine the adequacy of proposed shipping methods, with the method of satisfying those performance standards left to the ingenuity of the shippers. The proposed performance standards would be comparable with those developed by the International Atomic Energy Agency during the past 2 years.

"Subsequent to the publication of [the] proposed Part 71, a Memorandum of Understanding between the Interstate Commerce Commission (ICC) and AEC was signed. In the Memorandum, the two agencies agreed, subject to their respective statutory authorities, that (1) ICC will adopt appropriate regulations and requirements applicable to transport of all radioactive materials, and to shippers of all types and quantities of radioactive materials, but will avoid duplicatory standards with respect to preparation for shipments of fissile materials and large quantities of radioactive material, and (2) AEC will adopt appropriate regulations applicable to standards for the preparation for shipment of fissile material and large quantities of radioactive material and will be responsible for the adoption of regulations and requirements applicable to its licensees or contractors as may be necessary to protect against radiation and criticality hazards in the transportation of all radioactive material where shipment is outside the regulatory jurisdiction of ICC.

"Under the Memorandum of Understanding, the ICC will utilize the assistance of AEC on container approvals for fissile materials and large quantities of radioactive materials. The AEC and ICC are working together to develop criteria for additional 'specification containers' in order to reduce the number of special container permits issued by the ICC.

"Several changes have been incorporated in the regulation, as adopted, as a result of the Memorandum of Understanding, and the publication of amendments to ICC regulations on April 29, 1966 (31 F.R. 6492), covering some of the same areas covered in the notice of proposed rule making published by the AEC on December 21, 1965 (30 F.R. 15748). Thus, the following provisions that were contained in that AEC proposed rule have been omitted in the effective rule . . .

1. Section 71.11 of the proposed rule, which would have imposed ICC requirements through AEC authority;
2. References throughout the proposed rule to transport of radioactive material by a licensee;
3. The radiation level limitations in proposed § 71.34;
4. The definitions of 'milliroentgen per hour or equivalent' and 'transport unit' in proposed § 71.4(j) and (u);
5. The requirement in proposed § 71.40(b) that a Fissile Class II package be labelled [*sic*] as prescribed by ICC, although the procedure for determining the minimum 'radiation unit' for criticality control has been retained;
6. The requirement in proposed § 71.40 that a licensee not transport or deliver to a carrier more than 40 units of Fissile Class II packages, nor a single package with a calculated radiation unit of more than 10;
7. The requirement in proposed § 71.41(b) for Fissile Class III transport procedures to protect against commingling with other fissile material;
8. The requirement in proposed § 71.54 for routine determinations with regard to the radiation level limits, surface contamination limits, and transport procedures.

"The definition of 'carrier' in proposed § 71.4 has been modified to conform to usage under the Transportation of Explosives and Other Dangerous Articles Act (18 U.S.C. §§ 832–837), which is administered by the ICC.

"Other significant differences from the regulation published for comment are:

1. The definition of the term 'fissile material' has been restricted to those isotopes of uranium and plutonium which must now be controlled during transport to avoid criticality.
2. A requirement in proposed § 71.31(b) which imposed a temperature standard on the materials and fabrication of packaging has been deleted. Correspondingly, the temperature to be considered for Normal Conditions of Transport set out in Appendix A has been increased from 100°F. to 130°F. This increased ambient temperature would provide for the more extreme conditions which might be encountered in normal transport.
3. The requirement in proposed § 71.31(e) that primary coolant not circulate outside of the shielding has been deleted.

4. The lifting and tie-down device requirements in proposed § 71.31 (f) and (g) have been modified to make it clear that the standards apply only to devices which are a structural part of the packaging. The modified requirements are included in § 71.31 (c) and (d) . . . .
5. The pressure design standards of the proposed § 71.32(b)–(d), including that for a pressure relief device, have been replaced by an internal pressure test to be initially performed on each individual package which will be subjected to significant internal pressure, set out in § 71.53(b).
6. The specific temperature restriction, contained in proposed § 71.33, on large quantity packages, assuming loss of coolant and cooling devices, has been omitted, as has the corresponding test requirement of proposed § 71.53(b). Temperature restrictions will be effectuated through the performance standards of §§ 71.35 and 71.36. Requirements have been included in § 71.35 . . . to assure that there will be no loss of coolant under the Normal Conditions of Transport.
7. The limitation on loss of shielding under Hypothetical Accident Conditions (Appendix B) has been revised to specify an allowable increase in radiation levels to 1,000 milliroentgens per hour or equivalent at 3 feet from the external surface of the package.
8. The provisions relating to assumed inleakage of water to and outleakage of liquids from fissile material packages in determining subcriticality in proposed § 71.37(b)(3) have been revised and redesignated § 71.33.
9. The requirement in proposed § 71.39(a) that Fissile Class I packages be considered with other types of Fissile Class I packages has been deleted as unnecessary in view of the provision for assumed interspersed moderation.
10. The requirement in proposed § 71.51(a) for licensee quality control procedures has been replaced by a performance requirement in § 71.53(c) . . . that the licensee assure that the packaging is fabricated in accordance with the design approved by the AEC.
11. The list of items to be included in a licensee's operating procedures required by proposed § 71.51(b) has been deleted from the regulation.

"Additional minor changes from the proposed rule have been incorporated in the effective rule.
"The rule . . . establishes packaging standards for the shipment of fissile material, both unirradiated and irradiated, and of large quantities of licensed radioactive material. The rule specifies the quantities and methods of transport which are exempt from Part 71 requirements and those which are under a general license. The exemption and general license provisions are applicable to shipments which from a safety standpoint do not require an AEC packaging evaluation. Those shipments are subject to regulation by federal transport agencies. For shipments not exempted or generally licensed, the rule prescribes the determinations which must be made with respect to packaging and shipping precautions required in order to assure nuclear safety of shipping methods.
"With a few exceptions, the basic organization and standards . . . have not been changed significantly from those contained in the notice of proposed rule making, issued on December 21, 1965 (30 F.R. 15748). A detailed explanation of the organization and standards of Part 71 is made in the notice of proposed rule making.
"The rule . . . divides radionuclides into a number of groups, each having a comparable potential hazard in transport. These groups were derived from the International Atomic Energy Agency's Safety Series No. 6, 'Regulations for the Safe Transport of Radioactive Materials,' 1964 Revised Edition . . . .
"Published simultaneously with proposed 10 CFR Part 71 on December 21, 1965, were certain proposed amendments to 10 CFR Parts 30 and 70 (30 F.R. 15748), the basic licensing regulations for byproduct and special nuclear material, respectively, containing a reference to Part 71. Those amendments are no longer considered necessary and that notice of proposed rule making is, accordingly, withdrawn.
"Pursuant to the Atomic Energy Act of 1954, as amended, and the Administrative Procedure Act of 1946, the following revision of 10 CFR Part 71 is published as a document subject to codification, to be effective 30 days after publication in the FEDERAL REGISTER . . . ." [2]

Thus, with little fanfare, the first, real version of what we would now recognize as 10 CFR 71 went into effect on August 21, 1966. For Type B packaging requirements, we have been living within the basic constraints of those regulations ever since.

10.4 MAJOR CHANGES — 1968

In 1968, a series of substantive changes was introduced into the U.S. regulations for the transportation of radioactive materials. Two of these changes, a proposed rule and a final rule, were introduced into the DOT regulations; one month later, a set of miscellaneous changes was introduced into the AEC's regulations. Each of these changes is examined in more detail.

10.4.1 DOT Changes — 1968 Proposed Rule

In January, 1968, the DOT introduced a major set of proposed rule changes to its existing Hazardous Materials Transportation Regulations (49 CFR 170–190) [9]. In order to demonstrate the interactive linkage between the regulations of the DOT, the AEC, and the IAEA, the text of the preamble for this set of proposed rule changes is examined in more detail.

"On April 1, 1963, the Interstate Commerce Commission (ICC) published its Notice No. 58 in Docket No. 3666. The notice proposed to modify the ICC Regulations for transporting radioactive materials to bring them into accord with the recommended regulations of the International Atomic Energy Agency (IAEA). Based upon the comments received pursuant to that notice of proposed rule making and after discussion with representatives of the U.S. Atomic Energy Commission (USAEC), it became apparent that it would not be in the public interest to adopt those amendments at that time. This area of regulation was transferred to the Department of Transportation by the Department of Transportation Act (80 Stat. 931).
"Since that time this Department, the ICC, and the Atomic Energy Commission have worked toward the preparation of a revision to the radioactive materials regulations. Many

meetings have been held between industry and Government representatives. Several significant 'enabling' regulatory amendments have been adopted which now make it practical to propose a revised major revision of these regulations. In 1966, the USAEC published its packaging standards in Part 71 of Title 10, CFR. At the same time, the ICC published Order No. 70 relating to transportation of fissile radioactive materials. Early in 1967, the ICC also published Order No. 74 which made further modifications regarding radioactive materials.

"During the past 18 months, a task force comprised of representatives of the USAEC and its contractors prepared a series of draft regulatory changes designed to incorporate the principles of the recommended regulations of the IAEA into the regulations as amended by Orders 70 and 74. These drafts were further modified as a result of participation by representatives of the ICC, Federal Aviation Administration, U.S. Coast Guard, and various atomic energy and transportation industry personnel. The results of all of these reviews and discussions are reflected in this notice of proposed rule making.

"This notice includes proposed amendments to the Hazardous Materials Regulations of the Department of Transportation (49 CFR Parts 171–178) (formerly a part of the ICC Regulations) and Part 103 of the Federal Aviation Regulations (14 CFR Part 103). The purpose of this notice is to request public comment on procedures proposed for the transportation of radioactive materials. Interested persons are invited to participate in the making of proposed rules by submitting such written data, views, or arguments as they may desire . . . .

"Communications received . . . would be considered by the Board before taking final action on the notice. All comments will be available for examination by interested persons . . . both before and after the closing date for comments. The proposals contained in this notice may be changed in light of comments received.

"Several references are made in the proposed regulatory amendments to authorizations issued under Part 170 of Title 49, CFR. Part 170 has been reserved for the Rules of Procedure for the Hazardous Materials Regulations Board. Part 170 has been published as a notice of proposed rule making but has not yet been adopted. It is expected that Part 170 will be in effect before the expiration of the comment period for this notice of proposed rule making. Part 170 will include the procedures for general rule making as well as those for handling applications for special permits.

"The basic consideration in the transportation of radioactive materials is that they may present radiation and contamination hazards to transportation workers, passengers, and the general public. In addition, radiation exposure may damage other materials in transport, such as undeveloped photographic film. The proposed regulatory amendments will provide for the control of these potential hazards by considering the three basic factors of (1) relative hazard potential (2) packaging performance and (3) the transportation environment. The existing regulations place the primary emphasis on the packaging requirements for normal conditions of transportation. The proposed revisions will provide a system of allowing sufficient emphasis to be placed not only on the normal conditions of transportation, but also on the environmental conditions which a packaging of radioactive materials might encounter in an accident.

"This notice of proposed rule making establishes a separate hazard classification category for radioactive materials, apart from the poisonous category. Radioactive materials would be classified as radioactive materials and not as Class . . . D poisons as they currently are. Appropriate changes are being proposed to the commodity list in Part 172 . . . .

"In Part 178 revisions are made to specifications 6L and 12B, and two new specifications are being proposed. Specification 6L is being modified to provide a wider flexibility in drum size and centering mechanisms. Tests have shown the inadequacy of the present closure requirements and the specification is being modified to require higher strength locking rings. A newer specification 6M metal package is being proposed for both fissile and nonfissile radioactive materials.[††] The special specification 12B fiberboard box for radioactive materials would be deleted since the requirements contained therein would now be included in § 173.393. A new specification 7A general package is being proposed for radioactive materials. Specification 7A provides for performance criteria rather than detailed engineering design requirements. The shipper would be given a great deal of flexibility in the exact design of his specification 7A package.

"A number of editorial changes are being proposed in this Notice which do not directly bear on substantive requirements for the transportation of radioactive materials, but are being made in related provisions as a part of the general updating of the regulations . . . .

"This amendment is proposed under the authority of Title 18, United States Code, Section 9 of the Department of Transportation Act (49 U.S.C. 1657), and Title VI and Section 902(h) of the Federal Aviation Act of 1958 (49 U.S.C. 1421–1430 and 1472(h)).

"In consideration of the foregoing, it is proposed to amend Titles 14 and 49 of the Code of Federal Regulations as hereinafter set forth . . . ." [9]

10.4.2 DOT Changes — 1968 Final Rule

In October 1968, the DOT published the final version of its regulatory changes, based on the comments it had received as a result of its proposed rulemaking, earlier in the year [10]. The text of the preamble for this final set of rule changes is examined in more detail.

"On January 20, 1968, the Hazardous Materials Regulations Board published Docket No. HM-2; Notice No. 68-1 (33 F.R. 750), which proposed amendments to the Department's

[††] Author's Note: As a DOT Specification Package, the 6M package was, in effect, a Type B fissile shipping container that would be used extensively throughout the AEC-, the ERDA-, and the DOE-Complex, for more than 30 years. As a DOT Specification package, however, the 6M was *not* subject to the Hypothetical Accident Condition test requirements specified in 10 CFR 71. While this was not a problem in 1968, it would become a problem when the majority of the licensing responsibilities for Type B packages was transferred from the DOT to the AEC. (See Sections 10.5.1 and 10.5.2.) Although it would still be around for decades, the beginning of the end of the 6M package would eventually come with the regulatory changes introduced in 2002, and finalized in 2004. (See Sections 10.16 and 10.17, respectively.)

Hazardous Materials Regulations (49 CFR Parts 170–190 and 14 CFR Part 103). These proposals dealt with a major revision to the regulations for the transportation of radioactive materials, along with a number of other general packaging modifications. The public was given 90 days for comment. Numerous comments were filed and have been studied by the Department staff. Several meetings and discussions were held with staff personnel of the U.S. Atomic Energy Commission (AEC), as required by 18 U.S.C. 834(b), and the amendments reflect the results of those discussions. All other comments suggesting changes, additions, or deletions were carefully considered . . . .

"Many of the modifications in these amendments will require parallel changes in the AEC regulations (10 CFR Part 71) to assure harmony between the two complementary sets of regulations. The AEC has indicated that it expects to be able to publish the necessary amendments to its Part 71 prior to the effective date of these amendments.

"Many of the new procedures prescribed in these amendments have been previously authorized by Departmental special permits. Special Permit No. 5000 authorized the use of a drum-type birdcage now listed as the Specification 6M package. Special Permit No. 5300 authorized the use of a type of packaging now listed as the Specification 7A package. Special Permit No. 5400 provided for the shipment of enriched uranium under the terms of § 71.6 of the AEC regulations, and the terms of that permit are now included in § 173.396 of these regulations. Special Permit No. 5417 provided for the transportation of radioactively contaminated items, and the terms of that permit are not included in the low specific activity provisions of § 173.392. Accordingly, those special permits are no longer appropriate, and are hereby terminated . . . .

"The notice of proposed rule making did not utilize the Type A–Type B quantity provisions of the IAEA regulations, but instead referred only to specified quantities of radioactive materials for the various categories of packaging. This was done at the request of a number of interested parties in the atomic energy field. These parties felt that there was a certain stigma attached to these terms as a result of previous unsuccessful rule making efforts by the Interstate Commerce Commission. However, the comments received indicated that the use of those IAEA terms would be not only acceptable but would clarify and simplify the packaging provisions. Accordingly, those terms are defined and used in these amendments.

"On February 28, 1969, all existing Bureau of Explosives (Association of American Railroads) permits for radioactive materials packages will expire. Many comments indicated that the regulations were not sufficiently clear as to whether those previously authorized containers could ever be used again. The acceptability of these containers after February 28, 1969, will be a function of their ability to meet the prescribed structural integrity, shielding, and thermal resistance criteria. In each case, the shipper should examine the design and construction details of his container and compare them to the new regulations. If the container does not fit within one of the prescribed categories or usages, he may not use the container after that date without first having secured a Department special permit. The Department's safety evaluation of each of those containers will be based upon the criteria in these amendments . . . .

"The Department acts as the U.S. competent authority as that term is used in the IAEA regulations. In issuing special permits for radioactive materials packages, the Department is often asked to provide the certificate required of competent authorities in the IAEA regulations . . . . In order to provide this information, it will be necessary for the petitioner for the special permit to certify in his petition that his packaging, and the contents (particularly with respect to the special form criteria), meet all of the standards prescribed in the IAEA regulations. Although these amendments will bring the U.S. regulations more in harmony with the international standards, there are still some significant differences that will be dealt with in future rule making actions. It is the shipper's responsibility, as prescribed in § 173.393, to make the determination that his package meets all of the requirements of the foreign countries as well as the United States, and the shipper must certify to the Department that he has made that determination. He must present to the Department the basis of his evaluation that those standards have been met. The Department will review the petitioner's data and, if it is satisfied that the petitioner has in fact made a proper determination, it will issue the necessary IAEA certificate as a part of the special permit . . . .

"In addition to the general changes discussed above, a number of specific changes to the notice of proposed rule making are worthy of highlighting.

"Proposed § 173.22 has been modified to separate the subject of shipper's responsibility from the types of packages authorized under 'grandfather clauses.' The latter have been included in a new § 173.23. In § 173.23, two additional months have been provided for continued use of packages operating under permits from the Bureau of Explosives. The expiration date of the B of E permits is now February 28, 1969.

"A table of steel thicknesses has been added to the general construction standards in § 173.24. The general prohibition against vented packages has been deleted . . . .

"In § 173.390, an additional transport group, Group VII, has been added to conform with the IAEA regulations, and to obviate the need for descriptive limits throughout the packaging regulations. The provisions for determining the transport group of unknown mixtures have been expanded to conform with the IAEA definition . . . .

"Proposed § 173.393 has been modified to provide for a security seal, similar to the present special permit requirements, and in accord with the IAEA provisions. Section 173.393(d) has been clarified with regard to the requirements for internal bracing. Section 173.393 now includes restrictions on the surface temperatures in order to prevent injury to employees and to reduce the fire hazard to other cargo. The temperature restrictions are those commonly provided in special permits. Special permits are required for all shipments involving high internal decay heat, so this addition represents no change from present practice . . . .

"Proposed §§ 173.394 and 173.395 have been modified to provide for delivery of IAEA Type A packages to their destination in the United States without need for special permit. Type B packages, other than Spec. 55 or 6M, will require Departmental approval in every case at the present time due to a lack of specification containers for Type B quantities.

"Proposed § 173.396 has been modified to provide for package limits for the Specs. 6L and 6M metal packages. The limits are presently specified in Part 178.

"Proposed § 173.398 has been modified to prescribe the criteria for Type A packages (normal conditions incident to transportation) as well as the previously prescribed criteria for Type B packages (hypothetical accident conditions). The allowable release of radioactive material from packages under the Type B tests, and the test conditions themselves, have been clarified to conform with the present requirements of 10 CFR Part 71 of the AEC or the IAEA regulations . . . .

"Specification 2R, in § 178.34, has been modified to provide for reduced size of the letters of identification . . . .

"Specification 6L, in § 178.103, has been modified to provide for additional types of spacers ('spiders'). The total quantity of required vermiculite has been deleted as extraneous because the required density provides automatically for the total weight control. Marking requirements have been modified to conform with other steel drum requirements. Closure requirements have been modified to require a specified metal thickness and locking ring attachment. Recent accident tests demonstrated the inadequacy of the more common lightweight locking rings. Loading capacity limitations have been relocated to § 173.396 . . . .

"Because of the complex nature of these amendments, and the impact that they will have on the transportation of radioactive materials, and to allow a reasonable time for compliance with the changes made herein, the effective date of the amendments is December 31, 1968. However, compliance with these amendments is authorized on and after the date of publication in the FEDERAL REGISTER.

"In consideration of the foregoing, the Hazardous Materials Regulations of the Department of Transportation (14 CFR Part 103 and 49 CFR Parts 170–190) are amended effective December 31, 1968 . . . ." [10]

10.4.3 Miscellaneous Changes, AEC — 1968

In November 1968, a set of miscellaneous amendments was introduced into the requirements of 10 CFR 71 [11]. This set of amendments brought the requirements of 10 CFR 71 into agreement with the recently introduced changes in the requirements of 49 CFR Parts 170–190 [9,10].

"On July 22, 1966, the Atomic Energy Commission published in the FEDERAL REGISTER (31 F.R. 9941) regulations for the packaging of fissile material and large quantities of licensed radioactive material, 10 CFR Part 71. The explanatory statement indicated the relationship of those regulations to the safety regulations of the Interstate Commerce Commission (ICC). Among other things, the regulations of the ICC under the Transportation of Explosives and Other Dangerous Articles Act prescribed the conditions of transportation for shipments prepared in accordance with 10 CFR Part 71.

"On April 1, 1967, the functions of the ICC under the Transportation of Explosives and Other Dangerous Articles Act were transferred to the Department of Transportation (DOT). The DOT has continued to apply the former ICC regulations pertaining to safety in the transportation of radioactive materials; those regulations are now known as the DOT's Hazardous Materials Regulations (49 CFR Parts 170–190, 14 CFR Part 103).

"On January 20, 1968, the DOT published in the FEDERAL REGISTER (33 F.R. 750) for comment, as Notice 68-1, Docket No. HM-2, a proposed major revision of its regulations for transporting radioactive material. The DOT has given due consideration to the numerous comments received and, after consultation with the AEC and the atomic energy industry, has made modifications in the proposed requirements. On October 4, 1968, the DOT published in the FEDERAL REGISTER (33 F.R. 14918) a revision of its regulations pertaining to safety in transport of radioactive material, authorizing compliance on publication and making the amendments effective on December 31, 1968. The changes in the Commission's 10 CFR Part 71 set out below will conform 10 CFR Part 71 with the revision of the DOT regulations. Since the revision of the DOT regulations was published for public comment, the Commission has found that good cause exists for omitting notice of proposed rulemaking and public procedure thereon with respect to the following changes to 10 CFR Part 71, to the revision of the DOT regulations, as unnecessary . . . .

"Pursuant to the Atomic Energy Act of 1954, as amended, and Sections 552 and 553 of the United States Code, the . . . amendments of 10 CFR Part 71 are published as a document subject to codification, to be effective December 31, 1968. Compliance with these amendments is authorized on and after the date of publication in the FEDERAL REGISTER." [11]

10.5 TRANSFER OF LICENSING RESPONSIBILITIES FROM DOT TO AEC

In 1971 and in 1973, the AEC published a proposed rulemaking and a final rulemaking, respectively, the title of which, in both cases, was the *Approval of Type B, Large Quantity, and Fissile Material Packagings* [12,13]. In both cases, the rulemakings had to do with the transfer of specific licensing requirements from the DOT to the AEC.

10.5.1 Approval of Type B, Large Quantity and Fissile Material Packagings — 1971 Proposed Rule

"On January 8, 1971, with the agreement of the Atomic Energy Commission, the Hazardous Materials Regulations Board of the Department of Transportation (DOT) published in the FEDERAL REGISTER a notice (Docket No. HM-73; Notice 71-1) proposing to transfer the administrative requirement for approvals of radioactive materials packages from the Department to the U.S. Atomic Energy Commission (AEC). Interested persons were invited to comment on the proposal within 60 days after publication of the notice in the FEDERAL REGISTER. After consideration of the comments and consultation with the AEC and the atomic energy industry, . . . the DOT is publishing a revised notice of proposed rule making proposing amendments to 49 CFR Part 173 which would transfer the administrative requirement for approvals of radioactive materials packages to the AEC. The amendment would provide, inter alia, that DOT discontinue issuing special permits for packagings except for waivers or exemptions from DOT regulations and that shippers be required to have AEC approval for routine packaging for type B, large quantity, and fissile material shipments.

"The proposed changes in 10 CFR Part 71 . . . would provide a means for implementing the transfer of packaging approvals from DOT to AEC by adding to Part 71, standards and

requirements for AEC approval of type B packagings and describing the procedures for obtaining AEC approval of type B, large quantity, and fissile material packagings.

"The provisions of Part 71, in effect since August 1966, require AEC licensees who wish to ship fissile material or large quantities of byproduct, source, or special nuclear material to apply to the AEC for a license or license amendment indicating AEC approval of the type of package to be used. The amendments published herein would require AEC licensees also to apply for a license or license amendment approving of the package to be used to deliver to a carrier type B quantities of radioactive material.

"The proposed amendments to the DOT regulations . . . would require AEC approval of packagings, other than specification packagings prescribed in the DOT regulations, which are used to ship any quantity of fissile material, or more than a type A quantity (i.e., a type B or large quantity) of other radioactive material. AEC approval could be (1) a license (either specific or general) or license amendment issued under 10 CFR Part 71, (2) an administrative approval issued to AEC contractors by AEC field offices in accordance with standards and procedures published in the AEC manual, or (3) an approval issued by the AEC's Division of Materials Licensing to persons under DOT jurisdiction who are not AEC licensees. The latter category of non-AEC licensees would include, for example, agreement State licensees and radium shippers who wish to ship type B or large quantities of radioactive material.

"To obtain AEC approval, all persons, other than AEC license-exempt contractors, would be required to submit an application to the Director, Division of Materials Licensing, U.S. Atomic Energy Commission, Washington, D.C. 20545. The contents of the application are set forth in §§ 71.21, 71.22, 71.23, and 71.24 of 10 CFR Part 71.

"AEC license-exempt contractors would apply to the appropriate AEC field office for approval in accordance with the provisions of the AEC manual.

"Provisions would be made for uninterrupted use of containers which have been in use under DOT special permits which are valid on the date the revised rule goes into effect. Each AEC licensee would be permitted to continue to use fissile material and large quantity packagings under the AEC license or license amendment which was issued to him by the AEC under 10 CFR Part 71. Under the proposed § 71.8, an AEC licensee using a type B container under a valid DOT special permit would be allowed to continue to use that container until the AEC acts on an application which he had submitted no later than 90 days after the effective date of the rule or the expiration date of the special permit, whichever date is later.

"A non-AEC licensee, other than a license-exempt contractor, would be considered to have AEC approval for continued use of a type of packaging for which he had a DOT special permit in effect on the effective date of the amendments provided he submitted to the AEC a request for approval of that type of packaging within 90 days of the effective date or prior to the date on which the special permit expires, whichever date is later. This AEC approval would remain in effect until the application has been approved or rejected by the Commission.

"The proposed amendment to the DOT regulations, published concurrently, would authorize the use of packaging approved by the AEC. The amendment to DOT regulations also would require each person using a design of packaging approved for use by another to register with AEC prior to first use and to comply with the conditions of the original approval. AEC licensees are already required to follow that same procedure under the conditions of the general license in § 71.1(b) of the AEC regulations.

"Other changes being proposed in 10 CFR Part 71 are minor editorial changes, redesignation of some sections to bring together the exemption provisions, and addition of a new § 71.7 to exempt certain fissile materials from the nuclear criticality safety provisions of Part 71. Section 71.12, *Limited exemption for shipment of special nuclear material* would be deleted, since the authority granted by that section has expired . . . ." [12]

As a prelude of things to come, the following new definitions were added to the proposed regulations:

"(q) 'Type A quantity' and 'Type B quantity' means [*sic*] a quantity of radioactive material the aggregate radioactivity of which does not exceed that specified in the following table:

Transport Groups (Paragraph (p) of this section)	Type A quantity (in curies)	Type B quantity (in curies)
I	0.001	20
II	0.05	20
III	3	200
IV	20	200
V	20	5,000
VI and VII	1,000	50,000
Special Form	20	5,000

Although the values cited in the above table would not last, the concept of Type A and Type B quantities of radioactive material had finally been introduced into the U.S. regulations. It was a concept that was here to stay.

10.5.2 Approval of Type B, Large Quantity and Fissile Material Packagings — 1973 Final Rule

"On November 20, 1971, the Atomic Energy Commission published in the FEDERAL REGISTER (36 FR 22184) proposed amendments to 10 CFR Part 71 of its regulations. The proposed amendments would provide a means for implementing the transfer of the approval of type B packagings from the Department of Transportation (DOT) to the AEC (in its regulatory function) by adding to Part 71 standards and requirements for AEC approval of type B packagings, and procedures for obtaining AEC regulatory staff approval of type B, large quantity, and fissile material packagings. The transfer of the approval function for packages used by license-exempt AEC contractors is being implemented by a change in AEC manual, Chapter 5201. Proposed amendments to DOT regulations, published concurrently, would require AEC approval of packagings, other than specification packagings prescribed in the DOT regulations and packagings approved by a foreign national competent authority under the 1967 regulations of the International Atomic Energy Agency, used to ship quantities of fissile material which exceed the small quantities specifi-

cally exempted by DOT regulations or to ship quantities of other radioactive material which exceed type A quantities, as defined in DOT regulations.

"After consideration of the comments received and other factors involved, the Commission has adopted the amendments published for comment with the following changes:

1. The definition of a 'Type A quantity' in § 71.4(q) has been modified to limit Californium-252 in special form to 2 curies instead of 20 curies, to conform to that limit recently introduced into DOT regulations.
2. The general license provided in § 71.12 for shipment in DOT specification containers and in packages licensed for use by licensees has been amended to include packaging approved by a foreign national competent authority. The amendment to the DOT regulations, to be made effective concurrently, requires that packages approved by a foreign competent authority be revalidated by DOT before use in the United States.
3. In § 71.10 the period during which persons are exempted from the requirements for an AEC approval for Type B packages being used under a DOT special permit has been lengthened from 3 to 6 months after the effective date of the amendments.

"Other minor corrective and editorial changes have been made . . . .

"Pursuant to the Atomic Energy Act of 1954, as amended, and Sections 552 and 553 of Title 5 of the United States Code, the . . . amendments to Title 10, Chapter I, Code of Federal Regulations, Part 71, are published as a document subject to codification to become effective June 30, 1973 . . . ." [13]

10.6 DOUBLE CONTAINMENT FOR PLUTONIUM, AND QUALITY ASSURANCE REQUIREMENTS — 1973 TO 1978

Between August 1973 and June 1978, a series of changes was introduced into the requirements of 10 CFR 71. Centered on two major focal points, the changes dealt with plutonium issues and with Quality Assurance issues. All of the changes would have a long-lasting impact on the requirements specified in 10 CFR 71.

10.6.1 Double Containment for Plutonium — 1973 Proposed Rule

In August 1973, the AEC published a Proposed Rule in the *Federal Register*, a proposed rule that would eventually require double containment for plutonium [14]. Excerpts from the preamble for that proposed rule reads as follows:

"The Atomic Energy Commission is considering the amendment of its regulations in 10 CFR Part 71, 'Packaging of Radioactive Material for Transport and Transportation of Radioactive Material Under Certain Conditions' to require that all plutonium in quantities greater than 20 curies shall be packaged for shipment as a solid in capsules which meet the requirements for special form and shall be shipped inside packaging that meets the requirements of Part 71 for radioactive material in normal form. The proposed requirements would become effective three years after the effective date of the amendment.

"In light of anticipated significant changes in the characteristics and quantity of plutonium to be transported in the future, the Commission has considered the matter of form for shipping plutonium from the standpoint of public health and safety. Existing regulations permit the shipment of plutonium in any chemical or physical form, including liquid plutonium nitrate. Using the present criteria and requirements of Part 71, hundreds of plutonium nitrate shipments have been made with no reported instances of plutonium leakage from the containment vessel.

"However, the present situation with respect to plutonium transportation in the private sector is expected to change drastically over the next several years. Increasingly larger quantities of plutonium will be recovered from power reactor fuel. Consequently, increases in quantities of plutonium shipped and number of shipments made are expected. For example, the amount of plutonium available for recovery is estimated to be 500 kg in 1973 as compared to 21,000 kg in 1980.[‡‡] In addition, the specific activity of the plutonium will increase with higher reactor fuel burnup, resulting in higher gamma and neutron radiation levels, greater heat generation, and greater pressure generation potential from plutonium nitrate solutions in shipping containers.

"Because of these expected changes in plutonium transport and the inherent susceptibility of liquids to leakage, the Commission believes that safety would be significantly enhanced if the basic form for shipments of plutonium were changed from liquid to solid and if the solid form of plutonium were required to be shipped in a package providing at least double containment of the contents. Such a change is considered to be feasible from an economic and technological standpoint.

"The Commission's assessment indicates that there will not be a significant increase in the quantities of plutonium available for recovery in the next few years. However, the Commission believes that any change in the requirements regarding the form of plutonium for shipment should be announced promptly so that firms that design and build fuel reprocessing and fuel fabrication plants can make timely plans to accommodate this change. It is anticipated that if a solid form for shipment is required, plutonium recovered at fuel reprocessing plants would be converted to the oxide form for shipment to fuel fabricators. Based on the Commission's assessment of process and equipment changes necessary to permit shipment of plutonium as oxide, and the time when increased plutonium shipments will occur, about three years appears to be a sufficient time period. Accordingly, if the proposed amendments are adopted, the effective date would be specified as three years from the effective date of such adoption . . . ." [14]

[‡‡] Author's Note: In 1977, President Carter signed the documentation that effectively killed the prospects for fuel reprocessing in the United States. As a consequence, this part of the NRC's 1973 argument would later become a moot point. Although the *double containment* rule would, in fact, become a regulatory requirement in 1974 (see Section 10.6.3), it would later be removed from the requirements of 10 CFR 71. Before it could be removed, however, it would take another 30 years. (See Sections 10.15.2, 10.16, and 10.17.)

10.6.2 Quality Assurance Requirements for 10 CFR 71 — 1973 Proposed Rule

In December 1973, the proposed rule for Quality Assurance requirements for 10 CFR 71 was published in the *Federal Register* [15]. Excerpts from the preamble for that proposed rule reads as follows:

> "The Atomic Energy Commission has under consideration amendments to its regulations in 10 CFR Part 71 'Packaging of Radioactive Material for Transport and Transportation of Radioactive Material Under Certain Conditions,' to upgrade requirements for quality assurance in the design, fabrication, assembly, testing, use and maintenance of packagings for shipping and transporting licensed radioactive material. The amendments would also revoke, subject to a timely application for reapproval [*sic*], the present authority to use certain shipping casks for solid irradiated nuclear fuel which had been approved under criteria used before the current standards were developed.
> "Under the proposed amendments . . . each licensee subject to 10 CFR Part 71 would be required to assess the adequacy of his quality assurance program against the upgraded standards and requirements, and to make whatever changes are required to comply with those standards and requirements. AEC would verify compliance with the standards through its licensing and inspection programs. Each applicant for a license or license amendment under 10 CFR Part 71 would be required to describe his quality assurance program to be applied to the design, fabrication, assembly, testing, maintenance and use of his proposed packaging. The applicant would further be required to identify the codes, standards and general requirements to be imposed under the program. Within this framework, the licensee would be required to document his quality assurance program in detailed written procedures and requirements, and follow those procedures and requirements in his operations. The adequacy of the detailed written documents and the licensee's implementation of them would be determined through the Commission's compliance program. That adequacy will be judged in part on the complexity and proposed use of the package under consideration, and on the complexity and importance of safety of its components.
> "The quality assurance requirements proposed here would apply to a licensee's design, fabrication, assembly, testing, use and maintenance of a Type B, Large Quantity or Fissile material package which he constructs for himself or has someone else construct it for him. In the case of a licensee using a package approved for another licensee's use, in accordance with the general license provisions of present § 71.12, the quality assurance requirements of the licensee for whom the package was first approved must be followed in the use, testing and maintenance of the package by the second licensee. Any changes in the program must be approved by the Commission.
> "A new provision would require notification of the Commission's Directorate of Regulatory Operations before fabrication is begun of packaging with certain heat loads or anticipated internal pressures. This would facilitate communication between the licensee and the Commission's regulatory staff to resolve any differences on the adequacy of the quality assurance program before significant expenditures and irretrievable effort are committed to packaging of such importance . . . .
> "Authority to use certain shipping casks for solid irradiated nuclear fuel is contained in § 71.41 of Part 71 'Previously constructed packages for irradiated solid nuclear fuel.' This authority applies to shipping casks approved after September 23, 1961 and constructed by January 1, 1967, when the current package standards system was first adopted in the United States. Under these proposed amendments, any such casks still in use must be shown to comply with current package standards, either in their present condition or after modification . . . ." [15]

10.6.3 Double Containment for Plutonium — 1974 Final Rule

In June 1974, the final rule for double containment for plutonium was published in the *Federal Register* [16]. For the most part, the preamble for that final rule reads as follows:

> "On August 1, 1973, the Commission published in the FEDERAL REGISTER a notice of proposed rulemaking (38 FR 20482) that would have required that all plutonium in excess of twenty curies per package be shipped as a solid material contained within a 'special form' capsule placed within a package meeting the conditions for normal form material. The effective date proposed was three years after the adoption of the amendment. All interested persons were invited to submit written comments and suggestions for consideration in connection with the proposed amendment within 60 days after publication of the notice of proposed rulemaking in the FEDERAL REGISTER. After careful consideration of the comments received and other factors involved, the Commission has adopted the amendments as published for comment with the following changes:
>
> (1) The proposed requirement that the inner containment vessel meet the 'special form' capsule requirement has been replaced with a requirement that the inner containment vessel must maintain its integrity after the entire package has been subjected to the normal and accident test conditions prescribed by Part 71. The effect of the amended provisions is still to require double containment of the contents. A number of commenters [*sic*] expressed the view that while double containment of plutonium is an important safety objective, a requirement that the inner container meet the stringent performance specifications required of a 'special form' capsule was unnecessary. The Commission considers it most important that solid form plutonium be doubly contained and that both barriers in the packaging maintain their integrity under normal and accident test conditions. The present packaging required for normal form material provides the outer barrier. In specifying the 'inner barrier' in the proposed rule, the Commission proposed a form of encapsulation that was already defined in Part 71, with corresponding performance specifications. Since the inner containment requirements are intended to take into account the fact that the plutonium may not be in a 'nonrespirable' form, the Commission has concluded that if it can be demonstrated that the inner container will maintain its integrity in the packaging after the package is subjected to the normal and accident test conditions, sufficient protection will be afforded.
> (2) Solid plutonium in the following forms has been exempted from the double containment requirements: (a) Reactor

fuel elements; (b) metal or metal alloy; and (c) other plutonium bearing solids that the Commission determines suitable for such exemption. Since the double containment provision compensates for the fact that the plutonium may not be in a 'nonrespirable' form, solid forms of plutonium that are essentially nonrespirable should be exempted from the double containment requirement; [*sic*] Therefore, it appears appropriate to exempt from the double containment requirements reactor fuel elements, metal or metal alloy, and other plutonium bearing solids that the Commission determines suitable for such exemption . . . .

(3) The implementation period has been extended from three to four years. Many comments suggested that the proposed three-year implementation period was not long enough, considering the necessary plant design effort, licensing, and construction of facility modifications necessary to meet the requirements. Additional time was requested. The Commission believes that the increases in the amounts of plutonium to be shipped and the changing characteristics of plutonium will not change significantly in the next four years when compared to years beyond 1978. The four-year period for compliance should give the nuclear industry a sufficient period for implementation . . . ." [16]

10.6.4 Quality Assurance Requirements for 10 CFR 71 — 1977 Final Rule

In August 1977, the final rule for Quality Assurance Requirements for Transport Packages was published in the *Federal Register* [17]. The *Summary* for that final rule[§§] reads as follows:

"The Nuclear Regulatory Commission is amending its regulations for packaging of radioactive material for transportation and transportation of radioactive materials. The amendments would upgrade requirements for quality assurance in the design, fabrication, assembly, testing, use, and maintenance of packagings for shipping and transporting licensed radioactive material. The amendments would also revoke, subject to a timely application for re-approval, the present authority for licensees to use certain shipping casks for solid irradiated nuclear fuel which had been approved under criteria used before the current standards in these regulations were adopted . . . ." [17]

The importance of this (then) new rule cannot be overstated: 1) As is stated in the Summary, this Final Rule updated the 10 CFR 71 requirements for quality assurance in the design, fabrication, assembly, testing, use, and maintenance of packagings for shipping and transporting licensed radioactive material. 2) As was also stated in the Summary, this Final Rule revoked — subject to a timely application for re-approval — the existing authority for licensees to use certain shipping casks for spent nuclear fuel that had been approved under criteria used before the then current standards in 10 CFR 71 were adopted.

What was not stated in the Summary (but was clearly defined in the actual text), was that this Final Rule established the so-called *Grandfathering Clause*, that would gradually phase-out the use of *all* radioactive materials transport packages designed before the then-current standards of 10 CFR 71 were adopted.

What was also not stated in the Summary, was that this Final Rule for QA Requirements would have no immediate impact on the continued use of DOT Specification Packages, such as the 6M. (See the related footnote in Section 10.3.1. See also the related Discussions in Sections 10.16 and 10.17.)

10.6.5 Extension of the Implementation Period for QA Requirements — 1978 Effective Rule

In June 1978, an effective rule for Quality Assurance Requirements for Transport Packages was published in the *Federal Register* [18]. The purpose of this Effective Rule was to extend the effective date for the rule that had previously been proposed from July 1, 1978 to January 1, 1979.

10.7 NRC REGULATORY GUIDE 7.6

In March 1978, the NRC introduced Revision 1 of its Regulatory Guide (Reg. Guide) 7.6 into the situation [19]. Although a previous version of this Reg. Guide had been introduced some 13 months earlier, this was the first version to have some real substance to the content, and it was this version that would be relied upon for the next 13 years.

The title of Reg. Guide 7.6 was (is) *Design Criteria for the Structural Analysis of Shipping Cask Containment Vessels*. This was the first of the NRC Guidance documents to introduce ASME Boiler & Pressure Code requirements into the recommendations for the design for shipping containers for Type B quantities of radioactive materials.

"A. INTRODUCTION

"Sections 71.35 and 71.36 of 10 CFR Part 71, 'Packaging of Radioactive Material for Transport and Transportation of Radioactive Material Under Certain Conditions,' require that packages used to transport radioactive materials meet the normal and hypothetical accident conditions of Appendices A and B, respectively, to Part 71. This guide describes design criteria acceptable to the NRC staff for use in the structural analysis of the containment vessels of Type B packages used to transport irradiated nuclear fuel. Alternative design criteria may be used if judged acceptable by the NRC staff in meeting the structural requirements of §§ 71.35 and 71.36 of 10 CFR Part 71.

"B. DISCUSSION

"At present, there are no design standards that can be directly used to evaluate the structural integrity of the containment vessels of shipping casks for irradiated fuels. This guide presents containment vessel design criteria that can be used in conjunction with an analysis which considers the containment vessel and other principal shells of the cask (e.g., outer shell, neutron shield jacket shell) to be linearly elastic. A basic assumption for the use of this guide is that the principle of superposition can be applied to determine the effect of combined loads on the containment vessel. However, use of this guide does not preclude appropriate nonlinear treatment of other cask components (e.g., impact limiters and lead shielding).

[§§] Author's Note: As was noted in the Introduction, space limitations prevent the full text of this section from being reproduced here. The preamble-only version for this section can be found in Reference [1]. The full-text version can be found in Reference [17].

"Design criteria for nonlinear structural analyses are not presented in this guide because of the present lack of data sufficient to formulate substantial nonlinear criteria. The NRC staff will review criteria other than those given in this guide on a case-by-case basis.
"Section III of the ASME Boiler and Pressure Code contains requirements for the design of nuclear power plant components. Portions of the Code that use a 'design-by-analysis' approach for Class 1 components have been adapted in this guide to form acceptable design criteria for shipping cask containment vessels. The design criteria for normal transport conditions, as defined in 10 CFR Part 71, are similar to the criteria for Level A Service Limits (formerly called 'normal conditions') of Section III, and the design criteria for accident conditions are similar to those for Level D Service Limits (formerly called 'faulted conditions'). However, Section III was developed for reactor components, not fuel casks, and many of the Code's requirements may not be applicable to fuel cask design.
"The criteria in this guide reflect the designs of recently licensed shipping casks. The containment vessels having these designs were made of austenitic stainless steel, which is ductile even at low temperatures. Thus, this guide does not consider brittle fracture. Likewise, creep is not discussed because the temperatures of containment vessels for irradiated fuel are characteristically below the creep range, even after the hypothetical thermal accident requirement of 10 CFR Part 71. The nature of the design cyclic thermal loads and pressure loads is such that thermal ratchetting [*sic*] is not considered a realistic failure mode for cylindrical containment vessels. Containment vessel designs that are significantly different from current designs (in shape, material, etc.) may necessitate the consideration of the above failure modes . . . ." [19]

10.8 1979 PROPOSED RULE, 10 CFR 71

In August 1979, a proposed rule for major changes to 10 CFR 71 was published in the *Federal Register* [20]. As was noted by the NRC at the time, "The major changes . . . being proposed deal with [the] assignment of individualized Type A quantities for each radionuclide, and the addition of new Type B(U) and Type B(M) packaging standards . . . ." [20]

The full text of this section is not reproduced here. The preamble-only version of the text for this section can be found in Reference [1]. The full-text version can be found in Reference [20].

10.9 NUREG/CR-1815, 1981

In August of 1981, the NRC published NUREG/CR-1815, *Recommendations for Protecting Against Failure by Brittle Fracture in Ferritic Steel Shipping Containers Up to Four Inches Thick* [21]. Written by W. R. Holman and R. T. Langland of Lawrence Livermore National Laboratory, this NUREG/CR became the second NRC guidance document to link the requirements of 10 CFR 71 with the requirements of the ASME Boiler & Pressure Vessel Code.

As Holman and Langland noted in their Executive Summary,

"This report addresses the problem of brittle fracture in ferritic steels and recommends fracture toughness criteria that will provide three levels of safety in shipping containers licensed for transporting radioactive materials. Recommendations are given for defining three categories of fracture toughness criteria that will provide degrees of safety appropriate to the various materials transported in the containers . . . ." [21]

Holman and Langland further recommended that

1) A fracture control plan be implemented for each container design;
2) Fracture-critical components be identified and treated as specified in the report;
3) Specific fracture toughness testing requirements be established; and
4) Appropriate specification and qualification procedures be adopted for all fracture critical welds.

With respect to the category requirements, Holman and Langland went on to note that,

"The largest margin of safety is provided in Category I by requiring sufficient toughness to assure that there is no crack propagation at the lowest service temperature. Steels with this level of toughness can tolerate large flaws under dynamic loading conditions.
"A smaller margin of safety is allowed for Category II, in which the minimum level of toughness at the lowest service temperature is specified at somewhat above the level of toughness at the plane strain limit for dynamic loading conditions. If the shock mitigating system is effective in reducing the loading rate in the fracture critical components, then an intermediate loading rate can be assumed and an additional reduction in the minimum toughness is permitted for Category II.
"The level of safety required for Category III is less than that for Category II, and the minimum toughness requirements are correspondently reduced. Good engineering practices and selection of steels with a low NDT temperature make it unlikely that brittle fracture will occur . . . ." [21]

This was the first of three NUREG/CRs that would eventually lead to the publication of Reg. Guide 7.11. (See Section 10.13.)

10.10 1983 FINAL RULE, 10 CFR 71

In August 1983, the final rule for major changes to 10 CFR 71 was published in the *Federal Register* [22]. This was the follow-up to the 1979 Proposed Rule described above in Section 10.8.

As was noted above with respect to Section 10.8, the major changes being finalized in the 1983 Final Rule dealt with the assignment of individualized Type A quantities for specific radionuclides, and the addition of new Type B(U) and Type B(M) packaging requirements.

As was also noted above with respect to Section 10.8, the full text of this section is not reproduced here. The preamble-only version of the text for this section can be found in Reference [1]. The full-text version can be found in Reference [22].

10.11 ADDITIONAL REGULATORY GUIDANCE, NRC, 1985

In 1985, two additional guidance documents were produced by the NRC: NUREG/CR-3019 and NUREG/CR-3854 [23,24].

10.11.1 NUREG/CR-3019

In March of 1985, the NRC published NUREG/CR-3019, *Recommended Welding Criteria for Use in the Fabrication of*

Shipping Containers for Radioactive Materials [23]. Written by R. E. Monroe, H. H. Woo, and R. G. Sears of Lawrence Livermore National Laboratory, this NUREG/CR became the third in a series of NRC guidance documents to link the requirements of 10 CFR 71 with the requirements of the ASME Boiler & Pressure Vessel Code.[***] More importantly, this particular NUREG/CR became the first to reference the ASME Code requirements to quantify the *welding* requirements for 10 CFR 71 transport packages.

As Monroe, Woo, and Sears noted in their Summary,

> "This NUREG presents the recommended criteria for welding and related operations used in the fabrication of shipping containers for radioactive materials. The welding criteria given . . . are divided into three categories that are associated with the levels of safety for the type of containers and radioactive contents being transported. Category I provided the largest margin of safety; Categories II and III provide lesser margins of safety consistent with the characteristics and quantities of the radioactive material being transported. The same Category designations also have been used in the development of fracture toughness criteria applicable to the containment vessel. [See Section 10.9.] For each category, the welding criteria are further divided into three weld types that are associated with the functions of the welds. The three types are containment-related welds, criticality-related welds, and other safety-related welds.
> "The welding criteria include a number of related elements to ensure adequate control. The ten key elements are as follows:
>
> 1. Base Materials
> 2. Welding and Brazing Materials
> 3. Joint Preparation
> 4. Welding
> 5. Brazing
> 6. Heat Treatment
> 7. Qualification of Procedures and Personnel
> 8. Examination
> 9. Quality Assurance
> 10. Fracture Toughness.
>
> "For each Weld Type and Category, the selected welding criteria are based on an appropriate Section of the ASME Boiler and Pressure Vessel Code, as summarized in [the Table below]. These selected Code sections provide a level of confidence consistent with the Category and Weld Type . . . ." [23]

"Summary of Recommended Welding Criteria for Use in the Fabrication of Shipping Containers

Weld Type	Category I	Category II	Category III
Containment-Related Welds	ASME Code Section III, Subsection NB	ASME Code Section III, Subsection ND	ASME Code Section VIII-Division 1
Criticality-Related Welds	ASME Code Section III, Subsection NG		
Other Safety-Related Welds	ASME Code Section VIII-Div. 1 or Section III, Subsection NF (as appropriate)		

[***] Author's Note: As was noted in Section 10.7 with the development of Reg. Guide 7.6, the NRC had long since found it convenient to *recommend* the requirements of the ASME Boiler & Pressure Vessel Code as a metric to quantify the often subjective requirements of the regulations.

10.11.2 NUREG/CR-3854

In March of 1985, the NRC also published NUREG/CR-3854, *Fabrication Criteria for Shipping Containers* [24]. Written by L. E. Fischer and W. Lai of Lawrence Livermore National Laboratory, this NUREG/CR became the fourth in a series of NRC guidance documents to link the requirements of 10 CFR 71 with the requirements of the ASME Boiler & Pressure Vessel Code. Published as a companion document to NUREG/CR-3019, this particular NUREG/CR became the first to link ASME Code requirements to the *fabrication* requirements for 10 CFR 71 transport packages.

As Fischer and Lai noted in their Summary,

> "This NUREG provides fabrication criteria from the metal components of shipping containers used for transporting radioactive materials. The criteria are divided into three categories that are associated with the levels of safety for the types and quantities of radioactive materials being transported. For each category, the fabrication criteria are subdivided into three component safety groups that are formed according to their safety function. The categories and component safety group designations are the same as those used in developing the welding criteria in [NUREG/CR-3019].

"Summary of Fabrication Criteria Based on the ASME Code

Component Safety Group	Container Contents		
	Category I	Category II	Category III
Containment	Section III, Subsection NB	Section III, Subsection ND	Section VIII, Division 1
Criticality	Section III, Subsection NG		
Other Safety-Related	Section VIII, Division 1, or Section III, Subsection NF		

> "The fabrication criteria are based on the American Society of Mechanical Engineers Boiler and Pressure Vessel Code . . . , as summarized in [the Table above] for each of the categories and component safety groups. . . . The selected ASME Code criteria provide levels of confidence in controlling fabrication processes consistent with the categories and component safety groups. The criteria should be used with the welding criteria contained in [NUREG/CR-3019] when fabricating shipping containers for transporting radioactive materials . . . ." [24]

10.12 MAJOR CHANGES, 10 CFR 71, 1988 PROPOSED RULE

In June 1988, the proposed rule for major changes to 10 CFR 71 was published in the *Federal Register* [25]. The major proposed changes at the time were as follows: 1) additional accident test requirements for certain packages; 2) an expansion in the number of radionuclides with listed limits for the quantity of radioactive material in a single package; 3) a number of changes in the listed limits; 4) simplification of the fissile material transport classes; 5) updating requirements for shipment of low-specific-activity materials; and 6) inclusion of the criteria for air transport of plutonium.

The full text of this section is not reproduced here. The preamble-only version of the text for can be found in Reference [1]. The full-text version can be found in Reference [25].

10.13 REG. GUIDES 7.11 and 7.12, 1991

In June 1991, the NRC issued Reg. Guide 7.11, *Fracture Toughness of Base Material for Ferritic Steel Shipping Cask Containment Vessels with a Maximum Wall Thickness of 4 Inches* [26]. As an NRC policy statement, this document became a cornerstone in its own right because, for the first time, it provided the direct linkage between the Category I, Category II, and Category III criteria from NUREG/CR-1815, NUREG/CR-3019, NUREG/CR-3854, and the A_1 and A_2 values specified in 10 CFR 71.

In June 1991, the NRC also issued Reg. Guide 7.12, *Fracture Toughness Criteria of Base Material for Ferritic Steel Shipping Cask Containment Vessels with a Wall Thickness Greater than 4 Inches (0.1 m) but not exceeding 12 Inches (0.3 m)* [27]. While the issuance of this particular Reg. Guide was just as important in its own right as the issuance of its Reg. Guide 7.11 counterpart, it pertained to far fewer transportation-related containment vessels.

Selected excerpts from Reg. Guide 7.11 are presented below:

"A. INTRODUCTION

"Part 71, 'Packaging and Transportation of Radioactive Material,' of Title 10 of the Code of Federal Regulations requires that packages used to transport radioactive materials withstand the conditions in § 71.71, 'Normal Conditions of Transport,' and § 71.73, 'Hypothetical Accident Conditions.' In this guide, the terms packaging, shipping cask, and shipping container are used interchangeably.

"The regulations require that accident conditions with an initial temperature as low as –20°F (–29°C) be considered. At this temperature, several types of ferritic steels are brittle and subject to fracture. This guide describes fracture toughness criteria and test methods acceptable to the NRC staff for use in evaluating Type B (U) and Type B (M)[†††] ferritic steel shipping cask containment vessel base material having a maximum thickness of 4 inches (0.1 m) and having a maximum static yield strength of 100 ksi (690 kPa). The containment vessel is a major component of the containment system as defined in § 71.4 of 10 CFR Part 71. This guide is applicable to the containment vessel only and not to other components of the package.

"Alternative fracture toughness criteria and test methods may be used provided the applicant can demonstrate that their use will ensure equivalent safety . . . .

"B. DISCUSSION

"This guide presents fracture toughness criteria and test methods that can be used for evaluating ferritic steel containment vessel base material having a maximum wall thickness of 4 inches (0.1 m) with a maximum static yield strength of 100 ksi (690 kPa).

"Section III of the ASME Boiler and Pressure Vessel Code . . . contains requirements for material fracture toughness; however, these requirements were developed for reactor components only and do not address hypothetical accident conditions appropriate for packaging (e.g., severe impact loads at low temperatures). Therefore, the code requirements are not directly applicable to shipping container design.

"NUREG/CR-1815, 'Recommendations for Protecting Against Failure by Brittle Fracture in Ferritic Steel Shipping Containers up to Four Inches Thick' [Ref. 21], contains background and other information pertinent to the development of the criteria in this guide. These criteria are divided into three categories that are associated with the levels of safety appropriate for the radioactive contents being transported. Table 1 in this guide identifies the radioactivity limits for each of the three categories. Tables 4, 5, and 6 in NUREG/CR-1815[‡‡‡] . . . list the fracture toughness criteria associated with each category. . . . A qualitative description of the margins of safety against brittle failure for each of the three categories is given in Appendix C to NUREG/CR-1815 [Ref. 21].

Table 1

	Category I	Category II	Category III
Low Specific Activity		Greater than 30,000 Ci or greater than 3,000 A_1* or greater than 3,000 A_2*	Less than 30,000 Ci and less than 3,000 A_1 and less than 3,000 A_2
Special Form	Greater than 3,000 A_1 or greater than 30,000 Ci	Between 3,000 A_1 and 30 A_1 and not greater than 30,000 Ci	Less than 30 A_1 and less than 30,000 Ci
Normal Form	Greater than 3,000 A_2 or greater than 30,000 Ci	Between 3,000 A_2 and 30 A_2 and not greater than 30,000 Ci	Less than 30 A_2 and less than 30,000 Ci

* Defined in 10 CFR 71.4

"Additional information regarding the basis for the criteria is contained in Appendix B of NUREG/CR-1815 [Ref. 21] . . . ."

10.14 10 CFR 71, 1995 FINAL RULE

In September 1995, the final rule for major changes to 10 CFR 71 was published in the *Federal Register* [28]. This was the follow-up to the 1988 Proposed Rule described above in Section 10.12.

As was noted by the NRC,

". . . Most of the revisions presented in the proposed rule are being adopted in the final rule. These include additional hypothetical accident test criteria for certain types of packages, an increase in the number of radionuclides with listed A_1 and A_2 values, changes in the currently listed A_1 and A_2

[†††] "Type B(U) and Type B(M) packages are defined in 10 CFR 71.4." *(This footnote was part of the original citation.)*

[‡‡‡] "The following corrections should be made to the NUREG: Table 1, Category III revise to read '. . . Fine Grain Practice . . .'; Table 4, Criteria . . . , third line 'has $\sigma_{ys} \geq 70$ ksi, either:'; Figure 6, vertical scale should be '. . . 0, 20, 40 . . .'; Section 5.3.1, subsection 1, 'By selecting a normalized steel . . . .'" *(This footnote was also part of the original citation.)*

values for some radionuclides, simplification of fissile material transport classes, revised requirements for shipment of LSA materials, and inclusion of criteria for packages used to transport plutonium by air . . . .” [28]

The full text of this section is not reproduced here. The preamble-only version of the text can be found in Reference [1]. The full-text version can be found in Reference [28].

10.15 DOUBLE CONTAINMENT ISSUES REVISITED

In May 1997, the proposed rule for a change to the *Double Containment* requirements of 10 CFR 71 was published in the *Federal Register*[29].

10.15.1 Elimination of Double Containment for Plutonium for Vitrified High Level Waste — 1997 Proposed Rule

As the NRC noted in its Summary,

“. . . The Nuclear Regulatory Commission (NRC) is proposing to amend its regulations to remove canisters containing vitrified high-level waste (HLW) containing plutonium from the packaging requirement for double containment. This amendment is being proposed in response to a petition for rulemaking (PRM–71–11) submitted by the Department of Energy (DOE) . . . .” [29]

The full text of this section is not reproduced here. The preamble-only version of the text for can be found in Reference [1]. The full-text version can be found in Reference [29].

10.15.2 A Petition to Eliminate the Double Containment Requirement, 1998

In February 1998, a petition to eliminate the *Double Containment* requirements of 10 CFR 71 was published in the *Federal Register* [30]. In this case, however, the petitioner was seeking to eliminate the double containment requirement, all together:

“. . . The Nuclear Regulatory Commission (NRC) has received and requests public comment on a petition for rulemaking filed by the International Energy Consultants, Inc. The petition has been docketed by the Commission and has been assigned Docket No. PRM-71-12. The petitioner requests that the NRC amend its regulations that govern packaging and transportation of radioactive material. The petitioner believes that special requirements for plutonium shipments should be eliminated . . . .” [30]

The full text of this section is not reproduced here. The preamble-only version of the text can be found in Reference [1]. The full-text version can be found in Reference [30].

10.15.3 Elimination of Double Containment for Plutonium for Vitrified High Level Waste — 1998 Final Rule

In June 1998, the final rule for a change to the *Double Containment* requirements of 10 CFR 71 was published in the *Federal Register* [31].

As the NRC noted in its Summary,

“. . . The Nuclear Regulatory Commission (NRC) is amending its regulations to add vitrified high-level waste (HLW) contained in a sealed canister designed to maintain waste containment during handling activities associated with transport to the forms of plutonium which are exempt from the double-containment packaging requirements for transportation of plutonium. This amendment responds to a petition for rulemaking submitted by the Department of Energy, Office of Civilian Radioactive Waste Management (DOE/OCRWM). This final rule grants the petition for rulemaking, with modifications, and completes NRC action on the petition . . . .” [31]

The full text of this section is not reproduced here. The preamble-only version of the text can be found in Reference [1]. The full-text version can be found in Reference [31].

10.16 10 CFR 71, 2002 PROPOSED RULE

In April 2002, the proposed rule for major changes to 10 CFR 71 was published in the *Federal Register* [32]. We will look at the information presented in the preamble for the 2002 Proposed Rule. In this case, however, it important to note from the outset that the bureaucratic requirements with respect to the format and the content changed dramatically between what is presented in that Proposed Rule and what has been presented previously.

With that forewarning, selected excerpts from the preamble for the 2002 Proposed Rule for 10 CFR 71 reads as follows:

“**SUMMARY**: The Nuclear Regulatory Commission (NRC) is proposing to amend its regulations on packaging and transporting radioactive material to make them compatible with the International Atomic Energy Agency (IAEA) standards and to codify other applicable requirements. These changes would be compatible with ST-1 (TS-R-1), the latest revision of the IAEA transportation standards. This rulemaking would also address the unintended economic impact of NRC’s emergency final rule entitled ‘Fissile Material Shipments and Exemptions’ (February 10, 1997; 62 FR 5907) and a petition for rulemaking submitted by International Energy Consultants, Inc. (PRM–71–12: February 19, 1998; 63 FR 8362) . . . .

“The Commission directed the NRC staff in Staff Requirements Memorandum (SRM) 00–0117 dated June 28, 2000: (1) To use an enhanced public-participation process (website and facilitated public meetings) to solicit public input on the *Part* 71 rulemaking; and (2) to publish the staff’s Part 71 issues paper in the **Federal Register** (65 FR 44360; July 17, 2000) for public comment. The issues paper presented the NRC’s plan to revise Part 71 and provided a summary of all changes being considered, both IAEA-related changes and NRC-initiated changes. The NRC published the issues paper to begin an enhanced public participation process designed to solicit public input on the *Part* 71 rulemaking. This process included establishing an interactive website and holding three facilitated public meetings: a ‘roundtable’ workshop at the NRC Headquarters, Rockville, MD, on August 10, 2000, and two ‘townhall’ meetings—one in Atlanta, GA, on September 20, 2000, and a second in Oakland, CA, on September 26, 2000.

“SRM–00–0117 also directed the staff to proceed, after completion of the public meetings, with the development of a proposed rule for submittal to the Commission by March 1, 2001. Oral and written comments received from the public meetings, by mail, and through the NRC website, in response

to the issues paper, were considered in the drafting of the proposed changes contained herein.

"*Past NRC–IAEA Compatibility Revisions*

"Recognizing that its international regulations for the safe transportation of radioactive material should be revised from time to time to reflect knowledge gained in scientific and technical advances and accumulated experience, IAEA invited Member States (the U.S. is a Member State) to submit comments and suggest changes to the regulations in 1969. As a result of this initiative, the IAEA issued revised regulations in 1973 (Regulations for the Safe Transport of Radioactive Material, 1973 edition, Safety Series No. 6). The IAEA also decided to periodically review its transportation regulations, at intervals of about 10 years, to ensure that the regulations are kept current. In 1979, a review of IAEA's transportation regulations was initiated that resulted in the publication of revised regulations in 1985 (Regulations for the Safe Transport of Radioactive Material, 1985 edition, Safety Series No. 6).

"The NRC also periodically revises its regulations for the safe transportation of radioactive material to make them compatible with those of the IAEA. On August 5, 1983 (48 FR 35600), the NRC published in the **Federal Register** a final revision to *Part* 71, 'Packaging and Transportation of Radioactive Material.' That revision, in combination with a parallel revision of the hazardous materials transportation regulations of the U.S. Department of Transportation (DOT), brought U.S. domestic transport regulations into general accord with the 1973 edition of IAEA transport regulations. The last revision to *part* 71 was published on September 28, 1995 (60 FR 50248), to make *Part* 71 compatible with the 1985 IAEA Safety Series No. 6. The DOT published its corresponding revision to Title 49 on the same date (60 FR 50291).

"The last revision to the IAEA Safety Series 6 was named Safety Standards Series ST-1, published in December 1996, and was revised with minor editorial changes in June 2000, and was redesignated as TS-R-1. This rulemaking effort is to evaluate TS-R-1 for potential adoption in *part* 71 regulations.

"Historically, the NRC coordinated its *part* 71 revisions with DOT, because DOT is the U.S. Competent Authority for transportation of hazardous materials. 'Radioactive Materials' is a subset of 'Hazardous Materials' in Title 49 regulations under DOT authority. Currently, DOT and NRC co-regulate transport of nuclear material in the United States. NRC is continuing with its coordinating effort with the DOT in this rulemaking process. Refer to the DOT's corresponding rule for additional background on the positions proposed in this notice.

"*Scope of 10 CFR Part 71 Rulemaking*

"As directed by the Commission, NRC staff compared TS-R-1 to the previous version of Safety Series No. 6 to identify changes made in TS-R-1, and then identified affected sections of *part* 71. Based on this comparison, NRC staff identified 11 areas in *part* 71 that needed to be addressed in this rulemaking process as a result of the changes to the IAEA regulations. The staff grouped the *part* 71 IAEA compatibility changes into the following issues: (1) Changing *part* 71 to the International System of Units (Sl) (also known as the metric system) exclusively; (2) Radionuclide specific exemption values; (3) Revision of A_1 and A_2 values; (4) Uranium hexafluoride (UF_6) package requirements; (5) Introduction of criticality safety index requirements; (6) Type C packages and low dispersible material; (7) Deep immersion test; (8) Grandfathering previously approved packages; (9) Adding and modifying part 71 definitions; (10) Crush test for fissile material package design;[§§§] and (11) Fissile material package design for transport by aircraft.

"Eight additional NRC-initiated issues (numbers 12 through 19) were identified by Commission direction, and through staff consideration, for incorporation in the Part 71 rulemaking process. These NRC-initiated changes are: (12) Special package approvals; (13) Expansion of Part 71 quality assurance (QA) requirements to holders of, and applicants for, a Certificate of Compliance (CoC); (14) Adoption of the requirements of American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel (B&PV) Code for fabrication of spent fuel transportation packages; (15) Adoption of change authority; (16) Revisions to the fissile exempt and general license provisions to address the unintended economic impact of the emergency rule (SRM-SECY-99-200); (17) Decision on Petition for Rulemaking PRM-71-12, which requested deletion of the double containment requirements for plutonium; (18) Surface contamination limits as applied to spent fuel and high-level waste packages (SRM-SECY-00-0117); and (19) part 71 event reporting requirements. NRC published the first 18 issues in an issues paper in the **Federal Register** on July 17, 2000 (65 FR 44360).

"The Part 71 rulemaking is being coordinated with DOT to ensure that consistent regulatory standards are maintained between NRC and DOT radioactive material transportation regulations, and to ensure coordinated publication of the final rules by both agencies. On December 28, 1999 (64 FR 72633), DOT published an advance notice of proposed rulemaking regarding adoption of TS-R-1 in its regulations . . . ." [32]

10.17 10 CFR 71, 2004 FINAL RULE

In January 2004, the final rule for major changes to 10 CFR 71 was published in the *Federal Register* [33]. Because much of the information presented in the preamble for the 2004 Final Rule was (is) a repeat of the comparable information already presented for the 2002 Proposed Rule, the information presented in this section will focus primarily on the final results.

> "This section is structured to present and discuss each issue separately (with cross references as appropriate). Each issue has four parts: Summary of NRC Final Rule, Affected Sections, Background, and Analysis of Public Comments on the Proposed Rule.[****]

[§§§] Authors Note: The introduction of this so-called *Dynamic* Crush Test marked the beginning of the end for the DOT Specification 6M fissile material package. See also the related footnotes in Sections 10.4.1 and 10.17.

[****] Author's Note: For purposes of this discussion, the *Summary of the NRC Final Rule* and the *Affected Sections* will be presented, verbatim. For the complete discussion on the *Background* and the *Analysis of Public Comments on the Proposed Rule*, readers are encouraged to see the full text of Reference [33].

"*A. TS-R-1 Compatibility Issues*

"Issue 1. Changing part 71 to the International System of Units (SI) Only

"*Summary of NRC Final Rule.* The NRC has decided to continue using the dual-unit system (SI units and customary units) in *part* 71. This will not conflict with TS-R-1, which uses SI units only, because TS-R-1 does not specifically prohibit the use of a dual-unit system.

"We have decided not to change *part* 71 to use SI units only nor to require NRC licensees and holders and applicants for a Certificate-of-Compliance (CoC) to use SI units only because doing so will conflict with NRC's Metrication Policy (61 FR 31169; June 19, 1996) which allows a dual-use system. The NRC did not make metrication mandatory because no corresponding improvement in public health and safety would result; rather, costs would be incurred without benefit. Moreover, as noted in the proposed rule (67 FR 21395–21396), the change to SI units only could result in the potential for adverse impact on the health and safety of workers and the general public as a result of unintended exposure in the event of shipping accidents, or medical dose errors, caused by confusion or erroneous conversion between the currently prevailing customary units and the new SI units by emergency responders or medical personnel.

"*Affected Sections*. None (not adopted) . . . .

"Issue 2. Radionuclide Exemption Values

"*Summary of NRC Final Rule*. The final rule adopts, in §§ 71.14, 71.88 and Appendix A, Table A-2, the radionuclide activity concentration values and consignment activity limits in TS-R-1 for the exemption from regulatory requirements for the shipment or carriage of certain radioactive low-level materials. In addition, the final rule provides an exemption from regulatory requirements for natural material and ores containing naturally occurring radionuclides that are not intended to be processed for use of these radionuclides, provided the activity concentration of the material does not exceed 10 times the applicable values. These amendments conform *part* 71 with TS-R-1 and with DOT's parallel IAEA compatibility rulemaking for CFR 49.

"During the development of TS-R-1, it was recognized that there was no technical justification for the use of a single activity-based exemption value for all radionuclides for defining a material as radioactive for transportation purposes (a uniform activity concentration basis) and that a more rigorous technical approach would be to base radionuclide exemptions on a uniform dose basis. The values and limits in TS-R-1, and adopted in Appendix A, Table A-2, establish a consistent dose-based model for minimizing public exposure. Overall, NRC's analysis shows that the new system would result in lower actual doses to the public than the uniform activity concentration basis system. NRC's regulatory analysis indicated that adopting the radionuclide-specific exemption values contained in TS-R-1 is appropriate from a safety, regulatory, and cost perspective. Moreover, the final rule assures continued consistency between domestic and international regulations for the basic definition of radioactive material in transport.

"*Affected Sections*. Sections 71.14, 71.88, and Appendix A . . . .

"Issue 3. Revision of A_1 and A_2

"*Summary of NRC Final Rule.* The final rule adopts, in Appendix A, Table A-1 of *part* 71, the new A_1 and A_2 values from TS-R-1, except for molybdenum-99 and californium-252. The final rule does not include A_1 and A_2 values for the 16 radionuclides that were previously listed in *part* 71 but which do not appear in TS-R-1.

"The A_1 and A_2 values were revised by IAEA based on refined modeling of possible doses from radionuclides. The NRC believes that these changes are based on sound science, incorporating the latest in dosimetric modeling and that the changes improve the transportation regulations. The regulatory analysis indicates that adopting these values is appropriate from a safety, regulatory, and cost perspective. Further, adoption of the new A_1 and A_2 values will be an overall benefit to public and worker health and international commerce by ensuring that the A_1 and A_2 values are consistent within and between international and domestic transportation regulations. The NRC is not adopting the A_1 value for californium-252 because the IAEA is considering changing the value that appears in TS-R-1 back to what presently appears in *part* 71. The NRC is not adopting the A_2 value for molybdenum-99 for domestic commerce because this would result in a significant increase in the number of packages shipped, and therefore in potential occupational doses, due to the lower A_2 value in TS-R-1.

"*Affected Sections.* Appendix A . . . .

"Issue 4. Uranium Hexafluoride (UF_6) Package Requirements

"*Summary of NRC Final Rule*. The final rule provides, in new § 71.55(g), a specific exception for certain uranium hexafluoride (UF_6) packages from the requirements of § 71.55(b). The exception allows UF_6 packages to be evaluated for criticality safety without considering the in leakage of water into the containment system provided certain conditions are met, including that the uranium is enriched to not more than 5 weight percent uranium-235. The rule makes *part* 71 compatible with TS-R-1, paragraph 677(b). Other uranium hexafluoride package requirements in TS-R-1 (paragraphs 629, 630 and 631) do not necessitate changes for compatibility because NRC uses analogous national standards and addresses package design requirements in its design review process.

"The specific exception being placed into the regulations for the criticality safety evaluation of certain uranium hexaflouride [*sic*] packages does not alter present practice which has allowed the same type of evaluation under other more general regulatory provisions. NRC has decided to provide this specific exception: (1) To be consistent with the worldwide practice and limits established in national and international standards (ANSI N14.1 and IS 7195) and current U.S. regulations (49 CFR 173.417(b)(5)); (2) because of the history of safe shipment; and (3) because of the essential need to transport the commodity.

"*Affected Sections*. Section 71.55 . . . .

"Issue 5. Introduction of the Criticality Safety Index Requirements

"*Summary of NRC Final Rule.* The final rule adopts the TS-R-1 (paragraphs 218 and 530). Paragraph 218 results in NRC

incorporating a Criticality Safety Index (CSI) in *part* 71 that is determined in the same manner as current *part* 71 'Transport Index for criticality control purposes,' but now it must be displayed on shipments of fissile material (paragraphs 544–545) using a new 'fissile material' label. NRC's adoption of TS-R-1 (paragraph 530) increases the CSI-per package limit from 10 to 50 for fissile material packages in nonexclusive use shipments. (The previous Transport Index criticality limit was 10.) The TI is determined in the same way as the 'TI for radiation control purposes' and continues to be displayed on the traditional 'radioactive material' label. The basis for these changes that makes *part* 71 compatible with TS-R-1 is that NRC believes the differentiation between criticality control and radiation protection would better define the hazards associated with a given package and, therefore, provide better package hazard information to emergency responders. The increase in the per package CSI limit may provide additional flexibility to licensees by permitting the increased use of less expensive, nonexclusive use shipments. However, licensees will still retain the flexibility to ship a larger number of packages of fissile material on an exclusive use conveyance. The adoption of the CSI values would make *part* 71 consistent with TS-R-1 and, therefore, would enhance regulatory efficiency.

"*Affected Sections.* Sections 71.4, 71.18, 71.20, 71.59 . . . .

"Issue 6. Type C Packages and Low Dispersible Material

"*Summary of NRC Final Rule*. The final rule does not adopt the Type C or Low dispersible material (LDM) requirements for plutonium air transport as introduced in the IAEA TS-R-1. NRC decided not to adopt Type C or LDM requirements because the U.S. regulations in §§ 71.64 and 71.71 governing plutonium air transportation to, within, or over the United States contains more rigorous packaging standards than those in the IAEA TS-R-1. Furthermore, the NRC's perception is that there is a lack of current or anticipated need for such packages, and NRC acknowledges that the DOT import/export provisions permit use of IAEA regulations.

"*Affected Sections*. None (not adopted) . . . .

"Issue 7. Deep Immersion Test

"*Summary of NRC Final Rule*. The final rule adopts the requirement for an enhanced water immersion test (deep immersion test) which is applicable to any Type B or C packages containing activity greater than 10^5 A_2. The purpose of the deep immersion test is to ensure package recoverability. The basis for expanding the scope of the deep immersion test to include additional Type B or C packages containing activity greater that 10^5 A_2 was due to the fact that radioactive materials, such as plutonium and high-level radioactive waste, are increasingly being transported by sea in large quantities. The threshold defining a large quantity as a multiple of A_2 is considered to be a more appropriate criterion to cover all radioactive materials and is based on a consideration of potential radioactive exposure resulting from an accident. Also, the NRC is retaining the current test requirements in § 71.61 of 'one hour w/o collapse, buckling or leakage of water.' The NRC is retaining this acceptance criterion of 'w/o collapse, buckling, or leakage' as opposed to the acceptance criterion specified in TS-R-1 of only 'no rupture' of the containment. NRC has determined that the term 'rupture' cannot be determined by engineering analysis and the term 'w/o collapse, buckling or leakage of water' is a more precise definition for acceptance criterion.

"*Affected Sections.* Sections 71.41, 71.51, 71.61 . . . .

"Issue 8. Grandfathering Previously Approved Packages

"*Summary of NRC Final Rule*. The final rule adopts the following grandfathering provisions for previously approved packages in Section 71.13:

(1) Packages approved under NRC standards that are compatible with the provisions of the 1967 edition of Safety Series No. 6 may no longer be fabricated, but may be used for a 4-year period after adoption of a final rule;
(2) Packages approved under NRC standards that are compatible with the provisions of the 1973 or 1973 (as amended) editions of Safety Series No. 6 may no longer be fabricated; however, may still be used;
(3) Packages approved under NRC standards that are compatible with the provisions of the 1985 or 1985 (as amended 1990) editions of Safety Series No. 6, and designated as '–85' in the identification number, may not be fabricated after December 31, 2006, but may be continued to be used; and
(4) Package designs approved under any pre-1996 IAEA standards (i.e., packages with an '–85' or earlier identification number) may be resubmitted to the NRC for review against the current standards. If the package design described in the resubmitted application meets the current standards, the NRC may issue a new CoC for that package design with a '–96' designation.

"Thus, the final rule adopts, in part, the provisions for grandfathering contained in TS-R-1. The NRC believes that packages previously approved under the 1967 edition of Safety Series No. 6 lack the enhanced safety enrichments which have been incorporated in the packages approved under the provisions of the 1973, 1973 (as amended), 1985 and 1985 (as amended) editions of Safety Series No. 6. For example, later designs demonstrate a greater degree of leakage resistance and are subject to quality assurance requirements in subpart H of *part* 71. Furthermore, NRC believes that by discontinuing the use of package designs that have been approved to Safety Series No. 6, 1967, for both domestic and international transport of radioactive material, it will ensure safety during transportation and thus will increase public confidence. However, NRC has not adopted the immediate phase out of 1967-approved packages as the IAEA has, [*sic*] Instead, NRC implemented a 4-year transition period for the grandfathering provision on packages approved under the provisions of the 1967 edition of Safety Series No. 6. This period provides industry the opportunity to phase out old packages and phase in new ones, or demonstrate that current requirements are met. NRC recognizes that when the regulations change there is not necessarily an immediate need to discontinue use of packages that were approved under previous revisions of the regulations. The final rule includes provisions that would allow previously-approved designs to be upgraded and to be evaluated to the newer regulatory standards. Note that in 1996, IAEA first published that the 1967-approved packages would be eliminated from use. Thus, with the final

rule 4-year phase out of these older packages, industry will have had 12 years (i.e., until 2008) to evaluate its package designs and prepare for the eventual phase out.

"*Affected Sections*. Section 71.13 . . . .

"Issue 9. Changes to Various Definitions

"*Summary of NRC Final Rule*. The final rule adopts the TS-R-1 definition of Criticality Safety Index (CSI). NRC believes this provides internal consistency and compatibility with TS-R-1. Additionally, the following definitions have been revised to improve their clarity and maintain consistency with DOT: A_1, A_2, Consignment, LSA-I, LSA-II, LSA-III, and Unirradiated uranium. NRC believes that terms must be clearly defined so that they can be used to accurately communicate requirements to licensees. By modifying existing definitions and adding new definitions, the licensee would benefit through more effective understanding of the requirements of *part* 71.

"*Affected Sections*. Section 71.4 . . . .

"Issue 10. Crush Test for Fissile Material Package Design[††††]

"*Summary of NRC Final Rule.* The final rule adopts, in § 71.73, the TS-R-1 requirement for a crush test for fissile material package designs and eliminated the 1000 A_2 criterion, but maintained the current *part* 71 testing sequence and drop and crush test requirements.

"By adopting TS-R-1, the weight and density criteria will apply to fissile uranium material packages, and packages that were previously exempted because of the 1000 A_2 criterion will now require crush testing. Adopting crush test requirements and eliminating the 1000 A_2 criterion is appropriate because not adopting the TS-R-1 requirements would result in an inconsistency between *part* 71 requirements and TS-R-1, which could affect international shipments, and fissile material package designs would continue to not be evaluated for criticality safety against a potential crush test accident condition.

"The NRC did not adopt the TS-R-1 test sequence requirements because no new information existed to address concerns from a previous rulemaking regarding the difference in test requirements between essentially the same IAEA requirements contained in Safety Series No. 6 and *Part* 71. The NRC chose to remain more conservative than the IAEA by requiring both a drop and crush test, rather than one or the other as TS-R-1 would permit.

"*Affected Sections*. Section 71.73 . . . .

"Issue 11. Fissile Material Package Design for Transport by Aircraft

"*Summary of NRC Final Rule*. The final rule adopts TS-R-1, paragraph 680, Criticality evaluation, in a new § 71.55(f) that only applies to fissile material package designs that are intended to be transported aboard aircraft. Section 71.55 specifies the general package requirements for fissile materials, and the existing paragraphs of § 71.55 are unchanged. Among other requirements, TS-R-1, paragraph 680, requires that packages must remain subcritical when subjected to the tests for Type C packages, because:

(1) The NRC has deferred adoption of the Type C packaging tests (see Issue 6);
(2) TS-R-1, paragraph 680 requires Type C tests; and
(3) Paragraph 680 applies to more than Type C packages; only the salient text of paragraph 680 was inserted into § 71.55(f) and applies to domestic shipments.

"Adopting this change will provide regulatory consistency. Shippers would have been required to meet the TS-R-1 air transport requirements even if the NRC did not adopt them, because the International Civil Aviation Organization had adopted regulations consistent with TS-R-1 on July 1, 2001. U.S. domestic air carriers require compliance with the ICAO regulations even for domestic shipments. Therefore, these changes are expected to benefit industry by eliminating the need for two different package designs.

"*Affected Sections*. Section 71.55 . . . .

"*B. NRC-Initiated Issues*

"Issue 12. Special Package Authorizations

"*Summary of NRC Final Rul*e. The final rule adopts, in § 71.41, special package authorizations that will apply only in limited circumstances and only to one-time shipments of large components. Special package authorization regulations are necessary because there are no regulatory provisions in *part* 71 for dealing with nonstandard packages, other than the exemption provisions and § 71.41(c). The NRC processing of one-time exemptions for nonstandard packages, such as the Trojan reactor vessel, has required the expenditure of considerable NRC resources. Further, the NRC's policy is to avoid the use of exemptions for recurring licensing actions. Special package authorization requirements will result in enhanced regulatory efficiency by standardizing the requirements to provide greater regulatory certainty and clarity, and will ensure consistent treatment among licensees requesting authorization for shipment of special packages.

"Any special package authorization will be issued on a case-by-case basis, and requires the applicant to demonstrate that the proposed shipment would not endanger life or property nor the common defense and security, following the basic process used by applicants to obtain a CoC for nonspecial packages from NRC.

"The applicant will be required to provide reasonable assurance that the special package, considering operational procedures and administrative controls employed during the shipment, would not encounter conditions beyond those for which it had been analyzed and demonstrated to provide protection. The NRC will review applications for special package authorizations. Approval will be based on NRC staff determination that the applicant will meet the requirements of subpart D of 10 CFR *part* 71. If approved, the NRC will issue a CoC or other approval (i.e., special package authorization letter).

"NRC will consult with DOT on making the determinations required to issue an NRC special package authorization.

"*Affected Sections*. Section 71.41 . . . .

[††††] Author's Note: As was noted previously in Section 10.16, the proposed adoption of the so-called *Dynamic* Crush Test marked the beginning of the end for the DOT Specification 6M fissile material package. The actual death-knell for the package was finally sounded here, in 2004, with the adoption of the requirements in this Final Rule, since it required *both*, the Dynamic Crush Test *and* the 30-foot Drop Test.

"Issue 13. Expansion of part 71 Quality Assurance (QA) Requirements to Certificate of Compliance (CoC) Holders

"*Summary of NRC Final Rule*. The final rule adds the terms 'certificate holder' and 'applicant for a CoC' to subpart H, *part* 71 and adds a new section, § 71.9, on employee protection. Adopting these requirements will ensure that the regulatory scheme of *part* 71 will remain more consistent with other NRC regulations in that certificate holders and applicants for a CoC will be responsible for the behavior of their contractors and subcontractors.

"This expansion is necessary to enhance NRC's ability to enforce nonconformance by the certificate holders and applicants for a CoC. Although CoC's [*sic*] are legally binding documents, certificate holders and/or applicants and their contractors and subcontractors have not clearly been brought into the scope of *part* 71 requirements. This is because the terms 'certificate holder' and 'applicant for a certificate of compliance' do not appear in *part* 71, subpart H; rather, subpart H only mentions 'licensee' in these regulations. Consequently, the NRC has not had a clear basis to cite applicants for, and holders of CoC's [*sic*] for violations of *part* 71 requirements in the same way it has licensees.

"The NRC also added a new section (§ 71.9) on employee protection to *part* 71. The NRC believes that employee protection regulations should be added to cover the employees of certificate holders and applicants for a CoC to provide greater regulatory equivalency between *part* 71 licensees and certificate holders.

"*Affected Sections*. Sections 71.0, 71.1, 71.6, 71.7, 71.8, 71.9, 71.91, 71.93, 71.100, and 71.101 through 71.137 . . . .

"Issue 14. Adoption of the American Society of Mechanical Engineers (ASME) Code

"*Summary of NRC Final Rule*. The NRC has decided not to incorporate the ASME Code, Section III, Division 3 requirements into *part* 71. Public Law 104-113 requires that Federal agencies use consensus standards in lieu of government-unique standards, if this use is practical or inconsistent with other existing laws. Because a major revision to the ASME Code is forthcoming and because the changes in that revision are not yet available for staff and stakeholder review, the NRC staff considered it an imprudent use of NRC and stakeholder resources to initiate rulemaking on the current ASME Code revision only to have the ASME Code requirements change during the *part* 71 rulemaking.

"*Affected Sections*. None (not adopted) . . . .

"Issue 15. Change Authority for Dual-Purpose Package Certificate Holders

"*Summary of NRC Final Rule*. The Commission does not reach a final decision on the issue of change authority for dual-purpose package certificate holders in this final rule. The NRC has determined that implementation of this change would result in new regulatory burdens and costs which could be significant. The Commission believes it needs further input from stakeholders on the values and impacts of this change before deciding whether to adopt a final rule providing change authority for dual-purpose package certificate holders. The NRC staff plans to conduct public meetings with appropriate stakeholders to develop a final regulatory solution which it will propose to the Commission. At that time, the Commission will either issue a final rule resolving this issue, taking into account the comments received on the proposed rule and in any future public meetings, or will withdraw 10 CFR *part* 71 subpart I of the proposed rule.

"*Affected Sections.* None . . . .

"Issue 16. Fissile Material Exemptions and General License Provisions

"Summary of NRC Final Rule. The final rule adopts various revisions to the fissile material exemptions and the general license provisions in *part* 71 to facilitate effective and efficient regulation of the transport of small quantities of fissile material. The fissile exemptions (§ 71.15) have been revised to include controls on fissile package mass limit combined with package fissile-to-nonfissile mass ratio. The general license for fissile material (§ 71.22) has been revised to consolidate and simplify current fissile general license provisions from §§ 71.18, 71.20, 71.22, and 71.24. Under the final rule, the general license is based on mass-based limits and the CSI. In light of comments and applicable DOT requirements, the final rule removes proposed rule language references to 'storage incident to transportation.' Also, the exemptions for low level materials in § 71.14 were revised to apply only to nonfissile and fissile-exempt materials.

"Affected Sections. Sections 71.4, 71.10, 71.11, 71.18, 71.20, 71.22, 71.24, 71.53, 71.59, and 71.100. (Currently effective § 71.10 was relocated to § 71.14 with additional language. Currently effective §§ 71.18, 71.20, 71.22, 71.24, and 71.53 are replaced by new §§ 71.15 and 71.22.) . . . .

"Issue 17. Decision on Petition for Rulemaking on Double Containment of Plutonium (PRM-71-12)

"*Summary of Decision on PRM-71-12*. Currently in 10 CFR 71.63(b), plutonium in excess of 0.74 TBq (20 Ci) must be packaged in a separate inner container placed within an outer packaging. This is referred to as double containment. It is the combination of the inner container and the outer packaging that is subjected to the normal conditions of transport (§ 71.71) and the hypothetical accident conditions (§ 71.73). Upon application of the normal conditions of transport and hypothetical accident conditions, the acceptance criteria for shielding, containment, and subcriticality in § 71.51 must be also met for the total package (inner container and outer packaging), but the containment dispersal acceptance (10^{-6} A_2/hour or 1 A_2/week) are applied to each boundary (i.e., the inner container and the outer packaging). Note however, as a point of clarification, double containment does not mean two Type B containers nested into one.

"The final rule grants the petitioner's request to remove the double containment requirement of § 71.63(b). However, the requirement of § 71.63(a) that shipments whose contents contain greater than 0.74 TBq (20 Ci) of plutonium must be made with the contents in solid form is retained. Thus, the petitioner's alternative proposal is denied. This completes action on PRM-71-12.

"The NRC has decided to remove the double containment requirement because this regulation is neither risk informed nor performance-based. There are many nuclides with A_2 values the same or lower than plutonium's for which double containment has never been required. Thus, requiring double containment for plutonium alone is not consistent with the relative hazard rankings in Table A-1. The Type B packaging standards, which the outer containment of plutonium shipments must meet, in and of themselves, provide reasonable

assurance that public health and safety and the environment are protected during the transportation of radioactive material. This position is supported by an excellent safety record in which no fatalities or injuries have been attributed to material transported in a Type B package. The imposition of an additional packaging requirement (in the form of a separate inner container) is fundamentally inconsistent with this position and is technically unnecessary to assure safe transport. Further, removal of this requirement will reduce an unnecessary regulatory burden on licensees, will likely result in reduced risk to radiation workers, and will serve to harmonize *part* 71 with TS-R-1.

"On the other hand, the imposition of the requirement that plutonium in excess of 0.74 TBq (20 Ci) per package be shipped as a solid does not create a regulatory inconsistency with the Type B package standards. The NRC considers the contents of a package when it is evaluating the adequacy of a packaging's design. The approved content limits and the approved packaging design together define the CoC for a package. However, other than criticality controls and the solid form requirement of § 71.63(a), subparts E and F do not contain any restrictions on the contents of a package. Thus, while the inner containment requirement in § 71.63(b) can be seen as conflicting with the Type B package standard because the inner containment affects the packaging design, the solid form requirement of § 71.63(a) does not conflict with the packaging requirements of the Type B package standard because the solid form requirement affects only the contents of the package, not the packaging itself.

"*Affected Sections*. Section 71.63 . . . .

"Issue 18. Contamination Limits as Applied to Spent Fuel and High-Level Waste (HLW) Packages

"*Summary of NRC Final Rule*. The final rule does not adopt any changes to *part* 71 for this issue because experience with regulations requiring that licensees monitor the external surfaces of labeled radioactive material packages for contamination upon receipt and opening indicates the rate of packages exceeding allowable levels en route is low, and therefore, in transit decontamination of packages is not warranted. Further, requiring such decontamination of packages could result in a significant increase in worker doses without a commensurate increase in public health and safety.

"*Affected Sections*. None (not adopted) . . . .

"Issue 19. Modifications of Event Reporting Requirements

"*Summary of NRC Final Rule*. The final rule revises, in § 71.95, the event reporting submission period to provide a written report from 30 to 60 days. Other regulatory requirements to orally notify the NRC Operations Center promptly of an event and for licensees to report instances of failure to follow the conditions of the CoC while packaging was in use remain unchanged. The revision lengthening the time for submission of the written report is consistent with changes to similar requirements in part 50.

"*Affected Sections.* Section 71.95 . . . .

10.18 CONCLUSIONS

In the preceding pages, we have taken a look at the development of U.S. regulations for the transportation of radioactive materials. Primarily based on the requirements for Type B quantities of radioactive material, the information included a number of detailed interactions that have taken place between a variety of U.S. governmental agencies, commissions, and departments. The information also included details on the many interactions that have taken place between these governmental agencies and the IAEA.

From a regulatory perspective, the Chapter covered the time period from 1965 through 2004, or about 40 years. Starting in 1978, however, we also began to look at the interactions between the regulatory requirements of 10 CFR 71 and the regulatory guidance provided by the NRC in the form of Reg. Guides, NUREGs, and NUREG/CRs.

As we have seen above in Sections 10.7, 10.9, 10.11, and 10.13, the regulatory guidance provided by the NRC specifically noted that the requirements of 10 CFR 71 could be met by using the requirements defined in specific sections of the ASME's Boiler & Vessel Pressure Code (the Code) as a metric for the design, fabrication, assembly, testing, use, and maintenance of packagings used for the transport of Type B quantities of radioactive materials.

We have also seen that, for the most part, the NRC has been reluctant to introduce the requirements of the Code directly into the regulatory requirements of 10 CFR 71, preferring instead to introduce Code requirements through the use of its guidance documents. The one exception to this occurred with the adoption of the 1998 Final Rule for the *Elimination of Double Containment for Plutonium for Vitrified High Level Waste* (see Section 10.15.3). In this case, however, all direct references to Code requirements were later eliminated from 10 CFR 71 with the adoption of the 2004 Final Rule, and the simultaneous elimination of the long-standing, *double-containment* requirement for plutonium.

Finally, we have seen, in the 2004 Final Rule, that the NRC has chosen *not* to adopt ASME Boiler & Pressure Vessel Code requirements directly into the regulatory requirements for 10 CFR 71. Although it would now seem that we have come full circle, this may not be the case. In reality, two additional situations are at work: 1) the IAEA has adopted a two-year revision cycle for its regulations, in the hope that the latest revisions can be incorporated more quickly than under the previous ten-year revision cycle; and 2) major revisions to the ASME's Boiler & Pressure Vessel Code have, for some time now, been a work in progress with respect to transportation packages. (For additional detail on that subject, see Chapter 15, *Containments for Transportation and Storage of Spent Nuclear Fuel and High-Level Radioactive Material and Waste*, by D. Keith Morton and D. Wayne Lewis.) At some point, it seems likely that these situations will eventually cross paths, and that the requirements specified in a totally revised version of the ASME's Boiler & Pressure Vessel Code *will* find their way back into the regulatory requirements of 10 CFR 71. We may not have to wait too long, since the next Proposed Rule change for 10 CFR 71 is due out later in 2013, with a following Final Rule change due out a year or so after that.

10.19 ACKNOWLEDGEMENTS

The author would like to thank Roger W. Carlson, Larry E. Fischer, the late Jack Hovingh, Gerald C. Mok, Edward W. Russell, Jr., Michael K. Sheaffer, and Brian L. Anderson of Lawrence Livermore National Laboratory, for their help and guidance over these past many years. Without their dedication, and their long-term commitments to the regulatory issues associated with the requirements of 10 CFR 71, this Chapter could not have been written.

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CHAPTER

11

PIPELINE INTEGRITY AND SECURITY

Alan Murray[1]

11.1 INTRODUCTION

Pipelines provide a safe and economic means of transporting fluids such as natural gas, crude oil, refined products, and natural gas liquids products across great distances and over all manner of terrain. As man-made systems, however, they can and do fail from time to time, sometimes with catastrophic effect. Figure 11.1 illustrates the aftermath of a recent gas pipeline rupture followed by a fire which resulted in the death of 12 people [1]. Such fatal events, however, are rare, accounting for less than 0.02% of the 45,000 transport-related deaths that occur annually in the United States [2]. The consequences of failures, when they do occur, are more commonly measured in terms of lost product and its effect if any, on the environment, as well as a disruption to business while a repair is made [3]. Repairs and environmental remediation, especially in sensitive areas, can however be very expensive. For example, the clean up cost of a recent relatively modest crude oil pipeline break in Canada amounted to $24 million, in addition to a $1.4 million fine levied on the company for causing environmental pollution. In recent years several high profile pipeline leaks and ruptures particularly on liquid hydrocarbon lines have created a poor public image of pipelines. On July 26, 2010 a 30 inch diameter pipeline conveying diluted bitumen ruptured near Marshall in Michigan spilling almost 20,000 barrels into Talmadge Creek, which flows into the Kalamazoo River. Fortunately the response effort to this, the largest onshore spill in US history prevented bitumen reaching Lake Michigan. The cleanup effort has been estimated to have cost almost one billion dollars. In June and December 2010, two pipeline breaks resulted in 1,200 barrels of crude oil being leaked into Red Butte Gardens in Salt Lake City. In June of the following year 42,000 gallons/ 1,000 barrels of oil leaked into the Yellowstone River from a pipeline break associated with seasonal heavy flooding. Even more recently the same pipeline operator suffered a break on its 65 year old line in Arkansas releasing 500,000 gallons (11,900 barrels) of crude oil causing significant environmental damage in the process and posing a threat to the local water supply. While environmental damage can eventually be remediated or mitigated such is not the case when fatalities result from natural gas pipeline ignitions. In September 2010, eight people died when a natural gas pipeline located in the neighbourhood of San Bruno, California, ruptured and ignited. The root cause of this incident was attributed to a faulty long seam weld.

Many individual cases of fatalities involving members of the public however, are a direct result of external damage to the pipeline caused by either failing to accurately locate buried pipelines or flagrant disregard for their possible presence. The Common Ground Alliance (CGA) estimates that there are almost 19 million miles of underground utility pipelines in the United States. To help reduce societal and individual risk from these pipelines, the CGA have created a “call before you dig” program. However, in a recent sample survey, CGA found that 48% of homeowners who planned projects such as landscaping and fence post installation will put themselves and others at risk by not calling the 811 number which would start the freely available service to locate underground utilities.

Incident summary statistics collected by the US Department of Transportation’s Office of Pipeline Safety for the period 1986



FIGURE 11.1 GAS PIPELINE EXPLOSION IN CARLSBAD NEW MEXICO AUGUST 2000 RESULTING IN 12 DEATHS

[1]Rafael G. Mora was the co-author for the third edition of this chapter which has been updated for this publication by Alan Murray.

until June 2005 indicates that the collective property damage related to oil pipeline incidents amounted to just over 1 billion dollars, while almost half that amount ($447 million dollars) was associated with damage related to gas pipeline incidents [4].

Notwithstanding these incidents, pipelines continue to be the safest method of delivering gas and petroleum products, as attested by the hundreds of thousands of miles of major transmission pipelines operating continuously throughout the world, unseen to the general public. Protection of the public is paramount, so a safe, long lasting, and profitable pipeline is every operator's goal. Consequently, the use of integrity schemes and maintenance measures that are cost effective and prevent failures, or high repair costs, must be considered.

11.2 COST EFFECTIVENESS AND IMPORTANCE OF PIPELINE TRANSPORTATION

Pipelines are used to transport a wide variety of products ranging from commodities such as slurries of iron and copper ores to the more common hydrocarbons and water and sewage. It has been estimated that 59 different types of refined hydrocarbon product, including natural gas liquids, are shipped by pipeline within North America, some over very large distances. Pipeline transportation is relatively economic as may be seen from the comparison given in Table 11.1 which lists the energy required to ship a ton of product over the same distance using various modes of transport.

TABLE 11.1 COMPARISON OF OPERATING COST OF VARIOUS TRANSPORTATION SYSTEMS

Transportation System	%age Energy content used per 1000 km
Rail	0.8–1.0
Truck	3.2–5.4
Tanker (LNG)	08–1.1
Pipeline	<0.5

Although pipelines may be less flexible than any of the other systems, they are preferred in most situations because:

i. They can move large quantities of material quietly.
ii. They can traverse long distances. For instance in countries like the United States, Canada, and Russia, the sizeable oil and gas reserves are located at considerable distances from the major centers of population and industry.
iii. They are generally buried so they have minimal interference with ongoing surface activity.
iv. Once commissioned, they have comparatively low operating cost.

There is a very strong correlation between energy usage and economic wellbeing and in many instances it is through pipeline connectivity that the bulk of energy supplies in the form of hydrocarbons are moved efficiently to market. In the past decade the vast resources of oil and gas in Central Asia have found access to world markets, thus increasing diversity of global supply. The Baku-Tbilisi-Ceyhan crude oil pipeline for example, connected the Caspian Sea area to the eastern Mediterranean, transporting 1 million barrels of oil per day some 1760 km from Azerbaijan through Georgia and into Turkey. Its natural gas companion, the TransAdriatic Pipeline TAP has just entered its detailed design phases and is expected to transport 350 billion cubic feet of gas (10 Bcm) per year from the Azeri gas fields at Shah Deniz to Southern Europe, primarily Greece and Italy. In China two very large pipelines have been constructed and commissioned in the past decade linking the gas rich Xinjiang Province with the populous regions to the east. The first of these pipelines has a design capacity of 17 Bcm (600 bcf) per year, while the second conveys 30 Bcm (1.06 tcf) per year. A third pipeline in the West East sequence is currently being constructed and it too will transport 30 Bcm of gas per year. Russia, the second biggest producer of natural gas after the United States, and the largest exporter in the world, has announced plans for several large capacity pipelines to be constructed running both east and westward from its gas fields in Siberia. In North America the landscape for natural gas has undergone a tremendous and rapid change since 2008 when the first large quantities of shale gas entered the market to fill a void caused by quickly depleting conventional gas reserves. Fortuitously these shale gas deposits underlie existing pipeline infrastructure so major new pipelines are not immediately required. Their emergence has however cast some doubt on whether it will economically viable to construct two major pipelines to bring conventional gas supply from the Alaskan North slope and Canada's Mackenzie Valley to southern markets.

All of the aforementioned large transmission projects, whether they have been built, or are at various stages of design, have a common characteristic which is the threat to pipeline integrity posed by their relatively hostile working environment. All cross major rivers and mountainous regions, some traverse seismically active zones, others permanently or discontinuously, frozen ground. Each of these conditions are potentially harmful to the safe operation of the pipelines and require mitigative measures to be incorporated during their design.

11.3 BRIEF OVERVIEW OF PIPELINE SYSTEMS

The value chain of a pipeline system extends from the source of supply to the end user's means of consumption. For example, Fig. 11.2 illustrates schematically the inter relationship between gathering, transmission, and distribution pipelines for a natural gas system. A similar relationship exists for liquid hydrocarbon pipelines with the exception that delivery lines to tank farms or terminals replace the gas distribution grid.

A gathering system is a network of relatively small diameter lines, which conduct flow from the well head into a processing plant, in the case of natural gas, or a battery terminal in the case of oil. In most cases, the production from each well is measured at the well site before commingling with the production from other wells. The flows from individual gathering lines are combined into progressively larger lines which are designed on the basis of flow rates and the allowable design pressure. Such lines are usually constructed from low carbon steels even when conveying sour product, where it might prove more economic to add an inhibitor, or a corrosion allowance, in preference to using corrosion-resistant alloys.

Delivery from the processing plant or battery is into a transmission, or trunk line which is characterized as a large diameter, high pressure system.

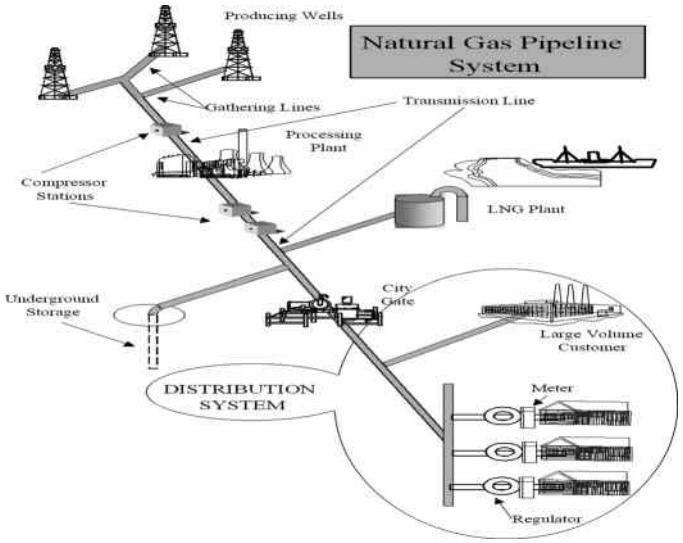


FIGURE 11.2 NATURAL GAS SYSTEM NETWORK

A transmission line transports large volumes of product to relatively few delivery points. Gas transmission systems operate in a "fungible" mode, that is, the shipper receives the same quality and quantity of product that it tendered for transport, but not the same molecules. Deliveries of the system are either directly to a heavy industrial user or into the "city gate" where transfer is made to the local distribution company.

Transmission of liquid products on the other hand is done in batch mode, that is, the shipper receives the same product that it tendered for shipment.

Distribution or, delivery lines, are characterized as making small shipments to multiple delivery points. In the case of natural gas distribution, the local distribution company will supply numerous customers using low pressure, small diameter, polyethylene pipe. Distribution pipelines account for 1.9 million of the 2.3 million miles of energy pipelines in the United States [4].

11.4 PIPELINE SYSTEMS—SAFETY AND ENVIRONMENTAL PROTECTION

Pipeline incidents can result in loss of life, serious injury, property, and environmental damage although, as noted earlier, major incidents are infrequent occurrences. For comparative purposes, and to be more reflective of industry safety and environmental performance, it is more appropriate to use multi-year averages, rather than the single year statistics, such as are provided in the United States, by the Bureau of Statistics annual reports [2].

Compared to other transportation modes, failures from pipelines cause relatively fewer safety and environmental consequences on an annualized basis. In the United States, oil pipelines reported an average of 2 deaths, 6 injuries, and $88,374,400 million in property damage per year during the period 2002–2007. Over the same period, gas transmission pipelines reported an average of 1 death, 5 injuries, and $74,808,072 million in property damage per year. Comparative data may be heavily distorted by multiple deaths from the Carlsbad incident in 2000 [1]. Data limitations make it very difficult to make direct safety comparisons between pipeline types and other transportation modes. However, in Table 11.2 an attempt has been made to normalize the incident information compiled from data contained in the Bureau of Transportation Statistics for the year 2000.

The Canadian Transportation Safety Board compiles similar statistical data [5]. In Europe, there is no mandatory obligation to report pipeline incidents to a common data base, though the European standard EN 1594 provides functional requirements for such reporting. In 1982, six European gas transmission system operators collectively undertook to gather data on the unintentional release of gas from their respective systems. The objective of this initiative was to provide a more realistic picture of the frequencies and probabilities of incidents than would be possible using individual company data. This co-operation was formalized through the setting up of the European Gas Pipeline Incident data Group (EGIG), which currently comprises the 12 major gas transmission system operators in Western Europe. A similar grouping of oil pipeline transporters exists in the form of the CONCAWE (Conservation of Air and Water Environment) [6]. Both groups produce annual incident statistics and by using information from all these data bases useful comparisons and trending can be performed such as the National Energy Board's annual Safety and Performance Indicators report [7].

As may be seen from Fig. 11.3, which shows the decade of construction, over half of the transmission pipeline systems and virtually all of the distribution lines, in North America are more than 40 years old.

Older pipelines have comparatively low strength and toughness properties, while little quality control may have been used during their construction. Protective coatings can deteriorate over time, leading, in the absence of effective cathodic protection, to time-dependent failure modes such as corrosion. As can be seen from the incident data presented in Fig. 11.4, corrosion is a common cause of reportable incidents in both oil and gas pipelines in the United States. Note that the Office of Pipeline Safety defines a reportable incident as:

i. A fatality or any injury requiring hospitalization.
ii. A fire or explosion that is not intentionally set.
iii. The release of more than 50 barrels of hydrocarbons (or 5 barrels of highly volatile liquid).
iv. Total costs equal to or exceeding $50,000, measured in 1984 dollars.

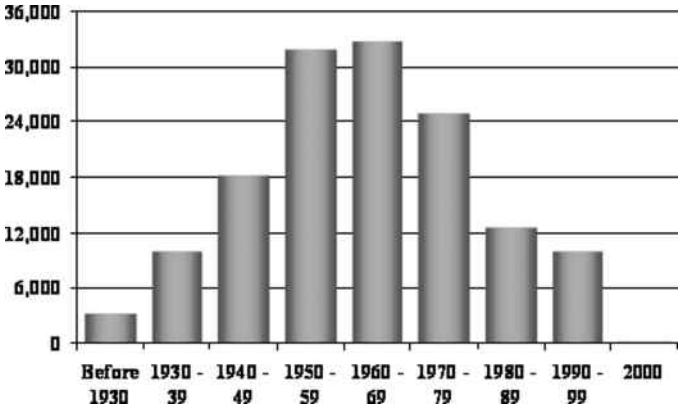


FIGURE 11.3 AMOUNT OF U.S. TRANSMISSION LINE CONSTRUCTION BY DECADE [8]

TABLE 11.2 APPROXIMATE FATALITY RATE BY MODE, 2001
(Source: US Bureau of Statistics [2])

	Truck	Rail	Water	Oil pipeline (hazardous Liquids)	Gas Pipeline (Transmission)
Deaths	5,282	937	119	1	15
Ton Miles (billions)	1,249	1546	646	577	276
Deaths/billion ton miles	4.229	0.606	0.135	0.002	0.091

Source [2] Transportation Statistics 2001 Annual Report

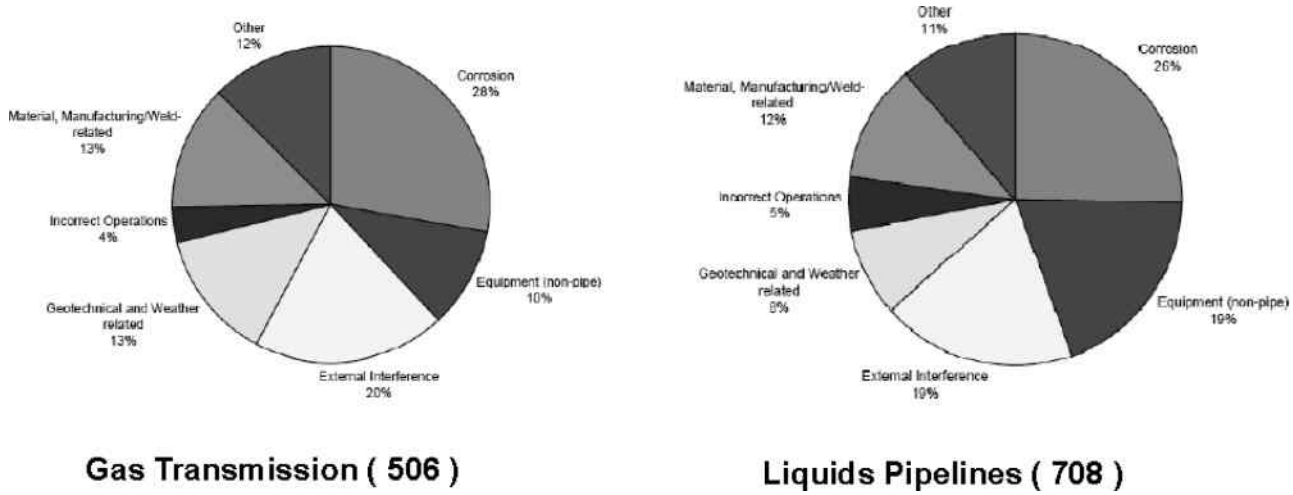


FIGURE 11.4 CAUSES OF PIPELINE INCIDENTS ON US PIPELINES FROM 2002–2007

With finite maintenance resources, it is essential that the available funds are spent where they are most effective in reducing the risks posed by pipeline failures to life, the environment, and property. Based on CSA-Z662 Annex N and ASME B31.8S approaches, potential threats to pipeline integrity can be mainly grouped within six categories:

1. Corrosion.
2. Cracking.
3. External Interference.
4. Material, Manufacturing/Weld related.
5. Geotechnical and Weather related.
6. Incorrect Operations.

Corrosion includes all forms of pipeline corrosion (internal, external).

Cracking can be in the form of stress corrosion cracking (SCC), Hydrogen-assisted cracking, mechanical damage-delayed cracking, corrosion, and fatigue cracking.

External Interference is sometimes referred to as contact damage such as first (i.e., employee), second (i.e., contractor's earth moving equipment), and third party interference (i.e., line strikes by farm implements, or vandalism).

Material, Manufacturing/Weld-related threats are related to defective long seam and girth weld and pipe body.

Geotechnical and Weather related refer to various types of ground movement, hydrogeotechnical, and weather-related hazards such as settlement, frost heave (freezing and thawing), landslides/slope movement, earthquake, wash outs erosion, and lightning.

Incorrect operations refers to improper operation such as over-pressuring that could have been caused by inappropriate procedures, training, or operator error.

Sound engineering design and construction practices, regular inspection, and a vigilant right of way patrol program will minimize, but cannot completely eliminate the effect of these hazards.

Pipeline failures can have a significant impact on the public and the environment, and may lead to a serious effect on business. The cost of cleaning up after a spill and the cost of repairing the pipeline can be very high. A recent study indicated that a typical incident costs between $1–4 million with an average cost of between $10–15 million [8].

Failures cause the pipeline to be shutdown which halts delivery of the product. A shutdown may cause plants or manufacturing facilities, to close or use a more costly form of transportation such as trucking.

Due to the public concern for safety and the impact on the environment, rigorous regulations are imposed on pipeline operators. The National Energy Board of Canada, for example, issued a strong recommendation regarding in-line inspection of pipelines following a number of pipeline ruptures across the country and held a Public Inquiry into SCC in Pipelines in 1996 [9]. In the United States, the Pipeline Safety Improvement Act of 2002, mandated integrity management programs (for details see Sections 11.5 and 11.6) that include a baseline assessment and periodic reassessment of portions of pipeline which have been designated high consequence areas. It is hoped that the ongoing use of planned, responsible, integrity programs may help to avoid further stringent regulations being imposed on pipeline operators, and enable

them to increase pipeline integrity without overly increasing pipeline operating and maintenance costs.

11.4.1 Pipeline Integrity, Integrity Management Program, and Integrity Management Systems

The following definitions are intended to assist the reader in clearly understanding key terms used by the pipeline industry when referring to Integrity:

- **Pipeline Integrity** is the status of a pipeline defined by its structural soundness, reliability, and availability and its ability to operate under safe and specified operational conditions.
- **Integrity Management Program (IMP)** is a process to develop, implement, measure, and manage the integrity of a pipeline through assessment, mitigation, and prevention of risks in order to ensure a safe, environmentally responsible, reliable service. An IMP (process) is usually valid for 2 or 3 years and is then updated to include new or modified processes, developed during the implementation of the pipeline integrity program, through multiple time-driven integrity plans.
- A **pipeline integrity plan** results from the process delineated by the Integrity Management Program. Pipeline Integrity plans are usually developed on a yearly basis and adjusted along with their implementation. Feedback from the integrity plans that could identify changes in processes should be discussed before deciding whether the IMP should be changed.
- **The Pipeline Integrity Management System** (PIMS) is a system used to manage the integrity of pipeline sections. This is done by providing processes such as IMP, Communications, Quality Assurance, Management of Change. Organization policies and structure; tools (software, administration/logistics), and support (... legal, R&D, etc.) to internal (engineers, technicians, field crews) and/or external users (e.g., ... community, regulators, contractors) must also be in place in order to achieve the integrity goals. Please refer to Fig. 11.6.

11.4.2 Typical Pipeline Failure Modes and Mechanisms, and Failure Assessment Classification

A pipeline failure mode can be defined as the manner in which a pipeline could potentially fail to meet the design service intent. Some typical failure modes include, overload (e.g., corrosion thinning, over-pressure), deformation (dents, wrinkles, buckles, etc.), and Cracking (SCC, seam weld anomalies, Hydrogen embrittlement, etc.). The failure modes are further classified by the manner in which they fail (e.g., leak or rupture).

Furthermore, a pipeline failure mechanism can be defined as the process or phenomenon behind a failure mode causing a pipeline to leak or rupture. Some of the more common failure mechanisms are corrosion/erosion, plastic deformation, impact, fatigue, environmental cracking, buckling/wrinkling, and creep.

Failure assessments can be classified as being either Flow Stress dependent, or Fracture Toughness dependent. A flow stress-dependent assessment assumes plastic collapse and hence uses either yield and/or ultimate tensile strength parameters. A fracture toughness-dependent assessment uses either a critical stress intensity factor or correlation with upper shelf Charpy-V Notch impact energy.

Fig. 11.5 illustrates several of the more common failure modes.



(a) Buckling Failure caused by ground movement

(b) Gouging and denting

FIGURE 11.5 COMMON FAILURE MODES

11.4.3 Pipeline Regulations

Public safety and environmental protection are largely met through the combined effect of regulations and the responsible actions of the operating company. There are, however, marked differences in the approaches taken by pipeline regulators throughout the world.

Possible approaches to regulation include prescriptive, and performance-based methods, with a hybrid of the two, in goal-oriented regulation.

Prescriptive regulations: Specify the methods or means and actions including timing/scheduling to be used to attain a required level of safety or environmental protection. No alternatives are allowed and there is limited engineering assessment input unless approved by the regulator or defined as a recognized industry practice.

Goal-oriented regulations: Specify the goals or results which must be achieved regarding safety and environmental protection. Methods employed are tied to individual circumstances and are a mixture of both prescriptive and performance-based regulations. This approach requires the definition of performance indicators capable of measuring the effectiveness of the integrity management program.

Performance based regulations describe the desired end results.

In the United States, the approach taken by the Office of Pipeline Safety (OPS) has been prescriptive with non-compliance dealt with punitively through heavy fines and even jail terms. Operating companies are required to perform a baseline assessment of their pipeline system, by specific dates, and must maintain a written Integrity Management Program (IMP). The state regulator in Texas requires that an operator in lieu of the foregoing must carry out pressure testing or in line inspection at 5- to 10-year intervals.

In contrast, the National Energy Board (NEB), in Canada, and the United Kingdom pipeline Regulator, have chosen to follow a goal-oriented approach, wherein desired outcomes are stated but the means of achieving them are left to the pipeline operator. In both regimes, guidelines are provided to the pipeline operator and a comprehensive audit process is in place to ensure compliance.

In addition, the United Kingdom's Pipeline Safety Regulations issued in 1996, requires the preparation of a major accident prevention document wherein all risks are identified. A safety management system must also be filed.

The European Commission is likely to enforce legislation shortly, requiring pipeline operators to have a major accident prevention policy and a management system in place to ensure regulatory compliance.

11.5 PIPELINE INTEGRITY MANAGEMENT PROGRAMS

11.5.1 Regulatory Requirements

In the United States, there are two current rules which apply to:

Hazardous Liquid Pipeline Operators (49CFR Part 195). Pipeline Safety: Pipeline Integrity Management in High Consequence Areas: Final Rule and Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) (49CFR Part 192 Sub Part O) Final Rule.

The final rule became effective on May 29th, 2001 for operators of hazardous liquids lines with 500 miles or more of pipeline under the jurisdiction of 49CFR Part 195 and on February 15, 2002, for operators with less than 500 miles of hazardous liquids lines.

The necessary changes to the regulation of natural gas transmission pipelines were enacted on December 15th, 2003.

Two further rules are in place to cover Distribution Pipelines and Gathering Lines.

The stated goals of these amendments of the OPS regulations are:

i. To provide increased assurance of safety to the public.
ii. Improve integrity management practices.
iii. Provide the structure for systematic logical evaluation/ management of pipeline threats.
iv. Foster more thorough risk analyses.
v. Foster data integration and better decision making.
vi. Incorporate technology and create incentives for technical advancements and their use.
vii. Identify high consequence areas (HCAs) in the event of a pipeline rupture.
viii. Accelerate pipeline integrity assessment in HCAs.
ix. Establish a clear government role in validating integrity management.

The primary purpose of the Liquids rule was to afford protection to high consequence areas which included unusually sensitive environmental areas, commercially navigable waterways, higher density urban, and other populated areas.

Operators of both gas and liquids pipeline systems are required to develop a written IMP which identifies all high consequence segments, and to provide a Baseline Assessment Plan prioritizing the higher risk areas. A phased implementation approach has been used which allowed operators 7 years to complete all assessments, and 3.5 years to complete 50% of their pipeline segments.

Periodic integrity assessments are required as part of the program with re-assessment intervals not to exceed 5 years for hazardous liquids pipelines and 7 years for gas transmission pipelines. The Gas rule also introduced the HCA concept as a function of Class location, potential impact circle, and human occupancy and associated frequency of utilization (i.e., an identified site). These assessments must include risk analyses, to identify any additional actions needed to protect HCAs, integrate all available information, and measure the effectiveness of the IMP.

The integrity assessment may include one of the following means of verifying the condition of the pipeline:

In Line Inspection.
Hydro testing.
Direct Assessment and Confirmatory Direct Assessment, if applicable.

These methods are described in more detail in Section 11.8 and are designed to uncover pipeline defects. There are rigid rules for the assessment (and set timelines for repair if necessary), of anomalies in both liquid and gas lines. Operators must evaluate all anomalous conditions identified through assessment and must remediate those that could reduce the integrity of the pipeline.

If a gas pipeline operator is unable to undertake remediation within the time limits set out in Section 7 of the ASME B31.8S, and given below, they must reduce the operating pressure to the safe operating pressure determined in accordance with accepted methods such as B31G or RSTRENG (see Section 11.9), or to a pressure not exceeding 80% of the operating pressure at the time the condition was discovered. Once the pressure is lowered, the operator must effect remediation within 365 days or provide justification for not doing so.

Conditions detected through assessment must be evaluated within 120 to 180 days of their discovery to determine if they represent a threat to pipeline integrity.

The US Department of Transportation 49 Code of Federal Regulation Parts 192 and 195 provide the criteria for scheduling remediation/repairs programs. For liquids pipelines, the repair schedule is divided into immediate, 60- and 180-day conditions, which can be accessed at the following website http://primis.phmsa.dot.gov/iim/docsr/finalruleamended.pdf.

For gas transmission pipelines, the repair schedule is divided into immediate action, 365 day monitoring conditions, details of which can be accessed at the following website http://primis.phmsa.dot.gov/gasimp/docs/FinalRuleAmendedGas_071707.pdf.

The OPS expectation is that pipeline operators will refer to their existing operating and maintenance practices as much as possible when establishing procedures, to minimize the impact of the rule changes. Generally, procedures should define how an operator intends to execute the specific integrity management regulatory obligations.

The Canadian pipeline standard, CSA Z 662-2007 [10], provides repair criteria and allowable repair methods in Section 10.8. It also contains detailed provisions in its non-mandatory Annex N for the use of an integrity management program. Clause 10.14.1 of the standard states, “Operating companies shall establish effective procedures for managing the integrity of pipeline systems so that they are suitable for continued service, including procedures to monitor for conditions that may lead to failures and to eliminate or mitigate such conditions.”

Clause 10.2.1 states “Operating companies shall:

(a) develop, implement, and maintain a documented safety and loss management system that provides for the protection of people, the environment, and property;
(b) prepare and maintain appropriate maps and drawings;
(c) keep those records necessary to administer such procedures properly; and
(d) modify such procedures from time to time as experience dictates and as changes in operating conditions require.”

Operating and maintenance procedures are required to be based on:

(a) safety considerations;
(b) knowledge of the facilities;
(c) operating and maintenance experience;
(d) sound engineering principles;
(e) service fluid;
(f) service conditions that could be anticipated to cause unacceptable damage; and
(g) the applicable requirements of the standard.

The Canadian standard also uses engineering critical assessments and risk analyses as the means of establishing the integrity of pipeline systems.

The NEB adopts the Canadian Standard Z662 by reference into its Onshore Pipeline Regulations (OPR) [11], thus giving it the force of law.

The fundamental difference between the United States approach and that adopted in Canada by the NEB, is the method of enactment. In the United States, Part 192.911 establishes the required content of a gas pipeline IMP. There is no allowance for deviation. In Canada, the NEB has taken a "softer" approach by simply requiring oil and gas pipeline companies to have an IMP. Section 40 of the Canadian OPR states:

40. A company shall develop and implement a pipeline integrity management program.

Rather than prescriptively spelling out the required content of an IMP, the NEB has provided a goal statement and guidance which is intended to allow companies flexibility when developing the content of their IMP. The goal as stated within the Guidance Notes for the OPR, 1999 [12] is:

GOAL (s. 40): To ensure that pipelines are suitable for continued safe, reliable, and environmentally responsible service.

The NEB approach to compliance is threefold:

(1) Companies are expected to perform a self audit.
(2) Board staff perform management system audits.
(3) Board staff conduct periodic inspections and hold informal meetings with companies to discuss their IMP.

A management system is a structured framework to establish policy and objectives and to achieve those objectives.

11.5.2 Related Standards

In 2001, the ASME released a supplement to its B31.8 standard entitled "Managing System Integrity of Gas Pipelines." [13] This Standard references the 21 threats to pipeline integrity that have been set out by the Pipeline Research Council International and which were adopted by the OPS's incident reporting process. The 21 causes are grouped in terms of their tendency to become more severe over time and are listed in Table 11.3.

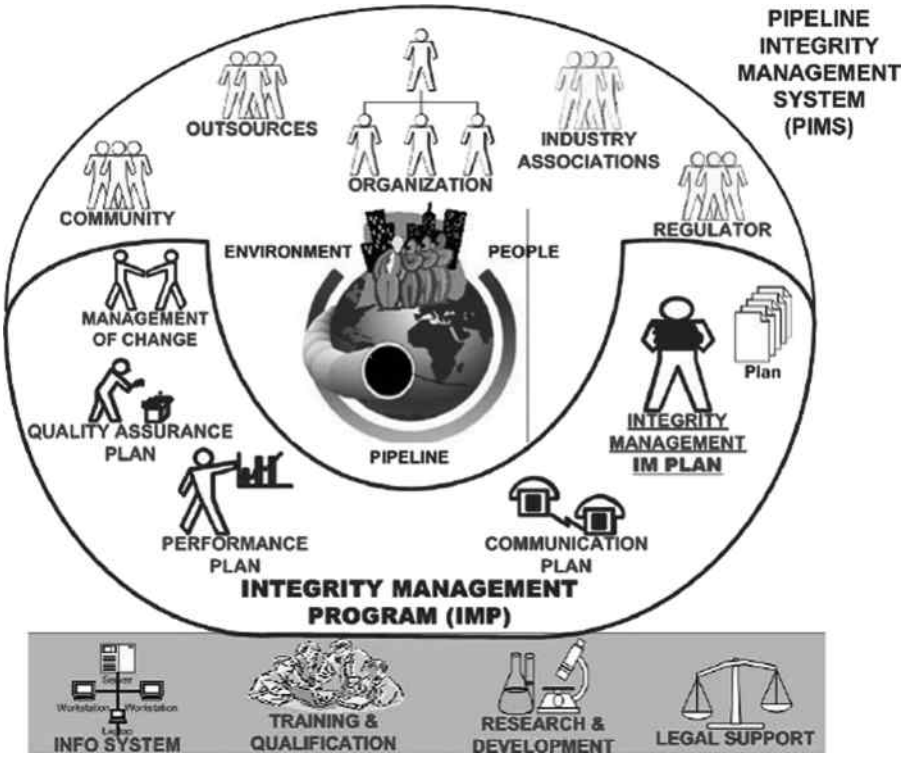


FIGURE 11.6 PIPELINE INTEGRITY MANAGEMENT SYSTEMS

TABLE 11.3 MAJOR THREATS TO TRANSMISSION PIPELINES ASME B31.8S [13]

External Corrosion	Internal Corrosion	Stress Corrosion Cracking
Defective pipe	Defective seam	Defective fabrication or girth weld
Wrinkle bend or buckle	Stripped threads or couplings	Failed gaskets, O-rings
Field packing, Seals	Pressure control or relief devices	Other non-pipe equipment
Third party damage	Previously damaged pipe	Vandalism
Incorrect operations	Cold weather	Lightning
Heavy rain, floods	Earth Movement	Miscellaneous

Two programs are contained within the standard, one prescriptive, the other performance based. The prescriptive format is quite conservative but easier to implement, the performance-based approach is more flexible but requires significantly more data and analysis. The user can select either program for the entire system, each segment or each threat within a segment. The standard contains 15 sections which outline both prescriptive and performance requirements with an appendix containing a step-by-step prescriptive approach for all 21 threats. The risk assessment process follows the steps shown in the flow chart (Fig. 11.7).



FIGURE 11.7 INTEGRITY MANAGEMENT PROCESS FLOW DIAGRAM (FROM ASME B31.8S)

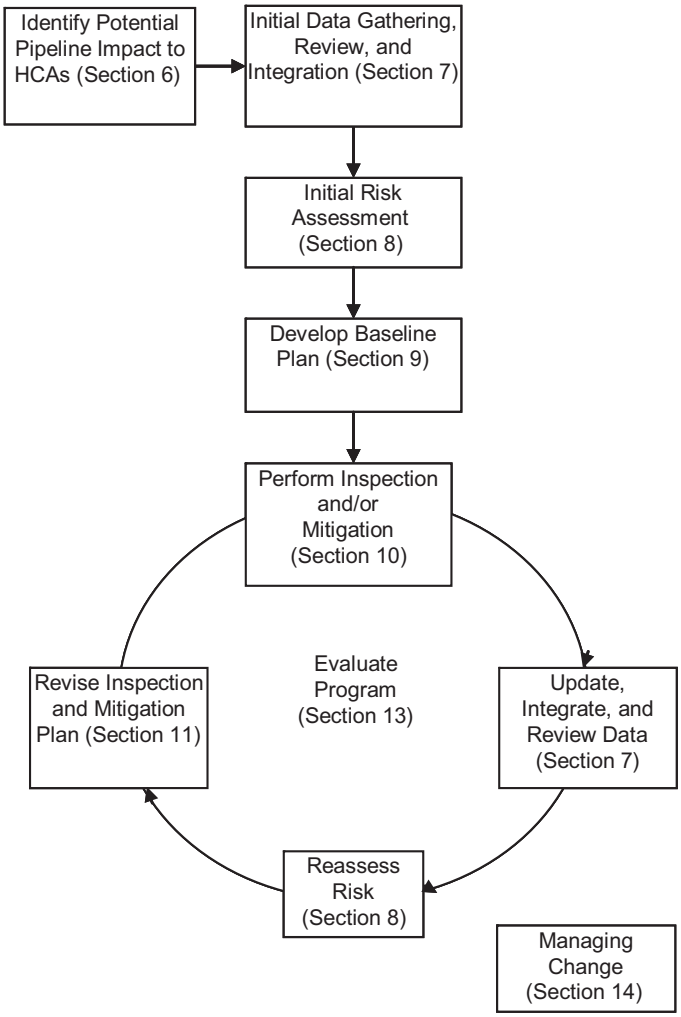


FIGURE 11.8 API 1160 MANAGING SYSTEM INTEGRITY FOR HAZARDOUS LIQUID PIPELINES

In November 2001, the American Petroleum Institute released a standard for managing the system integrity of hazardous liquids pipelines [14]. Fig. 11.8 illustrates the required process flow. There are 14 sections to the standard covering the following topics:

(1) Introduction
(2) Scope
(3) References
(4) Terms, Definitions, and Acronyms
(5) Integrity Management Program
(6) High Consequence Areas
(7) Data Gathering, Review, and Integration
(8) Risk Assessment Implementation
(9) Initial Baseline Assessment Plan Development and Implementation
(10) Mitigation Options
(11) Revision of the Integrity Management Program
(12) Integrity Management of Pipeline Pump Stations and Terminals
(13) Program Evaluation
(14) Managing Change in an Integrity Program

It is apparent that there are strong similarities and common formats to the integrity management requirements of all of the aforementioned codes and standards and that the central theme is the need for a management system framework.

11.6 ELEMENTS OF AN INTEGRITY MANAGEMENT PROGRAM

An integrity management program has twin objectives governed by a time frame. The short-term goal is the mitigation of societal and environmental impact arising from pipeline ruptures or pipe body leaks. The long term goal is to develop sustainable cost-effective mitigation and prevention programs that will ultimately lead to zero failures from time and non-time-independent growing failure mechanisms.

The IMP process is mainly defined by the following eight elements:

(1) Threat/Hazard Assessment: Identification, Classification, and Susceptibility.
(2) Consequence Assessment: Direct and Indirect.
(3) Risk Assessment: Analysis and Evaluation.
(4) Integrity Assessment: In-Line Inspection, Hydrostatic Testing, and Direct Assessment.
(5) Data Integration and Analysis.

(6) Mitigation.
(7) Prevention and Monitoring.
(8) Evaluation: Performance Indicators.

The IMP elements also need some support processes to effectively achieve their objectives within the PIMS System such as Management of Change, Quality Assurance, Communications, Research and Development, Information Technology, and Management Systems.

Hazard/Threat Assessment

Hazard or threat assessment is intended to identify the principal causes of pipeline failure or failure modes that could occur, or that may have occurred, during the operation of the line. A hazard assessment is comprised of three processes:

- Identification
- Classification
- Susceptibility

The *Hazard Identification* process uses existing information such as leak/rupture history, in-line inspections, and field investigations to identify hazards experienced in the past that may or may not be occurring in the present or which could occur in the future.

The *Hazard Classification* process determines the failure mechanisms of the identified hazards by classifying them as to whether they grew over time, or are expected to grow in the future. Pipeline characteristics, operating conditions, and inspection and maintenance findings over time are evaluated.

The *Hazard Susceptibility* process determines the potential for hazards that could affect, or may already be affecting, the integrity of the pipeline. These potential hazards have not been clearly identified as yet, but changes in the current or future pipeline integrity status (e.g., age, coating deterioration), operating conditions, that is, product, pressure cycling, cleaning practices, and environment/weather conditions (e.g., flooding, external interference) may introduce them as either new, or inactive threats. Susceptibility criteria and modeling, and selective/investigative digs are used to assist in the identification of the susceptible areas and associated potential hazards.

Consequence Assessment

The purpose of this assessment is to identify the consequences of a release in terms of safety (e.g., population exposure), and/or environmental and property damage impact. Census, topographical data and elevation models, environmental data, product characteristics, and weather conditions are some of the inputs required for developing consequence models. Such models analyze, for natural gas and LVP pipelines, product discharge, gas dispersion, vapor cloud formation, flammability and heat radiation levels, and toxicity in order to establish the extent of the affected area. Subsequently, the actual population and environment affected by the release can then be determined in terms of impact zones or consequence areas.

In the event of a gaseous pipeline rupture, it is now common place for the operators of such systems to link GIS to simple plume dispersion models in order to determine who in the vicinity may be affected, given prevailing wind directions. Right of way management and emergency response planning have been significantly improved by locating the positions of habitable dwellings and public places within the GIS data base.

Using GIS-based technology, an operator can view his pipeline in its environmental and safety context so as to quickly visualize high consequence areas and the need for possible upgrading of class location. GIS can also provide details of accessibility to a particular location, say a main line valve, in the event of an emergency.

Much of the recent technical development in this area has been stimulated by the U.S. National Pipeline Mapping System initiative [15], which requires the operators of natural gas pipelines and hazardous liquids pipelines to submit the location and selected attributes of their system in a GIS compatible format.

Risk Assessment

Risk assessment is a process to identify and locate risks, for example, external corrosion in an environmentally sensitive area. Risk assessment is comprised of two components, Risk Analysis and Risk Evaluation. Risk analysis will assist in determining the "how to" (e.g., Cathodic Protection (CP), In-line inspection (ILI), "where to" (e.g., which pipeline sections) and "when to" (e.g., prioritization) for mitigation and prevention planning purposes. Based on an acceptable criteria, risk evaluation will determine whether or not a given risk driver at a given location/pipeline segment would require the implementation of mitigation and/or prevention strategies.

Risk factors are the variables used in developing a risk model such as, pipeline characteristics, environmental- and business-related conditions, operation and maintenance approaches. Risk drivers are the identified risk factors found during the risk analysis that contributed to the highest risk results. Typical risk factors in a third party damage model could be the frequency of excavations and patrols, the effectiveness of line marking, one call, depth of cover, the proximity of highly developed areas, and pipe strength. A detailed description of this process is set out in Section 11.7.

Data Gathering and Integration

Data integration is a key process of the IMP in enabling a better understanding of the criticality of the identified threats and their consequences. During the last decade, computer-assisted geographic information systems (GIS) have been developed for gathering and integrating several types of data. Geographic information systems are specialty data bases which contain data that is referenced according to physical location. The underlying software contains common data base features such as structured query capability and statistical analysis combined with powerful visual displays of the data. Its usefulness in pipeline applications has been immeasurably improved by linking it to integrity management and systems record management.

It is now possible to layer information containing design and construction drawings, as built survey data, and emergency response plans on top of land owner contacts and detailed ILI reports and repair records. Database structures such as the Pipeline Open Database Standard (PODS) have been designed for capturing pipeline data in an industry standard format that take advantage of synergistic efforts of multiple companies to exchange data thereby assisting in effective Integrity data management.

Furthermore, structured GIS queries facilitate the analysis required for conducting mitigation and/or prevention strategies. For example, slope movements in sensitive areas can be tracked over time using historical data. Software applications have been developed which link the topography contained in the GIS database to a flow modeling capability and corrosion assessment module so that the internal corrosion of liquid lines can be continually assessed and monitored. Right of way management and emergency response planning have been significantly improved by locating the positions of habitable dwellings and public places

within the GIS data base. In the event of a pipeline rupture, it is now common place for the operators of such systems to link GIS to simple plume dispersion models in order to determine who in the vicinity may be affected, given prevailing wind directions.

Mitigation

Mitigation is a process intended to reduce risk through decreasing either probability of failure from identified threats or consequence, or both. Recently, integrity assessments such as ILI or hydro-testing have also been used as mitigation strategies providing knowledge that reduces risk uncertainty and assists in the effective selection of mitigation methods (e.g., operational improvements, training, awareness, repairs, etc.). The selection of the appropriate integrity assessment method(s) for performing an initial or Baseline Assessment of the threats to the pipeline system, and subsequent re-assessments is described in Section 11.8.

Prevention and Monitoring

Prevention is a process intended to reduce risk either through minimizing threat initiation or consequence impact. Prevention must be built into pipeline systems during the initial planning, design, and construction phases by anticipating their effects on the future integrity of the system. This enables the entire life cycle of the pipeline asset to be comprehensively addressed, and optimal integrity solutions to be found.

Complementary monitoring is a process to gather data on changes in pipeline operational, environmental, and other conditions that assists in anticipating potential threats or consequences.

Evaluation: Performance Indicators

The progress and effectiveness of an IMP should be frequently monitored and regularly reviewed–at least once per year. For instance, results of integrity assessments should be compared against the previously established company integrity performance measures. Corrective action can then be taken, as necessary, using the change control process set out in the IMP document.

The effectiveness of an IMP is determined using Performance Indicators. Three categories of indicator have been defined in ASME B31.8S, process, operation, and maintenance, and direct indicators and they are further classified within each category as lagging and leading indicators.

For example,

Process: the percentage completion of the baseline assessments (leading indicator). Number of delayed ILI as per planning schedule (lagging indicator).

O&M: number of additional significant metal loss features reported by ILI since the previous inspection (leading indicator). Number of repairs conducted on significant features (lagging).

Direct Indicators: number of leaks or ruptures (lagging indicator).

11.6.1 Regulatory Compliance

In order to be compliant with CFR (192.911), IMP filed by U.S. pipeline operators must contain the following elements:

- the identification of all high consequence areas;
- a baseline assessment plan;
- methods for the identification of threats which include data integration and a risk assessment (operators must use threat identification and risk assessment to prioritize and to evaluate the merits of additional preventive and mitigative measures);
- a direct assessment plan (if applicable);
- provisions for remediation of conditions found during an integrity assessment;
- a process for continual evaluation and assessment;
- a plan for confirmatory direct assessment;
- provisions for adding preventive and mitigative measures to protect high consequence areas;
- a performance plan;
- record keeping provisions;
- a management of change process;
- a quality assurance process;
- a communication plan that includes procedures for addressing safety concerns raised by:
  - the Office of Pipeline Safety (OPS); and
  - State or local pipeline safety authorities when a covered segment is located in a State where OPS has an interstate agent agreement;
- procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or IMP to:
  - OPS; and
  - State or local pipeline safety authorities when a covered segment is located in a State where OPS has an interstate agent agreement;
- procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks; and
- a process for identification and assessment of newly identified high consequence areas.

Formal risk assessment is a key element in achieving compliance, since it appears in four places in the IMP requirements:

(1) During the HCA identification.
(2) When establishing risk-based priorities for the Baseline Assessment Schedule.
(3) In evaluating the Preventive and Mitigative Measures.
(4) Determining the Integrity Re-Assessment Intervals.

11.6.2 Developing an Integrity Management Program

Companies approach this task as the development of a continuous pipeline integrity program to address unacceptable risks through assessment, mitigation, prevention, and monitoring. They generally use a risk-based approach to allocate their successive annual integrity budgets prudently.

The first step requires creating a framework to address all the required elements within the plan. This framework sets out the senior management commitment to the program, describes the current processes for ensuring pipeline integrity, and the process for making improvements. This latter requirement speaks to the need for flexibility as the program continues to evolve. It is important to keep key stakeholders in the process, that is, regulators, land owners etc., informed when significant changes are being considered.

A key component in linking the various elements of the program is the integration of the various information needs. Figure 11.8 illustrates the IMP framework suggested in the API 1160 document [14]. Performance indicators provide a measure of the success of the program and must be an integral part of it. It is important that processes are documented in sufficient detail for company personnel, and internal and external auditors to be able to follow them.

Cross-referencing should be provided, and flow charts used where possible, for clarification. The IMP should not stand alone from other established processes, for example, the Operations and Maintenance manual, so it is important not to duplicate material. The IMP should be made available to all persons associated with operation and maintenance activities.

A sample table of contents of a good IMP prepared as a process-oriented document might look like:

Section 1. Introduction
Section 2. Roles and Responsibilities
Section 3. Definitions
Section 4. Program Overview
Section 5. Training and Qualifications of Integrity Personnel
Section 6. Hazard Assessment: Identification, Classification and Susceptibility
Section 7. Consequence Assessment: Direct and Indirect Consequence Areas
Section 8. Risk Assessment
Section 9. Development of Baseline Integrity Assessments
Section 10. Data Gathering and Integration
Section 11. Risk Mitigation and Prevention Strategies
Section 12. Continual Integrity Assessments
Section 13. IMP Evaluation: Performance Indicators
Section 14. Records and Documentation
Appendices:
Appendix A. Pipeline Facilities List
Appendix B. In Line Inspection Assessment Procedures
Appendix C. Procedures for Indirect Assessment
Appendix D. Incident Investigation Procedures
Appendix E. Management of Change Process
Appendix F. Quality Assurance Plan
Appendix G. Communications Plan

Fuller descriptions of some of these aspects are provided in preceding and succeeding sections, and where this is not the case, a brief description of their purpose follows:

Roles and Responsibilities

Senior management commitment to the IMP is essential and overall accountability for it should be at an executive level in the operating company. The co-ordination responsibility for the program will depend on the size of the company but should be above the individual operating area/units, while the day-to-day implementation responsibility is at the operational level. It is very important that there is a general level of awareness about the program throughout the company.

Program Overview

The overview provides a description of the various elements of the program and how they are interconnected. It details how relevant decisions are, or will be made, by whom, and the timeline for decisions. Any constraints on program development and implementation (staff skills, equipment resources) are identified and the time needed to redress them, and to develop mature plans, are outlined. The overview also describes how the experience gained within the ongoing execution of the program will be captured and applied in continuous improvement.

Support Processes to IMP

In addition to the IMP elements, a successful implementation requires the support of processes such as records management, quality assurance, management of change, research and development, qualification and training and communications in order to sustain an effective IMP. Some of these processes are described below.

With respect to Records Management, it is essential to keep records that formally document decisions taken on plans to inspect, repair, or mitigate threats to the pipeline system. Ideally, a single person should be entrusted with the record keeping function and missing records must trigger corrective action. Recent written records and reports provide concrete evidence that an integrity management plan is working.

Management of change is also an important process ensuring that changes and/or modifications in process procedures, new assignments, organization, equipment, materials are evaluated and effectively implemented in order to avoid undesirable safety, environment, and business issues. The evaluation of changes is usually conducted by all parties involved in a change including management. The impact is assessed then minimized while strategies for implementation such as training, procedure updates, and communication are identified and scheduled.

11.6.3 Current Status and Lessons Learned

Integrity management regulations have now been in place in both the United States and Canada for a number of years. U.S.-based Liquid and Gas pipeline companies have completed their first application of formal IMP.

In Canada, all federally regulated pipelines have IMP in place. These are audited, both by the companies themselves, and independently by the NEB. Approximately, 400 findings of non compliance were issued in the period 2000–2005, the majority related to notification procedures on emergency response plans.

Performing the inspections has been straightforward; however, there are significant lessons being learned throughout the process. Chief of these has been the realization that significant resources are required to prepare an IMP document and that merely restating the regulations in the program is not acceptable. Evidence of suitable training of staff must also be provided.

If third party vendors are used to develop the plan, the pipeline operator is expected to control the IMP, and to ensure that processes and implementations are in regulatory compliance. Technical justifications for approaches to hazard and consequence identifications and risk estimating are important. The risk estimating process must be systematic and repeatable, and process documentation must be available, if a subject matter expert approach is used for risk estimation (see Section 11.7).

Measuring IMP performance has proven to be difficult and is not always included in the plan. Companies that do have performance metrics, have found it easier to report lagging indicators such as level of activity, miles of line inspected etc., rather than focus on outcomes, which are much more difficult to ascertain.

There is a large variation in the IMP document styles and content covered, some operators have complex programs, while others are much simpler. Many operators are struggling with the requirement to implement preventive and mitigative measures particularly when dealing with multiple threats. Implementing an IMP can highlight problems with internal communications and responsibilities requiring departments and people to co-operate more fully.

Managing pipeline integrity is a collective responsibility, with or without integrity management regulations. A key to a successful IMP is the ability to recognize early what works and what does not, and to change the program accordingly.

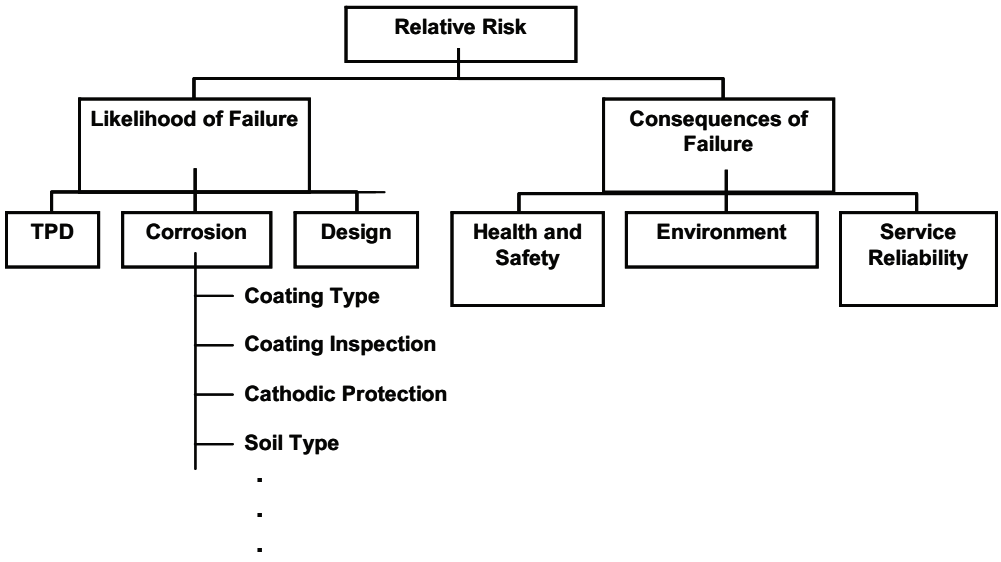


FIGURE 11.9 SIMPLIFIED RISK HIERARCHY

11.7 RISK ASSESSMENT AND RISK MITIGATION

The Concise Oxford Dictionary defines risk as the "chance of loss," which embraces two concepts, uncertain outcomes (chance) and undesirable consequences (loss). In pipeline terminology, this translates into the likelihood, or probability of occurrence, of a hazardous event and its consequence. In mathematical terms, it is expressed as

$$\text{Risk} = f(\text{Probability of an event} \times \text{Consequence of the event})$$

The pipeline operator seeks to minimize risk by attempting to control the probability of failure occurrence, its consequence should it occur, or a combination of both.

For the most part, minimizing failure probability amounts to adherence to design codes, applying quality assurance during pipe fabrication and installation, and practicing sound maintenance policies, all within an envelope of reasonable cost. Determining consequences is largely a function of the type and volume of product being carried and the population density along the pipeline route. These could be reduced through effective leak detection systems, right of way monitoring, automated valves and check valves spacing, emergency response plans, etc. A simplified hierarchy of pipeline risks is shown in Fig. 11.9.

Risk management has been defined by the OPS as, "a comprehensive management decision support process, implemented as a program, integrated through defined roles and responsibilities into the day-to-day operations maintenance, engineering management, and regulatory decisions of the operator."

Risk management includes all strategies and actions undertaken derived from the risk assessment (i.e., risk analysis and evaluation) such as mitigation, prevention, program performance evaluation, and monitoring.

11.7.1 Approaches to Pipeline Risk Assessment

Risk can be assessed either qualitatively or quantitatively. In simple terms, qualitative assessments are subjective, relative, and judgmental; they characterize risk without quantifying it. Quantitative assessments by comparison are generally more detailed objective, analytical, and absolute.

The qualitative approach to pipeline risk management uses the concept of risk indices [16] and assigns subjective scores to segments of the pipeline. For example, a third party damage risk index is created by applying a weighted score to two factors, depth of cover, and activity level, which in turn have been attributed a value. Thus,

$$\text{Third party damage Index} = \text{A} \times \text{depth of cover} + \text{B} \times \text{activity level}$$

The relative weighting scores A and B are usually provided by expert individuals or panels familiar with the company's operation on a scale of 0–1.0 where 0 indicates no influence and 1.0 complete influence. In circumstances where the belief is evenly shared as to influence then A and B would be equal to 0.5. The attributed values have a value often in range 0–10, where 0 indicates the worst possible case and 10 the best possible case.

For example, a pipe located close to the surface could have an attributed value of 0.0, whereas a deeply buried pipe might be assigned a 10.0. Thus, an expert assessing the possibility of third party damage to a section of a rural pipeline at a burial depth of 0.8 m might conclude that depth of cover is more influential than activity level and assign A = 0.8 and B = 0.2. In general, he might score the depth of cover as worth 7 and the activity level 4 in which case for this segment the index would be

$$0.8 \times 7 + 0.2 \times 4 = 6.4$$

In this manner, all the segments along the full length of the line can be ranked with respect to the threat of third party damage. The process is repeated for all the other identified threats and an overall ranking established for the segments by combining the weighted scores for the combined threats. Figure 11.10 illustrates some hypothetical relative ratings of four potential threats to a pipeline.

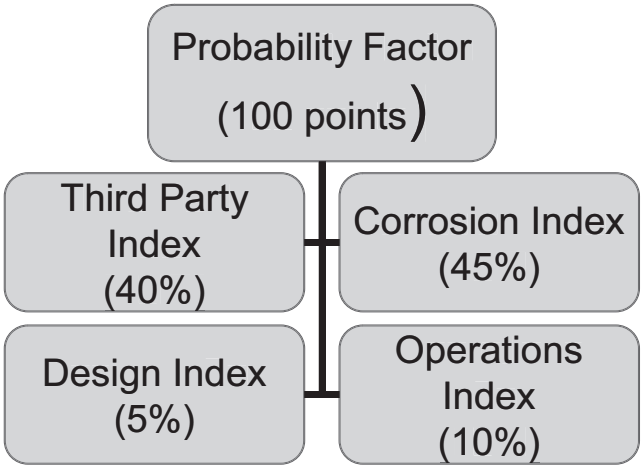


FIGURE 11.10 EXAMPLE OF RELATIVE RATINGS OF POTENTIAL THREATS

Consequence	Likelihood of occurrence		
	High	Medium	Low
High			
Medium			
Low			

FIGURE 11.11 RISK SCREENING MATRIX

The one-dimensional index approach can be extended to a two-dimensional matrix form by taking into account the consequences of failure. A similar allocation process is followed with respect to determining consequences. The main categories that should be considered in the consequence analyses are the impact on the local population, environmental damage, property damage, and other economic impacts that are applied in internal decision making (e.g., lost product, clean up costs, profit opportunities, other business impacts, regulatory, and public relations). In lieu of hard numbers, the consequences are categorized as low, medium, or high. A qualitative matrix screening tool can now be constructed as shown in Fig. 11.11 and the risk assessment for each pipeline segment is placed appropriately on the matrix. Those segments appearing in the top left portion of the array will warrant some mitigative action and generally capture the attention of the senior management.

A more sophisticated categorization of the information is also possible as is shown in Tables 11.4 and 11.5 [17] where five distinct groupings have been established.

The advantage of this approach is its ease of use, its limitations, however, are that the relative attributes could be inaccurate. It is also difficult to defend subjectivity to the public and the regulator.

Quantitative risk analysis can be used to overcome the limitations associated with qualitative risk estimation approaches. One may use statistical methods and past failure incident data to estimate risk components or analytical methods involving the use of physical or mathematical models. The process information flow shown in Fig. 11.12 is a useful template for performing quantitative risk assessment and maintenance planning. The first step is to identify hazards, which in this case is any condition with the potential for causing undesirable consequences. These may include:

TABLE 11.4 INDEX METHODS FOR RATING ANNUAL PROBABILITY OF OCCURRENCE

Category	Industry Term	Description
A	Frequently or Repeatedly	Current conditions indicate repeated future occurrences are possible for the system. Average probability of occurrence is 30% per year.
B	Several Times or Probable	Current conditions indicate future occurrences are probable several times for the system. Average probability of occurrences is 3% per year.
C	Occasional or Likely Sometime	Current conditions indicate occasional future occurrences are likely sometime for the system. Average probability of occurrences is 0.3% per year.
D	Not likely to Occur or Remote	Current conditions indicate isolated future occurrences are not likely to occur for the system. Average probability of occurrences is 0.3% per year.
E	Improbable or Practically Impossible	Current conditions indicate isolated future occurrences are practically impossible for the system. Average probability of occurrences is 0.003% per year.

TABLE 11.5 MATCHING RISK SEVERITY WITH LEVEL OF RESPONSE [17]

Category	Description
I	Major company-wide emergency response. Major cleanup for months/years. Potential widespread, long-term significant adverse effects on the environment or a large community. One or more facilities and/or serious long-term health impact on the public.
II	Division emergency response. Significant cleanup for weeks/months. Potential localized, medium term significant adverse effects on the environment or a small community. Permanent disabling injury or serious lost time injury.
III	Field level emergency response. Significant cleanup for weeks. Potential localized, moderate adverse effects on the environment or a small community. Minor lost time injury, medical aid, or restricted work duties.
IV	Local emergency response. Cleanup work for days/weeks. Potential minor effects on the environment or a few members of the public. First aid requirements only.
V	Confined to lease/site or close proximity. Inconsequential or no adverse effects on the environment or members of the public.

i. Design, construction, or operator error.
ii. Material or component failure.
iii. Degradation due to corrosion or erosion leading to wall loss.
iv. Third party activity.
v. Natural hazards.

An initial evaluation of the significance of each risk should be carried out based on the likelihood of occurrence and estimation of possible consequences. The consequence evaluation for each segment requires an assessment of the likely impact of any loss of product and should take into account:

i. The nature of the fluid, e.g., flammability, toxicity.
ii. The local topography.
iii. Likely dispersion of the fluid and probability of ignition.
iv. Environmental conditions.
v. Estimated size of the leak or rupture.
vi. Mitigating measures taken to restrict loss of containment such as leak detection and the use of isolation valves.

Estimating the failure probability involves considering all possible failure causes and modes.

Recently, pipeline operators in Europe and North America have identified benefits from applying semi-quantitative risk model given the increase of available data and the need for more accurate modeling.

The main causes of pipeline failure have been noted earlier. While a company can call upon its operating history to determine causes of failure, it is more usual to use industry wide historical data for frequency analyses quoted on a per mile basis. The advantages of such an approach are its simplicity and credibility since it is based on real data. The limitations of the statistical approach are that it is not pipeline specific and therefore does not take account of factors such as diameter, age, and coating type. Nor does it allow for the effect of maintenance actions or lack thereof. More generally, it cannot account for time-dependent deterioration.

The analytical approach uses mechanistic models to determine the failure probability by ascribing statistical distributions rather than single values to each of the parameters. In Section 11.9, a number of defect assessment models are presented each of which could be rewritten as limit state functions in terms of their resistance and the applied load. In each case, a distribution for pipe resistance, R, is obtained by inputting suitable distributions for the yield strength, wall thickness, defect size, and other relevant parameters. Similarly, the loading on the pipe will have an inherent variability L which has

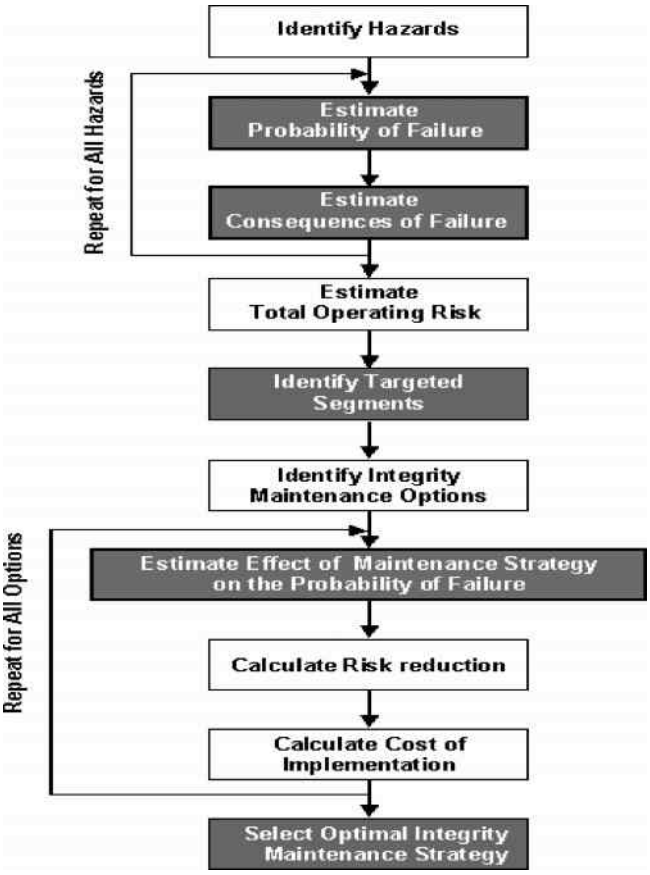


FIGURE 11.12 RISK ASSESSMENT AND MITIGATION PROCESS TEMPLATE

to be described in statistical terms. The safety margin can be described as the difference between L and R and is shown in Fig. 11.13. The calculations involved in developing the probability of failure are non-trivial and require the use of a suitable program.

The consequence analysis may require a similarly detailed analysis or could be straightforward depending upon the circumstance. Again, an analytical or statistical approach can be followed.

In the statistical approach, historical data from previous line failures are collected and from these, on a per incident basis, property damage, clean up costs, spill volumes recovered, and

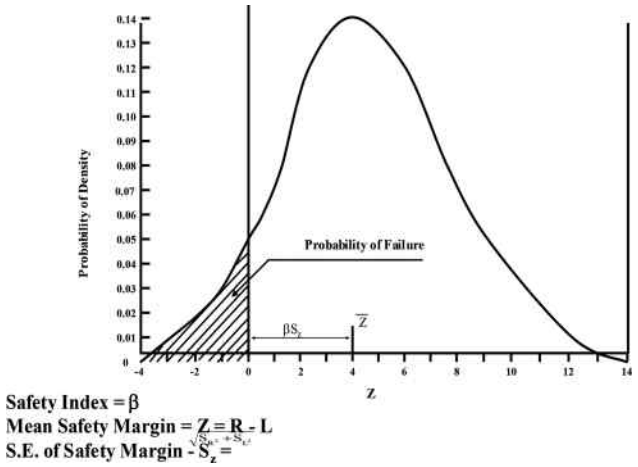


FIGURE 11.13 CALCULATING THE FAILURE PROBABILITY FROM A LIMIT STATE ANALYSIS

fatalities/injures incurred are computed. It is then possible to estimate costs. As noted earlier, this approach is both simple and credible but it is not pipeline specific and hence does not differentiate on land use, pipeline size, or operating pressure.

The analytical approach is based on pipeline attributes, weather conditions, and the type of hazard occurrence model. Figure 11.14 shows a simple event tree model for determining exposure rates following a gas pipeline rupture, while Fig. 11.15 illustrates several possible scenarios for evaluating consequences, in a process developed by CFER Technology for use by the OPS. The simple formula given in Eq. 11.1 has been developed to predict the radius of the hazard zone based on the working pressure and diameter of the ruptured pipe.

$$r = \sqrt{\left(\frac{2348\, pD^2}{I_{th}}\right)} ft \qquad (11.1)$$

$$r = \sqrt{\left(\frac{0.1547\, pD^2}{I_{\text{th}}}\right)} \text{ m}$$

where I_{th} is the threshold heat intensity (kW/m^2 or BTUs/hrft^2), p is the line pressure (Pa or psi), and D is the line diameter (m or inches).

The validity of this model has been established by a comparison between the predicted extent of damage and the actual extent of damage for significant gas pipeline failure incidents reported in the public domain. The interested reader is directed to Ref. [18] for a detailed description of the assumptions used in the model.

11.7.2 Risk Mitigation

The latter half of the Fig. 11.12 depicts the process steps required to mitigate risk once an assessment has been performed. The result of the assessment can be plotted on a risk acceptability diagram such as that shown in Fig. 11.16. The ALARP region demarcates where risk is as low as is reasonably practical, in short where extra expenditure will not result in significantly reduced risk. One of three situations will pertain:

i. *Risk reduction required:* Risk is initially not acceptable and other integrity options need to be considered to reduce risk.
ii. *Cost reduction opportunity:* Risk is already acceptable but further options should be explored to see if costs can be reduced without increasing risk to unacceptable levels.
iii. *Sustainability:* Risk is acceptable but will increase to unacceptable levels if a capital asset or system is not renewed or replaced (e.g., maintenance, software, or hardware replacement).

Often a number of possible risk reduction/integrity maintenance, strategies can be developed so the task becomes one of determining which is likely to be the most cost-effective. To determine which should be adopted, the risk is re-evaluated for each of the strategies in turn and the cost of implementation factored in. The result of each assessment is plotted on the risk acceptability diagram. Figure 11.17 illustrates a hypothetical circumstance where all three strategies reduce risk with option 1 providing the greatest reduction.

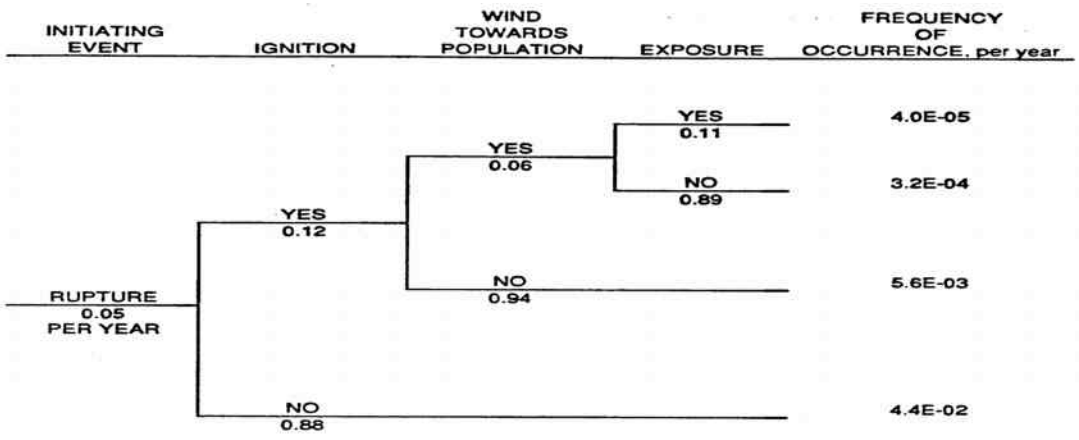


FIGURE 11.14 SIMPLE EVENT TREE TO PREDICT IGNITION PROBABILITY FOLLOWING RUPTURE

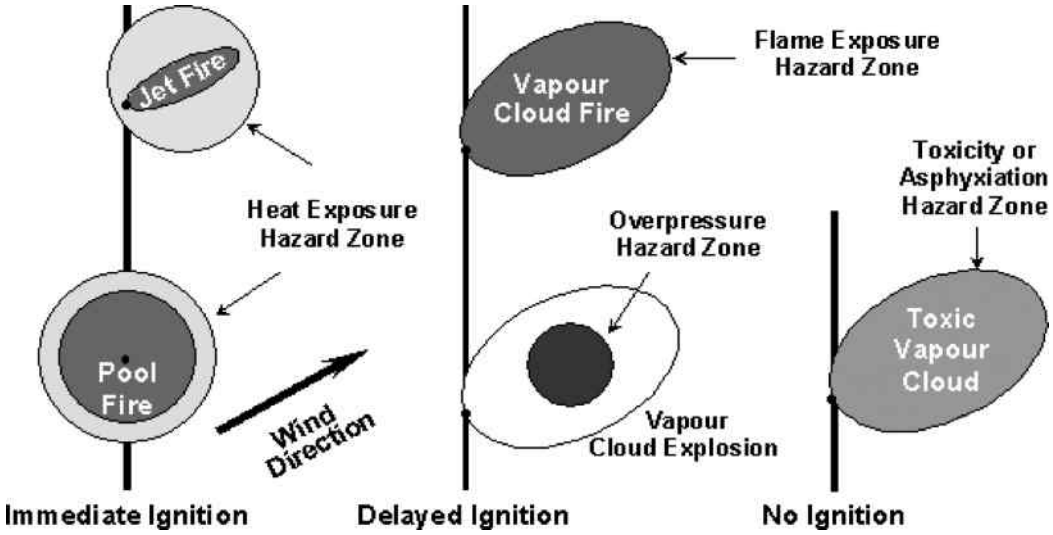


FIGURE 11.15 VARIOUS POSSIBLE SCENARIOS FOLLOWING A GAS PIPELINE RUPTURE

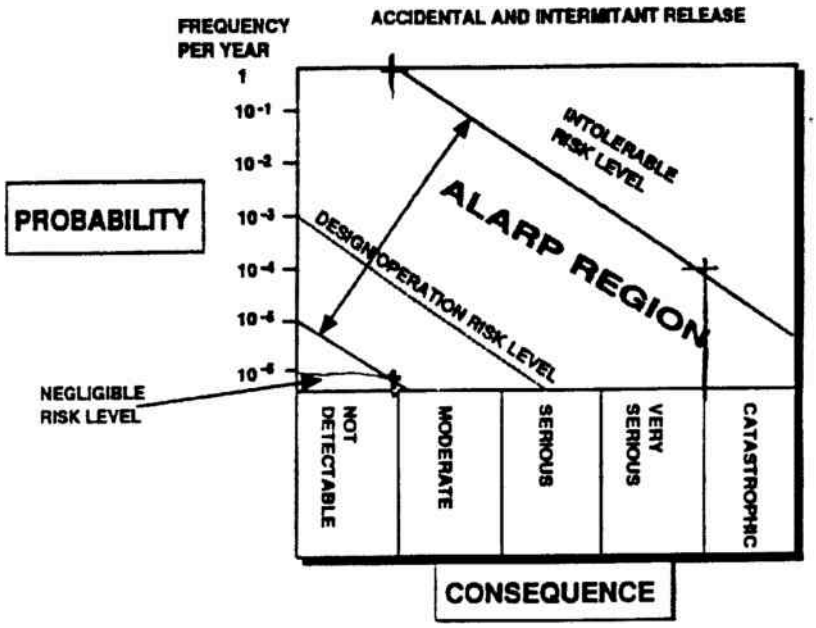


FIGURE 11.16 REPRESENTATION OF ALARP PRINCIPLE

11.8 INTEGRITY ASSESSMENT METHODS

There are three primary methods for conducting Pipeline integrity assessments. These are:

- Hydrostatic testing
- ILI
- Direct assessment

To meet the office of Pipeline Safety requirements for integrity verification in high consequence areas, each method must be capable of achieving comparable results. All methods are now in routine use with the method selected for use at a given time dependent upon operating conditions. Direct or indirect assessment, for example, may be acceptable alternatives in circumstances where ILI or hydrostatic testing (the preferred means) are not feasible or practical. Many pipelines, for example, are not amenable to pigging and to make them piggable could be difficult (e.g., multi-diameter segments under already developed areas).

11.8.1 Description of Assessment methods

11.8.1.1 Hydrostatic Testing Hydrostatic testing has been used since the early 1950s in the United States and elsewhere by the transmission pipeline industry and is mandated by codes as a proof pressure testing prior to in service use. It is now also widely accepted as a means of periodically checking the serviceability of existing pipelines and is a reliable method of mitigating stress

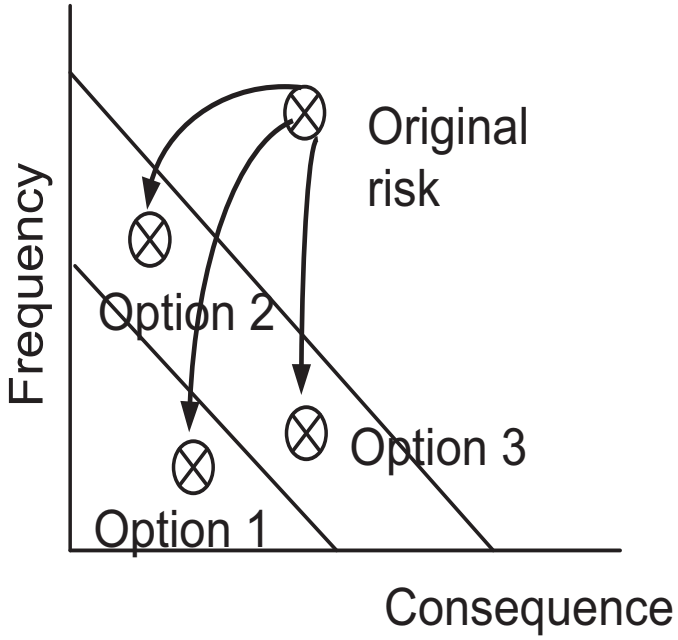


FIGURE 11.17 THE EFFECT OF THREE INTEGRITY STRATEGIES ON RISK REDUCTION

corrosion cracking in the medium-term. Figure 11.18 illustrates the result of a deliberate, successful, attempt to drive out SCC from a pipe section. The hydro test removes defects beyond a certain size, and may also tend to blunt any remaining defects, which assists in prolonging the fatigue life of the pipe. The effectiveness of the test in removing defects depends upon the difference in the test pressure and the maximum operating pressure, the greater the difference, the larger the implied margin of safety.

This is readily seen from Fig. 11.19 where the failure due to defects of various depths "d" and lengths "$2c$" at two pressure conditions are represented on a graph of non-dimensionalized depth/thickness versus non-dimensionalized length. ($2c/(Rt)^{\wedge 0.5}$), where R is the pipe radius [19]. The failure loci have been calculated using fracture mechanics, for combinations of non-dimensionalized depth and length at the design pressure (which causes a hoop stress in the pipe of 72% SMYS) and at the hydrostatic test pressure. The defects have been clustered in three groups, denoted, respectively, as classes 1, 2, and 3. Class 3 defects, which lie above the design pressure line, would cause failure at this operating condition. As can be seen from Fig. 11.19 as the defect size gets smaller the higher hydrostatic test pressure is needed to cause failure. The dimensions of the defects comprising the third cluster are sufficiently small that they will survive the hydro test.

During the operating life of the pipe especially for a liquids line, these small defects could grow perhaps by fatigue and they may eventually become large enough as to cause failure. This is why in the United States operators are required to retest their pipelines every 5 years to force out any defects that may have grown in the interim.

There are two possible failure modes during hydrostatic testing, fracture, and plastic collapse. Line pipe steels are generally tough and ductile and operate on the upper shelf of the transition curve. Fracture propagation therefore occurs as a combination of crack initiation, plastic flow, and ductile tearing. The relative importance of each factor is a function of the pipe toughness and the geometry of the defect. The burst strength of the pipe is directly related to its toughness and will increase with increasing toughness until an upper limit is reached, determined by the onset of plastic collapse. Collapse occurs locally at the ultimate tensile strength (UTS) of the pipe material. This means that when the ultimate tensile strength controls the failure mode, the defects are either very deep or, the nominal wall stress is very high [20].



FIGURE 11.18 AFTERMATH OF A SUCCESSFUL HYDRO TEST TO DRIVE OUT SCC

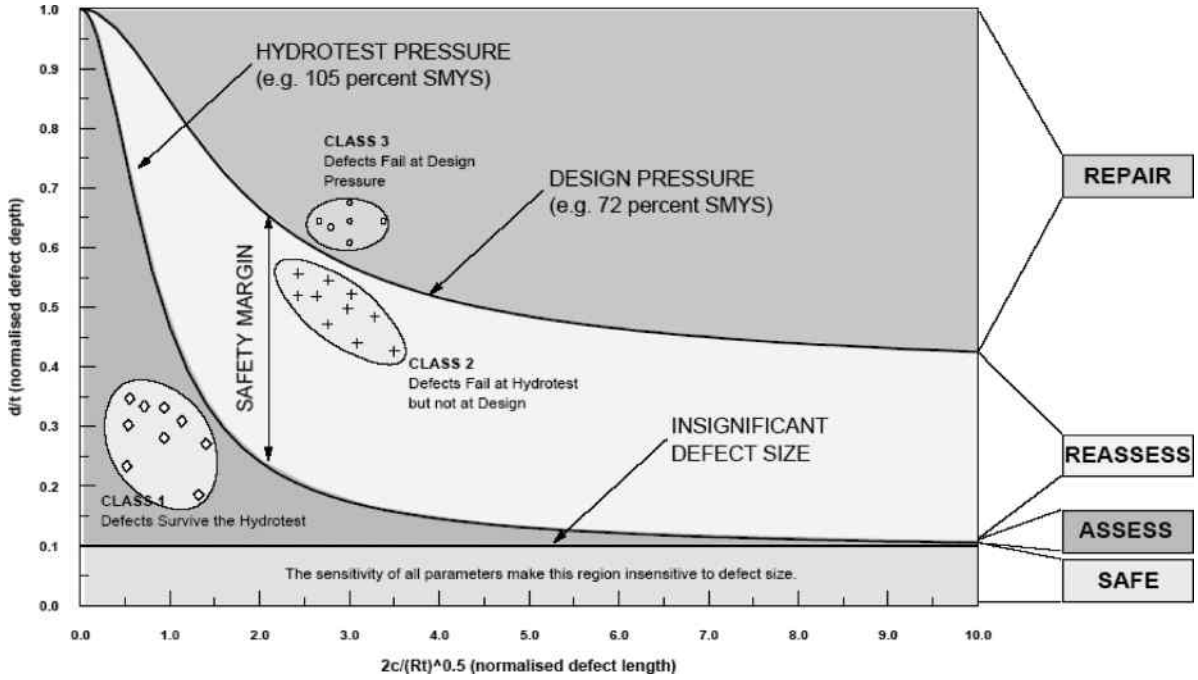


FIGURE 11.19 DEFECT ASSESSMENT CURVE

From a practical point of view, hydrostatic testing at a pressure sufficient to cause nominal wall stresses approaching ultimate tensile strength is unacceptable, as gross plastic deformation of the pipe results which will also damage the surface coating. Consequently, it is fairly typical for a company hydro test manual to stipulate a limit on the test pressure such that the pipe remains functional after testing. The limiting pressure is one which will cause the maximum wall stress not to exceed the actual yield stress of the material. For all but the very high strength steels, $\times 100$ and above, the ratio of the ultimate strength to actual yield stress is of the order of 1.1.

For the hydrostatic test to be fully effective, the toughness of the steel must be such that defects whose size compromises serviceability within some prescribed re- inspection interval fail the test [20]. As noted previously, the toughness that satisfies this criterion is a function of the line pipe strength and its geometry. Typically, toughness of the order of 50 ft.-lb (68J), is adequate for the usual re-test intervals involving SCC.

11.8.1.2 In-Line Inspection The early ILI tools were used for various forms of geometry survey. Intelligent or smart pig tool development began in the mid-1960s primarily for the purpose of measuring corrosion. Tuboscope were the early pioneers with their Linalog magnetic flux Leakage (MFL) pigs. This provided pipeline operators with an early warning of any major problems. The inspection log was essentially qualitative, providing a degree of defect severity grading. By the mid-1970s, British Gas and Batelle had completed major investigative programs on pipeline material properties and failure mechanisms. This led to the development of the first high resolution magnetic flux leakage inspection tools and the provision of quantitative performance requirements. Figure 11.20 illustrates the principle of magnetic flux leakage around a metal loss defect in the pipe wall. Sensors arrayed around the circumference of the tool detect the loss of signal strength. Some years later, in the 1980s, Pipetronix and NKK developed the alternative ultrasonic testing technique which requires fluid coupling between the tool and the pipe wall. In gas pipelines, this can be achieved by placing the tool in a liquid slug, or batch, as shown in Fig. 11.21. In this method, ultrasonic shear waves are used to detect cracks or metal loss on the internal or external surface of the pipeline wall.

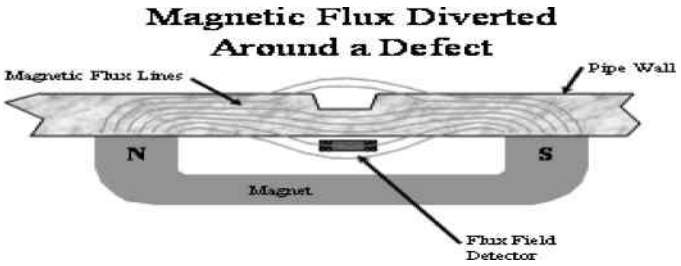


FIGURE 11.20 PRINCIPLE OF MAGNETIC FLUX LEAKAGE

These days in-line or on-line inspection tools can be classified as geometry, metal loss, or crack detection tools and employ a variety of technologies to evaluate the geometry and condition of the pipeline. It is important that the correct tool is selected for the task at hand. Reference [21] provides an excellent summary of the range of tools available, while Westwood and Hopkins [22] have set out the capability of these tools in terms of defect sizing as indicated in Table 11.6.

Internal inspection is improving in terms of the following:

- accuracy,
- sensitivity,
- memory,
- data quality,
- the speed of in-line travel, and
- the assessment of the measured results.

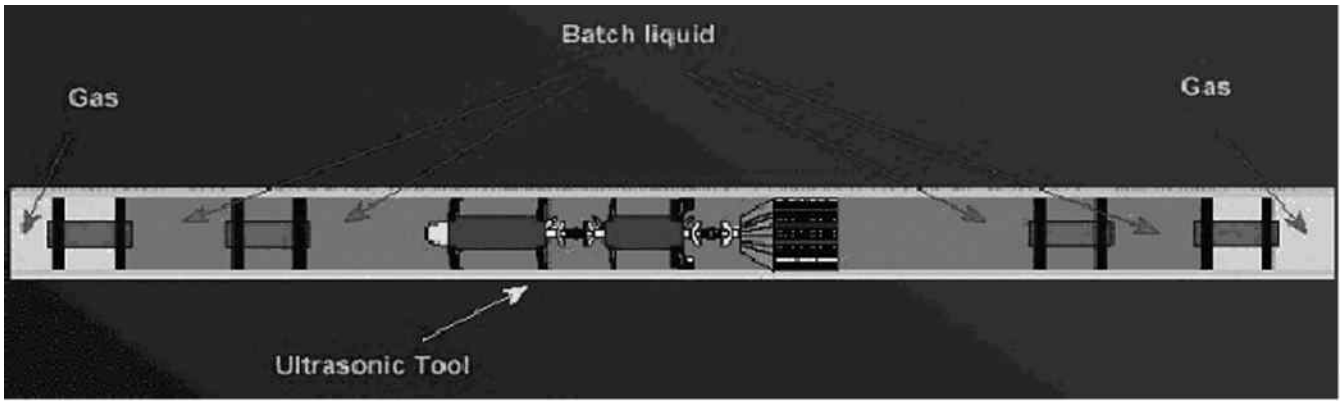


FIGURE 11.21 ULTRASONIC TOOL BATCHED FOR USE IN A GAS LINE

The need to identify long axially aligned defects, either in the form of corrosion or cracks, has led to improvements in the performance of ultrasonic tools and the development of transverse magnetic flux leakage tools. Since pipelines may contain both corrosion and cracks, many companies have chosen to run the two different types of ILI tools, which is quite an expensive undertaking. This has led to a concentrated effort to use a combination of techniques in a single tool for detecting different types of defects.

For instance, the most recent dual purpose ultrasonic tool uses phased array ultrasound. The sensors of this tool can be automatically adjusted to measure multiple types of defects. Metal loss is detected through perpendicular ultrasonic waves while angular waves are used to detect cracks. The tool consists of clusters of sensors, each of which is controlled by an on-board computer to determine the size, strength, and angle of the cluster's sound wave. These versatile waves can detect and measure external metal losses, mid-wall defects, and internal and external cracking. This development has been a joint international effort between a Canadian sponsor (Enbridge Pipeline), the GE Pipeline Solutions company in the United Kingdom, and a German ultrasonic group.

A major operational difficulty with using ultrasonic technology as a means of finding and sizing crack like indications on gas pipelines has been the need to run the tool in a liquid slug as indicated in Figure 11.21. The accuracy of the tool depends, in part, upon its speed of travel which is considerably less than the normal speed of gas transport in the pipeline, thus involving a curtailment of supply. Controlling tool speed, especially whenever elevation changes occur, or where there are branched connections, can be very difficult. The accuracy of the readings taken at these locations have to be carefully correlated with the actual tool speed. Placing the liquid slug into the line, removing it afterward and drying the line prior to a complete return to service, are other operational drawbacks. To overcome these operational impediments, the gas pipeline sector of industry has helped sponsor the development of two unique approaches to detecting axially oriented defects. The first of these, transverse field inspection (TFI) involves introducing a magnetic flux field in the circumferential direction into the pipe wall as opposed to the more conventional longitudinal direction shown in Figure 11.20. This orientation increases the sensitivity of detection of a long narrow axially oriented defect as this causes a greater disturbance to the magnetic field. It has been an especially useful method in detecting narrow axial external corrosion, which can be found close to the long weld seam. The TFI tool is deployed either singly, or in combination with a conventional MFL tool, thus increasing the overall rate of detectability. Some operators claim to have been able to detect stress corrosion and other types of cracks using the TFI method.

A more reliable method however has been the application of electro-magnetic acoustic technology, as a means of introducing sound waves into the pipe wall, without the need for a liquid couplant, since it is non-contacting. Specifically the ultrasonic transducer consists of a permanent magnet which sets up an underlying (static) magnetic field in the wall of the pipe. A coil oriented at right angles to the magnetic field, carries an alternating current which induces eddy currents in the near surface of the pipe material, setting up an AC magnetic field. The interaction of these magnetic fields results in the creation of what is known as the Lorenz force which generates pulsating compression waves in the pipe wall. The frequency range is of the order 20 kHz to 10 MHz. The transducers can be configured to also create waves at oblique angles to propagate along the pipe, so it is effective in finding no volumetric planar defects such as cracks. EMAT does require strong magnetic fields and large currents so there are some current restrictions on the duration and hence length of an in line inspection run using this method. It has been shown to reduce the number of false positives compared to the alternative of running a conventional ultrasonic in a liquid slug. Since excavation digs to validate tool calls are very expensive (upwards of $100,000), use of the EMAT is increasing and sensor development is continuing to evolve.

With the availability of ILI data, pipeline operators have additional information with which to develop the technical and economic justification for integrity verification programs (i.e., Fitness-for-Purpose) across an entire pipeline system. The Probability of Exceedance (POE) methodology [58] provides a defensible decision making process for addressing immediate corrosion threats identified through metal loss ILI and the use of sub-critical ILI data to develop a long-term IMP.

The POE-based methodology, as illustrated in Figs. 11.22 and 11.23, identifies the critical and sub-critical corrosion threats determining the excavation/repair and re-inspection interval alternatives summarized by integrity and financial indicators. Those indicators described by the unitized POE value (i.e., leak and rupture) and Net Present Value (NPV) levels provide the decision elements for comparing and evaluating each of the integrity program alternatives.

The POE methodology for corrosion features is integrated within deterministic corrosion growth models based on linear regression equations to provide a variety of potential repair/remediation

TABLE 11.6 DEFECT DETECTION CAPABILITY OF VARIOUS INSPECTION TOOLS [22]

Defect	Metal Loss Tools			Crack Detection Tools		Geometry Tools	
	MFL-LR	MFL-HR	UT	UT	MFL	Caliper	Mapping
Corrosion	D&S[1]	D&S	D&S	D&S	D&S	NO	NO
Axial cracks	NO	NO	NO	D&S	D&S	NO	NO
Circumferential cracks	NO	D[3]&S[4]	NO	D&S[2]	NO	NO	NO
Dents	d	D&S	D&S	D&S	D&S	D&S	D&S
laminations	d	d	D&S	D&S	NO	NO	NO
Mill defects	d	d	D	D	d	NO	NO
Ovality	NO	NO	NO	NO	NO	D&S	D&S[5]

D = Defects S = Sizing

[1]No discrimination on internal/external diameter
[2]Sensors have to be rotated 90 degrees
[3]Unreliable or reduced detection capability
[4]Unreliable or reduced sizing capability
[5]Tool is specially equipped to measure ovality
[6]SR Standard resolution; HR - high resolution
[7]MFL field is in transverse direction

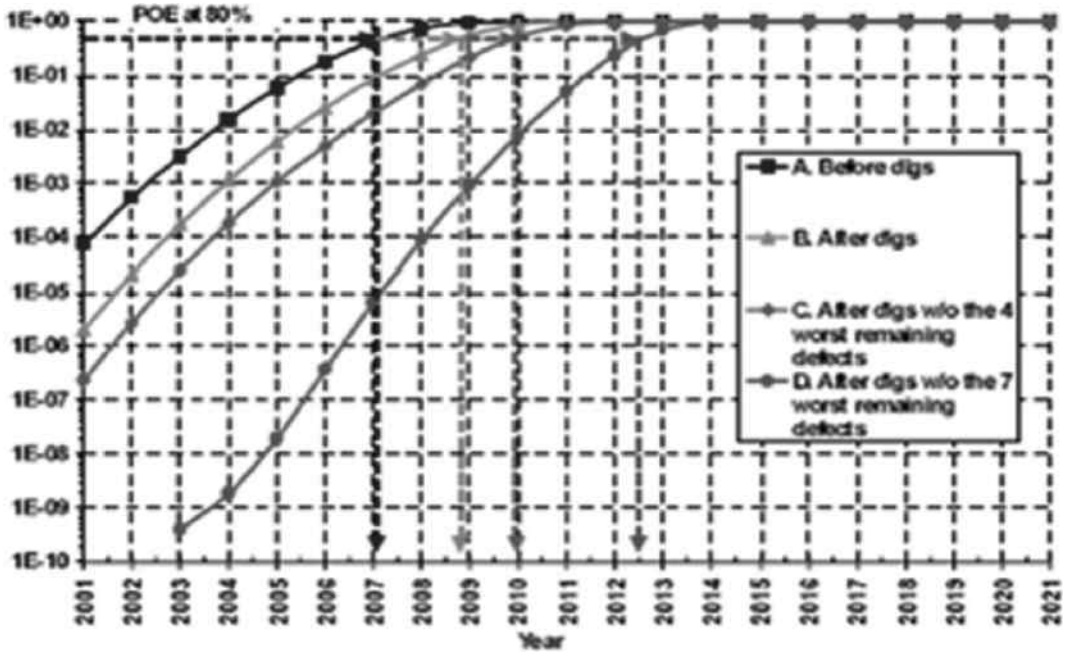


FIGURE 11.22 POE LEAK RISK SCENARIOS AT 80% W.T. PROBABILISTIC CORROSION GROWTH MODEL

schedules. The economics of each of these schedules are evaluated by preparing a cash-flow per alternative (i.e., for MFL Re-inspection, early and safe-latest repair/remediation schedules).

11.8.1.3 Direct Assessment External corrosion direct assessment provides integrity verification for pipeline segments that, for whatever reason, cannot be inspected by either ILI tools or hydro testing. In addition, it may also be used to complement the other two methods by providing on going condition monitoring between inspection and test intervals. Often local distribution company laterals provide the only source of supply to a business or community and the use of ILI or hydro testing could cause service disruption. Section 23 of the Pipeline Safety Improvement Act 2002 [24], permits direct assessment to be used if lines are not piggable, or where there are multiple threats that cannot be assessed using ILI. This is referred to as the "equivalency recommendation." It is important to note that direct assessment and ILI or hydrostatic testing work in fundamentally different ways. Direct assessment is used to ensure integrity by identifying regions where some form of degradation is active and to remediate it, whereas ILI and hydrostatic testing are directed toward identifying and removing the most severe defects present in the line. Equivalency may therefore be considered as the provision of a similar understanding of some future condition of the pipeline. There are, however, no agreed upon definitions of the term.

Some of the factors affecting pipeline piggability are the presence of less than full opening valves, sharp radius bends, short pipeline lengths, small diameters, telescopic connections (i.e., varying diameters), and low flow conditions which would mean

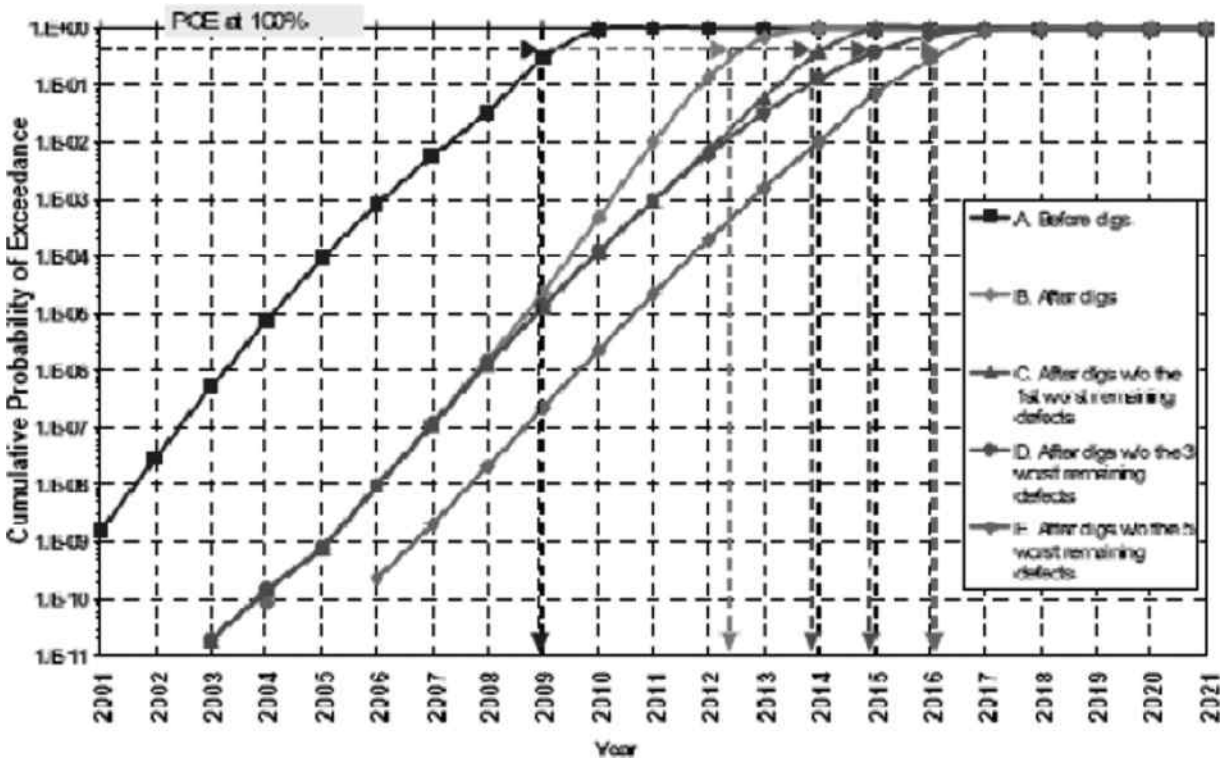


FIGURE 11.23 POE RUPTURE RISK SCENARIOS AT 100% MOP

insufficient driving force to propel the tool. A reluctance to use hydrotesting may be due to concerns of causing service interruptions, curtailing supply, or the growth of sub-critical defects. Water availability and disposal may also be factors in the decision.

All direct assessment processes have four sequential steps, as shown in Fig. 11.24. These are:

Pre-assessment or an initial assessment of a pipeline segment, to collect data and to determine if it is suitable for direct assessment.

Indirect measurements, or assessments and an information gathering phase which consists of a combination of remote measurements and data analyses.

Direct examination of the pipeline surface where the data collected is used to verify the results from the information gathering phase.

Post-assessment which determines the efficacy of the process and the re-assessment intervals.

The direct assessment processes that have been developed to date are based on industry best practices and are meant to improve pipeline integrity through repeated application. They are not cheap to undertake since the direct examination phase requires excavation and exposure of the pipe.

In 2002, NACE [25] issued a standard recommended practice pipeline external corrosion direct assessment methodology which is a step toward codifying the process. The underlying premise of direct assessment is that the condition of the pipe may be determined by considering external factors. For example, the above ground measurements can identify areas where external corrosion is either occurring or is likely to occur in the future. Similarly, a knowledge of the local terrain and soil conditions can assist in identifying areas where susceptibility to stress corrosion is possible. The initial pre-assessment process is used to identify vulnerable pipeline segments based on collecting information on system configuration, age, operating history, coating type, cathodic protection systems, soil types, and right of way accessibility. The determination is then made as to whether conditions preclude the use of indirect inspection tools or external corrosion direct assessment. Some of the conditions that could make external corrosion direct assessment difficult include coating that causes electrical shielding, the proximity of other buried metallic structures, frozen soil, or pipe buried below concrete. One should also check for the possible interference effects from AC power lines or DC traction equipment. Indirect measurement is used to identify coating breakdown and areas where external corrosion activity is, or may have been, occurring. At least two complementary indirect measurement techniques are required. Table 2 of the NACE standard recommended practice [25], provides useful guidance on the selection of indirect inspection tools and specifically addresses conditions under which some of the tools may be impractical or unreliable. The indirect techniques use either direct or alternating current. With the direct current method, the pipe to soil potential drop is measured and the location of any high cathodic protection demand to a small area is identified. The other approach uses an AC signal and the amount of current drain occurring, that is, the grounding, and its location are measured. The location of the highest alternating current drain is thus determined. Within each approach, there are several direct surveying techniques. Close interval surveys are used to measure the DC pipe to soil potentials at 5 ft. spacing to evaluate the cathodic protection levels. These are useful in identifying shorted casings, CP shielding, and stray current interference. Both the direct current and alternating current and voltage gradient methods are used to locate and "size" coating holidays in the pipe by measuring current flows. The direct current voltage gradient

TABLE 11.7 ATTRIBUTES OF VARIOUS PIPELINE PROTECTION METHODS

Tool/Procedure	Strengths	Weaknesses	Regulations	Cost
Hydrostatic testing	A good proof test. Can find longitudinal seam defects and other crack type defects such as environmental cracking that current smart pig technology has difficulty finding	Only a good test for that particular time. Corrosion and third-party damage may not be detected if metal loss has not been sufficient to lead to failure. Corrosion and third-party damage can occur after the test and then change the pressure-containing capability of the pipeline. The pipeline has to be taken out of service. Water used to test a pipeline that has already been in-use must be treated before discharging and water discharge permits may be difficult and time consuming to get. A hydro test can actually weaken pipe in some instances. This is called "pressure reversal"	All new pipe installed must be hydrostatically tested before use. (DOT 49 CFR Part 195 Subject E) New regulations require the testing of existing pipelines that have never been pressure tested before. Intrastate pipelines in California must be tested every 5 years absent a waiver. Waivers are frequently granted to allow smart-pigging in lieu of hydrostatic testing. (DOT/California State Fire Marshall)	Cost for new pipeline testing is low to moderate. Cost for testing existing pipelines can be very high, possibly up to 10 times higher
Maintenance Pigging	Clean pipe, no water or sediment in low points along the pipeline. Good flow rate. Helps mitigate internal corrosion	Debris and waste material that are removed by the pig have to be handled and disposed of in some instances. Some pipelines do not have traps to launch and receive pigs or may not be capable of moving pigs due to internal geometry	None	Low, if traps are required, cost would be moderate
Smart Pigs				
Magnetic Flax Leakage	Identifies and measures corrosion pitting so that remedial efforts can be performed. In most pipelines, it can be run while pipeline is operating. Does not require any pipeline downtime. Accepted industry-wide	Cannot be run in all pipelines. There are few tools that will fit pipelines 4″ diameter and smaller. Short inspection runs are costly. Short radius bends create problems with the pig's movement down the pipeline. The pipeline must be relatively clean. Regular launching and receiving traps are usually not long enough to accommodate inspection tools and must be lengthened. Because of the geometry of girth welds, they can cause "shadowy" which can prevent the detection of flaws near the welds. Has a tendency to magnetize the carrier pipe over time which creates maintenance welding problems. There are situations where too much distance exists between traps, requiring running the tool twice through the same section. Turn around time on data analysis may be excessive, may be many months	None, except DOT regulation requiring all new pipelines to be capable of smart-pigging (49 CFR Part 195, 120). Some pipelines in California must be hydro tested every 5 years. Smart-pigging has been allowed in lieu of hydro testing for some pipelines. (California State Fire Marshall)	Cost for low or conventional resolution would be $1000–$1500 per mile plus $12,500–$30,000 mobilization and demobilization (mob/demob), high resolution would be $2000–$3000 per mile plus $25,000–$50,000 mob/demob

Tool/Procedure	Strengths	Weaknesses	Regulations	Cost
Ultrasonic	Identifies and measures corrosion pitting so that remedial efforts can be performed. In most pipelines, it can be run while pipeline is operating. Does not require any pipeline downtime. Accepted industry-wide	Cannot be run in pipelines. There are few tools that will fit pipelines 4? diameter and smaller. There are fewer ultrasonic tools in all sizes compared to magnetic flux tools which makes scheduling more difficult. Short inspection runs are costly. Short radius bends create problems with the pig's movement down the pipeline. The pipeline must be extremely clean. The inspection tool can only be run in liquid due to its need for an electronic "coupling" to the pipe wall. Regular launching and receiving traps are usually not long enough to accommodate inspection tools and must be lengthened. Turn around time on data analysis may be excessive	None, except DOT regulation requiring all new pipelines to be capable of smart-pigging (49 CFR Part 195, 120) some pipelines in California must be hydro tested every 5 years. Smart-pigging has been allowed in lieu of hydro testing for some pipelines. (California State Fire Marshall)	Cost would be $3000–$6000 per mile plus $25,000–$50,000 for mob/demob
Geometry (also called Deformation, Caliper, or Band pigs)	In most pipelines, it can be run while pipeline is operating. Does not require any pipeline downtime. Accepted industry-wide. May find 3rd party damage that electronic internal inspection pigs would miss	Cannot run in all pipelines. There are few tools that will fit pipelines 4″ diameter and similar. Short inspection runs are costly. The pipeline must be relatively clean	None	Cost would be $300–$600 per mile plus $4500–$12,000 for mob/demob
Transverse Flux		Tool is still in development	None	
Pipeline Coating	Easy to install on a new pipeline. When used in conjunction with cathodic protection, results in a redundant barrier of protection from galvanic corrosion	When installed in the field, subject to contamination. When installed in a plant, the weld seams must be coated in the field and they do not provide the same level of protection. May be damaged by third parties or rocks in the backfill.	All components that are buried must be coated. (49 CFR Part 195.238)	
Cathodic Protection				
Rectifiers/Ground Bed	Compiles with DOT requirements. Effective method of reducing corrosion. Works for all types of pipelines	Rectify output is not instantaneous and the unit could be down for 2 months unless the operator uses a remote monitoring system (RMU). Rectifiers also require an AC Power source, which may be difficult to find in remote locations. Impressed current systems using rectifiers can be used on bare, poorly coated, as well as excellent coated pipelines. However, bare pipelines and poorly coated pipelines require a greater amount of current that will increase in cost due to additional units being needed	Required by DOT to have cathodic protection on all coated pipelines and any new pipeline that carries hazardous liquids (49 CFR Part 195.414 and 195.242)	$30,000 per installation

(*Continued*)

TABLE 11.7 (CONTINUED)

Tool/Procedure	Strengths	Weaknesses	Regulations	Cost
Pipe-to-Soil Potential	Satisfies Regulatory requirements to annually evaluate the cathodic protection system	Requires manual labor to obtain readings at all test stations	Required by DOT to have sufficient voltage reading to verify adequate cathodic protection per NACE Standards (49 CFR Part 195.416). Usually readings are taken every mile	
Test Stations	Enables annual requirement to measure the Pipe-to-Soil Potential of the pipeline. Acts as pipeline maker. Possible interference problems from foreign pipeline could be identified and mitigated	Susceptible to third party damage or deterioration over time	Required by DOT to have sufficient number to verify adequate cathodic protection (49 CFR Part 195.416). Usually installed every mile	Low
Close Interval Surveys	Effective at determining specific areas of a cathodic protection system that may need maintenance or upgrade	Close interval Surveys are more labor intensive than the annual test station survey. It is also more costly compared to other types of CP surveys. Typically, it demands landowner contact along the right-of-way as the survey is being conducted	Required by DOT to have sufficient voltage reading to verify adequate cathodic protection per NACE Standards (49 CFR Part 195.416)	Cost would be $1000 per mile with a $10,000 minimum
Sacrificial Anodes	Relatively inexpensive and easy to install. Effective at correcting isolated areas with inadequate cathodic protection potentials. Installed along pipeline route after conducting a hot spot survey to offset areas of anodic current flow, thus, satisfying hot spot cathodic protection orientation	Typically, a short-term solution to resolving identified cathodic protection system problem areas. Require additional monitoring	Required by DOT to have cathodic protection on all coated pipelines and any new pipeline that carries hazardous liquids (49 CFR Part 195.414 and 195.242)	Low
IR Free or Instant Off Readings	Minimizes resistance error	Requires additional equipment to be installed and all locations being tested must be synchronized.	Required by DOT to have sufficient voltage reading to verify adequate cathodic protection per NACE standards (49 CFR Part 195.416)	Moderate
Hot Spot Survey	Complies with DOT requirements. Effective method of reducing incidents. This is preferred and sometimes the only method to provide cathodic protection to a short, older, poorly coated, or bare steel pipeline.	Not instantaneous information	Required by DOT to have cathodic protection on buried pipelines (49 CFR Part 195.414 and 195.242). Fulfils requirement criterion for pipelines that are poorly coated or bare	Cost would be $3000 per mile with a $15,000 minimum

Tool/Procedure	Strengths	Weaknesses	Regulations	Cost
	Relatively inexpensive and easy to install anodes at identified "hot spots"			
Pressure Monitoring	Doing the pressure monitoring through SCADA is far more advantageous than having people at these remote sites for he following reasons: 1. With SCADA, one person can see the entire system from a single location (get the big picture); 2. If anything is detected one person can shutdown the entire system; 3. All of the pressures have alarming capability (audible and visual, currently active) that can alert a controller even if the SCADA operator is not looking at the particular point or device when it goes into alarm; 4. The pressures are continuously monitored regardless of any local weather conditions; 5. Often a back-up computer is installed and takes over the SCADA function if there is a failure of the primary computer	1. All of these remotely monitored sites are heavily reliant on various public power and communications systems; 2. Changes in the telecommunications industry have required operators to adapt to longer failures and system outages; 3. On most pipeline systems, the capability does not exist to monitor upstream and downstream pressures at remote valve locations	1. Periodic testing is required on a 6-month basis (not to exceed 7 months) on HVL systems, and once yearly on other (non-HVL) systems, (49 CFR Part 195.428); 2. The operator is required to maintain the operating pressure records for a three year period on all commodities (49 CFR Part 195.494(c)); 3. OPS advisory ADB-99-03 alerting operators of potential operational limitations associated with SCADA computing capacity	

(DCVG) method works by interrupting the nearest influencing rectifier on the cathodic protection system, using a fast, 0.3 s ON, 0.7s OFF cycle, whereas the alternating current voltage gradient (ACVG) method, measures the potential difference between two electrodes. Variations on the AC theme include the Pearson method in which an audio signal is applied to the line and a receiver picks up the signal strength at a coating holiday. All the above readings are tied to a global positioning system so that anomalous areas are accurately located along the pipeline. While all these methods have been described in the context of coated pipe, they can also be used on bare pipe and case crossings.

Direct examination involves excavating and collecting data where corrosion is most likely (as indicated for example by indirect measurements). Indications have to be categorized as to their severity and the immediacy of repair. This will require an adequate profiling of the defect shape (see Section 11.9 and assessment of the remaining strength). Dig outs are expensive so the total number of excavations to be undertaken will depend upon the assessed results from the above ground measurements. The data to be collected at the dig site includes pipe to soil potentials soil resistivity, water samples, soil bacteria, and the pH under any disbonded coating. Ultrasonic readings are taken at the locations of possible anomalies to detect internal metal loss. Extensive photographic documentation should be included in the records of the excavation.

The post-assessment phase involves assessing the effectiveness of the external corrosion direct assessment, process by comparing the above ground measured indications with the observations from the control digs. (The accuracy of the ILI methods are assessed in the same manner.)

Reasonable acceptance criteria would be a greater than 80% predictive capability.

When corrosion defects are found during direct examinations, the remaining life calculations are performed as shown in Section 11.9, assuming a conservative growth rate. The maximum re-assessment

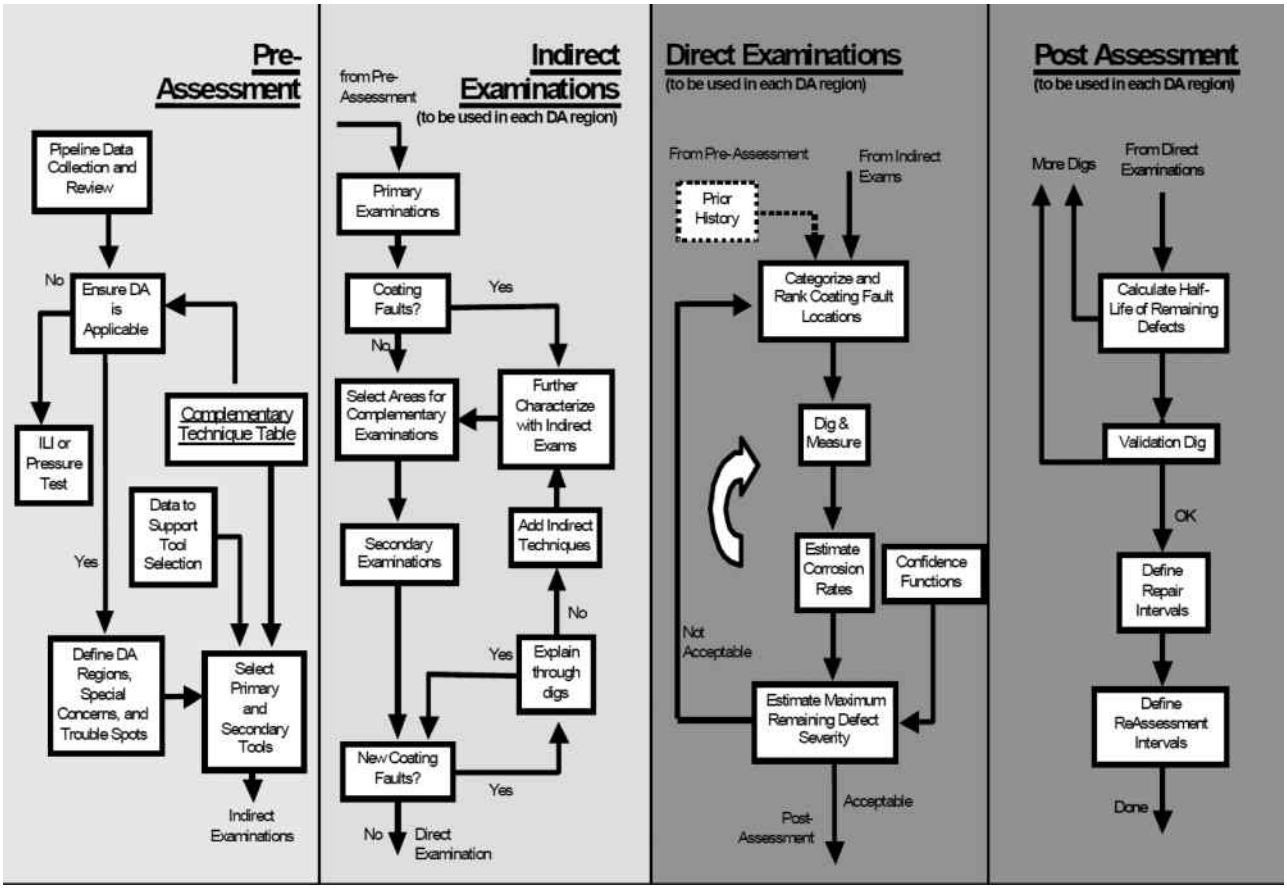


FIGURE 11. 24 FOUR STEP ECDA APPROACH

interval is established on the basis of half the remaining life. In the absence of corrosion defects, following the NACE-recommended practice, no remaining life calculations are required, it being assumed that the pipe is as good as new. In this circumstance, the re-assessment interval could be quite long. Regulatory requirements may, however, dictate a significantly shorter re-assessment interval.

Internal corrosion direct assessment (ICDA) has an identical four-step approach, intended to enhance the determination of the presence of internal corrosion in nominally dry gas pipelines. The underlying premise is that since corrosion is most likely to occur where water first accumulates, if these regions are found not to have corroded, other locations along the remaining length of pipe will most likely be corrosion free. The prediction of locations of surface wetting due to liquid hold up are determined from both topographical maps and by multi-phase flow modeling.

The pre-assessment phase is quite important, particularly the results of past inspections, cleaning pig results, corrosion coupon data and information on the topography of the line and the gas quality and flow velocity. It is usual to consider pipeline segments with similar construction and environmental characteristics. In general, there is little possibility of liquid accumulation on a segment of pipe which is directed down hill. Similarly, if the gas flow exceeds a particular speed there is little chance of liquid hold up on a level pipe. Attention is therefore focused on uphill segments of the pipeline where gravity and shearing forces oppose the momentum of the fluid. A critical angle of inclination will emerge from the modeling and this is used to pin point the critical portions within each segment. These areas can then be inspected for corrosion and, if none is found then, downstream corrosion is unlikely. Clearly other features that may trap water such as drip valves and dead ends should be investigated independent of the flow modeling which does not take them into account. ICDA may be regarded as a highly intuitive process enabling a focused examination of the areas likely to be susceptible to significant internal corrosion.

11.9 DEFECT ASSESSMENT METHODS

When a defect is discovered in a pipe causing uncertainty as to its continued serviceability, an engineering critical assessment can be performed, if sufficient information is available to determine its fitness for service.

The necessary information relates to the nature and physical dimensions of the defect, the geometric and material properties of the pipe, i.e., its diameter and wall thickness, its fracture toughness at the service temperature and the specified minimum yield stress. In addition, it is useful to know the recent operating pressure history so that maximum stresses can be calculated.

These parameters form the input to a model describing the interaction between the defect, the stress, and the toughness of the material. The types of defects which can be addressed in this manner include corrosion induced metal loss, and cracking or planar defects in the body and the long seam weld of the pipe.

While mandatory in the United States, many operators of transportation pipelines in other jurisdictions also already perform in

line inspection, hydrostatic testing, and direct assessment methods to verify the safety of their system. The ASME pipeline codes B31.4 and B31.8 [26,27], contain extensive sections on operating and maintenance including detailed acceptance criteria for certain types of in service defects. The methods subsequently developed to meet these criteria have their origins for the most part, in classical fracture mechanics, adjusted to account for strain hardening, and inelastic behavior. Their development and validation owes much to the extensive research efforts sponsored by individual pipeline operators and industry consortia such as the American Gas Association (AGA) the Gas Research Institute (GRI), and the Pipeline Research Council International (PRCI). Most of the methods are semi-empirical and involve simplifying assumptions about the characterization of the defect. Most pipeline steels may be regarded as being tough and ductile; hence the majority of defect assessment techniques consider plastic collapse as the limiting failure state. The major causes of pipeline failure throughout the world, tends to be either metal loss due to corrosion, or as the result of external damage. The dominant mechanism in a given jurisdiction is highly dependent upon the population density, and the types of pipeline system in place. For example, gathering systems are more prone to pitting corrosion failure than third party damage. Hence, regulatory authorities in producing regions are more likely to place corrosion top of the list whereas in Western Europe, with its high population density, external damage is most prevalent. In the following section, methods are provided for assessing corrosion and other blunt defects, dents, gouges, and fatigue cracks. Two worked examples have been included to help provide clarity.

11.9.1 Gouges

Gouges arise as a result of a scraping action on the surface of the pipe, and could be the result of the pipe having been dragged over a rock in the ditch, or by mechanical impact. The associated metal loss is often accompanied by local plastic deformation and the formation a thin layer of hardened material. This work hardened area may have very low ductility and may contain small cracks. Depending upon the orientation of the gouge, several methods of assessment are available. However, if the mechanical interference is severe enough to cause a dent on the surface, then an alternative approach must be used.

The gouge reduces both the burst strength and fatigue strength of the pipe with a longitudinally orientated gouge considered a more severe defect than one in the circumferential direction. The assessment of gouges assumes that failure is controlled by plastic collapse. These assessment methods have been validated against the results of 48 full scale vessel burst tests containing artificial, longitudinally orientated, machined V-shaped notches [28]. It is recommended that the measured depth of the gouge be increased by 0.5 mm to account for the possibility of cracking at the base of the gouge.

The assessment of gouges originates with the assessment of part wall defects referred to as the NG18 surface flaw equations. Figure 11.25(a) and (b) illustrate what is meant by a part wall and a through wall defect. For ductile pipe, subjected to internal pressure, the failure strength σ_f of an axially oriented gauge is given by

$$\sigma_f = \overline{\sigma}\left[\frac{1 - {}^{d}/_{t}}{1 - \mathrm{M}^{-1}\left({}^{d}/_{t}\right)}\right] \tag{11.2}$$

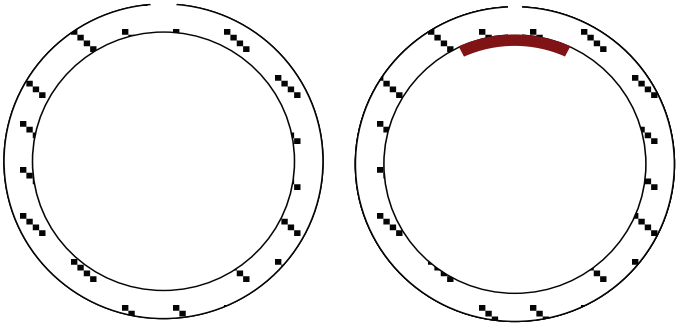


FIGURE 11.25 (A) PART WALL AND (B) THROUGHWALL DEFECTS

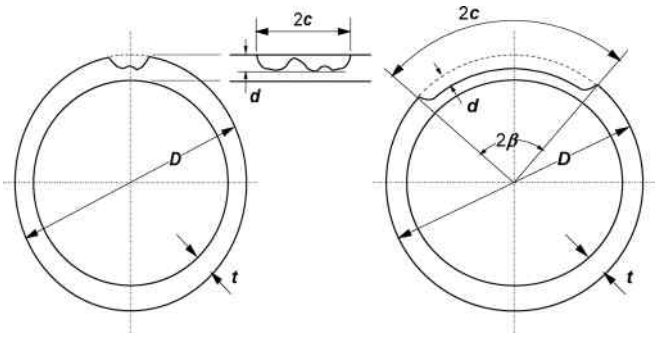


FIGURE 11.26 DIMENSIONS OF LONGITUDINAL AND CIRCUMFERENTIAL THROUGH WALL CRACK DEFECTS

where d is the defect depth, t the wall thickness, and the flow stress is given by

$$\overline{\sigma} = \left(\frac{\sigma_y + \sigma_{ult}}{2}\right) \text{ or } 1.15\,\sigma_y \tag{11.3}$$

The Folias factor M [29], is used to take account of the stress magnification as a consequence of bulging, due to wall weakness. The analytical solution for this factor is an infinite series, with three commonly used approximations given by

$$M = \sqrt{1 + 0.52\left({}^{2c}/_{\sqrt{Dt}}\right)^2} \tag{11.4}$$

$$\mathrm{M} = \sqrt{1 + 0.6275\left({}^{2c}/_{\sqrt{Dt}}\right)^2 - 0.003375\left({}^{2c}/_{\sqrt{Dt}}\right)^4} \tag{11.5}$$

$$\mathrm{M} = \sqrt{1 + 0.8\left({}^{2c}/_{\sqrt{Dt}}\right)^2} \tag{11.6}$$

The variables crack length $2c$, pipe diameter D, and wall thickness t, are shown in Fig. 11.26(a).

Kastner [30] developed the following plastic criterion for circumferential gouges which are assumed to be rectangular in profile and oriented perpendicular to the axis of the pipe:

$$\frac{\sigma_f}{\overline{\sigma}} = \frac{\eta(\pi - \beta(1 - \eta))}{\eta\pi + 2\sin\beta(1 - \eta)} \tag{11.7}$$

where $\beta = 2c/D$ and $\eta = 1 - {}^{d}/_{t}$
σ_f = axial stress at failure.

$2c$ is the maximum circumferential length of the defect, see Fig. 11.26(b) and the flow stress is taken to be the average of the yield and tensile strength. The model was developed for a single part wall defect subjected to internal pressure, axial, and bending loads. The failure criterion was developed solely for pressure loading; however, it has been shown to be applicable to any axial load by replacing the axial stress due to internal pressure (caused by the Poisson effect), with the total axial stress.

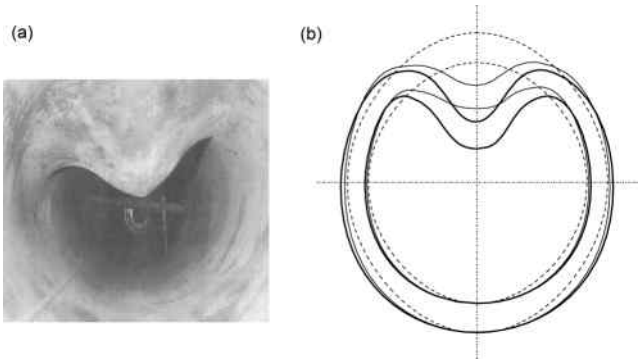


FIGURE 11.27 DENTS UNDER PRESSURE (A) AND (B)

11.9.2 Dents

A dent is a depression caused by contact with an indenter that results in plastic deformation of the pipe wall. It causes a local stress and strain concentration as well as a local reduction in pipe diameter and produces a gross disturbance in the curvature of the pipe wall (see Fig. 11.27(a)). Dents are defined by their geometry; a smooth dent causes a smooth change in the curvature of the pipe wall, whereas a kinked dent causes an abrupt change. Plain dents are smooth and have no wall thickness reductions.

Spring back is defined as the reduction in dent depth due to elastic unloading that occurs, when the indenter is removed from the pipe. An unconstrained dent will spring back or return to its former shape and attempt to re-round, when the indenter is removed (Fig. 11.27(b)). A constrained dent, usually found on the bottom of the pipe, however, is not free to re-round, because the indenter remains in contact with the pipe.

Re-rounding occurs when the dent attempts to move outward upon re-pressuring of the pipe. The change in dent depth under internal pressure does not significantly reduce the burst strength of pipe–unless the dent is very deep. An empirical limit for a plain dent under static internal pressure loading has been derived from the results obtained from extensive full scale testing. All dent depths in the full scale tests were measured at zero pressure; hence a correction for spring back is applied to dents measured while under pressure. Tests by Battelle, British Gas (BG Technology) and others, suggest that plain dents less than 8% of the pipe diameter (measured at pressure) do not significantly affect the burst strength of pipe [31]. Dents of 8% pipe diameter may restrict product flow and passage of pigs and render the pipe unserviceable. In the British Gas testing dents up to 24% pipe diameter (Fig. 11.27(a)), did not significantly reduce burst strength. These results could indicate that the code requirements are suitably conservative. Though failure has occured on pipelines with dents as low as 2%.

Cyclic pressure tests indicate that the fatigue life of a plain dent is less than that of an equivalent circular section of pipe. In general, the deeper the dent, the shorter the fatigue life, which also depends upon the mean stress level. Higher mean stresses promote re-rounding of the pipe. The length of the dent also influences the likely orientation and location of any fatigue cracking present. Long dents tend to have cracks that are axially orientated and usually occur in the center of the dent, whereas with shorter dents cracking occurs around the flanks.

The European Pipeline Research Group (EPRG), among others, has developed an empirical model for predicting fatigue life of plain dents [32]. It enables the fatigue life to be calculated using the S–N Curves of plain pipe, modified for a stress concentration.

A constrained plain dent will have a fatigue life that is at least that of an unconstrained plain dent of the same depth. Consequently, the same proposed method can also be used.

11.9.3 Dents and Gouges

For a smooth dent containing a defect, the fracture model is defined as follows in SI units:

$$\frac{\sigma_h}{\overline{\sigma}} = \frac{2\cos^{-1}}{\pi}$$

$$\times \left[\exp - \left\{ \frac{1.5\pi E\left[Y_1 - \left(\frac{1.8H_o}{D} \right) + Y_2\left(10.2\frac{H_o}{2t} \right) \right]}{\sigma^2 Ad} \right\}^{-2} \right]$$

$$\times \exp\left[\frac{\ln(0.738\, C_v) - K_1}{K_2} \right] \tag{11.8}$$

where $\overline{\sigma} = 1.15\sigma_y\left(1 - \frac{d}{t}\right)$, $K_1 = 1.9$, $K_2 = 0.57$

$$\text{And } Y_1 = 1.12 - 0.23\left(\frac{d}{t}\right) + 10.6\left(\frac{d}{t}\right)^2 - 21.7\left(\frac{d}{t}\right)^3 + 30.4\left(\frac{d}{t}\right)^4$$

$$Y_2 = 1.12 - 1.39\left(\frac{d}{t}\right) + 7.32\left(\frac{d}{t}\right)^2 - 13.1\left(\frac{d}{t}\right)^3 + 14\left(\frac{d}{t}\right)^4$$

Equation (11.8) takes into account the effects of both membrane action and bending due to the presence of a dent of depth H_o. The membrane and bending stresses are given, respectively, by the terms

$$\sigma_m = \sigma_h\left(1 - \frac{1.8H_o}{D}\right) \text{ and } \sigma_b = \sigma_h\left(10.2\frac{H_o}{2t}\right)$$

If the depth of a gouge exceeds a critical value then a through wall defect results. If the length of such a through wall defect exceeds a critical length L_c then rupture will occur. That is when,

$$L_{defect} \geq \sqrt{\left[\left(\frac{\sigma_h}{\sigma_y}\right)^{-2} - 1\right]\left(\frac{Dt}{0.8}\right)} \qquad (11.9)$$

11.9.4 Corrosion Defects

As noted in Section 11.8 corrosion damage in pipelines can be detected by various methods. When it is discovered, the primary concern is whether the pipeline remains structurally sound at the maximum allowable operating pressure (MAOP). If not, the pipe may leak or rupture.

A number of analytical techniques have been developed to determine if a defect will affect the pipeline's capability to operate at the MAOP. The best known method of assessing the remaining strength of corroded pipelines is that of the ANSI/ASME B31 G manual, first published in 1973 [33]. was later perceived to be conservative, so refinements to the underlying concepts were made leading to the development of a modified B31G and later the effective area method. All three approaches stem from the innovative work conducted by Kiefner and others at Batelle [34–36], in the early 1970s to predict the failure stress level for a through wall axial defect in a pipe. This model, commonly referred to as the log secant model, links the hoop stress at failure, to the geometry of the pipe and its toughness as follows:

$$\frac{K_c^2 \pi}{8c\bar{\sigma}} = \ln \sec \frac{\pi}{2}\left[\frac{M_p \sigma_p}{\bar{\sigma}}\right] \qquad (11.10)$$

where $K_c^2 = \dfrac{12C_v E}{A_c}$ and C_V is the upper shelf Charpy V-notch impact energy, ft.-lb, Ac is the area of Charpy V-notch specimen, square inches, E the elastic modulus, psi, L the length of area affected by corrosion and/or stress corrosion cracking, ins. $\bar{\sigma}$ the flow stress, psi (SMYS + 10,000 psi), σ_p p the failure stress, psi, SMYS the specified minimum yield strength, psi, and D is the nominal outside diameter of the pipe, ins.

The Folias factor M to take account of stress magnification as a consequence of bulging due to pipe wall weakness is given by

$$M = \sqrt{1 + 0.8\left(L \Big/ \sqrt{Dt}\right)^2} \qquad (11.11)$$

where t is the nominal wall thickness of the pipe, in consistent units.

The method used to determine the minimum toughness requirements is based on the Battelle/AGA relationship for ductile initiation developed by Kiefner et al. [34] from the work originally described by Burdekin and Stone [37]. They in turn had used the Dugdale [38] elastic plastic strip yield model to derive the relationship between the crack opening displacement and the applied stress in a biaxial stress field. added the Folias factor M_T and the use of flow stress to account for the strain hardening of typical pipeline steels.

Figure 11.28 shows one approach to determining the longitudinal extent and interaction distances within a region of localized corrosion. Several empirical interaction rules have been developed from full scale testing and/or the use of finite element modeling to enable a corrosion colony to be assessed. They are, however, limited in their coverage of pipeline size and defect geometries. One such rule is that in line defects are assumed to interact if the axial distance between them is less than the length

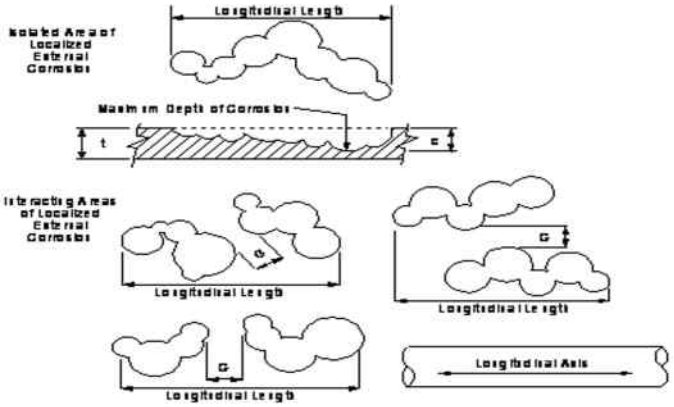


FIGURE 11.28 METHOD OF DETERMINING LONGITUDINAL EXTENT

of the shortest defect. In this circumstance, the combined length of the defect is the sum of the individual defect lengths *and* their separation distance(s). For circumferentially spaced defects that overlap in the axial direction, interaction is assumed to occur if, their circumferential separation is less than, or equal to, the full wall thickness. The combined defect length is taken to be the overall longitudinal extent of the corroded area.

The B31G assessment criterion was developed for smooth corrosion defects occurring on the body of pipelines operating at, or above 40%, of the specified minimum yield strength. The pipeline material was assumed to be weldable carbon or high strength low alloy steel. The smooth contour assumption is consistent with the requirement for no high stress raisers to be present in the defect. It need only be used in cases where the depth of corrosion exceeds 10% of the pipe wall thickness. The assessment of localized corrosion up to a depth of 80% of wall thickness is permitted. The appropriate equation to be used depends upon the value of a non-dimensional factor, A, which is determined from the following equation using the length of the corroded area, as shown in Fig. 11.28

$$A = 0.893L/\sqrt{Dt} \qquad (11.12)$$

For values of A less than or equal to 4,

$$P_{safe} = 1.1P\left[\frac{1 - 2d/3t}{1 - \left(2d \Big/ 3t\sqrt{A^2 + 1}\right)}\right] \qquad (11.13)$$

and for values of A greater than 4.0

$$P_{safe} = 1.1P[1 - d/t] \qquad (11.14)$$

Here, P_{safe} is the maximum safe operating pressure for the corroded pipeline and P is the greater of the established maximum allowable operating pressure or the design pressure, except that P_{safe} may not exceed P.

The distinction between Eqs. (11.13) and (11.14) arises from the assumption made regarding the corrosion defect shape. In the former instance, a parabolic-shaped defect is assumed (hence the

inclusion of the factor 2/3). It is more appropriate, however, for long corrosion defects to be characterized as a rectangular shape, which accounts for the different form of Eq. (11.14). Two other important assumptions in the derivation of the B31G approach are:

i. The maximum hoop stress is equal to the material yield strength.
ii. The flow stress is simply 1.1 times the yield stress.

One can present Eqs. (11.13) and (11.14) in terms of pipe hoop stress, the flow stress and the Folias factor, given by Eq. (11.11) as follows:

$$\sigma_f = \overline{\sigma}\left[\frac{1 - 2d/3t}{1 - M^{-1}\left(2d/3t\right)}\right] \tag{11.15}$$

The maximum length restriction on the validity of use of Eq. (11.15) corresponds to a value of Folias factor $M \leq 4.12$. The equivalent formulation for a long corrosion defect is given by

$$\sigma_f = \overline{\sigma}\left[1 - d/t\right] \tag{11.16}$$

A contiguous corroded area whose maximum depth is greater than 10% but less than 80% of the wall thickness can be assessed provided that its length, as derived from Fig. 11.28 does not exceed the value given by Eq. (11.17):

$$L = 1.12B\sqrt{Dt} \tag{11.17}$$

where L is the maximum allowable longitudinal length of the corroded area, and B is a value equal either to 4.0 for maximum depths less than 17.5% of the nominal wall thickness, or can be obtained from Fig. 11.29 for maximum depths between 17.5 and 80% of the nominal wall thickness; c is the maximum depth of the corroded area.

Equation (11.18) provides an alternative means of determining the non-dimensional factor B. The corroded area must be thoroughly cleaned and all corrosion products removed so that the dimensions can be accurately measured.

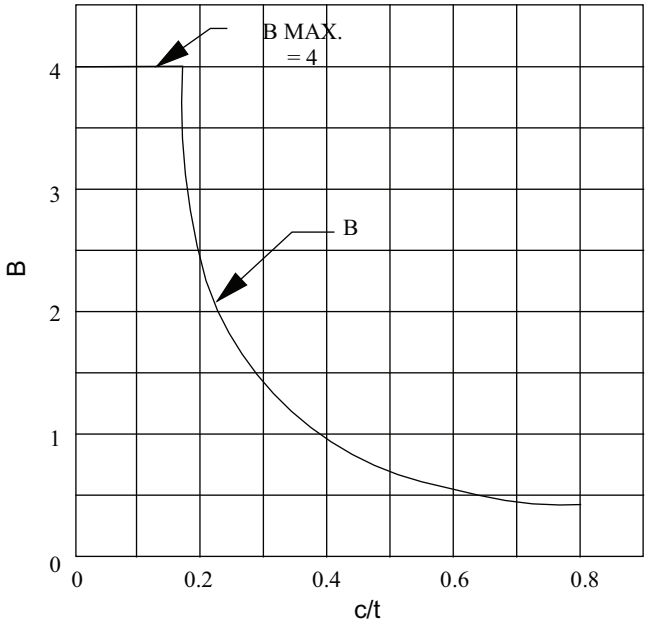


FIGURE 11.29 DETERMINATION OF NON DIMENSIONAL VARIABLE B

$$B = \sqrt{\left[\frac{c/t}{1.1(c/t) - 0.15}\right]^2 - 1} \tag{11.18}$$

Although widely used by the pipeline industry, a perception emerged that the formulations given above were unduly conservative *for shallow defects* essentially because of the underlying assumptions regarding flow stress, defect geometry, and the representation of the Folias factor. Accordingly, all three were reworked in an effort to improve accuracy. The flow stress definition was changed to that originally proposed by Kiefner et al in the research performed on behalf of the AGA [34,35], that is a simple addition of 10 ksi, or 68.94 Mpa, to the specified minimum yield stress of the material. This was considered to be a better description of the post yield behavior of relatively low strength steels and more in line with the conventional fracture mechanics description of flow stress (the average of the yield and ultimate tensile strength $(\sigma_y + \sigma_{ult})/2$). The three-term expression originally proposed for the Folias factor was reinstated and a geometric factor of 0.85, based on regressing data from full scale tests was substituted for the 2/3 used previously. The modified B31G equations are given by

$$\sigma_f = \overline{\sigma}\left[\frac{1 - 0.85d/t}{1 - 0.85d/t\ 1/M}\right] \tag{11.19}$$

where σ = SMYS + 10 ksi (68.94 MPa) and

$$M = \sqrt{1 + 0.6275\left(L/\sqrt{Dt}\right)^2 - 0.003375\left(L/\sqrt{Dt}\right)^4} \tag{11.20}$$

For $\left(L/\sqrt{Dt}\right)^2 \leq 50.0$

$$M = 0.032\left(L/\sqrt{Dt}\right)^2 + 3.3 \tag{11.21}$$

for $\left(L/\sqrt{Dt}\right)^2 > 50.0$

A further approach to more accurately define the corroded area was developed known as the effective area method which is probably better known by the term RSTRENG [39] (see Fig. 11.30). In both the effective area and the RSTRENG approaches, the surface defect is expressed in terms of a generalized area of metal loss A so that the nominal failure stress is given by

$$\sigma_f = \overline{\sigma}\left[\frac{1 - A/A_o}{1 - A/A_o\ 1/M}\right] \tag{11.22}$$

where A is the area of metal loss due to either corrosion- or stress corrosion cracking, A_o the area of metal, Lt, which would remain intact, if there were no flaws.

The remaining strength approach, RSTRENG, uses an iterative means to establish the lowest safe maximum working stress. The longitudinal, river bottom, profile of the defect (Fig. 11.31) is accurately defined at number of intervals which need not be regularly spaced. If N points are used to define the defect, then the number of possible combinations of defect length and depth which need to be evaluated is $N!/[2(N–2)!]$. Thus, for a 21 point profile, a total of 210 evaluations will be made from which the worst effective flaw is determined and the safe operating pressure calculated. The accuracy of the modified B31G and effective area

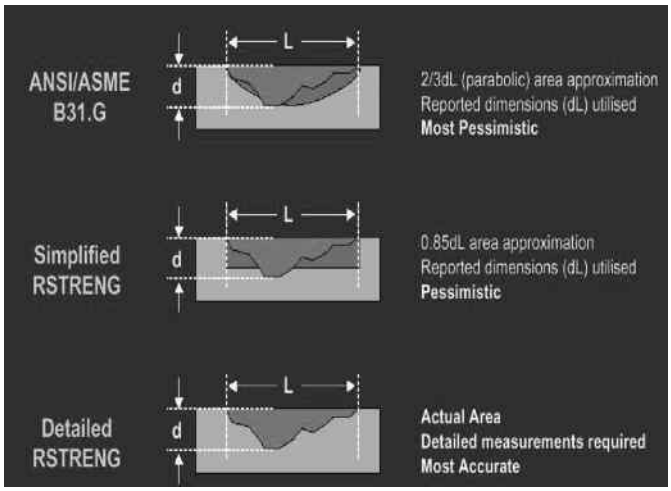


FIGURE 11.30 SIMPLIFIED AND DETAILED RSTRENG PROFILES

methods have been validated using 86 tests performed on pipes containing corrosion defects of known size. Kiefner and Associates [40] have made available a free download of a spread sheet named KAPA which performs these iterative calculations for both blunt corrosion defects and cracks.

Further enhancements to B31G were made in 1996 as a result of a joint industry study [41], undertaken by BG Technology (now known as Advantica). The project produced guidance for the assessment of single and interacting defects as well as a means for determining the actual shape of the defect. Following the same underlying principles as B31G, the significant changes were those made to the Folias factor and the definition of flow stress. The latter is based on the ultimate tensile strength rather than the yield strength of the steel which was considered appropriate for flaws failing by plastic collapse. The method was validated using the results obtained from 70 full scale tests performed on fully restrained pipes containing machined single and interacting defects. In addition, three-dimensional non-linear finite element analyses were performed to further validate the approach. The single defect equation is given by

$$\sigma_f = \overline{\sigma}\left[\frac{1 - d/t}{1 - d/t\,1/Q}\right] \tag{11.23}$$

where

$$Q = \sqrt{1 + 0.31\left(\mathrm{L}\Big/\sqrt{\mathrm{Dt}}\right)^2} \tag{11.24}$$

and $\overline{\sigma} = 0.9\,\sigma_{\mathrm{ult}}$.

The process for determining the safe working pressure is like RSTRENG, iterative, but characterizes the defect as a number of pits contained within a corrosion patch. The assessment determines whether or not the defect behaves as a single irregular patch or as a series of single pits within each patch. Interaction between the pits is also considered and the failure pressure is taken to be the minimum from all of the analyses.

The results and methods obtained from the BG Technology study were subsequently incorporated into another joint industry study undertaken by Det norske Veritas (DnV) [42]. In addition, to simply considering the effect of internal pressure, this study also considered axial and bending loads, leading to the development

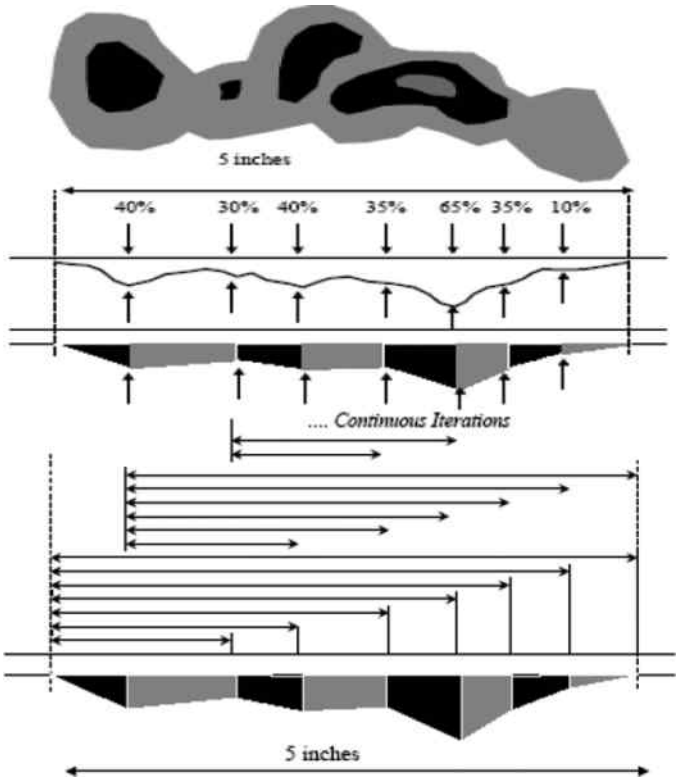


FIGURE 11.31 PROFILE OF CORROSION DEPTH

of equations for assessing single defects under combined loading. The methodology for assessing corrosion under internal pressure only, has been validated against results obtained from 138 full scale vessel tests, which included both real corrosion and machined defects. The methods developed in both joint industry studies have been incorporated into a DnV recommended practice [43]. To be consistent the Society's safety philosophy, a probabilistic calibration of the equations was performed taking into account both defect sizing and material properties uncertainty. This results in a partial safety factor approach based on the Load and Resistance Factor Design (LFRD) methodology. Within the recommended practice, partial safety factors are given for different types of inspection method and for differing levels of measurement accuracy. An alternative approach uses the allowable stress design format, and enables the calculated failure pressure to be multiplied by a single safety factor based on the original design factor, with the user making a judgment call on the effects of uncertainty associated with the defect sizing.

Table 11.8 summarizes the main differences in the various methods used to make a remaining strength assessment of corroded pipe. Both have their respective strengths and weaknesses. No in line inspection technique is perfect, while extensive data on the current condition of the pipeline is obtained, important information related to defects can be missed. On the other hand the hydrotest is a binary pass/fail test finding critically sized defects but providing no information on the extent of the sub-critical flaws that remain.

11.9.5 Weld Defects

The acceptability of flaws contained within gas or arc welded carbon and low alloy steel pipe can be undertaken using the workmanship standards set out in several standards. API 1104 [44], for example, covers the acceptance standards to be applied to

TABLE 11.8 SUMMARY OF STRENGTHS AND WEAKNESS OF VARIOUS ASSESSMENT TECHNIQUES

Method	Strengths	Weaknesses
Hydrotesting	Assurance a pipeline can provide containment at a given pressure level	Provide no information on remaining flaws or their severity
In-line inspection	Provides a lot of information on flaws that exist on the pipeline	May miss, incorrectly size, or fail to identify some flaws.

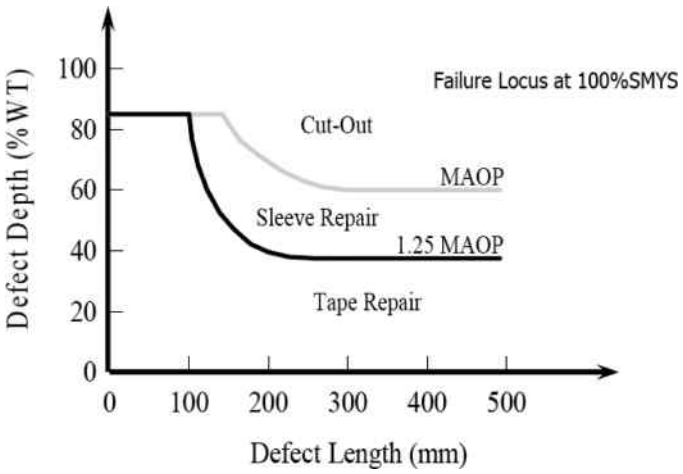


FIGURE 11.32 REMAINING STRENGTH ASSESSMENT REPRESENTATIVE OF METAL LOSS

production welds tested either to destruction or non-destructively inspected by radiography, magnetic particle, liquid penetrant, and ultrasonic test methods. These acceptance standards are based on empirical criteria and place primary importance on flaw length. Such criteria have been proven to have an excellent record in practice. In addition, API 1104 allows the use of an alternative approach, based on fracture mechanics analysis, which incorporates the significance of flaw depth as well as length. The fitness for purpose criteria used, provides for more generous allowable flaw sizes, but only if additional stress analysis and inspections are performed. The method requires that the welding procedures are qualified for either of two minimum CTOD toughness levels; 0.005 in., or 0.01 in.. The allowable defect depth is inferred from a given maximum applied strain. The actual defect depth may be determined from non-destructive testing or by considering the inherent size limitations imposed by the weld pass geometry.

A similar approach may be found in Appendix K of the Canadian pipeline standard CSA Z 662-07.

11.9.6 Worked Examples

Example 1

Consider a 30 in. outside diameter natural gas pipeline having a nominal wall thickness of 0.375 in. and made from 52 × (Grade 357) steel. The normal operating pipe of the pipe is 936 psig and it has been found to contain a defect 5.5 in. long with a maximum depth 60% of the wall thickness. The design factor for the pipe may be taken to be 0.72 and there is no need to consider its operating temperature. Use the B31G method to determine the pipe's fitness for service.

Since the defect depth exceeds 10% but is less than 80% of the through wall in accordance with the B31G manual, an evaluation is required. The first check is on the validity of the approach since it excessively conservative when the flaw length L is greater than $\sqrt{20Dt}$.

$$\mathrm{L} = \sqrt{20.(30.0.375)} = 15 \text{ inches}$$

Hence, we can use the maximum flaw length and depth in the evaluation.

$$\mathrm{L_{allowable}} = 1.12B\sqrt{\mathrm{Dt}}$$

Using Eq. (11.18), we first need to evaluate the term B

$$\mathrm{B} = \left\{\left[\frac{d/t}{1.1(d/t) - 0.15}\right]^2 - 1\right\}^{0.5}$$

$$\mathrm{B} = \left\{\left[\frac{0.6}{1.1(0.6) - 0.15}\right]^2 - 1\right\}^{0.5} = 0.6197$$

$$\mathrm{L_{allowable}} = 1.12(0.6197)\ \sqrt{30\,(0.375)} = 2.328 \text{ in.}$$

Since the actual defect length is greater than 2.328 in. the metal loss is unacceptable and hence a safe operating pressure for the pipe must be found. This is given by Eq. (11.13)

$$\mathrm{P_{safe}} = 1.1\mathrm{P}\left[\frac{1 - {}^{2\mathrm{d}}/_{3\mathrm{t}}}{1 - \mathrm{M}^{-1}\left({}^{2\mathrm{d}}/_{3\mathrm{t}}\right)}\right]$$

P is the greater of the maximum allowable operating pressure or the calculated design pressure using the appropriate code conditions, $P = 2\ t$ SMYS F_dF_t/D where F_d is the design factor and F_t the temperature derating factor. In this instance, the

pressures are the same, that is, 936 psig. The Folias factor is given by Eq. (11.11)

$$M = \sqrt{1 + 0.8\left(L/\sqrt{Dt}\right)^2} = 1 + 0.8(5.5/\sqrt{30.(0.375)})^2$$

$$M = 1.775$$

The safe operating pressure is therefore:

$$P_{safe} = 1.1(936)\left[\frac{1 - 0.666(0.6)}{1 - 1.775(0.666(0.6))}\right]$$

$$= 798 \text{ psig or } 5500 \text{ KPa}$$

Example 2 (using SI units)

A pipeline 508 mm in diameter with a nominal wall thickness of 6.35 mm is constructed from Grade 359 steel and has a certificated operating pressure of 6460 KPa. Two surficial defects have been found the first measuring 22.9 mm in length and having a maximum depth 2.54 mm, the second a length of 76.2 mm and maximum depth of 3.62 mm. Use the simplified RSTRENG effective area method to determine the failure pressures associated with these defects.

The appropriate equation to determine the hoop stress at failure is (11–22), that is,

$$\sigma_f = \overline{\sigma}\left[\frac{1 - A/Ao}{1 - A/Ao^{1/M}}\right]$$

where

$\overline{\sigma}$ = SMYS +68.94 MPa =359 +68.94 = 427.94 MPa and

A = 0.85 * the area of metal loss

Ao = the area of metal, L*t, which would remain intact, if there were no flaws.

Determining which of the equations one should use to calculate the Folias factor requires calculating the value of the quantity $(L/\sqrt{Dt})^2$, where L is the length of the defect.

For Case 1. $(L/\sqrt{Dt})^2 = (22.9/\sqrt{508*6.35})^2 = 0.162$ hence one should use equation (11.20).

$$M = \sqrt{1 + 0.6275\left(L/\sqrt{Dt}\right)^2 - 0.003375\left(L/\sqrt{Dt}\right)^4}$$

Substituting in this equation,

$$M = \sqrt{1 + 0.6275*0.162 - 0.003375*0.162^2} = 1.0497$$

From which $M^{-1} = 0.952$

A = 2.54 * 22.9 = 70.7 mm^2 and

Ao = 6.35 * 22.9 = 145 mm^2 hence

A/Ao = 70.7/145 = 0.4847

$$\sigma_f = 427.94\left[\frac{1 - 0.4847}{1 - 0.4847*0.952}\right] = 409.7 \text{ MPa}$$

The associated failure pressure $p_f = 2t\,\hat{U}_f/D = 2*409.7*6.35/508 =$ 10.42 MPa, which is considerably greater than the certificated operating pressure.

Case 2

$(L/\sqrt{Dt})^2 = (76.2/\sqrt{508*6.35})^2 = 1.8$ hence one should use again equation (11.20) to determine the Folias factor that is.

$M = \sqrt{1 + 0.6275*1.8 - 0.003375*0.18^2} = 1.455$ so

$M^{-1} = 0.687$

A = 2.54 * 76.2 = 164.5 mm^2 and

Ao = 6.35 * 76.2 = 483.9 mm^2 hence

A/Ao = 70.7/145 = 0.339

$$\sigma_f = 427.94\left[\frac{1 - 0.339}{1 - 0.339*0.687}\right] = 368 \text{ MPa}$$

The associated failure pressure $p_f = 2t\,\hat{U}_f/D = 2*368*6.35/508 =$ 9.2 MPa again higher than the certificated operating pressure so both these defects will survive normally operating conditions.

Example 3

An oil pipeline 30 in. in diameter, connecting to a tank farm undergoes frequent and significant pressure cycles. The pertinent facts are, the material is Grade 358 (52(), 0.375 in. thick with full size Charpy V notch upper shelf energy of 25 ft.lb. The line cycles four times per day between operating pressures of 936 psig (6458 KPa) and 100 psig (690 KPa). The initial flaw size is 6 in. in length with a depth of 0.104 in. It is appropriate to use a Paris Law crack growth model and assume an elliptical flaw with a stress intensity factor given by $K_i = 1.12 \times (\pi a/Q)^{0.5}$ where Q is a flaw shape parameter.

Crack growth is defined by : $da/dN = A\,(\Delta K)^n$ where N is the number of fatigue cycles and a reasonable value for A is 2.12×10^{-11} for ΔK in ksi $\sqrt{\text{in.}}$ units and $n = 4$.

The hoop stress at the highest operating pressure is found from the Barlow equation $\sigma_p = pD/2t$) to be 37,440 psi and at the lower operating pressure = 4000 psi making the stress excursion per cycle equivalent to 33.44 ksi.

The Folias factor M_T corresponding to the given flaw length is found from Eq. (11.5)

$$M_T = \sqrt{1 + 0.6275\left(L/\sqrt{Dt}\right)^2 - 0.003375\left(L/\sqrt{Dt}\right)^4}$$

$$M_T = \sqrt{1 + 0.6275\left(6/\sqrt{30(0.375)}\right)^2 - 0.003375\left(6/\sqrt{30(0.375)}\right)^4}$$

$$= 1.7244$$

and $M_T^{-1} = 0.58$.

To find the depth at which the flaw will fail at the highest operating pressure of 936 psig, we use the log secant method.

$$\frac{K_c^2\pi}{8c\overline{\sigma}} = \text{In sec}\frac{\pi}{2}\left[\frac{M_p\sigma_p}{\overline{\sigma}}\right] \text{ where } K_c^2 = \frac{12\,C_vE}{A_c} \text{ we can write.}$$

$$\frac{\dfrac{12C_vE}{A_c}\pi}{\dfrac{8c\overline{\sigma}}{}} = \ln\sec\frac{\pi}{2}\left[\frac{M_p\sigma_p}{\overline{\sigma}}\right]$$

$$= \frac{12\,\pi\,(25/0.124)(30)(10)^6}{8(3)(62000)^2} = 2.4716$$

$$\ln\sec\frac{\pi}{2}\left[\frac{M_p\sigma_p}{\overline{\sigma}}\right] = 2.4716 \text{ hence } \frac{M_p\sigma_p}{\overline{\sigma}} = 0.94617$$

At the highest operating pressure, the Folias factor
$M_p = \dfrac{0.94617\ (62{,}000)}{37{,}440} = 1.56684$ and $Mp^{-1} = 0.63823$.

Now M_p and M_T are related through:

$$M_{p^{-1}} = \left[\frac{1 - A/A_o}{1 - A/A_o\,1/M_T}\right]$$

Rearranging to solve for A/A_o we have,

$$A/A_o = \left[\frac{1 - Mp^{-1}}{1 - Mp^{-1}M_T^{-1}}\right] = \left[\frac{1 - 0.63823}{1 - 0.63823(0.58)}\right] = 0.57434$$

The cross-sectional area at failure A for an elliptically shaped flaw is $(\pi/a)\ La_{final}$, while the original defect area is given by Lt.

$$\text{Hence } a_{final} = \frac{0.57434(4)(0.375)}{\pi} = 0.274 \text{ inches}$$

To find whether the final flaw will cause a rupture or simply leak, we need to determine the hoop stress at the failure pressure for a 6 in. through wall flaw.

$$\frac{M_T\sigma_{TW}}{\overline{\sigma}} = 0.94617, \text{ from which}$$

$$\sigma_{TW} = \frac{0.94617(62000)}{1.7244} = 34020 \text{ psi}$$

Since the hoop stress of 34,020 psi is less than the maximum hoop stress 37,400 psi, the final flaw will cause a rupture.

In order to determine the number of cycles and hence the time needed for the defect to grow to a critical size, the fatigue crack growth model is used

$$\int_{a_{initial}}^{a_{final}} \frac{da}{A(\Delta K)^n} = \int_{a_{initial}}^{a_{final}} \frac{da}{A\left(1.12\Delta\sigma\left(\dfrac{\pi a}{Q}\right)^{0.5}\right)^4}$$

$$N = \int_{a_{initial}}^{a_{final}} \frac{da}{A\left((1.12)(33.44)\left(\dfrac{\pi a}{Q}\right)^{0.5}\right)^4}$$

$$N = -\left[\frac{1}{A\left((1.12)^4(33.44)^4\left(\dfrac{\pi}{Q}\right)^2 a\right)}\right]_{a_{initial}}^{a_{final}}$$

An estimate for Q, can be obtained by substituting a mean values of crack depth/length, a/L, and the ratio of actual stress/yield stress (σ/σ_y) into the following equation:

$$Q = [0.8 + 0.77(a/L) + 4.25(a/L)^2] + [0.2 + 0.0.14(\sigma/\sigma_y) - 0.22(\sigma/\sigma_y)^2]$$

mean 0.0317. 34020/ 62000 = 0.654, mean 0.625.

From this, a mean value of 0.9 for Q is obtained and substituting in the equation for N,

$$N = -\left[\frac{10^{11}}{(2.12)(1.5735)(1.2505)10^6(\pi/0.9)^2(0.274)}\right] + \left[\frac{10^{11}}{(2.12)(1.5735)(1.2505)10^6(12.185)(0.104)}\right]$$

$N = 18{,}917 - 7180 = 11{,}737$ cycles which at four cycles per day would cause failure after 8.5 years.

11.10 PIPELINE REPAIR

The purpose of a repair is to restore a pipeline to full serviceability, although sometimes only a temporary repair can be made. It is of the utmost importance, when making a repair, to ensure the safety of the repair crew, since a defect could be about to fail. Lowering the operating pressure is essential in circumstances where a defect is the result of actual, or assumed mechanical damage, or when it has been categorized as an ``immediate repair condition'' following an ILI. The pressure generally is reduced to 80% of the normal operating line pressure, unless the safe working pressure, calculated for the defect, is a lesser value. Prior to any excavation work taking place, it is essential that the correct lock and tag out procedures are followed to isolate the section of line, and that power to the cathodic protection rectifiers are turned off.

Before excavating in the vicinity of the line, it must be located accurately and hand exposed, often to within 1 m on either side of the line, though this distance is set by company procedure rather than a code requirement.

The work crew will wear appropriate personal protective equipment and if working near a gas line, or in a confined space they should also carry gas detection equipment.

The excavated bell hole or trench must be suitably shored to prevent collapse and have the means for speedy egress at both ends of the excavation.

All repairs should only be undertaken after careful planning has occurred. This planning stage involves obtaining a detailed knowledge of the pipe being repaired, its diameter, wall thickness, steel grade, chemistry, toughness, and method of manufacture. The terrain surrounding the defective pipe and site access are important considerations, as is the proximity of populated premises. Permits may have to be obtained, and contact made with other utilities that may have facilities close by the repair site. These will need to be located. There may be a need to restrict public access to the area which will necessitate liaison with local authorities and landowners.

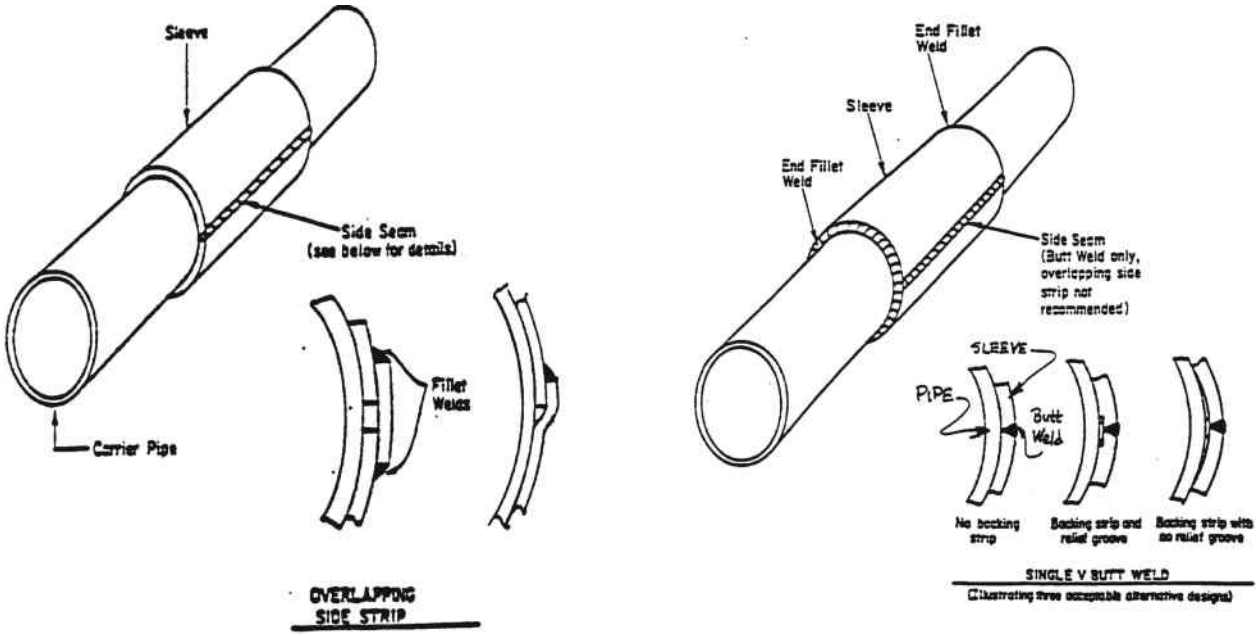


FIGURE 11.33 CORROSION DEFECT REPAIRS USING (A) TYPE A AND (B) TYPE B SLEEVES

TABLE 11.9 RELEVANT CODES AND STANDARDS FOR MAKING REPAIRS

Gas Pipelines	Oil Pipelines
49 CFR 192	49 CFR 195
ASME B31.8	ASME B31.8
ASME B31.8S	API 1160
CSA Z662	CSA Z662
PRCI pipeline repair manual	PRCI pipeline repair manual
Company operating procedures	Company operating procedures

The nature and extent of the anomaly will be a major factor in determining the selection of the repair method(s) since these have to be made in compliance with both code requirements and the operator's own safe operating procedures. As an example, Fig. 11.33 presents a pictorial guideline based on code requirements for repairing corrosion defects using sleeves. Table 11.9 provides a list of codes and standards which make reference to repair requirements. The costs of repair, time to complete with the associated service impact inconvenience, are other factors which affect the choice of repair scheme.

The repairs must be made by competent personnel working under experienced supervision. The type of defects that can, under appropriate circumstances, be repaired include internal and external corrosion, stress corrosion cracking, long seam defects, girth weld defects, dents, construction damage, and metallurgical features. The types of repair which can be made are:

- Cut out and replace.
- Grinding or Dressing.
- Weld deposition.
- Mechanical Clamps.
- Metallic sleeves Snug fit and Stand off sleeves.
- Non-metallic (composite) sleeves.
- Hot tapping, Stopple, and Bypass.

If the anomalies are extensive in nature, a cut out will be required necessitating replacement of the pipe with pre-tested material taken from stock. Cold cutting of the pipe to remove the defective section is usual and sufficient pipe must be exposed to enable proper fit up to occur of the replacement section.

Superficial or low level defects are removed by grinding or dressing leaving a smooth profile free from stress raisers. Skill is required to perform this task and it should only be done using a low-powered grinder. The profile of the defect should be carefully measured and recorded. Grinding is also used to remove mechanical damage in dents provided the material removed does not amount to more than 40% of the wall thickness. Extreme care must be taken when evaluating the surface damage caused by denting to ensure all cracks have been removed.

Corrosion pits may be repaired using weld deposition and the method is well suited to repairing small corroded areas that cannot be sleeved such as elbows and tees. It is inappropriate, and potentially *dangerous*, to use production welding procedures to make in service welds, since the flowing condition in the line will cause higher weld cooling rates leading to possible cracking. Special in service welding procedures have therefore to be developed and welders trained to use them. This often involves a staged learning process starting with welding on a specially developed rig flowing water through the test section at a prescribed rate.

Mechanical, bolt on, clamps may be used to make temporary repairs and are very versatile since they can accommodate pipe out of roundness. Some of these types of clamp can be welded to make a permanent seal. The larger sizes of clamp are heavy and relatively expensive. When fitting sleeves, it is imperative that the manufacturers' instructions are followed fully in order to reduce the possibility of in service failure.

Three different generic types of sleeve repairs are currently available, two of which use a metal sleeve, the other a non-metallic composite. Sleeves are generally used to reinforce the damaged pipe by restraining the bulging which might take place at the defect, rather than to share the hoop stress. The exception is the



FIGURE 11.34 COMPOSITE WRAP REPAIRS

use of the pre-heated compression sleeve which, upon cooling, clamps in place around the pipe and relieves some of the hoop stress. The two halves of the compression sleeve are welded to a side bar so that there is no welding to the pipeline.

Type A sleeves are non-pressure retaining and the side seams are fillet welded joining both halves of the sleeve, as shown in Fig. 11.33(a). The end gaps are sealed to prevent the ingress of water. With Type B pressure retaining sleeves (Fig. 11.33(b)), the side and end seams must use groove butt welds. The welding procedures for the end seams must be suited to the pipe metallurgy and the computed cooling rates to prevent cracking.

Two types of fit up are possible–a snug fit, and where a stand off distance is used. With the snug fit, both halves of the sleeve are in intimate contact with the pipe surface, and pre-tensioning is sometimes used to achieve fit up. The stand off sleeve is better suited to circumstances where the pipe is slightly out of round or has a very slight longitudinal curve. Hardenable polyester filler material is used to patch corroded areas under both types of sleeve and to fill the annular gap with the stand off fitting.

Specially shaped coupling sleeves, known as Dresser couplings, may be used to repair girth welds.

Composite wrap repairs (see Fig. 11.34) are made using a polymer-based matrix reinforced with either a woven fabric or oriented fibers. Some wraps are preformed as coiled rolls; such as the Clock Spring ™, others are hand laid up as a wet bandage applied to the pipe surface. Both types are chemically bonded to the pipe and within each inter leaving layer as these are continuously wound around the pipe (Fig. 11.35) and are cured in place.

Hot tap/stopple bypassing is a useful, but expensive technique, of making a cut out repair without having to take the line out of service. (see Fig. 11.36). Four permanent split tee fittings are placed in pairs on either side of the section of pipe to be removed. Permanent sandwich type valves are attached to the tees, through which a hot tapping tool is entered to cut through the pipe wall. Upon completion of the hot taps, a by pass section is created by attaching a length of pipe to the flanged ends of the two outermost valves. The process is completed by installing two stopple plug fittings through the inner pair of valves and purging the section of line between them before cutting away and replacing the unwanted pipe section. After the new section has been purged, the stopple plug fittings and the by pass line are removed and blind flanges fitted to all four valves.

Freeze plugging can be used to isolate pipe segments containing liquid product without the need to drain down the entire section of line. At the appropriate locations, a cooling jacket is placed around the pipe and liquid nitrogen circulated so as to freeze the contents. The frozen plug is held in place by virtue of the contraction of the pipe. Prior to undertaking such a repair, the pipe should be subjected to a rigorous non-destructive evaluation to ensure that there is minimal cracking present.

The applicability of all of the above types of repair methods with respect to sever pipeline codes is set out in Tables 11.10, 11.11, and 11.12.



FIGURE 11.35 CLOCK SPRING™ REPAIR

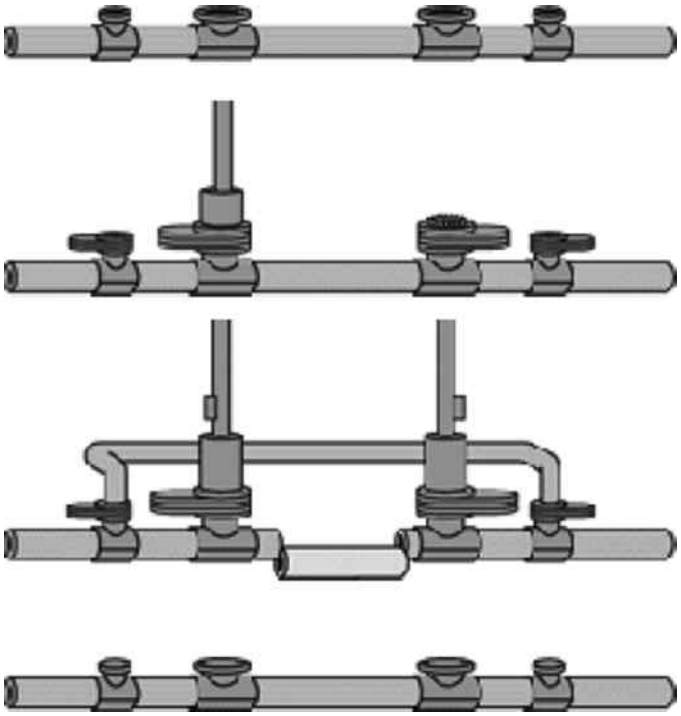


FIGURE 11.36 STOPPLE FITTING FOR LINE REPLACEMENT

TABLE 11.10 PERMISSIBILITY OF CORROSION REPAIR TECHNIQUE

Repair Method	ASME B31.4	ASME B31.8	CSA Z662
Cut out	Yes as complete cylinder		
Grind out	No		
Reinforcement Sleeve Type A	Yes, if not leaking and not selective on an ERW seam	Yes, if not leaking	
Pressure containing sleeve Type B	Yes		
Compression sleeve	Treat as Type A or B	Treat as Type A or B	Yes
Composite wrap	Yes, if not leaking and $d/t < 0.80$ and not selective on an ERW seam	No	Yes, if not leaking and $d/t < 0.80$
Mechanical Clamp	Yes	Yes	No
Hot tap or fitting	Yes if fitting size < NPS 3	Yes	
Weld Deposition	Yes		External corrosion only

TABLE 11.11 PERMISSIBILITY OF CRACK REPAIR TECHNIQUE

Repair Method	ASME B31.4	ASME B31.8	CSA Z662
Cut out	Yes as complete cylinder		
Grind out	Yes if grinding depth < 40% wall thickness		Yes, per corrosion limit
Reinforcement sleeve Type A	Yes, after grinding out and grinding depth < 40% wall thickness	Yes	Yes, after grinding out
Pressure Containing sleeve Type B	Yes		
Compression sleeve	Treat as Type A or B	Treat as Type A or B	Yes, after grinding out
Composite wrap	Yes, after grinding out and grinding depth < 40% wall thickness	No	Yes, after grinding out
Mechanical clamp	Yes	No	Yes
Hot tap or fitting	Yes	Yes	
Weld deposition		No	

TABLE 11.12 PERMISSIBILITY OF MECHANICAL DAMAGE REPAIR TECHNIQUE

Repair Method	ASME B31.4	ASME B31.8	CSA Z662
Cut out	Yes as complete cylinder		
Grind out	Yes if grinding depth d < 12.5% wall thickness and d/diameter < 6%	Yes if grinding depth d < 10% wall thickness any length d < 40% wall thickness limited length and d/diameter <4%	Yes
Reinforcement sleeve Type A	Yes, after removal by grinding and use of filler	Only with use of filler	Yes, after removal by grinding
Pressure containing sleeve Type B	Yes		
Compression sleeve	Treat as Type A or B	Treat as Type A or B	Yes
Composite wrap	Yes, after removal by grinding and use of filler	Only if design is proven	Yes, after removal by grinding and not on a dent
Mechanical clamp	Yes	No	No
Hot tap or fitting	No		
Weld deposition	No		

11.11 PIPELINE CORROSION CONTROL

Corrosion is commonly defined as the chemical or electrochemical reaction between a material, usually a metal, and its environment. In the context of pipelines, the reaction usually causes a progressive deterioration or destruction of the pipe material leading to metal loss and in extreme cases loss of containment.

Corrosion can only occur when the following four elements are present simultaneously:

i. An anode (the electrode at which oxidation occurs, meaning it supplies electrons and corrodes).
ii. A cathode (where reduction occurs meaning it accepts electrons and is thus protected from corrosion).
iii. A common electrolyte in which the anode and cathode must be immersed.
iv. A metallic path connecting the anode and cathode.

Collectively, they form an electrochemical corrosion cell which is accompanied by the passage of electric current, and for this to occur, a potential difference must exist between the two electrode regions. In a pipeline, the metal pipe acts as both the cathode and anode, which continually "jump" around the surface. When external pipeline corrosion occurs, the soil or atmosphere acts as the conducting electrolyte and the conducting path. With internal pipeline corrosion, the medium flowing through the pipe acts as the conducting electrolyte and conducting path. Figure 11.37 shows a schematic of a differential corrosion cell that is setup on a metal pipeline surface for corrosion to occur. Note that all four corrosion elements are present.

Depending upon the nature and source of the corrosion, a number of possible ways of combating it are available as shown in Table 11.13. A number of these methods are discussed in more detail in Section 11.12.

11.11.1 Costs and Effects of Pipeline Corrosion

A recent study [45] conducted on behalf of the Federal Highway Agency into corrosion costs and preventive strategies in the United States indicated that the direct economic impact of corrosion to the national economy was of the order of 3% of the annual gross domestic product (GDP), or $276 billion dollars. This value only included directly incurred costs on the part of the owner/operator and did not take into account the indirect costs to the end user or the public. It has been estimated that such indirect costs are of a similar magnitude to the direct costs. The report investigated the threefold impact on economics, safety, and the environment, of corrosion on gas and oil transmission pipeline infrastructure by considering a network of 135,000 miles (217,000 km) of hazardous liquid pipelines, 21,000 miles (34,000 km) of crude oil gathering lines, 300,000 miles (483,000 km) of natural gas transmission pipelines and 28,000 miles (45,000 km) of gas gathering lines. The cost to the transmission pipeline industry was estimated to lie between $5.4 billion and $8.6 billion dollars annually, made up of operating and maintenance costs (52%), capital replacement (38%)and the cost of failures (10%).

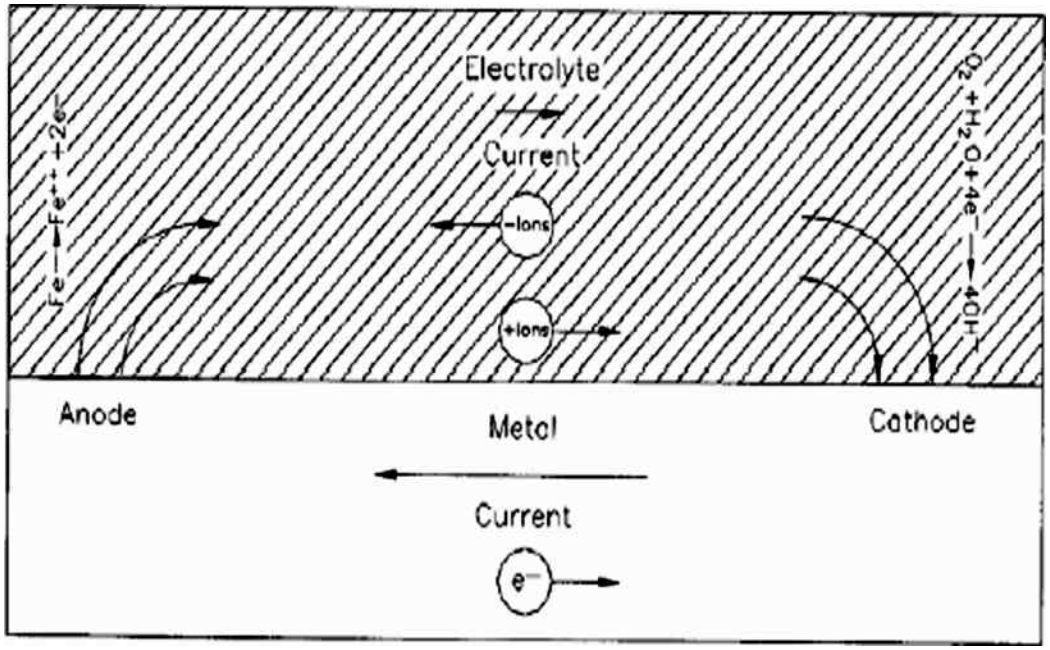


FIGURE 11.37 CORROSION CELL

TABLE 11.13 PIPELINE CORROSION PREVENTION

Source of Corrosion	Method of Detection	Mitigation
Internal Corrosion		
Corrosive product	Coupons/probes	Inhibitors, internal liners
Microbially induced corrosion	Sample analysis	Biocides, pigging
Metal Loss	Caliper pigging Intelligent pigging	Repair or replace
Anaerobic	Oxygen monitoring	Oxygen scavengers
External Corrosion		
Surface preparation	Visual and instrument inspection	Repeat preparation
Poor coating application	Visual inspection; Holiday detection; Thickness tests	Repair or recoat
Coating defects due to construction	Coating evaluation surveys	Cathodic protection Excavate and repair
Stone/rock damage		
Soil Stresses		
Disbondment		
Deterioration	Close interval potential surveys	
Contact with metal surface	Coating evaluation surveys Close interval potential surveys	Excavate and remove contact
Inadequate cathodic protection	Close interval potential surveys	Increase current output; Install additional cathodic protection; Remove and repair defect; Remove and recoat surface
Third party damage	Coating evaluation surveys Surface and aerial patrols	Repair
Metal loss	Intelligent pigging	Repair or replace
Ground disturbance	Surveillance/notification	Repair

These figures have been based on 1998 costs and do not take account of the cost of complying with more recently announced regulatory changes related to pipeline inspection. The latter address a prescriptive requirement for a pipeline integrity management program to assure public safety and environmental protection.

An over arching goal of pipeline company governance is the protection of the asset base and interestingly the study indicated that the estimated replacement cost of the United States transmission pipeline infrastructure is of the order of $541billion dollars.

11.11.2 Types of Corrosion

There are six principal categories of pipeline corrosion, general, galvanic, pitting, microbial, stress corrosion, and that caused by stray current. General corrosion is characterized by the uniformity

TABLE 11.14 M GALVANIC SERIES OF COMMON COMMERCIAL METALS AND ALLOYS IN BRINE (TEMPERATURE APPROXIMATELY 25°C)

Magnesium	Most active (less noble)
Zinc	
Aluminum	
Mild steel	
Stainless steel	
Gold	
Platinum	Least active (more noble)

of attack and a constant corrosion rate over the surface. Microscopic anodes and cathodes on the surface continuously swap roles.

Galvanic corrosion occurs when two electrochemically dissimilar metals or alloys are metallically connected and exposed to a corrosive environment. Table 11.14 lists a range of commercial metals and alloys arranged in galvanic series, that is, in the order of their corrosion potentials, with the most easily corroded, or most active at the top. Changes in the ambient conditions or temperature can affect the order of the galvanic series. When two of these metals are connected together, one will corrode (the one which is less noble/more anodic). The farther apart two metals are on the table, the greater the tendency for galvanic corrosion if they are joined. The rate of galvanic corrosion depends upon the potential (volts) difference between the two metals, the nature of the electrolytic environment and the polarization behavior of the metals.

11.11.3 Environmental Factors Affecting Corrosion

The nature and condition of the flowing product in a pipeline has a marked effect on the occurrence and progression of corrosion. Operators of gas transmission pipelines impose gas quality conditions on the receipt of product to ensure that they are transporting dry (no water content), sweet (no hydrogen sulphide content) gas. Hence, they do not experience internal corrosion problems. However, in gas gathering systems, or under upset conditions at a processing plant, water may be present in the pipeline and will dissolve any carbon dioxide or hydrogen sulphide present to form, respectively, carbonic or sulphuric acid, both of which can quickly corrode or crack the pipe.

If a flowing liquid product contains entrained particulates, then depending upon the stream velocity, the particles can physically erode the surface of the pipe wall including any protective film present. This form of mechanical wear commonly occurs at elbows and is referred to as erosion corrosion. At slower speeds, the particulates settle out of the fluid and are deposited on the bottom of the pipe, preventing any chemical inhibitor treatment from reaching the surface of the metal, and leaving it vulnerable to corrosion. The deposition of any solid on to a metal surface can cause increased corrosion under the deposit due to differential concentrations. Bacteria will also thrive under the deposits.

Bio-corrosion or microbial influenced corrosion (MIC) is the result of microbes, fungi, etc., living in colonies in the environment adjacent to the surface of the pipe and producing hydrogen sulphide, which is corrosive. On the external surface of the pipe, dead micro organisms combined with silt or clay can result in sulphide reducing bacteria producing corrosive iron sulphide. Living organisms can change the oxygen content of the environment often affecting overall corrosion rates. Since electrons can only be released at the anode as fast as they can combine with oxygen in the environment, at the cathode, a high level of oxygen means more electrons can be transferred and the corrosion is accelerated. Crevice corrosion will occur when a concentration cell is depleted of oxygen or some other oxidizing agent inside a crevice.

A low pH (acidic) environment dissolves some oxides that form at the anode, exposing new metal surfaces which had previously been protected. Corrosion reactions are speeded up at higher temperatures, while temperature variations within short distances along the pipe, such as at a transition from below to above ground, will cause the warmer portion to become anodic.

Dissolved solids may interfere with the formation of corrosion inhibitor films. They will increase the solution's conductivity which leads to an increased corrosion rate.

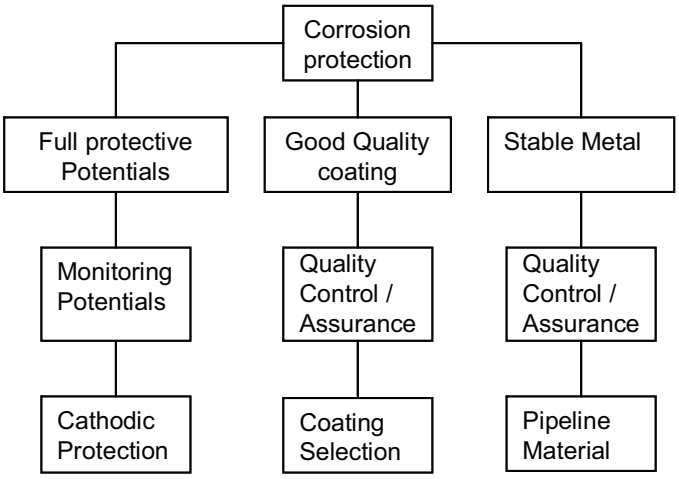


FIGURE 11.38 METHODS OF MITIGATING PIPELINE CORROSION

The ratio of cathode to anode size is important, if the anodic area is small in comparison with the cathode, then corrosion will be concentrated in a smaller area and will occur more quickly than if the anode was larger. This is the cause of many leaks on storage tanks.

11.12 PIPELINE PROTECTION—COATINGS, CATHODIC PROTECTION, INHIBITION

The integrity of a new pipeline is best assured through effective engineering design and construction using the appropriate codes, applying quality control measures, preventing external damage, and using corrosion protection systems. Each of these means of affording protection is discussed in detail in the following sections.

The most effective method of mitigating corrosion on the external surface of a buried or submerged facility utilizes a dual system of a protective coating supplemented by cathodic protection as shown in Fig. 11.38.

11.12.1 Coatings

The primary function of an externally applied coating to the surface of a pipe is to establish a permanent barrier between it and its immediate environment. Long-term coating performance is essential to prevent deterioration of a pipeline. Errors in coating selection may lead to failure and remedial repair costs which can easily exceed the increased initial cost of a higher integrity coating. The choice of coating largely depends upon the in service conditions and the type of handling that may occur during transportation and installation. Hence, before making a coating selection, it is important that the environmental and construction conditions of the buried pipeline facility are well understood.

Consideration of the relevant chemical, electrical, environmental, geotechnical, and mechanical conditions experienced by a pipe coating system during its service life, leads to the conclusion that an optimum external pipeline coating for buried service should have good:

- water resistance,
- adhesion,
- chemical resistance,

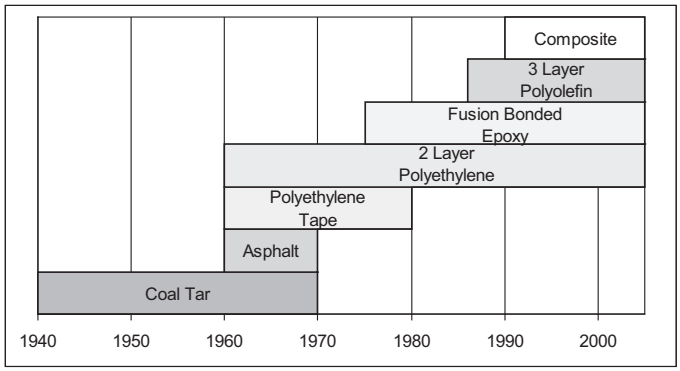


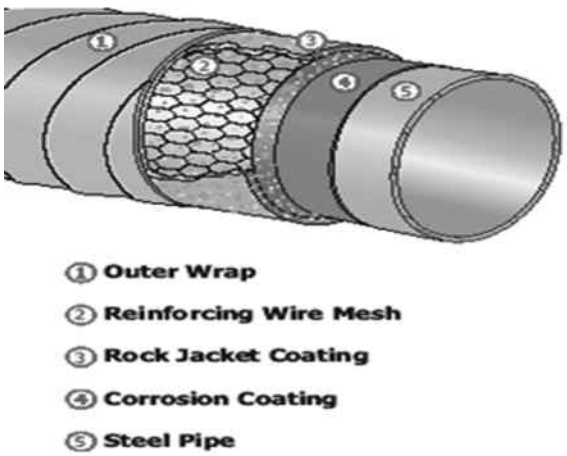
FIGURE 11.39 HISTORY OF COATING DEVELOPMENT

- electrical resistance,
- temperature stability,
- compatibility with cathodic protection,
- flexibility,
- hardness/abrasion resistance,
- impact resistance,
- penetration resistance,
- soil stressing resistance,
- weathering resistance,
- compatibility with repair and girth weld coating material.

These characteristics are elaborated upon further in Section 11.12.1.2.

11.12.1.1 Types of Pipeline Coatings Figure 11.39 shows a timeline of the development of seven coatings that have found common usage in providing pipeline protection. The original pipeline coating material, coal tar, was introduced over 75 years ago and in general has proven to be one of the most cost-effective, efficient, and effective barriers between the environment and the pipe surface. Coal tar-based coating products are in fact still in use on more in service pipelines throughout the world than any other coating type. Application in the field was originally carried out using line travel equipment, incorporating a mechanical wire brush cleaning system, for surface preparation. A subsequent improvement was the use of an asphalt enamel which could be plant applied. Furthermore, it had fewer associated health hazards. Polyethylene tapes also became popular for a time and could be field applied using purpose built tape wrapping machines. A number of pipeline failures in the United States, in the mid 1960s and early 1970s, however, gave rise to an increasing concern about external corrosion. Stress corrosion and inter granular cracking were considered to be the most probable cause. Further testing indicated that hydrogen embrittlement, arising from hydrogen generated at the steel surface by the cathodic protection system, following a break down of the coating, was a contributory factor. A solution was required in the form of improved coating technology which resulted in the development of fusion-bonded epoxies (FBEs). These have the advantage of not shielding the cathodic protection. FBEs are single layer coatings, and while they have proven to be generally very effective, there are operating environments where they have limited performance. For example, they have low abrasion resistance and so are not well suited for use in rocky terrain or when making a directional drilled crossing. In these circumstances, a three-layer polyolefin coating will have better handling capability as well as being more resistant to moisture. Highly engineered polymer coatings are now invariably used in new pipeline construction. The choice of coating largely depends upon the in service conditions and the type of handling that may occur during transportation and installation. FBE forms the substrate providing corrosion protection. Figure 11.40(a) and (b) illustrates two further examples of special purpose multi layer coatings which have been designed, respectively, to provide negative buoyancy, when pipelining underwater, and to reduce the heat loss by insulating the pipe.

11.12.1.2 Coating Selection and Performance Criteria The following considerations are critical when selecting the essential properties of the coating material:



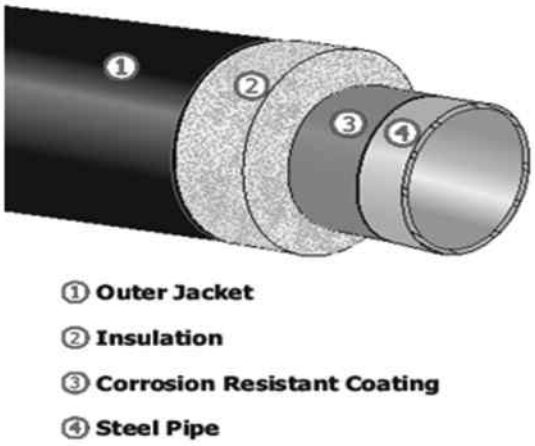


FIGURE 11.40 MULTI LAYER COMPOSITE COATING

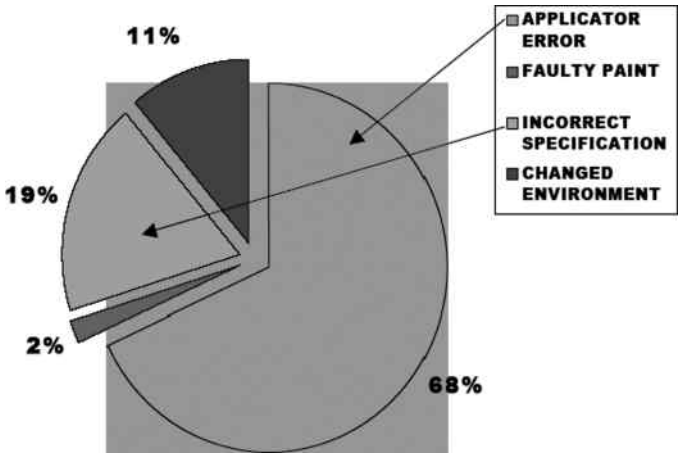


FIGURE 11.41 SOURCES OF COATING FAILURE ON AUSTRALIAN PIPELINES

Water resistance

The coating must be reasonably impermeable to water if it is to provide satisfactory protection against corrosion.

Adhesion

Strong, permanent adhesion to the pipe surface is essential if it is to withstand the forces exerted on the pipeline. The area beneath a disbonded coating may permit moisture to accumulate between the structure and coating, and it is shielded from the influence of cathodic protection. High initial adhesive strength is achieved by having a suitably prepared surface, and good coating flow during application. The longevity of the bond is dependent upon its resistance to moisture penetration, soil strength, and cathodic disbondment. The importance of good surface preparation and application technique can be seen in Fig. 11.41 which shows that poor application accounted for 68% of the pipe coating failures in Australia [46].

Chemical Resistance

The soil environment will vary along a right of way so the coating must be capable of resisting a range of chemical or bacterial attacks.

Electrical Resistance

An effective underground coating must have good dielectric strength to ensure high electrical resistance, which should not change appreciably with time or with exposure to water.

Thermal Stability

Coatings must retain good mechanical strength at temperature. This is particularly necessary downstream of a compressor station discharge where temperatures as high as 50°C are not uncommon.

Compatibility with the Cathodic Protection

Where the coating has been damaged or is missing, cathodic protection is used to protect the pipe from corrosion. However, cathodic protection can cause the formation of hydrogen gas at the exposed surface and increase the transportation of water to the coating defect site. These two effects can singularly or in combination increase the loss of coating adhesion at the edge of a "holiday," that is, at a failure point in the coating. It is important therefore to choose a coating which will not shield the cathodic protection.

Mechanical Strength

A coating needs high impact strength to withstand severe handling during storage, transportation, pipe laying, and backfilling. During operation, the coating is subject to deformation and damage caused by soil movement, as the soil alternately expands with absorption of moisture and subsequently contracts during drying. Some soils have sufficient gripping action as to remove the coating during contraction. Coatings must be able to withstand this type of soil movement, which can also be exacerbated by temperature cycling of the pipeline.

Flexibility

Coatings must be sufficiently flexible to resist cracking or disbondment during field bending and construction.

Weathering Resistance

Since coatings are generally factory applied, well in advance of proposed construction and/or in service dates, they must be resistant to ultraviolet degradation and extreme temperature changes.

Compatible Repair and Girth Weld Coating Material

The girth weld coating system and repair coating should be compatible with the coating on the parent pipe and possess properties which meet the construction and operating conditions.

A comparison of the advantages and disadvantages of a number of typical coating types is given in Table 11.15.

11.12.1.3 Field Applied Joint Coatings/Shrink Sleeves In order to enable field welding of joints, factory applied coatings are terminated about 100 mm (4 in.) from the ends of the pipe. The resulting unprotected areas have to be coated in situ, sometimes under very poor field conditions. The frequency of corrosion failures at pipe joints highlights the need to ensure that field applied coating is fully compatible with the factory applied pipeline coating. FBE, is extremely difficult and expensive to apply in the field, so liquid epoxies have been developed having performance properties which closely match the parent coating. Issues remain with this method though, such as cold temperature application (requires careful application of pre-heat to be successful), the variability in film thickness, and most importantly, the dependence upon the skill of the applicator. The compatibility issue is even more challenging with three-layer polyethylene or high performance composite coatings since the behavior of all three substrates (FBE primer, co-polymer adhesive and polyethylene/polypropylene top coat) have to be matched.

Heat shrinkable sleeves mirror the three layer polyethylene system with an epoxy primary layer, adhesive and polyethylene outer layer, as a result they are the most popular means of providing pipe joint protection with this type of parent coating.

While there are numerous coating standards and specifications covering mainline pipe coatings, such is not the case for field joint coatings. Instead, individual users and contractors have developed their own specifications often with little bearing on the operating performance. Surface cleanliness is the chief requirement in achieving a good joint coating and in the sometimes difficult conditions found in the field, it can only be achieved by blast cleaning. Pipe preheat is required prior to cleaning and again before coating application. This ensures that there is no condensed surface moisture present. A good anchor pattern profile at least 2.5 mm, deep is highly desirable to ensure the adhesion of coatings.

As noted previously, an alternative and often superior method to field applied coatings, is to use a compatible shrink sleeve. This

TABLE 11.15 ADVANTAGES AND DISADVANTAGES OF PIPELINE COATINGS

COATING	ADVANTAGES	DISADVANTAGES
Coal tar enamel	Simple technology and capital equipment Long and successful track record Excellent protection against corrosion	Poor cold weather handling Known carcinogen Low soil stress resistance Characteristics sensitive to temperature Poor field bending
Asphalt enamel	Simple technology and capital equipment	Poor resistance to moisture and soil stress Poor long-term stability Very sensitive to temperature; Poor cold weather characteristics
Polyethylene tape	Simple application in field	More documented pipeline failures than any coating; Adhesives subject to biodegradation Very poor resistance to soil stress, particularly at elevated temperatures Spiral under lap void and bridging across external welds often results in cathodic shielding ⟶ Stress Corrosion Cracking (SCC)
2-Layer extruded polyethylene	Excellent resistance to handling and installation damage Excellent corrosion resistance	Limited pipe sizes (<24" {610 mm} O.D.) Long and successful history Poor shear stress resistance; Limited temperature range
FBE	Excellent corrosion resistance Does not shield cathodic protection systems High adhesion limits damaged areas	Low impact results in considerable field damage (holidays); Very sensitive to steel surface conditions during application High moisture absorption and permeation
3-layer polyolefin	Excellent low temperature bend ability and impact resistance Yellow jacket—crosshead extrusion is seamless and lamination-free Excellent handling Excellent resistance to moisture	Prone to tenting across raised weld seams—best suited for ERW pipe Excellent corrosion resistance Can use spiral side extrusion and very thick (2–3.5 mm) thickness to virtually eliminate weld tenting—very expensive Side extrusion is prone to laminations and voids – process must be carefully controlled
Composite coating	Potential to cover external raised welds Cost-effective combination of the best characteristics of FBE and polyolefin Exceptional low-temperature bend ability and impact resistance Excellent handling Excellent corrosion resistance Excellent resistance to moisture Cathodic disbondment resistance Excellent adhesion	New technology with very limited field experience Prone to pinholes along weld neck—used only on ERW pipe Powdered polyolefin is more expensive than pellet form

requires the use of skilled operators and following sound procedures to be successful, otherwise wrinkling or tenting over the weld bead can occur.

11.12.1.4 Testing Requirements There are an extensive number of standardized tests for pipeline coatings available and an excellent detailed description of many of them can be obtained by referring to Papavinasam [47,48]. In essence, they are classified in five categories that for convenience have been summarized in Table 11.16.

11.12.1.5 Coating Damage and Repair Holidays in the pipe coating which are detected during construction are repaired by either applying a patch or painting on a two-part epoxy mixture. More extensive coating repairs are necessary when the pipe is exposed as a part of a direct assessment process. In this circumstance, it is usual to apply a tape coating to the affected area. When it is apparent that there are potentially serious problems with the effectiveness of a coating, for example, following an assessment of stress corrosion cracking vulnerability, it may be prudent to remove and replace the coating in its entirety. There are a number of

TABLE 11.16 CLASSIFICATION OF PIPELINE COATING TESTS

Property Test	Standards					Coatings						
	ANSI	ASTM	CSA	ISO	NACE	Coal Tar Enamel	Asphalt Enamel	PE Tape	2-Layer	FBE	3-Layer	Composite
Steel												
Surface Profile		•		•	•	•	•	•	•	•	•	•
Steel-coating interface												
Interface contamination			•		•	•	•	•	•	•	•	•
Adhesion	•	•	•		•							
Cathodic disbondment						•		•	•	•	•	•
Bendability/flexibility	•	•	•		•				•	•		
Coating												
Composition		•			•							
Gel time			•		•					•		
Particle size			•							•		
Total volatile vontent					•					•		
Porosity	•	•	•		•					•		
Viscosity		•	•						•		•	•
Flow		•	•						•		•	•
Softening point	•	•				•						
Shelf life					•					•		
Filler content		•				•						
Density/specific gravity		•	•		•				•	•		
Curing			•		•					•		
Thermal conductivity		•			•	•						
Tensile strength	•	•	•			•			•			
Sag	•					•						
Low temperature crack test	•					•						
Pliability	•					•						

(*Continued*)

proprietary techniques for performing over the ditch coating rehabilitation, which involves removing the old coating, cleaning, and preparing the surface of the pipe and reapplying the new coating.

11.12.2 Cathodic Protection

11.12.2.1 Impressed Current Systems This type of system is used to protect pipelines and associated facilities from corrosion by imposing a negative charge on the steel. Anodes are installed at specific locations along the right of way or at facility locations and maintain electrochemical potentials sufficient to protect the steel from corrosion. The circuit is composed of an external AC power source, a rectifier, a ground bed of anodes, a metallic connection from the anodes to the pipeline, and a common environment (the ground). These anodes are often made of high silicon iron or graphite which permits a large amount of current to flow from them in proportion to their own corrosion or consumption rate. Current leaves the anodes and travels through the ground before entering the pipeline at holidays or voids in the pipe coating. It then moves along the pipe to a thermite welded cathode cable which is connected to the rectifier. The rectifier contains meters to monitor the current output and the voltage output.

The advantages and the limitations of an impressed current system are as follows:

Advantages:
Can be designed for wide range of voltage and current.

- High ampere year output available from a single ground bed.
- Large areas can be protected by single installation.
- Variable voltage and current output.
- Applicable in high-resistivity environments.
- Effective in protecting uncoated and poorly coated structures.

Limitations:
- Can cause cathodic interference problems with adjacent pipelines.
- Subject to power failure and vandalism.
- Requires periodic inspection and maintenance.
- Requires external power which involves costs.
- Overprotection can cause coating damage.

TABLE 11.16 (CONTINUED)

	ANSI	ASTM	CSA	ISO	NACE	Coal Tar Enamel	Asphalt Enamel	PE Tape	2-Layer	FBE	3-Layer	Composite
Breaking strength	•					•						
Dielectric strength	•	•			•	•			•			
Insulation resistance	•							•				
Electrical conductivity		•			•	•						
Film thickness		•			•	•	•	•	•	•	•	•
Indentation hardness		•				•	•	•	•	•	•	•
Penetration resistance	•	•			•	•		•	•		•	
Water permeation	•	•	•		•	•	•	•	•	•	•	•
Blistering		•								•		
Chemical resistance		•	•		•				•	•		
Weathering		•			•				•			
Cohesion	•	•	•		•	•	•		•	•	•	•
Environmental stress cracking resistance		•				•	•	•	•	•	•	•
Resistance to oxidation						•		•	•	•	•	•
Compressive properties						•	•	•	•	•	•	•
Thermal expansion		•				•	•	•	•	•	•	•
Brittleness temperature		•				•	•	•	•	•	•	•
Coating soil interface												
Shear												
Peal test		•							•		•	•
Microbial resistance		•				•	•	•	•	•	•	•
Abrasion resistance	•	•			•	•	•	•	•	•	•	•
Impact resistance	•	•	•		•	•	•	•	•	•	•	•
Freeze thaw stability		•				•	•	•	•	•	•	•
Resistance to elevated temperature		•							•		•	•
Pipe soil interface												
Holiday detection		•			•	•	•	•	•	•	•	•

11.12.2.2 Sacrificial Anode Systems This type of system relies on galvanic reaction between the anodic material and the pipeline as its source of power. The anodes are constructed of magnesium, zinc, or sometimes aluminum. Current flow is from the anodes to coating holidays on the pipeline via the ground. The potential gradient caused by the current flow effectively prevents current from leaving the surface and hence prevents corrosion. Since all electrical circuits must be continuous in order to work, the current flows along the pipeline to the cathode cable connection a thermite weld. The circuit is completed by joining the cathode and anode cables.

The following lists the advantages and limitations of galvanic systems:

Advantages:

- No external power required.
- Low maintenance.
- No regulation required.
- Uniform distribution of current.
- Easy to install.
- Installation (of anodes at time of construction) can be inexpensive.
- Minimum of cathodic interference.
- Minimum right-of-way/easement costs.
- Anodes can be readily added.
- Efficient use of protective current.

Limitations:

- Limited driving potential.
- Low/limited current output/unit.
- Installation (of anodes after construction) can be expensive.
- Poorly coated structures require many anodes.
- Can be ineffective in a high-resistivity environment.

It might appear that galvanic systems would be the first choice for cathodic protection application since no external power sources or rectifiers are required. However, for extensive pipeline systems, the impressed current system is generally more practical. The major advantages of the impressed current system over the sacrificial anode system are:

- Its wide range of voltage and current output.
- The large area covered from a single location.
- It is effective in protecting poorly coated pipelines.

11.12.2.3 Typical Design Calculations The following is an example of the design for an impressed current cathodic protection facility. The estimated length of the 600 mm diameter pipeline to be protected is 40 km, and the external coating is a FBE. Field experience and attenuation calculations confirm that in the area where the pipeline is to be installed, the maximum protective range is 50 km for the cathodic protection installation. At a suitable site for the ground bed installation, the soil resistivity at anode burial depth and below the anodes is less than 5000 ohm-cm.

The current required after 20 years of service is estimated to be 0.000070 amps/m2. Hence, the total current requirement for this 40 km section of pipe is 5.3 amps which is calculated as follows:

$$\text{Total Current Requirement} = \text{Current Density} \times \text{Total Surface Area (DL)}$$
$$= 0.0007 \times \pi \times 0.6 \times 40000$$
$$= 5.3 \text{ amps}$$

The standard size of rectifier is 8 amps.

Silicon–chromium cast iron anodes will be used, each possessing an individual weight of 20 kg. Equation (11.25) can be used to determine the number of these anodes which will be required for a specified lifespan:

$$\text{N} = \frac{(\text{Life, years}) \times (\text{Size of Rectifier, amps}) \times (\text{Consumption Rate, kg/amps})}{(\%\text{ volume consumption}) \times (\text{Mass of anode, kg})} \tag{11.25}$$

In this case, a consumption rate of 0.45 kg per amp-year and a 60% volume consumption were assumed for the 20-year lifespan. Equation (11.1) indicates that six anodes will be required, i.e.,

$$\text{N} = \frac{20 \times 8 \times 0.45}{0.60 \times 20} = 6$$

The major components of the circuit resistance (R_T) are the anode-to-electrolyte resistance (R_A), the structure-to-electrolyte resistance (R_C), and the cable resistance (R_w).

There are various formulas available for determining R_A. The formula used is dependent on the ground bed installation configuration. In this case, the anodes are installed horizontally at a depth of 2.5 m, the center-to-center spacing will be 4.5 m and the canned anode diameter is 0.3 m. The equation for determining R_A in this example is as follows:

$$R_A = \frac{0.001588p}{L}\left[2.3 \ln \frac{4L^2 + 4L\sqrt{S^2 + L^2}}{DS} + \frac{S}{L} - \frac{\sqrt{S^2 + L^2}}{L} - 1\right] \tag{11.26}$$

where

R_A = anode-to-electrolyte resistance, ohms (2.0 ohms),
p = soil resistivity, ohm-cm (5000 ohm-cm),
L = length of installation, m (6 anodes × 4.5 m/anode = 27 m),
D = canned anode diameter, m (0.3m),
S = twice the depth of anode, m (2.5 m × 2 = 5.0 m)
In = natural logarithm.

The structure-to-electrolyte resistance (R_A) is estimated to be 0.05 ohms after 20 years.

$$R_A = \frac{0.001588}{27} \times 5000$$
$$\left[2.3 \ln \frac{4 \times 27^2 + 4 \times 27(5^2 + 27^2)}{0.3 \times 5} + \frac{5}{27} - \frac{(5^2 + 27^2)}{27} - 1\right]$$
$$= 0.05 \text{ ohms}$$

The cable resistance (R_w) is calculated by determining the length of positive and negative cable to be used, the wire size, and wire resistance. In this example, 130 m of positive and 50 m of negative (wire size is AWG #4) is used. Therefore, R_w equals 0.15 ohms (180 m × 0.000833 ohms/m).

Adding R_A = 2.0 ohms, R_c × 0.05 ohms, and R_w = 0.15 ohms, the total resistance (R_T) in this example is found to be 2.2 ohms.

The rectifier voltage can be calculated using Ohm's Law, where V_{REC} = 2.2 ohms × 8 amps × 1.2 (safety factor) = 21 volts. The Manufacturer's standard size is 24 volts.

The easement length is determined as follows. The first anode needs to be remote from the structure, usually at least 100 m away. The installation was determined to require six anodes with a spacing of 4.5 m, so the total ground bed length must be 127 m (round to 130 m).

The results of the design are:

- Size of rectifier (24 volts, 8 amps).
- Number of anodes required (6).
- Size of easement required (12 × 130 m^2).

11.12.2.4 Ground bed Types and Location Anodes can be placed, near the surface or at considerable burial depth 300 ft. (100 m). Those near the surface can be oriented either vertically or horizontally whereas deep ground beds are invariably created by installing the anode vertically. Normally, a vertical anode arrangement is preferred over the horizontal, but the latter is sometimes required if unfavorable soil resistivity conditions occur at depth. The choice of a shallow versus deep ground bed is often made based on the availability of land and/or the proximity of a number of other underground facilities to the pipeline to be protected. Since with deep beds the anodes are all stacked vertically into a single drilled hole, the footprint for the ground bed is quite small. This means a limited amount of surface land is required which is advantageous in congested areas and also reduces the acquisition costs of right of way. The ground bed can in fact be placed, at depth, directly below the pipe in the same right of way.

Furthermore, since the current discharge from the anode occurs at a considerable depth below the buried pipe, the potential gradient is not as extensive near the surface thus reducing the possibility of anodic interference with other buried utility structures. Deep ground beds therefore have a significant advantage when used in built up areas and on plant sites. Deep ground beds are installed by first drilling a borehole to the maximum depth required using a conventional water well drilling rig and a licensed drilling crew. As the borehole is drilled, a driller's log is maintained of the strata being drilled through, including their ability to store and conduct

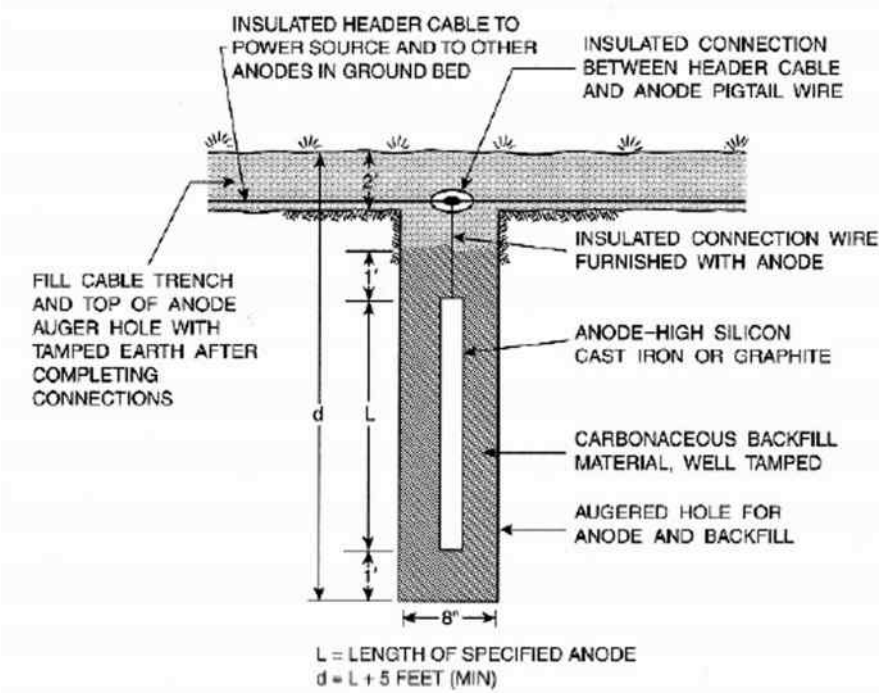


FIGURE 11.42 ANODE GROUND BED

water. The drilling depth varies from place to place but could be as much as 120 m. The anodes are lowered into the bore hole and coke slurry is pumped to the base of the hole through a stand pipe or temporary fill pipe. Approximately, 75% of the whole depth is filled with anodes and the slurry. The borehole is then filled with a bentonite drilling mud to within 2 to 3 m of the surface. Normally, the remaining portion of the hole is filled with native soils. Figure 11.42 shows a typical galvanic anode ground bed arrangement.

11.12.2.5 Cathodic Protection Monitoring Regularly excavating the pipeline is impractical, so corrosion technicians use special instruments to monitor the cathodic protection.

This is carried out by measuring the pipe-to-soil potential difference using a high input impedance potentiometer with a reference cell (usually a saturated copper/copper sulfate reference cell) and some type of metallic connection to the pipeline–a test lead.

A widely accepted standard for cathodic protection states that the potential difference between the pipe and the soil shall be no more electropositive than −950 mV for a standard saturated $Cu/CuS0_4$ reference cell. Also, a typical maximum allowable potential of −3000 mV (Cu/CuS04) is set to prevent adverse effects on some coating types.

To assess the status of the cathodic protection along the pipeline, two wire test leads are placed at regular intervals, usually every 3 km, and at locations of possible concern such as pipeline crossings, cased crossings, and river crossings. Two wires are attached as a safety precaution in case one of the wires becomes disconnected. The potential readings can be determined through an attachment to either wire. Typically, a four wire test lead is installed at insulation flanges, cased crossings, and pipeline crossings. Two wires are attached to each structure, which allow the monitoring of possible adverse effects from the foreign structure on the protected pipeline. If any effect is noticed, the test lead may be used to mitigate the problem.

Pipe-to-soil meters are permanently installed meters which monitor the cathodic protection. They are usually located at the ends of one pipeline system or in areas of high concern. The meters allow non-specialist technicians to easily monitor and record the cathodic protection status. All pipe-to-soil meters and rectifiers (volt and amp output) are monitored once per month. All test leads are monitored at least once a year to determine the electrical pipeline potentials. This survey provides a more accurate determination of the status of the cathodic protection along the entire length of pipeline than the monthly pipe-to-soil meter readings.

11.12.3 Corrosion Inhibition

Inhibiting the development of internal corrosion involves the elimination of one or more of the ingredients essential to the corrosion reaction. Internal coatings and linings can be used to isolate the corrosive fluids from the pipe wall. Dehydration and separation of water from the process stream will prevent the formation of acids from any dissolved gases.

The use of special chemical inhibitors results in a self-healing coating of the internal pipe surface offering protection from any acids present. In specific cases, pipe materials resistant to the type of attack expected may be selected prior to construction, and may be the most economic option over the life-time of the facility. Regular cleaning or pigging of the affected pipeline will remove any trapped condensed water and will break up any deposits which can harbor bacteria or produce stagnant conditions.

11.13 THIRD PARTY DAMAGE AWARENESS AND CONTROL

External interference, better known as mechanical or third party damage, is the major cause of transmission pipeline failures in Western Europe and on gas distribution systems in many parts

of North America. While mechanical damage often causes the pipeline to puncture, it can also result in metal loss through gouging the pipe surface or causing a geometric distortion through denting. A potentially very serious situation occurs if gouging accompanies denting, particularly if the line contact goes unreported. It is possible for a crack to develop, and grow, to a critical length at some time in the future, causing a delayed failure.

Mechanical damage by its nature is confined to the top portion of the pipe so particular attention must be paid to the results of geometric pig runs indicating denting in this portion of the pipe.

11.13.1 Line Marking and Locating

There are several preventative measures that can be taken to mitigate against damage caused by third party activity during design, construction, and subsequent operation. The most obvious of these that can be done during design is to use the appropriate wall thickness for the class location. In construction, it is important to ensure an adequate depth of cover over the pipe. As a minimum, this must meet code requirements, but is preferable to go further and check the farming practices in the area with respect to plough depth and the burial depth of any drainage tiles. Marker tape and the use of high tensile plastic netting located some distance above the top of the pipe are simple means of indicating the presence of a pipe even if somewhat imprecisely. Both are permeable and do not interfere with external scans of the pipe. It is good construction practice to provide slab or tile cover above the pipe at road and railway intersections, since these are potential locations for excavation and ditch cleaning. It is also essential to clearly mark the right of way at all crossings and boundaries and to alert third parties to the presence of pipelines before they commence any activity on the company's right of way. This is often referred to as the "First Call" or "Call before you dig" program. It involves company personnel accurately locating their line before giving permission for the third party to proceed.

11.13.2 Right of Way Patrols

Aerial patrols of the right of way, usually at two week intervals, can avert third party encroachment by looking for unusual activity, as well as providing one means of detecting possible leaks. At speeds of nearly 100 mph, helicopters flying at an altitude of 200 m can provide extensive coverage at reasonable cost. These costs can be shared by companies sharing a common right of way.

11.13.3 Remote Sensing of Leaks

The early detection of a leak is critical to the protection of people and the environment, there are also economic and potential social/legal consequences associated with a leak.

The four principal technical means available to the pipeline operator to detect a leak are as follows:

- detecting the noise emanating from the location of the leak;
- detecting the effect of spilled product on or close to the right of way;
- noticing pressure drops and flow changes on the line; and
- detecting a temperature drop on the line.

None of them are fool proof and it is salutary, if not a small comfort, for European pipeline companies to have 45% of their leaks discovered and reported by third parties [49].

Acoustic sensing devices have had some moderate success in pin-pointing the location of a leak while remote optical sensing of vapor releases has been shown to work. The "Listening ball" is one acoustic based method for leak detection, which has been used in liquids pipelines. The polyurethane ball has an aluminium core containing a power module, electronics and a memory card. Typically it has a diameter of about one third that of the pipeline, though its size can be influenced by factors such as the pipe diameter, and the size of any valves or appurtenances through which it must pass. It is inserted into, and withdrawn from, the pipeline using launcher/receiver traps and is in free flow, rolling along inside the pipe. As it moves, it listens for the sound of a leak caused by the pressure energy change as the leaking fluid expands though the hole.This data is recorded and post processed together with signals emitted by above ground markers attached to the pipe that help determine the position of the leak. The method claims to be able to locate small leaks to within ten feet.

Vapour sensing is a tried and true method of leak detection using trained dogs to sniff the ground above the pipe, although to provide total coverage it clearly requires the dogs to walk the entire length of the right of way. Using this method, leaks have been detected on pipelines buried as deep as 18 feet (6 m). A technological equivalent has been prototyped at small scale, involving burying tubes having a hydrocarbon permeable wall, just below the pipeline. The assumption is that when a leak occurs the hydrocarbons will accumulate within the tubes. Every 12 hours, or so, the tubes are flushed and highly detectors placed at end of the tube look for hydrocarbons wit. A variation of this approach is to use fibre optic cables placed above the pipeline, if it conveys natural gas and underneath the line, if it is carrying liquid hydrocarbons. Ordinarily light entering the cable is completely reflected within it. The amount of light reflected does however depend upon the refractive index of the cladding which changes when hydrocarbons are present.

The most common method of leak detection for liquids pipelines is computational pipeline monitoring. In this approach, real-time pressure, temperature, and flow measurements are taken and used in a transient model of the system to deduce a line, mass, or volume balance of the product. In simple terms, these methods determine the difference between the amount of fluid entering and leaving the pipeline system over a specified time period–the sampling time.

To be effective, the model has to account for the amount of fluid already in the line (the line pack) as well. Difficulty arises in that the line pack depends upon product density as well as the pipe volume and the density depends upon pressure and temperature so these have to be measured accurately and often. The line pack error can be quite high with batched products and for fluids whose density is very dependent on temperature (e.g., natural gas); so much so that it could mask any losses from the system. As an example, a 1% change in density can result in a 2% difference in volume flow rate on a liquids line.

The difficulty with computational-based leak detection system is their dependence upon frequent and accurate measurements. These are taken using Supervisory Control and Acquisition Data (SCADA) systems which for most pipelines were installed for a completely different purpose. The work around for this has been to develop real-time transient models which compute a running average over time and are set to alarm whenever a deviation from the normal pipeline state is suspected. This leads quite often to false alarms which must nevertheless be examined by the control operator. To reduce the number of such alarms, statistical processing techniques have been developed which apply a probability of occurrence test to time series data of flow differences. Sufficient

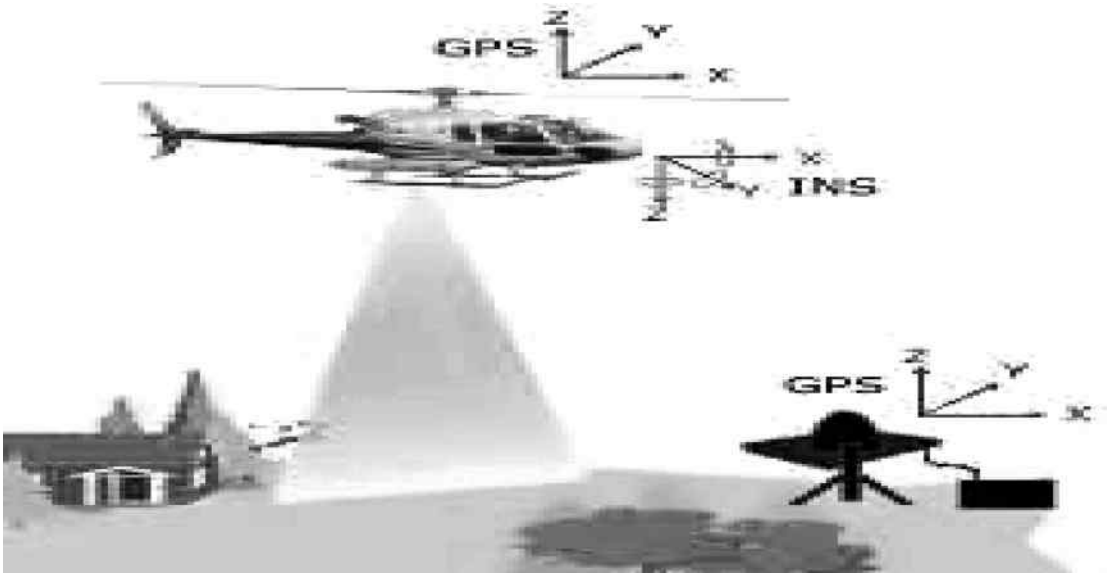


FIGURE 11.43 HELICOPTER BORNE LIDAR USED FOR SURFACE TOPOGRAPHY AND LEAK DETECTION

number of operational data must be analyzed quickly so as to cover a wide range of operating possibilities for the imbalances.

Light Detection and Ranging (LIDAR) is a useful remote sensing technology which uses laser light, in a manner similar to RADAR, to detect the presence and concentration of hydrocarbons in the atmosphere resulting from a pipeline leak.

Both the US Office of Pipeline Safety and a European consortium of gas pipeline companies (GERG) have separately commissioned and conducted research and development efforts directed toward developing airborne LIDAR as an effective means of detecting gas pipeline leaks. Differential Absorption LIDAR (DIAL) is used to measure chemical concentrations of methane in the atmosphere. DIAL uses two different laser wavelengths which are selected so that one of the wavelengths is absorbed by the methane molecule while the other wavelength is not. The difference in intensity of the two return signals can be used to deduce both the concentration of any methane present and the shape of the dispersion plume. Clearly in order to be successful, the light beam must be directed so as to pass through the hydrocarbon plume.

Both the US and European tests were very successful and indicated that very small concentrations of methane could be detected from measurements taken at an altitude of up to 150 m and cruising speeds up to 150 km/hr.

Historically, gas leak detection has depended upon using point sensing devices to physically sample the air above a pipeline right of way. This is a relatively slow process and difficult to do in urban areas. A recent improvement involves using a ground-based mobile optical methane detection system specifically designed for inspecting buried gas gathering, transmission, and distribution pipelines. The device is placed on a utility vehicle and can accurately detect the presence of methane at 1 ppm while traveling at modest speed along the right of way.

11.13.4 Remote Sensing of Encroachment

Encroachment may be monitored remotely and in real-time using fiber-optic sensors buried close to the pipeline (Fig. 11.44). A laser light in the fiber cable will detect the effect of vibration caused by above ground equipment or a ground disturbance in the immediate area. Research and field development undertaken in separate projects by the NYSEARCH group of the North East Gas Association and a consortium comprising Tokyo Gas and the seven companies making up the European Gas Pipeline Research Group (GERG), clearly demonstrated the practicality of this system [50]. Test locations were selected in urbanized areas which generate a wide variety of background noise such as that from vehicular traffic and railways.

The detection system has been able to discriminate between near-field (possible encroachment) and far-field sound sources enabling pipeline operators to intervene. While some false alarms are inevitable, this approach to monitoring third party interference takes advantage of new construction to lay a fiber-optic communications cable in a common ditch with the pipeline.

11.13.4.1 Satellite Surveillance There are two types of imaging systems available for use on earth observation satellites–optical systems and synthetic aperture radar (SAR). The former are highly dependent upon the weather and time of day, since they require a clear line of sight of their target area.

High quality optical images taken from space are being used in many parts of the world to assist with route selection for new pipelines. This has proved to be particularly helpful in regions where topographical maps are either inaccurate or non-existent or where there is some reluctance to conduct aerial reconnaissance. The required images are captured using high resolution optical satellites and are accurate to within a meter in black and white and 4 m for

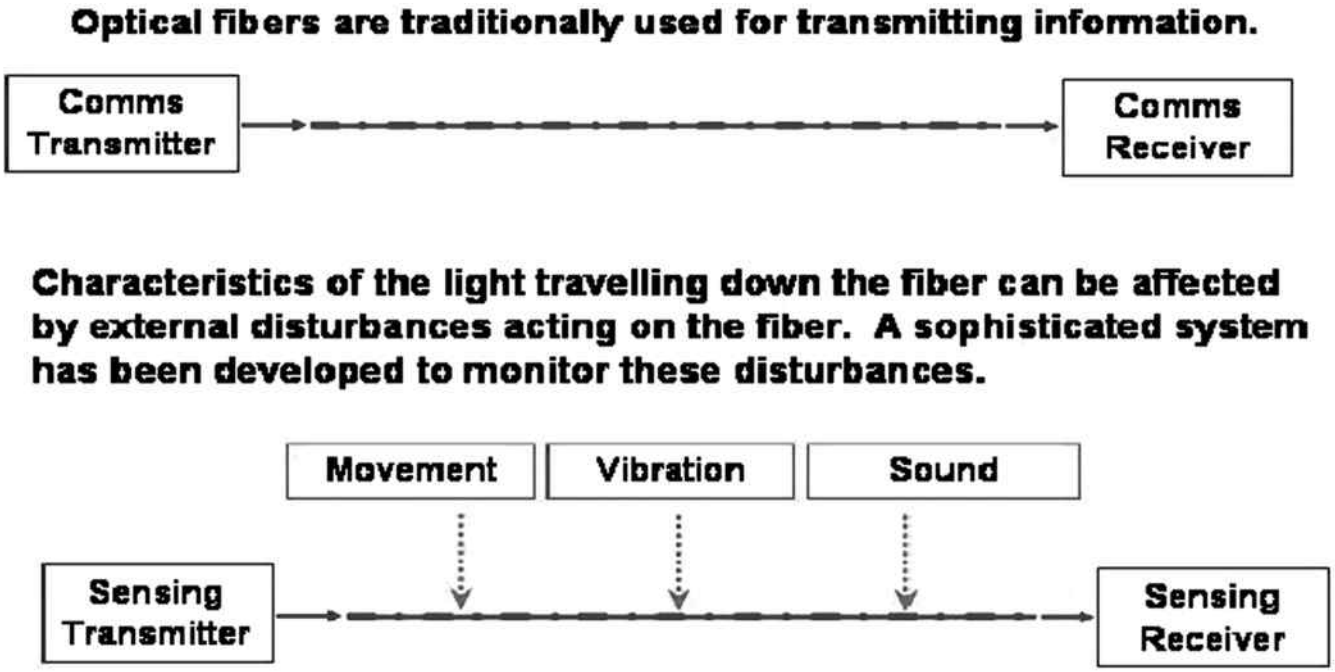


FIGURE 11.44 BURIED FIBRE OPTIC GROUND MOVEMENT SENSOR

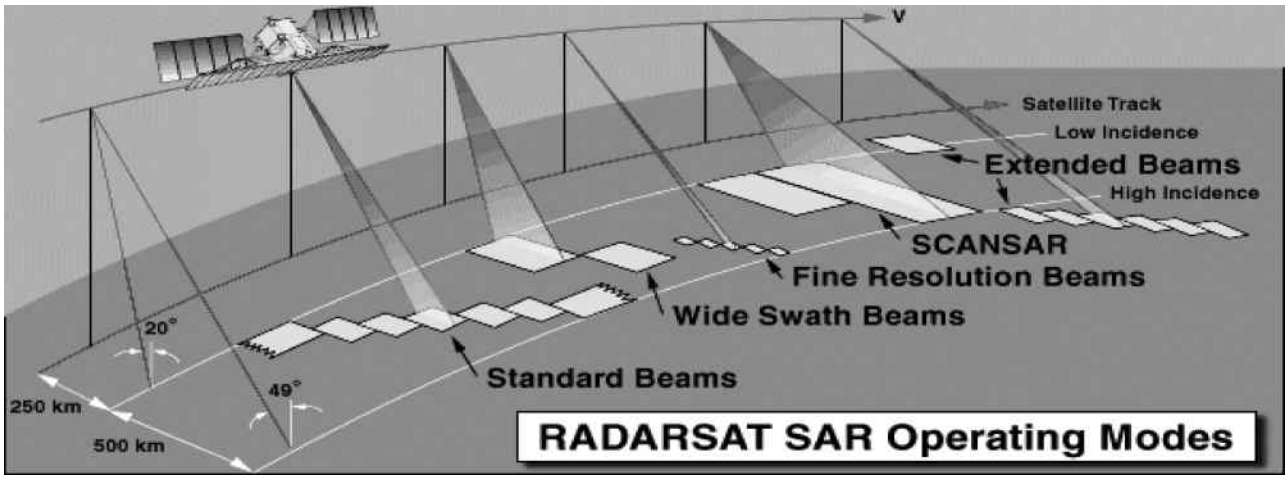


FIGURE 11.45 SYNTHETIC APERTURE RADAR SCANNING SWATHS FROM ORBITING SATELLITES

lower resolution color images. The on-board cameras record light in both the visible spectrum and in the very near infra red (VNIR).

VNIR is useful in identifying vegetation types which in turn can influence route selection. Features such as damaged vegetation can also be detected, opening up the possibility of detecting small oil spills on a right of way from space.

Optical images are expensive, costing around $3500 per dedicated image. Each image covers a lineal distance of approximately 9.8 km (6 miles) at the required resolution. There are currently few commercial pressures to cause this price to drop in the immediate feature.

Since SAR imaging is unaffected by darkness or cloud cover, it can collect data at any time. Furthermore, it can provide very accurate ground elevation information which makes it highly useful as a monitoring tool for ground movement and possible resulting damage on a buried pipe. A SAR satellite typically orbits the earth at a height of 800 km and constantly emits a microwave signal (a sine wave) from the satellite which is reflected off the earth's surface and returns to the satellite (Fig. 11.45). The time of flight very accurately determines the distance from the satellite sensor to the targeted area. The back scattered signal is processed to provide a black and white image made up of light and dark pixels.

To measure differential ground movement over a specified time period (the typical return period for the Canadian Space Agencies RADARSAT-1 satellite is 24 days), requires two SAR images of the same area, which are then compared using a process known as interferometry. The resulting phase difference between similar pixels on the two images can be used to evaluate the ground movement in three dimensions to within millimetres. These movements can then be monitored over time and used to determine a timely intervention to avoid over-straining of a buried pipe [51].

In a proof of principle project PRCI and in collaboration with two of its member companies TCPL and El Paso, demonstrated the potential for using SAR imaging to detect encroachment on a pipeline right of way. In 35 blind tests, equipment was moved on to a right of way and their radar signatures detected from SAR images 73% of the time. While the detection frequency was considered to be reasonably good, satellite over flight intervals of 28 days are inadequate to intervene and prevent encroachment [52].

An alternative approach to encroachment detection using optical and VNIR satellite imagery was undertaken as a joint industry project conducted under the auspices of the UK's Health and Safety Executive. Thirty 1×1 m^2 radar reflecting targets were placed along rights of way in farmland, suburban areas, and in moor land. They reported a success rate of detection of 82% except in suburban areas where it dropped to 67% because of the surrounding clutter [53].

11.14 SECURITY MANAGEMENT PROGRAMS

Pipeline facilities, like any physical asset, are vulnerable to vandalism and terrorist attack. The means of attack may be physical, in the form of mechanical damage to equipment or the pipeline, causing disruption of flow or loss of containment. Alternatively, computer control systems may be "cyber attacked" resulting in shut downs or malfunctions. It is possible for both forms of attack to be co-ordinated so as to occur simultaneously.

Oil and gas pipelines have been a favorite target for terrorists outside of the United States. Occidental's Cano Limon pipeline in Colombia, for example, has been bombed on 950 separate occasions since 1986, disrupting flows for months at a time and costing an estimated $2.5 billion in lost revenue. One of these attacks led indirectly to the deaths of over 100 people, when the leaked product migrated to a river and later caught fire near a town. In recent years, British police have thwarted a number of planned terrorist-inspired attacks on pipeline infra structure, while oil and gas pipelines have repeatedly come under attack in Iraq, Nigeria, the Sudan, Pakistan, and Myanmar.

Not all malicious acts directed toward pipelines are terrorist inspired; some are caused by disgruntled employees, while others are criminal acts directed toward seeking financial gain. In 1997, police in Texas prevented an attempt by Ku Klux Klan members, to bomb natural gas storage tanks as a diversionary tactic to facilitate a simultaneous funds raising robbery. More recently, an individual has been charged in Canada with plotting to blow up the Trans-Alaska pipeline, for personal profit by trading in oil futures. Figure 11.46 shows the result of a vandal's attack on the same pipeline carried out using a high powered rifle.

It is worth noting that in the United States, the criminal provisions under 49US 60123 as amended by the Pipeline Safety Improvement Act of 2002 (PL 107-355) [24] state that "a person knowingly and willfully damaging or destroying, or attempting to damage or destroy, an interstate gas pipeline facility or interstate hazardous liquid pipeline facility shall be fined ...., imprisoned for not more than 15years, or both."



FIGURE 11.46 A VANDALIZED ATTACK ON THE ALYESKA PIPELINE CAUSING MILLION OF DOLLARS OF ENVIRONMENTAL DAMAGE

While these provisions were primarily intended to deter unsafe excavator operators and vandals from damaging pipelines, they could also be applied to terrorists, or disgruntled employees.

All pipeline companies should have a corporate security management program. This program must be systematic, comprehensive, and proactive in managing security risks.

A pipeline security management program should contain the following elements:

i. A security policy setting out the senior management commitment.
ii. Well defined roles, responsibilities and authorities.
iii. A communication plan supportive of the pipeline security management program that is linked to a national security threat assessment system.
iv. Procedures to:
    a. identify and rank critical facilities and operations,
    b. evaluate vulnerabilities of facilities and operations,
    c. identify interdependencies of facilities and operations,
    d. manage physical security,
    e. manage secure information which, if compromised, would impact the operation of the pipeline system,
    f. manage the security of process control and SCADA systems,
    g. protect cyber information and supporting infrastructure,
    h. control physical access to security sensitive areas,
    i. provide well established hiring and termination procedures for security sensitive positions,
    j. screen visitors to facilities and operations.
v. Effective training programs.
vi. Performance monitoring to continually assess conformance with the security management program including mechanisms for corrective action and preventive measures in the event of nonconformance.

Ensuring the reliability and security of critical pipeline infrastructure is essential to today's modern economy. Recognising the importance of protecting critical U.S. infrastructure, President Obama proclaimed December 2012 as 'Critical Infrastructure and Resilience Month', continuing an ongoing debate for national cyber security standards. The emergence of highly complex computer 'worms' such as Stuxnet, Duqu and Flame and their deployment against the SCADA systems of power plants, refineries, electrical distribution grids, air traffic and rail control equipment have been well documented. So well documented in fact that the building blocks of the Stuxnet malware are now widely available, increasing rather than diminishing the threat of newer, 'better' malware. There was sufficient information publicly available in March 2009 to enable Popular Mechanics to publish an article entitled, 'How Hackers could take down a Natural Gas Pipeline.' Stuxnet targeted SCADA and distributed control systems and was designed to replicate itself while searching for industrial software specific applications that were being run under the Microsoft Windows operating system. It was successful in disabling approximately half of Saudi Aramco's refining capacity for a period of time. It also appears to have been responsible for an attack on RasGas in Qatar. With respect to pipelines, the Baku-Tbilisi-Ceyhan pipeline referred to in Section 11.2, came under attack in August 2009 causing a suspension of flow and redirection through the Russian-Baku-Novorossiysk pipeline. The Azeris alleged State sponsored infiltration of the system, by a foreign government. The U.S. Department of Homeland Security announced in April 2012 that they were aware of persistent tightly focused cyber-attacks on the Nation's natural gas transmission pipeline network over the preceding five months. Many instances of cyber-attack appear to go unrecorded for reasons such as corporate embarrassment; however it is evident that from publicly available data, that it is on the increase. Congress debated a comprehensive Bill in 2012 to address cyber security concerns but reached no consensus. Meantime there are very stringent compliance requirements in place from the Department of Homeland Security. Its Chemical Facility Anti-Terrorism Standards require companies that store and handle high risk chemical products, (which includes pipelines transporting hydrocarbons), to set performance standards when securing cyber systems. In addition, the Securities and Exchange Commission, issued disclosure guidance to publicly traded companies regarding the reporting of any significant cyber security event.

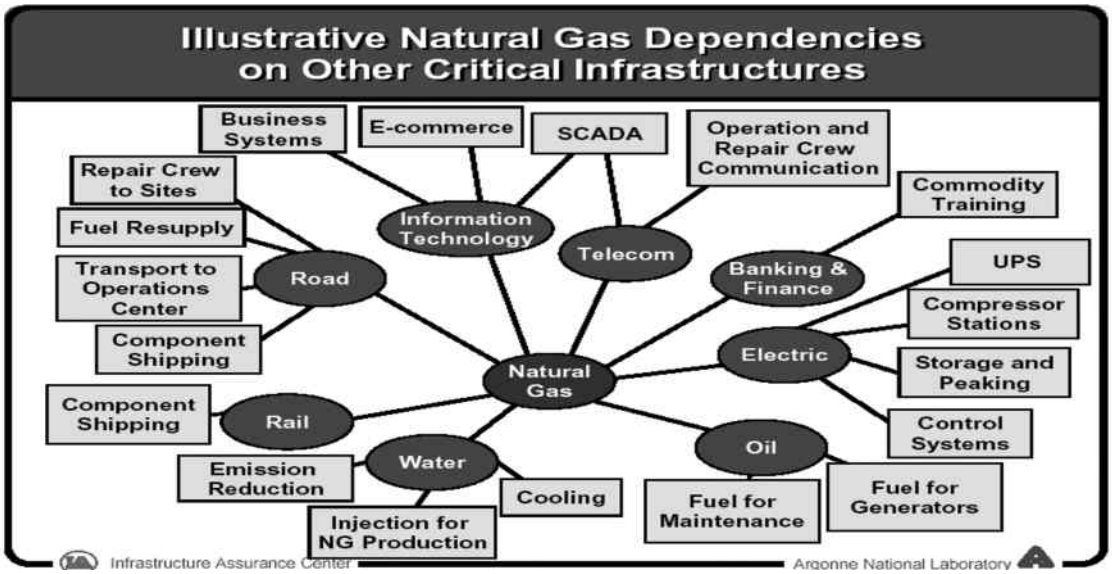


FIGURE 11.47 GAS PIPELINE SYSTEM DEPENDENCIES SOURCE ARGONNE NATIONAL LABORATORIES

The immediate physical response to reducing the likelihood of a successful infiltration is to increase the layers of protection. Segmenting networks, erecting firewalls, increasing anti-virus detection are straightforward protective measures to put in place. A more sophisticated approach to developing and testing communication protocols and more robust operating systems is also required. Incorporating the experience gained in developing military grade cyber security is an obvious next step that the Pipeline Industry Associations and the responsible Government Departments are currently pursuing.

11.14.1 Vulnerability Assessments

It is widely accepted that pipelines are inherently vulnerable although the physical risk is mitigated significantly by the fact that most of the facilities are buried. Rather than attempting to provide uniform protection for his entire system, it is prudent for an operator to be selective and emphasize security of especially vulnerable areas. These include tank farms, control centers, road, river and rail crossings, and pumping stations. Protection may be afforded by ensuring adequate surveillance, and in some instances, constructing physical barriers to forced entry.

Besides a direct attack on facilities, pipelines may be compromised indirectly through attacks on regional electricity grids or telecommunications networks so it is vital to assess the dependency of a pipeline on other critical systems. Figure 11.47 illustrates schematically one such interdependence for a gas pipeline system.

11.14.2 Government and Industry Response

The Presidential Decision Directive 63 (PDD-63) [54], issued during the Clinton Administration, assigned the lead responsibility for pipeline infrastructure security to the Department of Transportation. In November 2001, the Aviation and Transportation Act (PL107-71) came into effect, establishing the Transportation Security Administration (TSA) within the Department of Transportation.

This act gave the TSA a range of duties and powers, such as intelligence management, threat assessment, and security measures oversight. Section 403 of the Homeland Security Act of 2002 (P.L. 107-296) transferred the TSA to the Department of Homeland Security, from which time the agency has taken the lead as national transportation security manager for pipeline security to protect critical infrastructure from terrorist attack. In Canada, the NEB Act was amended to include security considerations and gave the NEB the authority to order a pipeline company or certificate holder for an international power line to take measures to ensure the security of the pipeline or power line, buildings, structures, or systems, including computer or communication systems, or methods employed to protect them.

Meanwhile, the pipeline operators have been active in securing their systems against vandalism and terrorist attack. The United States gas pipeline operators, for example, working under the auspices of the Interstate Natural Gas Association (INGAA) have formed a security task force to co-ordinate and oversee the industry's security effort. This has meant every member company having to designate a senior manager to be responsible for security matters. Together with the Department of Energy and TSA, the INGAA has assessed industry security programs and has begun developing common risk-based practices for common threat notification, incidence deterrence, detection, and system recovery [55]. The inter connectivity of the North American pipeline grid and the fact that a high proportion of the United States demand for oil and natural gas is met from Canada has caused the vulnerability assessment to extend to north of the border. The NEB recently completed a similar type of informal security assessment of regulated companies to that conducted by the INGAA. All of the companies assessed were found to have a security management program in place, while a few had completed a formal, documented, criticality assessment of their pipeline operations. Most companies use a formal, or informal, risk-based approach to managing security. Typically, security management programs are integrated into existing operational programs.

North American pipeline companies, in general, appear to have strengthened their contingency planning, business continuity and emergency response programs following the September 11th attacks in the United States. There is increased evidence of liaison with law enforcement, greater scrutiny of visitors and vehicles to pipeline property, and increased security awareness among employees. The industry has also started work on developing encryption protocols to protect SCADA systems from cyber attack [55,56].

11.14.3 Emergency Response Plans

Under United States Federal law, pipeline companies must have detailed and extensive emergency response plans in place, which have been approved by the Department of Transportation. Similar mandatory requirements are to be found in other jurisdictions. Common to all such plans is a requirement to have a central unified command center, available at all times, for handling emergency response. This center must be suitably equipped and staffed by personnel who have the authority to make operational, and financial decisions. (It is also good practice to have someone familiar with procurement and contracting procedures to be part of the central team, enabling local contractors to be hired, as and when needed. Specialist, on call, contract help should already be in place.)

The command center must contain current copies of the companies approved emergency response manual including regional and site maps. Many companies make use of their GIS database information to physically display maps of the affected neighborhood so that the presence of potential hazards, the location of other utilities, and the proximity of hospitals, etc.; can be quickly identified.

As with any safety emergency, the primary goal is to secure the site (to preserve evidence), protect the safety of the surrounding area and where possible, contain the release.

It is important that the company maintains detailed records that are readily accessible, of the contact information of local landowners who may need to be evacuated during an emergency. This is particularly the case in circumstances of a sour gas or natural gas pipeline leak or break, where the product, being lighter than air, will rise and dissipate very quickly into the surroundings. With sour gas, it may be more prudent to adopt a shelter in place policy rather than evacuation, but this needs to be determined before hand and shared with first responders.

Liquid releases must be quickly contained, to prevent extensive environmental damage, and the clean up operation should begin as soon as possible, using a variety of means to recover the product. Subsequently, measures will be required to remediate and monitor the affected areas, but this is generally outside the scope of the emergency response plan.

It is vital that company field personnel meet at frequent intervals with the local emergency service providers, throughout their system, to keep them fully informed of any changes made to emergency response procedures. It is also useful to stage regular table top exercises or replicate full alerts to test the adequacy of emergency procedures.

In addition to protecting the general public, the well being of company employees must also be ensured in the event of an uncontrolled product release at a facility. Natural gas is potentially

explosive and can displace air in confined spaces, it is therefore an asphyxiant. All buildings, which have pipeline or equipment that contain natural gas, must be equipped with gas detection devices.

These devices sound an alarm when a gas leak is detected and will automatically shut down the compressor station before the gas can reach a concentration that supports combustion or an explosion. In addition, all buildings must be equipped with smoke and fire alarms. The information from these gas, smoke, and fire detection devices is instantly communicated to a gas control office. If a fire does occur, because of a leak or equipment failure, in most cases the compressor station is isolated from the mainline and the fire is allowed to burn out. It is usual to locate chemical-based fire suppression equipment throughout compressor facilities.

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CHAPTER

12

DECOMMISSIONING TECHNOLOGY DEVELOPMENT

Harold E. Adkins and Anibal L. Taboas[1]

"Energy, environment, education, and economy are inextricably linked."

12.1 INTRODUCTION

This chapter presents an editorial view of essential elements for an effective D&D technology development program, and a compendium of challenges and needs from the perspective of technology end-users. The term "D&D" is used herein to describe a formal project management process that involves removal of real property from active or standby status and transition to a long-term end state (such as an industrial brown-field or an unrestricted green-field). Interim steps depend on the actual facility, and include characterization, deactivation, decommissioning, decontamination, demolition, waste management, and disposition or recycling of excess facilities and equipment. Life-cycle-cost analyses include surveillance and maintenance (S&M) while awaiting completion of D&D.

The Environmental Management Program (EM) of the Department of Energy (DOE) in the United States, and the Nuclear Decommissioning Authority (NDA) in the United Kingdom, manage the largest D&D programs in the world. Specific issue programs, such as disposition of submarines, have technology development components. Blurred lines of responsibility [S&T 2004] contribute to negligible effort to remediate intentional contamination.

The estimated cost to remediate the initial set of 19 facilities for which the NDA is responsible, increased from £55.8 B in 2005, to £73.6 B in 2008 [NDA 2008a].

EM indicates similar uncertainty in its ability to deliver as expected. The total estimated life cycle cost is envisioned to increase by $50 B, of which $40 B is associated with existing scope [DOE 2007].

Programmatic risk, regulatory issues, litigation, expanding scope, and unexpected technical complexity, all contribute to the increasing cost estimates. At the NDA as well as at EM, forgone opportunity is also a major contributing factor to the cost of delay. Other influencing factors include non-productive expenditures, bias against innovation, and limited incentives to accelerate transition to future missions.

D&D represents an increasing fraction of the cost of environmental remediation, but progress has been disappointingly slow. Unintended contractual biases against innovative technology include (1) the assurance of profit, particularly when fixed as a percentage of level of effort, and (2) the loss of competitive advantage through early disclosure of innovative technology and methods.

Funding for each component of D&D technology development (basic, applied, short and long term) has dwindled as to primarily support desk-type study. Fiduciary responsibility calls for continuously demonstrating that resources consumed by industry and government in the safe and compliant environmental remediation of radiological and nuclear facilities remain commensurate with the risks averted.

Reversing the funding trend requires integrated planning, strategic action, and effective communication. This includes: (1) developing and presenting the business case; (2) investing in high visibility projects of demonstrably high return on investment (ROI); (3) meeting customer-identified expectations; (4) tracking leading indicators and contractual incentives; (5) addressing key policy issues; and (6) transparency of action.

In a global economy, demonstrating a compelling ROI requires leveraging resources, such as through partnerships between DOE, NDA, and other funding sources, as well as with regulators, industry, and competing stakeholders.

Descriptions of D&D processes and of the state of the art on technology are readily available [ASME 2004]. After much repetition, little has actually changed [ITRC 2008] in the implementation of "authoritative" regulatory guidance.

12.2 NATIONAL EFFORTS

DOE issued a Cleanup Technology Roadmap identifying five program areas for strategic R&D initiatives [DOE 2008]. These are presented as Table 12.1 Deactivation & Decommissioning Strategic Initiatives of the US Department of Energy. The roadmap emphasizes timely insertion of existing commercially available technologies, buy-before-make approach to innovative technology, and local case-by-case justification for procurement. The designation of Savannah River

[1]Anibal L. Taboas was the author of the initial write-up in Second and Third Editions of this chapter that appeared in the "Companion Guide to the ASME Boiler & Pressure Vessel Code, Volume 2." For this current publication it is now updated by Harold E. Adkins. – Editor

TABLE 12.1 DEACTIVATION & DECOMMISSIONING STRATEGIC INITIATIVES OF THE US DEPARTMENT OFENERGY [DOE 2008]

Background Description	Initiative Details	Outcome and Benefits
Strategic Initiative: Adapted Technologies for Site-specific and-Complex Wide D&D Applications		
Focus on innovative application and timely insertion of existing commercially available technologies, processes and hardware systems to address the identified D&D risks and challenges. This is accomplished by adapting, modifying (for site-specific requirements), optimizing (for assured safety, better efficiency and lower cost) and demonstrating existing technologies and hardware to produce sufficient technical data and operating parameters to allow the site D&D operators to insert these technologies into their baseline operation with confidence. The initiative stresses the buy-before-make approach in the acquisition of improved technology. Developing enabling novel technologies, when justified by the site-needs and deployment schedule, will be considered on a case-by-case basis. This initiative supports development of an informed facility D&D strategy; enhanced verifiability of the efficacy of D&D operations; increased productivity and personnel safety of D&D operation; and facilitation of acceptable facility end-state.	***Characterization - Improve Characterization and Monitoring Technologies for Detection and Quantification of Penetrating Radiation, Radioactive, and Bio-Contaminants*** – Develop: portable real-time Beryllium characterization and monitoring devices for facilities and equipment; regulator-approved field characterization technologies and methods that would facilitate quicker decision-making regarding contaminant removal efforts for concrete; hot cell radionuclide inventory characterization technology; and technology for non-destructive characterization of waste containing high concentrations of radioisotopes that are difficult to characterize.	Deploy improved characterization and monitoring technology into the D&D baseline operations at applicable DOE-EM sites. Facilitate the development of effective facility D&D strategies based on defensible analysis and evaluation of facility conditions and hazards.
	Deactivation - Enhance D&D Technologies and Equipment – Develop: pool liner integrity monitoring technology; technology to treat sodium contaminated process components and equipment; improved contaminant control methods or fixatives for facility deactivation and/or in-situ closure; improved concrete scrabbling methods; and improved personnel protective technologies.	Deploy advanced technologies and processes allowing for safe deactivation of facilities.
	Decontamination - Advance Remote and Robotic Systems to Access and Assess Highly-Contaminated and Unsafe Old Facilities – Develop: remote sampling equipment for characterization/analysis of tank wall and bottom residue; package or skid mounted treatment units for treatment of inert status chemicals or radioactive components generated during facility deactivation or demolition; systems for the separation of massive equipment laden with radioactive material; and improved personnel protective clothing technologies.	Deploy advanced equipment that effectively accesses and characterizes unsafe facilities, and removes large and complex structures with limited operator involvement.
	Demolition - Improve Containment, Disassembling, Size-Reduction and Demolition Technologies – Develop: non-intrusive tools to detect and locate energized electrical lines or conduits in soils and in concrete; improved methods for dust suppression during demolition; underwater cutting, retrieval and packaging techniques; and improved methods for demolition of off-gas stack and associated facilities.	Deploy enabling demolition technologies and improved methods for better suppression and containment of dust and contaminants during facility demolition.
	Closure - Develop Technology for Informed End-State Strategies – Develop: canyon disposition (in-situ decommissioning) modeling and in-situ removal and stabilization of contaminants; the Permeable Adsorptive Liner (PAL) technology for onsite disposal of contaminated D&D construction debris, facility waste, small discrete waste sites, and pipelines; technology for surveying large area radiological and hazardous materials; real-time processing of survey data for end-state verification; and stand-alone powered environmental samplers.	Complete demonstrations of targeted D&D operations to demonstrate effective achievement of required end-state conditions.

National Laboratory as "EM corporate laboratory" might be indicative of renewed interest in interdisciplinary approaches.

A panel of the National Research Council (NRC), part of the Academy of Sciences, provides technical and strategic advice in the development of a roadmap that identifies technology gaps in the DOE program and a strategy to address them [NRC 2008]. In an interim report, the highly credible panel indicated that it is generally agreeable to the ongoing DOE effort, but that it does not represent an appropriate sense of urgency in resolving increasing technological challenges to effective D&D.

Preliminary observations of the NRC panel include:

(1) *The complexity and size of EM's cleanup task require the results from a significant, ongoing R&D program so that EM can complete its cleanup mission safely, cost-effectively, and expeditiously.*
(2) *By identifying the highest cost and/or risk aspects of the site cleanup program, the EM roadmap can be an important tool for guiding DOE headquarters investments in longer-term R&D to support efficient and safe cleanup.*

In its conclusions, the committee highlighted that:

. . . According to the range of technology needs presented . . . the committee judges that existing knowledge and technologies are inadequate for EM to meet all of its cleanup responsibilities in a safe, timely, and cost-effective way. Meeting current and future EM challenges will require the results of a significant, ongoing R&D program. [and] *. . . the medium- and long-term research component of EM's program has largely disappeared. Implementing the roadmap will require substantial and continuing federal support for medium- and long-term R&D for technologies focused on high-priority cleanup problems.*

In the UK, the NDA issued a draft Proposed Research and Development Strategy [NDA 2008a], which includes consideration of concepts such as a National Nuclear Laboratory, cooperation with the British Geological Survey, relationships with organizations in other countries (including EM, Electricité de France, and others), and the recent launching of a National Nuclear Skills Academy. Direct application to D&D technology development is evident in Table 12.2 Focus of R&D on the Various Phazes of the Provisional Implementation Plan [NDA 2008b].

TABLE 12.2 FOCUS OF R&D IN THE VARIOUS PHASES OF THE PROVISIONAL IMPLEMENTATION PLAN [NDA 2008B]

PHASE	Desk-based Siting Studies	Site Characterisation	Underground Investigation & Construction	Operation
RESEARCH DRIVER				
Be prepared for future phases	Prepare for site characterisation	Plan underground confirmatory tests		
Build Confidence in the Concept				
Address residual technical uncertainties	Generic	Site specific	Outstanding issues	
Long-term demonstration experiments	Initiate	Ongoing		Retrieval & closure issues
Support 'Upstream Optimisation'	React to proposals, but also be proactive		Additional issues	Retrieval & closure issues
Input into Disposal System Safety Case				
Data and processes – Near field	Main thrust	Outstanding issues		
Data and processes – Geosphere	Generic	Site specific	Confirmation & demonstration	Confirmation & demonstration
Work to support broader strands of DSSC	Support development	Site specific	Confirmation & demonstration	
Develop the concept for HLW & SF				
Recognise work of sister organisations Understand issues for a single facility	Main activity (not as mature as ILW)		Outstanding issues	
Contribute to the wider RWMD programme	Support as required; anticipate requirements			
Programme Review	Regular reviews, with high-profile reviews at key stages of the programme			
Key	Preparatory activities	Main period of work	Outstanding or newly arising issues	Other supporting or underlying activities

Technology development appears to have a greater role in procurement competitions in NDA than in EM. NDA, however, tracks private funding, which enables transparency in evaluating liabilities and the costs of delay. The environmental mission of the NDA is simpler than the EM mission, which contributes to the ability to focus technology development and interaction with stakeholders.

12.3 MANAGING RISK

It is common presumption that barring special circumstances such as "one-of-a-kind" facilities that require specific consideration, the tried and true construction management processes are appropriate for D&D projects this is not the case. The applicability of rules originally established for construction-type projects merits review. For example, the appropriate level of safety basis documentation for indefinite continued facility operation is intuitively different from what is required during short term de-construction.

Characteristics of exceptional projects include capture of best management and practical lessons-learned, a well-supported baseline, and strong scientific and regulatory competence. The voice of science remains largely unheard in risk-management. For example, significant investment to remediate small levels of tritium contamination to current drinking water standards [EPA 2008] might be fully compliant, but hardly a high-risk aversion or good science. Therefore, developing technology to capture minute quantities of tritium absorbed in reinforced concrete would not be of high priority.

On occasion, regulatory trends conflict with site-specific reality. The emerging trend for mercury, for example, is to establish target levels for total maximum daily load (TMDL) in surface water — the greatest risk being contaminant transport to surface water, and uptake of methyl mercury by fish, plants, and other animal life. The logic is remarkably simple and sound; meeting TMDL eventually leads to a safe and clean environment. Reality at the Y-12 National Security Complex, in Oak Ridge, TN, includes ~900 tons of mercury unaccounted for in buildings, soils, and other facilities. It is advisable for D&D planners to understand that remediation does not eliminate environmental liabilities, and that the linkage between source reduction and emerging TMDL stream protection standards exists only in a geological timeframe. A comprehensive regulatory strategy is of utmost importance in managing risk.

Mechanisms to identify and reduce technical risk and uncertainty, presuming timely and effective follow-up, include:

- Ground Truth—Disciplined local self assessment, documentation, and tracking of risk management actions
- Sponsor Assessments—readiness reviews that enable commitment to a defined baseline (including overall approaches and technology gaps)
- Independent (external) Peer Review—Aimed at facilitating capture of best practices and lessons learned, and timely incorporation of strategic decision-making
- External Assistance—Preferably, by best in class experts with applicable execution experience in similar projects, and dedicated to project enhancement.

The process of assessing technology needs and gaps, however, is susceptible to myopic and self-serving influence. Review by non-implementing independent peers is invaluable [TECH 2008], particularly when appropriately involving regulators. Risk reduction through strategic application of innovative products requires a demonstrable corporate level or "top down" commitment.

12.4 APPLIED D&D ENGINEERING MANAGEMENT

Securing a corporate commitment for long-range investment in D&D technology development requires demonstrated strategic management. Effectiveness of technology development can be quantified through valuation and tracking of changes in operational safety, schedule and cost, and averted risk. Influencing factors include:

- Technology development role in critical decisions
- Input to all D&D activities and funding priorities
- Countering the tendency to maintain infrastructure
- Accelerate/incentivize the disposition of real estate
- Investing in selective high payoff technology needs
- Application of Best Practices & Lessons Learned
- Transparency of action
- Independent assessment using Best Available Science
- Tracking few leading performance indicators
- Increased emphasis on overall risk management
- Re-capture missed regulatory opportunities
- Realize the economies of scale, e.g., conceptual design
- Implement appropriate contractual incentives
- Encourage multi-disciplinary approaches

12.5 TECHNOLOGY DEVELOPMENT NEEDS

A logical grouping of challenges and needs, as indicated by various sources of technology end-users appears in Table 12.3 A Compendium of Projected D&D Technology Development Needs. Previous similar surveys indicate that the stated needs have changed little over the last decade.

Expectations, however, change rapidly. There is a growing realization that some policies need revision based on changing technology and better understanding of risk. Some sites require use of web-based portals for hazards analyses that assure consideration of facility characteristics based on historical archives.

A sampling of the type of issues where resolution would facilitate an effective D&D program is presented as Table 12.4 Other Related Factors and Policy Issues. The following section highlights sample hypothetical development tasks, as illustrations of the intended interdisciplinary context of Tables 12.3 and 12.4.

12.5.1 Hypothetical Task: Asbestos

A large number of asbestos-containing buildings remain without characterization because of the lack of fast and easy methods to detect asbestos in air, surfaces, and building materials. Current approaches include sampling and microscopic characterization for qualitative determinations.

The aim is to develop instrumentation and fixatives for reliable field detection and/or passivation of asbestos contamination. Portable detection equipment would allow early determination on trigger abatement methods. One concept for such detection would be similar to spraying lumisol in order to detect the presence of human blood under ultraviolet light.

TABLE 12.3 COMPENDIUM OF PROJECTED D&D TECHNOLOGY DEVELOPMENT NEEDS

FIXATIVES

- Remote sprayer platform for fixative application
- Fixatives designed specifically for:
  - substrates with corroded or degraded surfaces
  - dust
  - internal ventilation systems
  - fogging properties
  - long term fixation (>500 yr)
  - high activity transuranics
  - non-flammable properties
  - In-situ stabilization of containers, tanks, & piping

REMOTE TECHNOLOGIES

- Retrieval technologies (e.g., tunnels)
- S&M, including non-intrusive roof inspection
- Removal of pool basin liners, cable trays, & piping
- Equipment removal in difficult/hazardous environments
- Hot cell decommissioning
- Characterization and removal of residues and hot spots in hard to reach places (e.g., concrete walls, effluent stacks, tanks, and pipes) such as with liquid metal and electromagnetic pumps for passive removal of actinide solutions
- Disposable multi-purpose remote operated robots

HAZARD DETECTION AND ABATEMENT

- Portable Be detection and monitoring
- Non-intrusive detection of utilities in soil & concrete
- Remote self contained and powered air monitors
- Passivation of anhydrous hydrogen fluoride transfer lines
- Capture /handling of bag house materials
- Asbestos abatement technology evaluation
- Information technology and control systems for underground hard wired lines (e.g., isolate, detect, bypass, activate, and/or de-energize utilities)
- Characterization of facilities unsafe for human entry, such as with 3 dimensional imaging technology
- Non-intrusive detection of energized electrical lines and conduits within soils or concrete

CHARACTERIZATION

- Rapid screening for segregation & sorting
- Free release surveys of rail lines
- Rapid field screening for hazardous materials such as lead, chromium, barium, asbestos, and beryllium
- Non-intrusive identification of deposits, obstacles, and "hotspots" in piping, ducts, and process equipment
- Characterization of elevated structures
- Waste not readily suitable for real time non-destructive analysis (e.g., containing highly mobile technetium-99)
- Low source intensity and field deployable radiographic imaging for early waste segregation and handling
- Assay and characterization of transuranics and hazardous material contamination in large structures, equipment, and containers

IN-SITU DISPOSITION

- Grout formulation & applications & product quality
- In situ entombment of pipes trenchless
- Techniques for automated repetitive drilling of reinforced concrete - a safety issue
- Identification of voids in large scale monoliths
- Models to determine long term stability of reinforced structures filled with grout and other stabilizers
- Applicability of permeable adsorptive liner technology for disposal of construction debris and discrete waste
- Encapsulation and near-term isolation of high contamination areas (including hot cells)
- Void space fillers for ducts, tanks, and pipes

CONTAMINATION CONTROL

- Containment envelopes to existing facilities involving drainage of contaminated fluids from basins and pools
- Large-area dry decontamination
- Improved methods of dust control, including no-water
- Contamination control specifically tailored to Pu-238
- Incorporation of recent developments in personnel protective clothing technology for increased freedom of movement, durability, and minimization of heat stress
- Gels tailored to capture selective surface contaminants
- Skid mounted vacuum systems that treat-to-inert status dust generated during deactivation or demolition

CUTTING TECHNIQUES

- Fast cutting in confined or limited spaces (such as in dismantling high-density polyethylene liners and drums, and for cutting large diameter metal piping where heat-intensive cutting is not appropriate)
- Underwater cutting, retrieval and packaging
- Lasers for size reduction

DEMOLITION

- Evaluate application of improved portable shielding
- Removal of high elevated structures & demolition
- Applicability of clean room technology, such as for dust suppression (e.g., tents, foggers, filtration, negative pressure, water spraying, electrostatic precipitators, and central vacuum systems)

TABLE 12.4 OTHER RELATED FACTORS AND POLICY ISSUES

MISCELLANEOUS	KNOWLEDGE MANAGEMENT
• Treatability studies for dielectric fluid • Pilot implementation for design/engineering guidance • Temporary roofing systems • General area cooling • Removal and transportation of heavy monoliths • Monitoring reactor pool liner integrity • Development of "as-built" & material take off • Large-area radiological mapping techniques with rapid survey data processing • Modular sole source utilities (e.g., electric, gas, potable, chilled and process water, compressed air, HVAC, and collection & disposition of sewer and process effluents)	• Portal-based Body of Knowledge, results of previously completed D&D work, and inventory of facility histories • Tracking and reporting of ALARA, Best Practices, and Lessons Learned, and availability via Hotline • Develop programmatic guidance for in situ D&D • Optimize risk management & work sequencing models • Review expanded application of explosive demolition • Current knowledge of regulatory considerations and options • Centralized source of reporting on status of corporate involvement with national and regional level regulators

METHODS AND POLICY ISSUES	
• Corporate approach to removal, retrieval, and passivation of asbestos [including transite panels, which contains non-friable asbestos] • Develop waste acceptance criteria for super-structured buildings (such as existing nuclear materials processing canyons), including models to determine the range of materials that can be disposed by grouting in place in a safe and environmentally compliant manner • Technical requirements in resolving "hard to deal with" items (such as large tritium-bearing beryllium reflectors, mercury-bearing radioisotope thermoelectric generators, and paper insulated lead cables)	▪ Re-evaluate the risk and benefits of decontamination, survey, and salvage of low-contamination bulk metals ▪ Determine a waste disposal path for all materials to ensure no orphan waste, and curtail the potential for new generation of waste with unusual characteristics ▪ Development of package or skid mounted treatment units for managing chemicals or radioactive components generated during facility deactivation ▪ Characterization, demolition, and removal of elevated equipment and structures (e.g., storage silos, off-gas effluent stacks, and underground storage tanks)

Potential innovative technologies include conjugating an asbestos binding small molecule [BIOTCH 2008] with simple dyeing methods to detect chrysotile, [ENVRS&T 2008] the most commonly used form of asbestos.

12.5.2 Hypothetical Task: Work Sequencing

Nearly all D&D activities require tradeoffs. The removal of an intense source of radiation deep inside a facility may require trading varying levels of cumulative dose among different sets of workers. Early removal may result in a cumulative dose, at the expense of re-contamination of a clean zone. Insertion of temporary shielding may be effective in lowering dose, but at the expense of increased waste volume. A few established radiation dose and shielding calculation models have demonstrated usefulness in sequencing work by helping to minimize overall dose and maximize the continued availability of the workforce through individualized limits.

Commercially available project management software are standard tools in the work force loading, scheduling, and cost estimating, and for defining a critical path to completion. Availability includes models to create and manipulate virtual images that replicate a facility's geometry, structure, composition, and other physical factors. Applications range from landscaping and kitchen design, to finite-element stress analysis of three-dimensional structures, including airplanes.

The aim is to integrate software applications (shielding/dose calculation models, project management software, and modeling of facility conditions) into a predictive tool. A few site-specific parameters (e.g., geometry, radiation and contamination levels, pathways, and shielding) could be leveraged into evaluating

options for sequencing, timing, and scheduling D&D, in a manner that minimizes cost and maximizes sieverts averted.

Expanded potential applications include merging with existing characterization tools [MARSIM], dynamic process hazard identification and analysis, and confirmation of successful completion of decontamination, through an electronic process guide that results in appropriate radiological instrumentation choices and points for final status survey.

12.5.3 Hypothetical Task: Roofing Systems

Innovative application of low-technology concepts may add value. Numerous deactivated facilities awaiting D&D have not been subject to adequate S&M – including many arched metal buildings, or "quansa" huts. Due to vintage, circa 1945, these facilities frequently involve peeling lead paint, PCB, and electrical wiring containing lead, asbestos, and other radioactive and/or chemical contamination. Some locations curtail respirator type work at these facilities to limit heat stress. Weather exposure accelerates emissions, which complicates environmental compliance.

The aim is to develop temporary roofing systems, and other engineered caps and barriers that contribute to S&M performance and minimization of effluents. Options to examine include air filled/ pressure controlled shelters similar to those used in winter for indoor golf courses, and tarps and other weather shields, to mitigate weather exposure and related migration. Large-scale temporary roofing may enable sequencing of demolition without maintaining the structural integrity of pre-existing roofs, and simplify containment of dust and other particulate emissions.

12.6 CONCLUSIONS

While basic and applied D&D engineering and technology development have played a crucial role in many past successes, a decade of cost creep and funding cuts has decimated ongoing national programs.

Developing an integrated D&D technology development roadmap is a useful component of a disciplined management approach. Technology needs have not changed significantly; however, opportunities and expectations change rapidly.

Reversing the funding trend requires integrated planning, strategic action, and effective communication. This includes: (1) developing and presenting the business case; (2) investing in high visibility projects of demonstrably high return on investment (ROI); (3) meeting customer-identified expectations; (4) tracking leading indicators and contractual incentives; (5) addressing key policy issues; and (6) transparency of action.

Society needs to know that it is getting is a reasonable ROI. The NDA planning effort yielded greater understanding of the underlying cost and vulnerabilities, but the effect of resulting management changes remains unclear; therefore it maintains a current rating of "peer perform." For various reasons, the EM D&D Technology Development effort is poised for optimism and greater efficiency; therefore, the current rating changes from "underperform" to "perform."

It is neither complicated nor counter-intuitive: globalization causes energy, environment, education, and economy to remain inextricably linked; and an earned corporate level "top down" commitment remains essential for successful strategic R&D investment.

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CHAPTER

14

SEISMIC PROTECTION FOR PRESSURE PIPING SYSTEMS

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14.1 INTRODUCTION

The objective of this chapter is to provide some highlights on the requirements, analysis, and issues related to the seismic protection of piping systems. Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50) Appendix A [1] contains General Design Criteria for Nuclear Power Plants. General Design Criterion 2, Design Bases for Protection Against Natural Phenomena under Group I of 10 CFR 50, mandates that structures, systems, and components (SSCs) important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches, without loss of capability to perform their safety functions.

The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated; (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena; and (3) the importance of the safety functions to be performed.

10 CFR Part 50 .55a(b)(1)(iii) addresses the codes and standards to be used in seismic design of piping for ASME Section III, Division 1 Code Classes 1, 2, and 3 safety-related piping. Therefore, it is essential that the piping systems in nuclear power plants are adequately designed protecting them from seismic events using the appropriate codes and load combinations.

The causes of the damage and failures observed in power plant piping due to earthquakes can be summarized into three main categories: 1) Seismic Anchor Motion, SAM; 2) Spatial Interaction; and 3) Corrosion and Erosion. The mechanisms which lead to these damages and failures can also be summarized into three categories as determined by tests 1) seismic stress ratcheting, 2) fatigue, and 3) plastic instability or plastic rupture. (NUREG/CR-6240, "Application of Bounding Spectra to Seismic Design of Piping Based on the Performance of Above Ground Piping in Power Plants Subjected to Strong Motion Earthquakes" [2].

This chapter presents the following topics: (1) an overview on seismic analysis of piping systems, (2) recent changes to the Section III of the ASME Boiler and Pressure vessel Code [3] rules accepted by the United States Nuclear Regulatory Commission (USNRC) with conditions, and (3) GI-199 [4] issue related to seismic input to nuclear plants in the central and eastern United States (CEUS) (Implications of *Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants.*)

14.2 SEISMIC HAZARD

Regulatory Guide 1.165 [5], "Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground Motion," developed in the early 1990s, specifies a reference probability for exceedance of a safe-shutdown earthquake (SSE) ground motion (i.e., seismic hazard) at a median annual value of 1E-5. This reference probability value is based on the annual probability of exceeding the SSEs for 29 CEUS nuclear power plant sites, and it is used to establish the SSEs for future nuclear facilities. Based on results from the work performed by the United States Geological Survey (USGS) in 2004, it appears that the reference probability for the 29 CEUS nuclear power plant sites has increased to about 6 to 7E-5. Information summarized by the USGS as part of the National Seismic Hazard Mapping Program indicates that the estimated likelihood of seismic activity (i.e., seismic hazard) in some CEUS locations has increased from previous estimates. The general consensus and the crux of the issue is that the seismic input to plants in the central and eastern US (CEUS) may have more high-frequency content than estimated in the past.

This seismic update included new Electric Power Research Institute (EPRI) models to estimate earthquake ground motion and updated models for earthquake sources in the CEUS, such as around Charleston, South Carolina, and New Madrid, Missouri.

A NUREG on Central and Eastern United States Seismic Source Characterization (CEUS-SSC) for nuclear facilities, NUREG-2115 [6] was published in January 2012. Consensus seismic-hazard estimates (a product of a joint USNRC, U.S. Department of Energy, USGS, and EPRI project) will become available in the near future (sometime in 2015). These consensus seismic hazard estimates will supersede the existing EPRI, Lawrence Livermore National Laboratory, and USGS hazard estimates used in the GI-199 safety/risk assessment.

The ability of a plant's SSCs to successfully withstand an earthquake beyond the required design-basis level was demonstrated based on the reduced scope seismic margin analysis

performed by several operating nuclear plants to obtain seismic margin assessments (SMAs) as noted in NUREG/CR-6926 [7]. The limited scope screening analysis concluded that the seismic designs of operating plants in the CEUS provided adequate safety margins (42% to 147% providing factors of safety of 1.42 to 2.47 as indicated in Ref. [7].

In addition, as noted in EPRI Report NP-5617 [8], worldwide performance data from fossil, nuclear, and other industrial facilities that experienced earthquakes indicates that above ground welded steel piping not designed for seismic loading (but designed to resist pressure loads and weight loads due to normal gravitation can easily withstand seismic inertial loads from an earthquake with ground motions up to 0.5 g. The study identified seismic anchor movement, system interaction, and corrosion as the major causes of piping failures.

Seismic design considers a combination of either SSE or OBE and plus other loads under different conditions. Large safety margin was demonstrated as noted by the margins mentioned previously from post-earthquake investigations at the North Anna, Kashiwazaki, Fukushima, and other Japanese plants. It has been concluded from GI 199 safety/risk assessment evaluation that there are no imminent seismic safety concerns for US nuclear power plants (NPPs) even if their SSE levels are exceeded during an earthquake. Rigorously designed structures, systems, and components (SSCs) have large safety margins, as noted above, to resist earthquake ground motion. Performance of safety-related SSCs in nuclear power plants (NPPs) during large earthquakes around the world has demonstrated the validity of the above conclusion. The March 11, 2011 earthquake that affected Fukushima Daiichi nuclear plant units exceeded the design basis earthquake. The design g level for unit 2 was 0.446 g, while the earthquake caused a maximum acceleration of 0.561 g. The structures, systems, and components at Fukushima-Daiichi nuclear plant units withstood the March 11, 2011 earthquake performed well with no significant damage, but the serious damage was caused by the tsunami that followed.

Based on the March 11, 2011 Fukushima earthquake, the August 23, 2011 earthquake near North Anna plant in Virginia, and revised seismic hazard estimates for Central and eastern United States, there is a need to evaluate the seismic spectra used in the original design of nuclear power plants for beyond the design basis earthquakes. On August 23, 2011 at 13:51:04, a magnitude 5.8 g earthquake occurred, which affected North Anna NPP. The epicenter of the earthquake was located at Mineral, Virginia (37.944°N, 77.942°W), at a depth of 3.7 miles. This location is approximately 11 miles South-South East (154°) from the North Anna Nuclear Power Plant (NANPP). The Design Basis Earthquake (DBE) g values at NANPP are 0.12 g for structures, systems, and components (SSCs) founded on top of rock, and 0.18 g for SSCs founded on top of soil. These design values were exceeded by the peak ground acceleration of 0.26 g recorded during the 2011 earthquake near NANPP. Post-earthquake investigations at the North Anna NPP further confirmed that the SSCs overall performed satisfactorily; however, one of the Emergency Diesel Generator developed a coolant leak.

Operating plant seismic hazards were characterized deterministically based on historical records. Recent new reactor licensing activities, using a probabilistic seismic hazard analysis, identified higher seismic hazard estimate for those co-located operating reactor sites, which are existing operating plant sites, where new reactors are planned. A request for licensees to re-evaluate the seismic hazard was initiated by the Generic Issue GI 199 but was subsumed by a recent 10 CFR 50.54f NRC Letter [9] request as a result of lessons learned from the Fukushima nuclear accident. The reader is directed to refer to chapter 30 for additional details on the 50.54f NRC letter. The NRC letter 50.54f requests that Nuclear Power Plant (NPP) licensees re-evaluate the seismic and flooding hazards at their sites against current NRC requirements and guidance and, if necessary, to perform a risk evaluation. GI 199 issue is included in the 50.54f letter.

14.3 SEISMIC ANALYSIS OF PIPING SYSTEMS

ASME Code Classes 1, 2, and 3 piping systems are required to be analyzed for seismic loading and shown to be structurally adequate to maintain pressure boundary integrity for the applicable load combinations. ASME Code Class 1 piping systems require explicit fatigue analysis, while Code Classes 2 and 3 piping systems do not require explicit fatigue analysis. Typically, two different levels of seismic loading, known as Operating Basis Earthquake (OBE), and Safe Shutdown Earthquake (SSE), are considered. However; if OBE is less than or equal to $^1/_3$ of SSE, then OBE need not be explicitly considered. Seismic Inertia effects as well as seismic anchor motion (SAM) effects must be considered in the piping analysis.

In general, seismic analysis of piping systems is conducted using seismic response spectra inputs for the applicable floor elevations, at which the piping is supported from. Very rarely, time history analysis is performed for seismic loading. Piping analysis using response spectra seismic loading is a linear elastic analysis, which means that neither geometric nor material non-linearities are permitted. Geometric non-linearities are large clearances or gaps at the pipe supports, and single acting supports. Material non-linearities include plasticity, visco-elasticity of the materials.

The licensing basis commitments must be followed in selecting the applicable edition and addenda of the ASME B&PV Code Section III and the code cases that have been approved by the USNRC with or without limitations and additional requirements. The equations for combining stresses and the allowable stress criteria have also changed in certain code editions and addenda, and therefore plant-specific licensing bases must always be reviewed and utilized. Any deviations from licensing bases have to be based on proper reconciliation.

For Class 1 components and piping systems, the ASME B&PV Code, Section III, Division 1 contains Subarticle NB-3200, Design by Analysis, (detailed analysis approaches like using detailed Finite Element Analysis technique), or Subarticle NB-3600, Design by Rule (simplified but somewhat conservative equations) for design of Code Class 1 piping systems. In general, piping analysis is normally performed utilizing NB-3600 for Code Class 1 piping systems, and Subarticles NC-3600 and ND-3600 for Code Classes 2 and 3 piping systems, respectively, by utilizing design by rules technique. Occasionally, NB-3200 design by analysis technique is used for special situations.

Special purpose piping stress analysis computer programs have built in stress intensification factors (i) stress indices (B, C, K) and piping equations. The results from three orthogonal direction earthquakes, and modes up to 33 HZ, and zero period acceleration (ZPA) or static effects above 33 HZ are combined in accordance with RG 1.92 [10].

Piping systems have complex requirements. Thermal expansion considerations require a flexible piping system, while seismic considerations require rigid piping system. In general, less number of rigid supports in a piping system is beneficial in keeping normal thermal expansion stresses low but contributes to higher seismic stresses, and vice versa. Thus, supporting thermally hot piping systems is very challenging as one has to carefully balance the number of rigid supports to simultaneously satisfying thermal and seismic requirements.

Snubbers provide support to the piping system for seismic loading without interfering with thermal expansion when they function properly. However, sometimes, these snubbers malfunction lock up prematurely and impede thermal movements. Therefore, snubbers are required to be periodically inspected and tested adding to the costs. Thus, it is preferable to minimize or avoid the use of snubbers if at all possible. The analyst must exercise his expertise based on his experience in coming up with optimum support system for the piping system. Further, the support types and locations chosen should be practical to build the appropriate support based on the availability of the building steel, columns, floors, embedded plates, and others. Longitudinal pipe bracing requires the use of a pipe clamp, riser clamp, welded lug, or other hardware that positively attaches to the pipe to prevent slippage. Friction connections, such as U-bolts, should not be used for longitudinal restraint because they are especially slip-prone.

Building massive support structures not only impedes the access to other safety components in the vicinity but also increases the costs significantly. Obstructing or impeding the thermal and other movements of nearby systems should also be avoided. The movements of the pipes in proximity moving toward each other during operating conditions need to be evaluated for interference.

14.3.1 Geometry of Piping System

A finite element model of the piping system is constructed using straight pipe beam elements, elbow elements, mass elements for valves, flanges, and other concentrated masses from the layout of the piping system and proposed support scheme considering the feasibility for support locations. All of the inline components, such as reducers, tees, flanges, and any eccentric masses, such as heavy valve operators, should be captured. The code-defined stress indices and stress intensification factors for welds, elbows, tees, reducers, branch connections, and any other special fittings are applied to the specific locations. The model should be fine enough to capture the geometric details and represent mass distribution accurately in accordance with the routing. Connected branchlines should be included in the seismic analysis. Special purpose finite element programs specific for piping system analysis makes the modeling effort simpler.

14.3.2 Geometric and Material Properties

Since seismic analysis is generally a dynamic analysis, the mass and stiffness of the piping system has to be correctly captured. The appropriate pipe size (diameter, wall thickness), the pipe material density, contents (fluid density), any insulation thickness and density should be specified. The material properties include the mass density, modulus of elasticity, Poisson's ratio, and the design stress intensity and allowable stress values, as applicable. The metal cross-sectional area, area moment of inertia, and torsional moment of inertia are calculated by the program based on pipe diameter and thickness.

14.3.3 Boundary conditions

The piping system is supported by rigid supports (struts, axial supports, lateral supports, guides, box supports with very small gaps ($\leq$ 1/16 in.), dynamic supports, such as mechanical or hydraulic snubbers, and in-line anchors, and terminal anchors (physical anchors, equipment nozzle connections, containment flued head anchors). Rod hangers, spring hangers do not provide seismic support to the piping system.

14.3.4 Seismic Loading Input

The seismic excitation to the piping system is through the input of the applicable floor response spectra of proper damping for elevations where the piping system is supported. This may involve several elevations. Most of the nuclear plants analyze for seismic input from three directions, namely, North-South (N-S), East-West (E-W), and Vertical. Therefore, response spectra for three directions for each elevation are required. Some old vintage plants based on their licensing basis considered two directions, namely one horizontal, and vertical (N-S and Vertical, or E-W and Vertical).

There are two options for seismic input: (1) enveloped response spectrum which uses envelope of spectra based on elevations involved for each direction including the nearest floor below, all the intermediate ones, and floor above as applicable for each of the three directions, and (2) Independent Support Motion: instead of conservatively using envelope of response spectra, the piping system is divided into zones based on floor elevations or structures (higher floors, lower floors, intermediate floors, reactor building, auxiliary building, etc.) from which the piping is supported, and the applicable spectra for the specific zones are input.

14.3.5 Damping

Damping is a measure of a structure's ability to dissipate energy as it responds to dynamic excitation. For convenience, damping is usually assumed as viscous in nature. Higher damping values result in lower dynamic response of the structure. The practice, followed in modal response spectrum dynamic analysis for seismic inertia loading effects, is to express damping as a percent of critical damping. Damping is an effect that reduces the amplitude of oscillations in an oscillatory system, and the damping value when the system returns to equilibrium as quickly as possible without oscillating is called critical damping. Therefore, the damping values used in analysis should be realistic, typically established based on testing. In the 1960s and 1970s, very conservative damping values of 0.5% critical were used in seismic analysis of piping systems using response spectra. In 1973, the USNRC issued Regulatory Guide 1.61 [11], "Damping values for Seismic Design of Nuclear Power Plants," that specified 1% of critical damping for OBE, and 2% of critical damping for SSE seismic analyses of piping systems of NPS 12 and smaller piping. The ASME Code Case N-411 [12] issued in 1986 specified variable damping values: of 5% of critical damping for frequencies between 0 and 10 Hz; linearly decreasing damping from 5% to 2% of critical damping for frequencies between 10 and 20 Hz, and 2% of critical damping for frequencies above 20 Hz for use in both OBE and SSE analyses. The NRC accepted the Code Case N-411 but placed some conditions on its use. Later on, in 2007, the NRC revised damping values in Regulatory Guide 1.61, Revision 1, allowing damping equal to 3% of critical damping for OBE and 4% of critical damping for SSE for seismic analyses of piping systems. The NRC has not accepted 5% of the critical damping for OBE and SSE analyses of piping systems proposed

in Table N-1230.1 of Appendix-N of ASME B& PV Code, Section III, and Division 1 [3].

14.3.6 Alternate Seismic Rules (New)

EPRI TR-102792 [8, 13], Piping and Fitting Dynamic Reliability Program, 1994. The ASME B&PV Code Section III for design of nuclear piping includes requirements for dynamic and seismic loads dating back to the late 1960s. Researchers from EPRI have conducted an extensive experimental program to measure the failure modes and margins for dynamic loading on piping systems and components. Forty-one (41) component tests to failure included tees, elbows, reducers, nozzles, and integral attachments. Dynamic tests under resonant conditions showed that pressurized piping did not fail by ductile rupture even though the imposed loads were well in excess of the static collapse loads. The failure mode of piping under high reversed dynamic loading was observed to be fatigue, ratcheting, or a combination of the two, and not plastic collapse as was assumed by the ASME Code in 1960s. This led the ASME to propose revised or new seismic rules (alternate rules) in 1994 addenda that can be used as an alternate to the existing seismic rules. The NRC did not agree with these new seismic rules, and the ASME revised those in 2006 Addenda, and the NRC accepted those with some conditions. The 2011 addenda incorporated the NRC conditions regarding Do/t limitation of 40 or less and consideration of piping moments from earthquake when OBE > 1/3 SSE. The ASME Code contains two approaches for seismic evaluation of piping systems, the traditional approach, and the alternate (new seismic) approach. In the new seismic rules, seismic is considered as a reversing dynamic load, and checked by itself with some requirements.

14.3.7 Code Class 1 Piping

Only highlights are presented here, and for complete details, the readers should refer to Paragraphs NB-3652 through NB-3656 of Subsection NB of ASME Section III of the Boiler and Pressure Vessel Code. There are additional evaluations based on equations (10), (11), (12), (13), (14), and thermal stress ratchet in NB-3600, which are not discussed here for simplicity as seismic is the focus of this topic. Note that when Level A & Level B Service Limits are specified in the Design Specification, they require primary plus secondary stress range and fatigue evaluation which includes OBE seismic inertia and SAM loads.

Refer to Paragraph NCA-2142.4 for Design, Service, and Test Limits[3].

The primary stress intensity limit is satisfied if the requirement of NB-3652 eq. (9) is met:

14.3.7.1 Traditional approach When reversing dynamic loads (seismic) are combined with non-reversing dynamic loads: This traditional approach is applicable for $D_o/t_n \leq 100$ for B and C indices, and $D_o/t_n \leq 50$ for B indices.

$$B_1 P D_o/(2t) + B_2\, D_o M_i/(2I) \leq 1.5\, S_m \qquad \text{Eqn. 9-Design}$$

$$B_1 P D_o/(2t) + B_2\, D_o M_i/(2I) \leq \text{smaller of } 1.8\, S_m \text{ or } 1.5\, S_y \qquad \text{Eqn. 9-B}$$

$$B_1 P D_o/(2t) + B_2\, D_o M_i/(2I) \leq \text{smaller of } 2.25\, S_m \text{ or } 1.8\, S_y \qquad \text{Eqn. 9-C}$$

$$B_1 P D_o/(2t) + B_2\, D_o M_i/(2I) \leq \text{smaller of } 3\, S_m \text{ or } 2\, S_y \qquad \text{Eqn. 9-D}$$

where

B_1, B_2 = primary stress indices for the specific product under investigation (NB-3680)
D_o = outside diameter of pipe, in. (mm) (NB-3683)
I = moment of inertia, in.^{4} (mm^4) (NB-3683)
M_i = resultant moment due to a combination of Design Mechanical Loads, in.-lb (N·mm).

All Design Mechanical Loads and combinations shall be provided in the Design Specification. In the combination of loads, all directional moment components in the same direction shall be combined before determining the resultant moment (i.e., resultant moments from different load sets shall not be used in calculating the moment M_i). If the method of analysis for earthquake or other dynamic loads is such that only magnitudes without relative algebraic signs are obtained, the most conservative combination shall be assumed.

P = Design Pressure, psi (MPa)
S_m = Allowable design stress intensity value, psi (MPa) — ASME Section II, Part D, Properties [3]
t = Nominal wall thickness of product, in. (mm)
S_y = Yield strength, psi (MPa)

14.3.7.2 New Seismic (Alternate) approach When reversing dynamic loads (seismic) are not required to be combined with non-reversing dynamic loads: ($D_o/t_n \leq 40$). The new seismic alternate approach is limited to $D_o/t_n \leq 40$ as the results were only validated by testing done for D_o/t_n less than or equal to 40.

When Level D Service Limits are specified:

$$B_2\, D_o\, M_W/(2I) \leq 0.5\, S_m$$

$$B_1 P_D D_o/(2t) + B_2'\, D_o\, M_E/(2I) \leq 3\, S_m \qquad \text{(Level-D)}$$

$$C_2\, D_o\, M_{AM}/(2I) \leq 6\, S_m\ (*) \qquad \text{(Level-D)}$$

$$F_{AM}/A_M \leq S_m \qquad \text{(Level-D)}$$

When Level C Service Limits are specified:

$$B_2\, D_o\, M_W/(2I) \leq 0.5\, S_m$$

$$B_1 P_D D_o/(2t) + B_2'\, D_o\, M_E/(2I) \leq 2.1\, S_m \qquad \text{(Level-C)}$$

$$C_2\, D_o\, M_{AM}/(2I) \leq 4.2\, S_m \qquad \text{(Level-C)}$$

$$F_{AM}/A_M \leq 0.7\, S_m \qquad \text{(Level-C)}$$

(*) Refer to NB-3656(b)(5) for limitations in the use of 6 S_m limit.

M_W = resultant moment due to weight effects, in.-lb (N·mm)
B_2' = B_2 from Table NB-3681(a)-1, except as follows:
$B2'$ = 1.33 for girth butt welds between items with different wall thicknesses
B_2' = $0.87/h^{2/3}$ for curved pipe or butt-welding elbows (h as defined in NB-3683.7), but not < 1.0
B_2b' = 0.27 $(R_m/T_r)^{2/3}$ and B_2r' = $0.33(R_m/_{Tr})^{2/3}$ for butt-welding tees but not < 1.0
R_m, T_r = Mean radius, and nominal wall thickness of run pipe respectively, in (mm)
M_E = Amplitude of the resultant moment, in.-lb (N·mm)

P_D = Pressure occurring coincident with the reversing dynamic load, psi (MPa)
M_{AM} = Range of the resultant moment from the earthquake and other reversing type dynamic loading
F_{AM} = Amplitude of the longitudinal force resulting from the earthquake and other reversing type dynamic loading
A_M = Cross-sectional area of metal in the piping component wall, in.^{2} (mm^2)

14.3.8 Code Class 2 and Class 3 Piping

Only highlights are presented here, and for complete details, the readers should refer to Paragraphs NC/ND-3652 through NC/ND-3655 of Subsections NC and ND of ASME Section III, Division 1 [3]. There are additional evaluations based on equations (8), (10), and (11) in NC/ND-3600 that are not discussed here for simplicity as seismic is the focus of this topic.

14.3.8.1 Traditional Approach This traditional approach is applicable for $D_o/t_n \leq 100$ for *B* and *C* indices, and $D_o/t_n \leq 50$ for *B* indices. The effect of pressure, weight, other sustained loads, and occasional loads, including reversing (e.g., OBE seismic) and non-reversing dynamic loads, for which Level B Service Limits are designated, must meet requirements of

For Level-B Occasional Loads (NC/ND-3653.1)

$B_1P_{max}\ D_o/(2t_n) + B_2\ (M_A + M_B)/Z \leq$ Smaller of 1.8 S_h or 1.5 S_y Eqn. 9a-B

For Level-C Occasional Loads (NC/ND-3654)

$B_1P_{max}\ D_o/(2t_n) + B_2\ (M_A + M_B)/Z \leq$ Smaller of 2.25 S_h or 1.8 S_y Eqn. 9a-C

In addition, if the effects of anchor motion, M_{AM} from reversing dynamic loads are not considered in eq. (10a).

i $M_C/Z \leq S_A$ then the requirements of the following equations shall be met:

$C_2\ D_o\ M_{AM}/(2I) \leq 4.2\ S_h$ (Level-C)

$F_{AM}/A_M \leq 0.7S_h$ (Level-C)

For Level-D Occasional Loads (NC/ND-3655)

$B_1P_{max}\ D_o/(2t_n) + B_2\ (M_A + M_B)/Z \leq$ Smaller of 3 S_h or 2 S_y Eqn. 9a-D

In addition, if the effects of anchor motion, M_{AM} from reversing dynamic loads are not considered in eq. (10a).

i $M_C/Z \leq S_A$ then the requirements of the following equations shall be met:

$C_2\ D_o\ M_{AM}/(2I) \leq 6\ S_h$ (Level-D)

$F_{AM}/A_M \leq S_h$ (Level-D)

where:

B_1, B_2 = primary stress indices from Table NC-3673.2(b)-1]
C_2 = secondary stress index from Table NB-3681(a)-1]
D_o = outside diameter of pipe, in. (mm)
M_A = resultant moment loading on cross section due to weight and other sustained loads,
P = internal Design Pressure, psi (MPa)
S_h = basic material allowable stress at Design Temperature, psi (MPa)
t_n = nominal wall thickness, in. (mm)
Z = section modulus of pipe, in.^{3} (mm^3) (NC-3653.3)
M_B = resultant moment loading on cross section due to occasional loads, such as thrusts from relief and safety valve loads from pressure and flow transients, and reversing and non-reversing dynamic loads, if the Design Specification requires calculation of moments due to reversing and non-reversing dynamic loads, in.-lb (N·mm). For reversing and non-reversing dynamic loads, use only one-half the range. Effects of anchor displacement due to reversing and non-reversing dynamic loads may be excluded from eq. (9a) if they are included in either eq. NC 3653.2(a)(10a) or eq. NC-3653.2(c) (11).
P_{max} = peak pressure, psi (MPa)
S_h = material allowable stress at temperature, psi (MPa).
S_y = material yield strength at temperature, psi (MPa).

14.3.8.2 New Seismic (Alternate) Approach When reversing dynamic loads (seismic) are not required to be combined with non-reversing dynamic loads: ($D_o/t_n \leq 40$). The new seismic alternate approach is limited to $D_o/t_n \leq 40$ as the results were only validated by testing done for D_o/t_n less than or equal to 40.

When LevelB Service Limits are specified (NC/ND-3653.1)

$B_1P_{max}\ D_o/(2t_n) + B_2'\ (M_A + M_B')\ /\ Z \leq$ smaller of 1.8 S_h or 1.5 S_y Eqn. 9a-B

When Level C Service Limits are specified (NC/ND-3654)

$B_2\ D_o\ M_W/(2I) \leq 0.5\ S_h$

$B_1P_DD_o/(2t) + B_2'\ D_o\ M_E/(2I) \leq 2.1\ S_h$ (Level-C)

$C_2\ D_o\ M_{AM}/(2I) \leq 4.2\ S_h$ (Level-C)

$F_{AM}/A_M \leq 0.7\ S_h$ (Level-C)

When Level D Service Limits are specified (NC/ND-3655)

$B_2\ D_o\ M_W/(2I) \leq 0.5\ S_h$

$B_1P_DD_o/(2t) + B_2'\ D_o\ M_E/(2I) \leq 3\ S_h$ (Level-D)

$C_2\ D_o\ M_{AM}/(2I) \leq 6\ S_h$(*) (Level-D)

$F_{AM}/A_M \leq S_h$ (Level-D)

(*) *Refer to NC/ND-3655(b)(5) for limitations in the use of 6 S_h limit*.

M_B' = Resultant moment loading due to Reversing dynamic loads (seismic- Level-B) that are not required to be combined with non-reversing dynamic loads
M_W = resultant moment due to weight effects, in.-lb (N-mm)
B_2' = B_2 from Table NC-3673.2(b)-1, except as follows:
B_2' = 1.33 for girth butt welds between items with different wall thicknesses
B_2' = $0.87/h^{2/3}$ for curved pipe or butt-welding elbows (h as defined in NB-3683.7), but not < 1.0
B_2b' = $0.27(R_m/T_r)^{2/3}$ and $B_2r' = 0.33(R_m/_{Tr})^{2/3}$ for butt-welding tees but not < 1.0
R_m, T_r = Mean radius, and nominal wall thickness of run pipe respectively, in (mm)

M_E = Amplitude of the resultant moment (inertial loading from reversing (seismic) dynamic loads, Level C or Level D Service Limits, as applicable, in.-lb (N-mm)
P_D = Pressure occurring coincident with the reversing dynamic load, psi (MPa)
M_{AM} = Range of the resultant moment from the earthquake and other reversing type dynamic loading
F_{AM} = Amplitude of the longitudinal force resulting from the earthquake and other reversing type dynamic loading
A_M = Cross-sectional area of metal in the piping component wall, in.^{2} (mm^2)

It should be noted that the 1980 Edition of the Code with addenda prior to Winter 1981 Addendum, NC-3600 eq. (9), and the 1983 Edition of the Code with addenda prior to Summer 1984 addenda, ND-3600 eq. (9) upset (Level B Service Limit) used stress intensification factor (i) and not B stress indices: $P\ D_o/(4t_n) + B_2'\ (M_A + M_B)/Z \leq 1.2\ S_h$

14.4 SEISMIC ANCHOR MOTION (SAM) ANALYSIS

The seismic movements of the structure corresponding to the support attachment elevation for each support are input. If the supports are attached to different structures, the structures are considered to move out of phase. Pseudo-static analyses are performed separately for OBE and SSE cases. The piping stresses resulting from SAM analyses are classified and treated as secondary stresses. In the design of pipe supports, all the loads from various piping analyses are considered using the appropriate load combinations.

The results from seismic analyses combined according to the applicable load combinations should satisfy the required acceptance criteria based on plant specific licensing basis codes for various items. These include pipe stresses, pipe support acceptance criteria, piping movements acceptability at wall and floor penetrations, valve acceleration limits, and equipment nozzle loads acceptance criteria.

14.5 SEISMIC II/I PIPING SYSTEM PROTECTION

Seismic II/I denotes non-seismic Category II SSCs interacting with seismic Category I SSCs as described in Position C.2 of Regulatory Guide 1.29 [14], .Seismic Design Classification.

The operating experience has shown that seismically supported seismic II/I piping at nuclear plants, whether new or old, has not fallen during a seismic event.

There are two types of seismic qualifications in the nuclear world. One is called a “II over I” where a non-safety related component must be ensured to stay in place and not fall onto a safety related component during/after the seismic event. It is not necessary for the component to remain functional. For such a case, typically, only the anchorage has to be verified to be strong enough to hold the component in place. The other type of seismic qualification is where not only must the component remain in place, but it must continue to function after the seismic event in order to ensure safe operation/shutdown of the plant. Thus, seismic II over I piping supports should be designed to withstand the SSE loading so that the non-seismic or seismic category II piping that is physically above the seismic category I piping remains in its place during a seismic event.

14.6 SEISMIC/NON-SEISMIC INTERFACE

Some seismic category I piping systems continue into other areas such as non-seismic buildings (such as turbine building in PWR plants, and therefore, change their classification into seismic category II (or non-seismic) classification. In such situations, there are two possibilities to achieve protection of the seismic category I piping during a seismic event.

(1) Provide a physical anchor at the interface and design the interface anchor to pipe break loads from the non-seismic side, considering the non-seismic piping to fail under seismic (SSE) loading. Typically, non-seismic piping is not seismically supported (for axial and lateral directions), which means it is supported for dead weight and thermal considerations only. Thus, the interface anchor will be a very hefty anchor because pipe break loads are quite large for large diameter high-pressure piping, such as main steam and feedwater piping.
(2) Analyze and support the non-seismic side of piping for SSE loading. If providing a physical anchor to isolate the seismic (seismic category I) and non-seismic (seismic category II) portions is not feasible, then the piping analysis model of seismic category I piping includes the non-seismic portion, and the combined piping system model is analyzed for seismic loading (OBE and SSE). This requires the non-seismic portion of the piping is also supported for seismic loading. The non-seismic piping as well as its supports are designed and qualified for the seismic loading.

14.7 REFERENCES

1. Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50).
2. NUREG/CR-6240, “Application of Bounding Spectra to Seismic Design of Piping Based on the Performance of Above Ground Piping in Power Plants Subjected to Strong Motion Earthquakes,” February 1995.
3. ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Facility Components, Subsections, NB, NC, and ND, 2010 Edition including 2011 Addenda; &ASME Section II of the Boiler and Pressure Vessel Code, Part D, Properties.
4. GI-199, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants.”
5. Regulatory Guide 1.165, Identification and Characterization of Seismic Sources and Determination of Safe Shutdown Earthquake Ground Motion, Revision 0, March 1997, USNRC.
6. NUREG-2115, “Central and Eastern United States Seismic Source Characterization (CEUS-SSC) for Nuclear Facilities,” January 2012.
7. NUREG/CR-6926, “Evaluation of the Seismic design Criteria in ASCE/SEI Standard 43-05 for Application to Nuclear Power Plants,” March 2007.
8. EPRI Report NP-5617, “Recommended Piping Seismic Adequacy Criteria Based on Performance During and After Earthquakes,” February 1988.

9. 10 CFR 50.54(f) letters by USNRC to all licensees : Request to Reevaluate the Seismic (NTTF 2.1] and Flooding (NTTF 2.3) Hazards at Their Sites Using Updated Seismic and Flooding Hazard Information, USNRC, March 12, 2012.
10. Regulatory Guide 1.92, Combining Modal Responses and Spatial Components in Seismic Response Analysis, Revision 3, September 2012, USNRC.
11. Regulatory Guide 1.61, Damping Values for Seismic Design of Nuclear Power Plants, Revision 1, March 2007, USNRC.
12. ASME Nuclear Code Case N-411-1, “Alternate Damping Values for Response Spectra Analysis of Class 1, 2, and 3 Piping,” 1988.
13. EPRI TR-102792, “Piping and Fitting Dynamic Reliability Program,” 1994.
14. Regulatory Guide 1.29, Seismic Design Classification, Revision 4, March 2007, USNRC.

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CHAPTER

15

GENERATION III+ PWRs[1]

Part A: AP1000® PWR E. Keith Schwab
Part B: EPR Marty Parece
Part C: US-APWR Masanori Onozuka

15.1 INTRODUCTION

From the commissioning of the first commercial nuclear reactor more than 50 years ago, the nuclear power industry has been developing and improving reactor technology with particular emphasis on reliability and safety. There are several generations of reactors that have been developed or are being developed. These reactors are generally categorized as Generation I, II, III, III+, and IV reactors. Figure 15.1 illustrates the technology distilled from 50 years of successful nuclear operating experience that has led to the Generation III+ pressurized water reactors (PWRs).

Generation I reactors were developed in the 1950s and 1960s, Generation II reactors were developed in the 1970s through the 1990s, and Generation III reactors were developed in the 1990s and 2000s. Generation III reactors are considered to be evolutionary reactors such as the System 80+, and advanced pressurized water reactor (APWR). Generation III+ reactors are based on the nomenclature from the Department of Energy, that is, Generation III reactors with improved economics and safety. Generation IV reactors are new technologies that are being developed for future reactors.

The Generation III+ PWR reactors discussed in this chapter have design features with more robust design improvements, higher availability and longer operating life, extended fuel life, and improved and innovative safety features over the currently operating reactors. The Generation III+ Boiling Water Reactors (BWRs) are discussed in Chapter 16.

15.2 SCOPE OF COMMENTARY

The scope of this commentary is to describe in some detail the Generation III+ PWR plant design features, technology, safety and reliability features, and the elimination or mitigation of degradation issues associated with Generation I, and II PWR designs.

This chapter provides commentary on the following Generation III+ PWRs that have received Design Certification approval or are in the process of receiving certification approval from the U.S. Nuclear Regulatory Commission (NRC):

- **AP1000®** PWR
- EPR
- US-APWR

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The outlines of these sections are as follows:

Section 15A **AP1000** PWR

- **AP1000** Plant Design
- Operational Technology
- Safety Features
- Containment Design
- Modularization and Construction
- Operation and Maintenance
- ASME Code Aspects
- Future Direction on the **AP1000** Plant
- References
- Nomenclature

Section 15B EPR

- EPR Development
- EPR Plant Design
- EPR Safety
- Containment Design
- Construction
- Operation and Maintenance
- Code Aspects
- Building Now
- References

Section 15C US-APWR

- US-APWR Plant Design
- Operational Technology

[1]This chapter initially appeared as Chapter 57 in the Third Edition of "Companion Guide to the ASME Boiler & Pressure Vessel Code" and was authored by John Land for Part A, Marty Parece for Part B, and Masahiko Kanedo for Part C. This is now completely revised for Parts A and C by E. Keith Schwab and Masanori Onozuka, respectively. Marty Parece continued to update Part B. – Editor

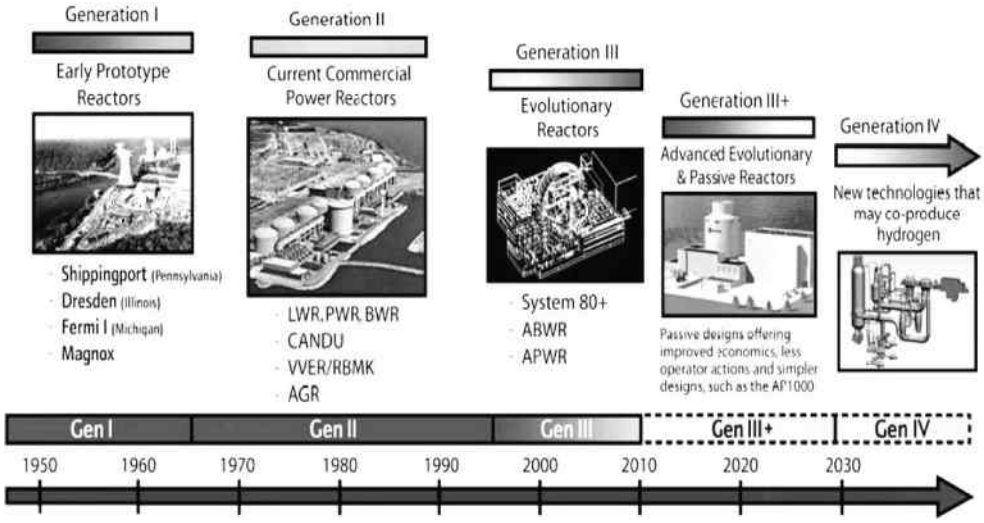


FIG. 15.1 GENERATIONAL REACTORS (*Source*: Westinghouse Electric Company, LLC)

- Safety Features
- Containment Design
- Modularization and Construction
- Operation and Maintenance
- ASME Code Aspects
- Future Direction on the US-APWR
- References
- Nomenclature

15A AP1000® PWR

15A.1 INTRODUCTION

The commentary in this section on the Westinghouse **AP1000** PWR is based primarily on public information documents [1–3].

The major design objectives of the **AP1000** nuclear power plant are simplification of the overall safety systems, improved reliability, and reduced costs over Generations I, II, and III reactors.

The simplification of the safety systems is accomplished by reductions in the number of components such as valves, cable, and the seismic building volume. The reliability is accomplished by improved technology with concomitant increases in safety margins. The reduced costs are accomplished by minimizing the number of components requiring inspection, and modularization and construction techniques that shorten construction and consequent costs.

15A.2 AP1000 PLANT DESIGN

The **AP1000** nuclear power plant was the second PWR plant to receive Design Certification from the NRC. The Design Certification process for the **AP1000** plant was assisted by the fact that a similar design, the Westinghouse **AP600**™ nuclear power plant, was previously certified by the NRC. The **AP1000** plant was an upgrade in power and consequently, the differences in the design features were addressed during the Design Certification process. The **AP1000** plant has received NRC approval for two Combined Operating Licenses (COLs) in the U.S. for plants in Georgia and South Carolina. Those plants consisting of two **AP1000** nuclear power plant units each are under construction. In addition, the **AP1000** plant is currently undergoing COL reviews for other plant sites in the U.S.

Simplification was a major design objective for both the **AP600** plant and **AP1000** plant. Simplifications in overall safety systems, normal operating systems, the control room, construction techniques, and instrumentation and control (I&C) system provide reduced costs over current operating plants. Plant simplification yields fewer components, cable, and seismic building volume, which increases savings in capital investment and lowers operational and maintenance costs. Table 15A.1 summarizes the component differences between an existing 1000-MWe plant and the **AP1000** plant. Table 15A.1 shows that there are significant reductions in the number of components between the **AP1000** plant and a reference plant with about the same electrical output power rating.

In addition to plant simplification improvements, the reactor vessel and internals, steam generator (SG), fuel, and pressurizer designs are improved versions of those found in currently operating Westinghouse-designed PWRs. Table 15A.2 summarizes the operational technology incorporated into the **AP1000** PWR.

TABLE 15A.1 AP1000 PLANT COMPONENT COMPARISON WITH OPERATING 1000-MWe PLANT (*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY, LLC)

Plant Simplification Yields Fewer Components, Cable, and Building Volume		
Component	1000-MWe Reference Plant	**AP1000** Plant
Pumps	280	180
Safety class valves	2,800	1,400
Safety class piping	110,000	19,000
Cable, million ft.	9.1	1.2
Seismic building volume, million ft.^{3}	12.7	5.6

TABLE 15A.2 AP1000 PWR OPERATIONAL TECHNOLOGY
(*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY, LLC)

Component	Prior Use of Technology
Reactor vessel and internals	Doel 4, Tihange 3
CRDMs	Westinghouse plants worldwide
Fuel	South Texas 1&2, Doel 4, Tihange 3
Large Model F steam generators	ANO-2, San Onofre, Waterford, Palo Verde
Canned motor reactor coolant pumps	Fossil boilers and other industrial applications (inverted canned motor pumps)
Pressurizer	70 Westinghouse plants worldwide

15A.3 OPERATIONAL TECHNOLOGY

The **AP1000** plant is a two-loop PWR with a power rating of 3415 MWt and a nominal net electrical output of approximately 1117 MWe, depending on the ambient air conditions and the type of condenser cooling configuration used. The **AP1000** plant has a 157-fuel assembly core for base load generation. The **AP1000** plant is designed for 24-month fuel cycles, with current plans to operate on 16 to 20-month alternating fuel cycles for optimum economics, with an expected availability goal of 93% over a 60-year design basis. Refueling outage capability is estimated to be around 17 days.

Figure 15A.1 illustrates a rendering of the **AP1000** PWR reactor coolant system (RCS) design and layout. Figure 15A.1 shows the primary equipment consisting of the reactor pressure vessel (RPV), SGs, reactor coolant pumps (RCPs), and pressurizer.

Each loop consists of one hot leg outlet pipe and two cold leg inlet pipes. Each SG has two sealless RCPs mounted below the cold leg outlet channel head of the SG. The reactor vessel and reactor internals are similar in design to Westinghouse 3XL and 4XL 14-ft. fuel assemblies, with the core closest to the bottom of the RPV.

The RCS flow rate and fluid temperatures are similar to operating Westinghouse plants. The cold leg temperature in the RPV nozzle is 535°F (279°C) and the hot leg temperature at the RPV outlet nozzle is 612°F (322°C). The **AP1000** PWR fluid system incorporates a low boron core design to increase safety margins for accident scenarios such as anticipated transients without scram (i.e., anticipated transients with the added failure of the reactor trip function).

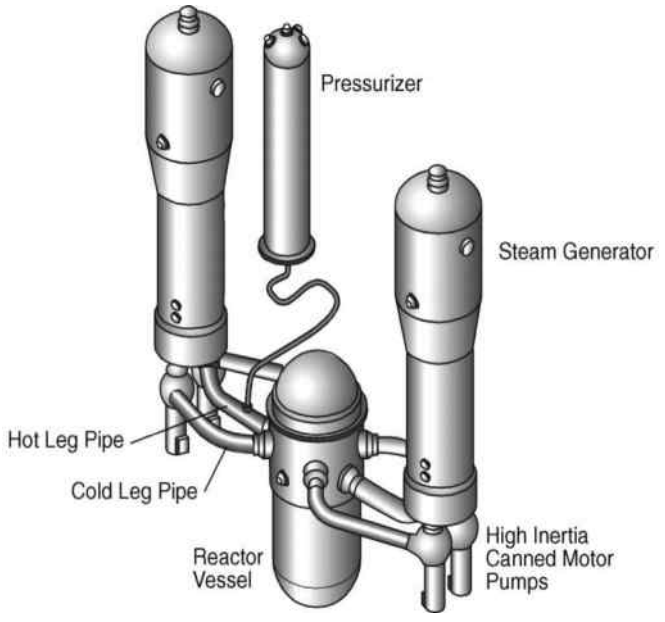


FIG. 15A.1 AP1000 PWR REACTOR COOLANT SYSTEMS
(*Source*: Westinghouse Electric Company, LLC)

The **AP1000** plant primary equipment and fuel are mostly evolved from Westinghouse PWR designs but with some innovative design features. Many of these improved design features are a result of solving material degradation issues in existing Generation I and II PWR plants. These material degradations issues are discussed in Chapters 11, 20, and 21.

The **AP1000** plant major primary equipment, fuel, and instrumentation design features are summarized below from Refs [1–3]:

Reactor Pressure Vessel

- Four inlet nozzles and two outlet nozzles
- Hot leg outlet nozzle located below the cold leg inlet nozzles
- Two safety injection nozzles
- Shortened hemispherical bottom head
- Penetrations for top-mounted in-core and T/C conduits

Reactor Internals

- Two hot leg outlet nozzles 180° apart
- Two safety injection diverters 180° apart
- Guide tubes with improved rodlet wear mitigation features
- Reduced-worth control rods (gray rods) to achieve daily load follow without requiring changes to the soluble boron concentration
- Accommodation hardware for in-core and T/C instrumentation
- Welded core shroud to eliminate the concern for baffle–barrel bolt cracking
- Bottom-head flow skirt to improve flow distribution into fuel assemblies

CRDMs and Driveline

- CRDMs and driveline similar to 4XL design

Steam Generators

- Two large SGs with Delta-125 designation and triangular pitch tubing
- Single vertical support column for SG
- Full-depth hydraulic expansion of tubes in tube sheets
- Stainless steel broached tube support plates
- Inconel 690 tubing to minimize stress corrosion cracking
- Upgraded antivibration bars to reduce wear
- Upgraded primary and secondary moisture separators

Pumps

- Two sealless pumps for each SG mounted under cold leg outlet nozzle of each SG
- Elimination of pump shaft seals simplifies the auxiliary fluid systems that support a canned motor pump, reduces maintenance, and eliminates possible accidents involving seal failures
- Integration of pump suction at cold leg channel head eliminates the crossover leg of coolant loop piping, reduces the loop pressure drop, simplifies the foundation and support system for the SG, and eliminates the potential for uncovering the core during a small LOCA.

Pressurizer

- Larger than other Westinghouse designs with a volume of 59.5 cu m. (2100 cu ft.)
- Elimination of PORVs (power-operated relief valves)

Fuel

- 157 Fuel assemblies with zircaloy grids and removable top nozzles
- 17 × 17 fuel assembly with 14-ft. core
- Longer burn up features
- Improved core hold-down spring design w/o bolts
- Margin of more than 15% from nuclear boiling limit

In-core Instrumentation

- Fixed top-mounted in-core instrumentation

Thermocouple Instrumentation

- Thermocouples mounted in reactor internals similar to existing Westinghouse configuration with an improved sealing system

15A.4 SAFETY FEATURES

The **AP1000** plant provides multiple levels of defense for accident mitigation (defense-in-depth), resulting in extremely low core-damage probabilities while minimizing the occurrences of containment flooding, pressurization, and heat up. Westinghouse submitted a probabilistic risk assessment (PRA) for the **AP1000** plant in accordance with NRC regulatory requirements. Accident mitigation is reflected in the PRA results from the benefits of both safety and nonsafety systems that actuate following an event. Table 15A.3 compares the calculated **AP1000** PWR core damage frequency (CDF) events per year with the NRC goal, current plant estimate, and the Utility Requirements Document (URD) goals. The PRA was acceptable for certification purposes. The mean estimates of the risk metrics are shown in Table 15A.3.

TABLE 15A.3 AP1000 PLANT PROBABILISTIC RISK ASSESSMENT METRICS (*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY, LLC)

PRA	NRC requirement	Current plants	URD requirement	**AP1000** plant
CDF[a]	1×10^{-4}	5×10^{-5}	1×10^{-5}	$<5 \times 10^{-7}$
LRF[b]	—	—	—	$<6 \times 10^{-8}$

[a]CDF – core damage frequency events per year
[b]LRF – large release frequency per year

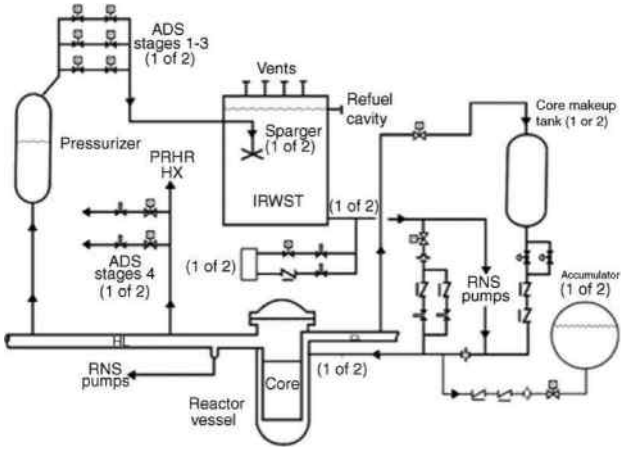


FIG. 15A.2 CMTs AND ACCUMULATOR PIPING SYSTEM (*Source*: Westinghouse Electric Company, LLC)

The unique safety feature of the **AP1000** plant is the use of a passive safety system concept. In the event of an accident, the use of natural forces such as natural circulation, gravity flow, convection flow, and compressed gas are used to maintain core cooling and containment integrity. The major design feature of the passive safety-related system for the **AP1000** plant is to provide safety injection from the core makeup tanks (CMTs), accumulators, and in-containment refueling water storage tank (IRWST) illustrated in Fig. 15A.2.

Heat removal is accomplished by the passive residual heat exchanger removal system (PRHR HX) and the IRWST, as illustrated in Fig. 15A.3.

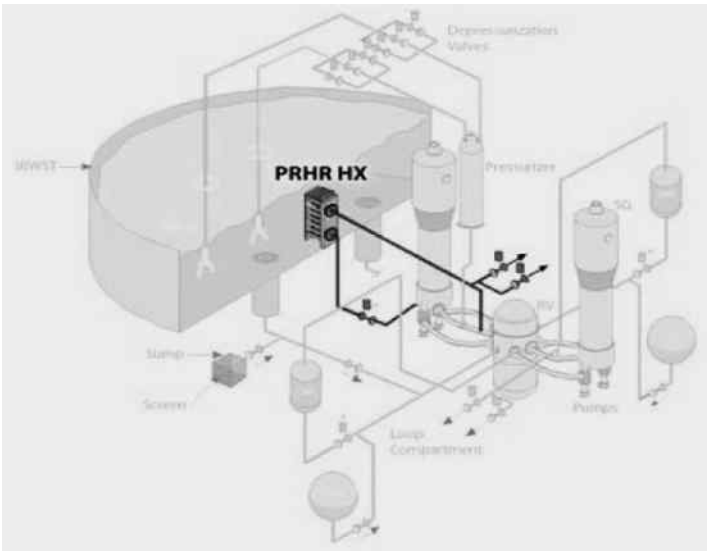


FIG. 15A.3 AP1000 PLANT PASSIVE RESIDUAL HEAT REMOVAL SYSTEM (*Source*: Westinghouse Electric Company, LLC)

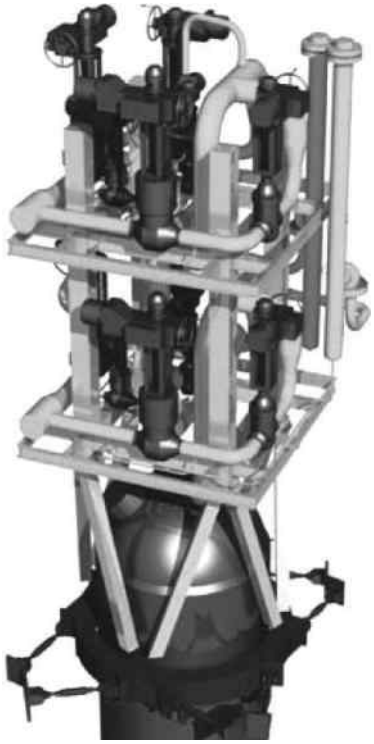


FIG. 15A.4 AP1000 PLANT AUTOMATIC DEPRESSURIZATION SYTEMS (ADS) (*Source*: Westinghouse Electric Company, LLC)

In addition, the RCS automatic depressurization system (ADS) is located above the pressurizer, as illustrated in Fig. 15A.4.

15A.4.1 Discussion of Safety Features

The following safety features contribute to the defense-in-depth of the **AP1000** plant:

- Passive Safety-Related Systems
- In-Vessel Retention of Core Damage
- Fission Product Release

15A.4.1.1 Passive Safety-Related Systems The most significant aspect of the **AP1000** plant is that it is a passive plant which requires no AC power to provide plant safety to mitigate design basis events. Passive systems do not rely on AC power to maintain core and spent fuel pool cooling. The passive safety features along with a very careful design of the failure modes of the safety systems on loss of AC power provide the **AP1000** plant with unique capabilities to respond to events from earthquakes and flooding, or other unanticipated plant events.

The occurrences of catastrophic events which could lead to an extended loss of power and limit site access were an integral part of the early design of the Westinghouse **AP600** plant. The **AP600** plant passive systems concept was subsequently applied to the **AP1000** plant design. Catastrophic events were considered in the design of both plant designs many years before the earthquake struck off the northeast coast of Japan on March 11, 2011. Three of the six nuclear reactors (#1, 2, 3) at the Fukushima Dai-ichi nuclear plant complex were operating normally when the earthquake occurred. The three operating reactors shut down automatically as a result of the earthquake. The active plant safety systems and diesel generators functioned to begin core cooling. The other three reactors (#4, 5, 6) had been shut down before the earthquake for planned maintenance and refueling. The reactors rely on AC powered pumps for decay heat removal from the core and from the spent fuel. All six of the Fukushima Dai-ichi Power Station reactors are of the Boiling Water Reactor (BWR) type based on General Electric designs.

Approximately one hour after the earthquake a 14 meter high tsunami struck the site. The flood waters caused significant damage to the site as well as the area surrounding the complex and infrastructure, which resulted in a station blackout. Without AC power, reactors #1, 2, 3, 4 subsequently experienced fuel damage and generation of hydrogen. A series of hydrogen explosions consequently occurred at the site.

While the Fukushima event is well beyond the normal design basis, the primary challenge from the beyond design basis event earthquake and tsunami was the resulting station blackout in which all electrical power sources in the plant were lost. Typically after a period of 4 to 8 hours battery supplied DC power sources deplete and no electrical power was available at the plant.

By contrast, the **AP1000** plant will automatically establish and maintain safe shutdown conditions for 72 hours following such an event. During this time period, no operator actions and AC power sources are required. The **AP1000** plant design also has provisions for both onsite equipment and safety-related connections for use with transportable equipment and supplies to provide safety functions for an indefinite time after a station blackout begins. The **AP1000** plant Passive Safety Concept achieves a dramatic reduction in risk resulting from loss of offsite power events (station blackout) compared even to the most advanced active PWR designs.

Westinghouse has evaluated the performance of the **AP1000** plant design if it were subjected to a Fukushima-type event. The evaluation concluded that the **AP1000** plant design with its passive safety features, combined with limited operator actions and with assumed offsite assistance at 72 hours, would have:

- Prevented damage to the core and spent fuel
- Prevented hydrogen generation and possibility of hydrogen explosion
- Provided containment cooling to maintain low containment pressure

The passive safety-related systems include the passive core cooling system (PXS), containment isolation, passive containment cooling system (PCS), and the main control room (MRC) emergency habitability system.

Passive Core Cooling System (PXS) The PXS is designed to perform two major functions: safety injection by providing borated reactor coolant makeup and passive residual heat removal (PRHR). Safety injection is achieved by using various passive injection sources at different pressures: high-pressure safety injection with CMTs, intermediate pressure safety injection with accumulators, low-pressure reactor coolant makeup from the IRWST, and long-term cooling for containment recirculation.

The high-pressure safety injection with CMTs is used following transients where the normal makeup system is inadequate or is unavailable. Figure 15A.2 illustrates the CMTs and accumulator piping configuration for the **AP1000** plant. Two CMTs filled with borated water in redundant trains are designed to function at any

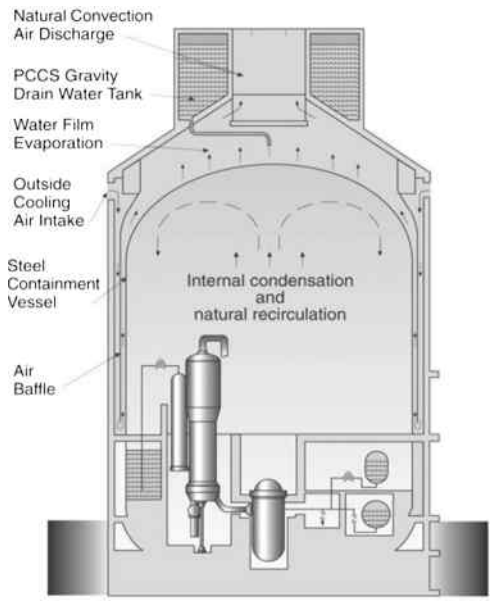


FIG. 15A.5 AP1000 PLANT PASSIVE CONTAINMENT COOLING SYSTEM (*Source*: Westinghouse Electric Company, LLC)

RCS pressure using gravity, with the temperature and height differences from the RCS cold leg as the driving force for natural circulation injection. The tanks are designed for full RCS pressure and are located above the RCS loop piping. If the water level or pressure in the pressurizer reaches a set low level, the reactor as well as the RCPs is tripped and the CMT discharge isolation valves open automatically. The water from the CMTs then flows naturally into the reactor vessel.

The accumulators provide intermediate pressure safety injection, similar to current PWRs, to provide rapid refill/reflood of the core in the event of a large loss-of-coolant accident (LOCA). The accumulators are pressurized to 700 psig with a nitrogen cover gas. The pressure differential between the pressurized accumulators and the dropping RCS pressure ultimately forces open check valves that normally isolate the accumulators from the RCS. Two accumulators in redundant trains are sized to respond to the complete severance of the largest RCS pipe by rapidly refilling the vessel downcomer and lower plenum and reflooding the core. The accumulators continue delivery to supplement the CMTs in rapidly reflooding the core.

Low pressure reactor coolant makeup from the IRWST is supplied by gravity injection from the large IRWST (see Fig. 15A.3), which is located inside the containment at a height above the RCS loops. This tank is at atmospheric pressure and, as a result, the RCS must be depressurized before injection can occur. The **AP1000** plant automatically controls depressurization of the RCS to reduce its pressure near atmospheric pressure, at which point the head elevation in the IRWST is sufficient to overcome the small RCS pressure loss in the injection lines.

Passive Residual Heat Removal System The PRHR system is illustrated in Fig. 15A.3. The system includes the passive RHR heat exchanger consisting of banks of tubes that are connected to a natural circulation loop. The difference in water temperature between the hot inlet water and the cold outlet water of the heat exchanger, as well as the elevated location of the heat exchanger, drives the natural circulation decay heat removal loop. If the RCPs are running, the passive RHR heat exchange flow will be increased. The IRWST is the heat sink for the passive RHR heat exchanger. The IRWST water volume is sufficient to absorb decay heat for about 2 hr before the water starts to boil. Thereafter, the steam from the boiling IRWST condenses on the steel containment vessel walls and then drains back into the IRWST.

Passive Containment Cooling System The function of the **AP1000** plant PCS is to prevent the containment from overheating and exceeding the design pressure, which could result in a breach of the containment and the loss of the final barrier to radioactive release.

The PCS is shown in Fig. 15A.5. The steel containment vessel provides the heat transfer surface that allows heat to be removed from inside the containment and rejected to the atmosphere. Heat is removed from the steel containment vessel by a natural circulation of air through the annulus formed by the outer shield building and the steel containment vessel it houses. Outside air is pulled in through openings near the top of the shield building and pulled down around the baffle and then it flows upward out of the shield building. The flow of air is driven by the chimney effect of air heated in the containment vessel annulus and is exhausted up through the central opening in the shield building roof. If needed, the air cooling can be supplemented by water evaporation on the outside of the containment shell. The water is drained by gravity from a tank located on top of the containment shield building. Three normally closed, fail-open valves will automatically open if a high containment pressure is reached. The water flows from the top, outside, domed surface of the containment shell and down the sidewalls allowing heat to be transferred and removed from the containment by evaporation. The water tank has sufficient capacity for three days of operation, after which time the tank could be refilled.

Containment Isolation Containment isolation is provided to prevent or limit the escape of fission products that may result from postulated accidents. In the event of an accident, the containment isolation provisions are designed so that fluid lines penetrating the containment boundary are isolated. The containment isolation system consists of the piping, valves, and actuators that isolate the containment. Containment isolation is improved in the **AP1000** plant because the number of normally open penetrations is reduced by 50%; penetrations that are normally opened are fail safe (fail in the closed position); there is no recirculation of irradiated water outside of containment for design-basis accidents; and the steel containment is a high-integrity (steel) pressure vessel surrounded by a concrete vessel.

Main Control Room Emergency Habitability System The MCR can be isolated in case of high airborne radiation levels. The MCR emergency habitability system is comprised of a set of compressed air tanks connected to a main and an alternate air delivery line. Components common to both lines include a manual isolation valve, a pressure regulating valve, and a flow metering orifice. This system is designed to provide the ventilation and pressurization needed to maintain a habitable environment for up to 11 people in the MCR for 72 h following the design basis accident.

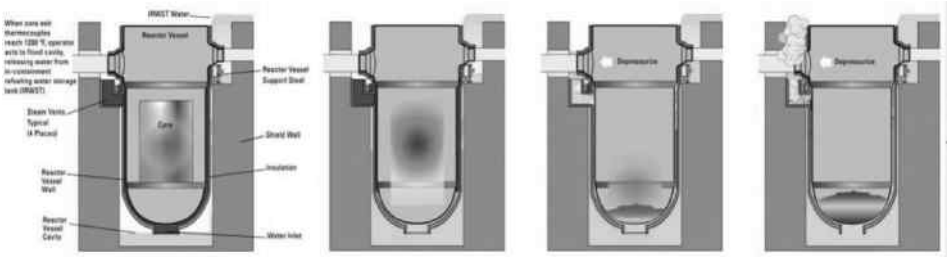


FIG. 15A.6 AP1000 PLANT IN-VESSEL RETENTION OF CORE DAMAGE
(*Source*: Westinghouse Electric Company, LLC)

15A.4.1.2 In-Vessel Retention of Core Damage The **AP1000** plant is designed to mitigate a postulated severe accident such as core melt. Figure 15A.6 is used in the explanation of this event. In this event, the reactor cavity can be submerged with water from the IRWST, submerging the reactor vessel. An insulating structure surrounds the reactor vessel to provide the pathway for water cooling to reach the vessel, flow around the bottom vessel head and up the vessel insulation wall annulus, and to vent steam that results from cooling the vessel from the reactor cavity. The cooling is sufficient to prevent molten core debris in the lower head from melting the steel vessel wall and spilling into the containment. Retaining the debris in the reactor vessel protects the containment integrity by simply avoiding the uncertainties associated with ex-vessel severe accident phenomena, such as ex-vessel steam explosion and core concrete interaction with the molten core material.

15A.4.1.3 Fission Product Release Fuel cladding is the first barrier that prevents the release of radiation in the event of an accident. The second barrier is the reactor pressure boundary that includes the reactor pressure vessel and the reactor coolant piping. Furthermore, in conjunction with the surrounding shield building, the steel containment vessel provides the third additional protection barrier by establishing natural convection air currents to cool the steel containment. The natural convection cooling is enhanced with evaporative cooling by allowing water to drain from a large tank located at the top of the shield building.

15A.4.2 Nonsafety Active Systems

Many of the active safety-related systems in existing and evolutionary PWR designs are retained in the **AP1000** plant but are designated as nonsafety related. Examples of nonsafety-related systems that provide defense-in-depth capabilities are as follows:

- Chemical and Volume Control System (CVCS)
- Normal RHR
- Start-up (Back-up) Feedwater System

These systems utilize nonsafety support systems such as the standby diesel generators (DGs), the component cooling water system (CCS), and the service water system (SWS). The **AP1000** plant also includes other active nonsafety-related systems, such as the heating, ventilation, and air-conditioning (HVAC) system, which removes heat from the I&C, cabinet rooms, and the MCR. Although these are familiar systems that are used in current PWRs for safety systems, the **AP1000** plant uses these systems as simplified nonsafety related first line of defense, which are backed up by the passive safety grade systems already described.

15A.5 CONTAINMENT DESIGN

One of the major cost and safety improvements for the **AP1000** plant is the use of a passive safety system concept. The economic benefit is that less seismic category 1 building volume is required to house the safety equipment (approximately 45% less than the typical reactor). The modular construction design of **AP1000** plant further reduces cost with work shifted to factories with their better quality and cost control as well as labor costs that are less than those at the construction site. This also allows more work to be done in parallel. The development of heavy lift cranes enable an "open top" construction approach, which is effective in reducing construction time.

The **AP1000** plant by design has a smaller footprint than existing nuclear power plants with similar generating capacity. Figure 15A.7 illustrates a comparison between the **AP1000** plant and a Generation II PWR nuclear island building configurations.

The **AP1000** plant arrangement provides separation between safety-related and nonsafety related equipment. Separation between redundant, safety-related equipment trains and systems

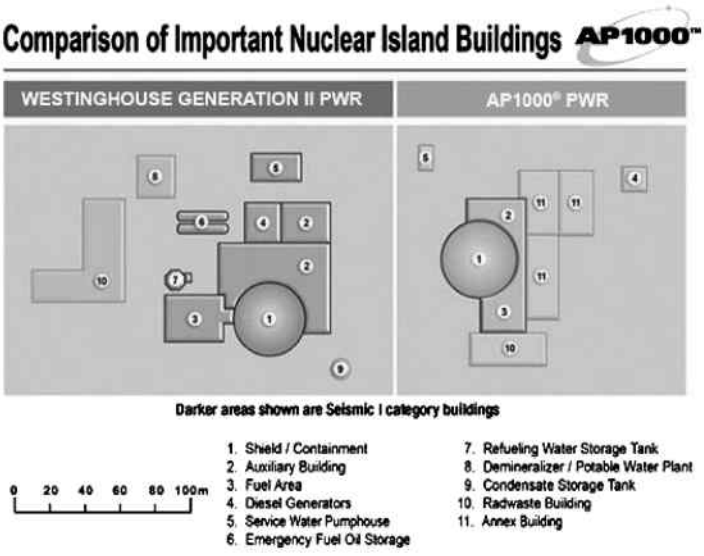


FIG. 15A.7 COMPARISON OF NUCLEAR ISLAND BUILDINGS (*Source*: Westinghouse Electric Company, LLC)

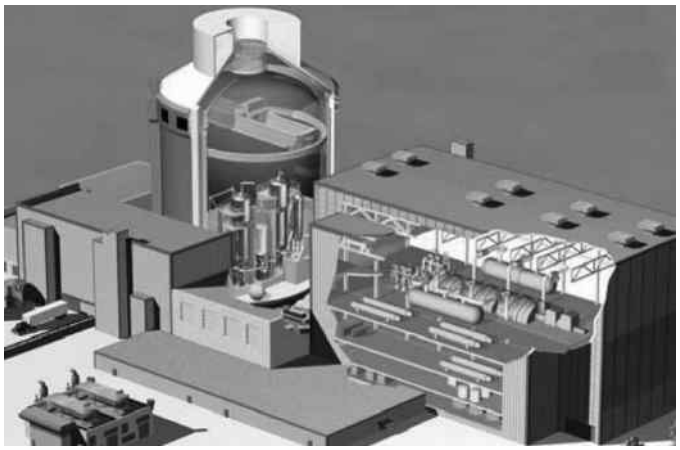


FIG. 15A.8 AP1000 PLANT (*Source*: Westinghouse Electric Company, LLC)

provides confidence that the safety design functions can be performed. In general, this separation is achieved by partitioning an area with concrete walls.

The **AP1000** plant, illustrated in Fig. 15A.8, is arranged with the following principal building structures, each on its own base mat:

- Nuclear island (the only Seismic 1 Category structure)
- Turbine island
- Annex building
- DG building
- Radwaste building

The nuclear island consists of the *steel containment*, the *concrete shield building*, and the *auxiliary building*. The nuclear island is designed to withstand the effects of postulated internal events such as fires and flooding without loss of capability to perform safety functions. A description of the nuclear island structures and buildings are discussed below.

15A.5.1 Steel Containment

The containment vessel is a freestanding steel structure with a wall thickness of 1.75 in. (4 cm) and a diameter of 130 ft. (40 m). Ring sections and vessel heads are constructed at an off-site facility and shipped to the site for assembly and installation using a large-capacity crane.

The primary containment prevents the uncontrolled release of radioactivity to the environment. It has design leakage rate of 0.10 wt % per day of the containment air mass that was present at the start of a design basis accident and the resulting containment isolation.

The **AP1000** plant containment contains a 16-ft. (4.9 m) diameter main equipment hatch and a personnel airlock at the operating deck level, and a 16-ft. (4.9 m) diameter maintenance hatch and a personnel airlock at grade level. These large hatches significantly improve accessibility to the containment during outages. The containment hatches are located at two different levels, thereby allowing activities occurring above the operating deck to be unaffected by activities occurring below the operating deck.

The containment arrangement provides significantly larger laydown areas than most conventional plants at both the operating deck level and the maintenance floor level. Ample laydown space is provided for staging of equipment and personnel, equipment removal paths, and space to accommodate remotely operated service equipment and mobile units. Access platforms and lifting devices are provided at key locations, as are service provisions such as electrical power, demineralized water, breathing and service air, ventilations, and lighting.

15A.5.2 Concrete Shield Building

The **AP1000** plant containment design incorporates a shield building that surrounds the primary containment vessel and forms the natural convection annulus for containment cooling. This building is a cylindrical, reinforce, concrete structure with a conical roof that a supports the water storage tank and air diffuser of the PCS. It shares a common base mat with the primary containment and auxiliary building, and is designed as a seismic category 1 structure.

The two primary functions of the shield building during normal operation are (1) to provide an additional radiological barrier for radioactive systems and components inside the containment vessel and (2) to protect the containment vessel from external events, such as tornados and tornado-driven objects that might impinge on it. Under design basis accident conditions, the shield building serves as a key component of the PCS by aiding in the natural convection cooling of the containment.

15A.5.3 Auxiliary Building

The auxiliary building is designed to provide protection and separation for the seismic category 1 mechanical and electrical equipment located outside the containment building. The building also provides protection for safety-related equipment against the consequences of internal and external events. Specifically, the auxiliary building houses the MCR, I&C systems, batteries, fuel handling and spent fuel area, mechanical equipment areas, liquid and gas radwaste areas, containment penetration areas, and main steam and feedwater isolation valve compartments. Large staging and laydown areas are provided outside the two equipment hatches.

15A.5.4 Nonseismic Buildings

The nonseismic category structures contain no safety-related equipment. They are designed for wind and seismic loads in accordance with the Uniform Building Code (UBC). The following are the nonseismic buildings:

(1) **Annex Building.** The annex building serves as the main personnel entrance to the power generation complex and houses the health physics area, the nonclass AC and DC electric power system, the ancillary DGs and their fuel supply, the technical support center, and various HVAC systems. The annex building also provides a large staging and laydown area outside the equipment hatches.

(2) **Turbine Building.** The turbine building houses the main turbine, generator, and associated fluid and electrical system. It also houses the makeup water purification system.

(3) **Diesel Generator Building.** The DG building houses the diesel generators and their associated HVAC equipment.

(4) **Radwaste Building.** The radwaste building contains facilities for segregated storage of various categories of solid waste prior to processing, for processing mobile systems, and for storing processed solid waste in shipping and disposal containers.

15A.6 MODULARIZATION AND CONSTRUCTION

The **AP1000** plant has been designed to make use of modern, modular construction techniques. Modularization allows construction tasks that were traditionally performed in sequence to be completed in parallel. Factory-built modules can be assembled at the site in a planned construction schedule from first concrete pour to fuel load. Table 15A.4 illustrates the number of **AP1000** plant modules for the containment and auxiliary buildings.

Modularization reduces the calendar time for plant construction, thereby reducing the cost of money and the exposure risks associated with plant financing. Furthermore, the labor and specialized equipment costs are also greatly reduced because of the reduced amount of work required at the site. To achieve proper interfaces with the rest of the plant systems and structures, interconnected piping between modules is represented in computer-designed three-dimensional (3D) models. This eliminates the interference concerns of typical field installations. Figure 15A.9 illustrates modularization to reduce construction time and costs.

TABLE 15A.4 ILLUSTRATION OF AP1000 PLANT BUILDING MODULES (*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY LLC)

Typical Breakdown of **AP1000** Plant Modules				
Location	Structural	Piping	Mechanical Equipment	Total
Containment	65	20	13	98
Auxiliary building	32	34	42	108
Turbine building	31	45	6	82
Annex building	10	—	—	10
Total	138	99	61	298

TABLE 15A.5 AP1000 PLANT CONSTRUCTION SCHEDULE (*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY LLC)

Site Preparation	Site Construction	Start-Up and Testing
18 months	36 months	6 months

The **AP1000** plant construction schedule is estimated to be 5 years from order placement with a goal of 3 years from the first concrete pour to fuel loading. Table 15A.5 illustrates the **AP1000** plant construction schedule.

15A.7 OPERATION AND MAINTENANCE

The **AP1000** plant design philosophy is to focus on plant operability and maintainability. The passive safety features use a much smaller number of valves than do the multiple trains of active pump-driven systems, and therefore there are no safety pumps at all; so, there is less in-service testing to perform. Also, the simplified safety systems are designed to reduce surveillance requirements, simplify technical specifications, and reduce the potential for forced shutdowns.

The variable speed canned motor RCPs mounted on the bottom of the SGs are designed to simplify plant start-up and shutdown operations. They are to be capable in providing varying RCP speed to better control operating mode transitions. The RCPs operate at constant speed during power operation, thereby simplifying control actions during load shifts.

The digital I&C design should require less I&C surveillance testing and should simplify troubleshooting, repair, and postmaintenance testing. The plant includes automation of some cooldown operations. The advanced control room is designed to improve operator interfaces and plant operation capabilities.

Plant layout ensures adequate access for inspection and maintenance. Laydown space provides for staging of equipment and personnel, equipment removal paths, and space to accommodate remotely operated service equipment and mobile units. Access platforms and lifting devices are provided at key locations as are service provisions, such as electrical power, demineralized water, breathing and service air, ventilation and lighting, and computer data highway connections.

The **AP1000** plant incorporates radiation exposure reduction principles to keep worker dose ALARA. Exposure length, distance, shielding, and source reduction are fundamental criteria that are incorporated into the design, thereby resulting in the following radiation protection improvements:

- Minimized operational radiation releases
- Reduction in worker radiation exposure
- Total radwaste volume minimized

The **AP1000** plant is designed for rated performance with up to 10% of the SG tubes plugged and with a maximum hot leg temperature of 321°C (612°F). The plant is designed to accept a step-load increase or decrease of 10% between 25 and 100% power

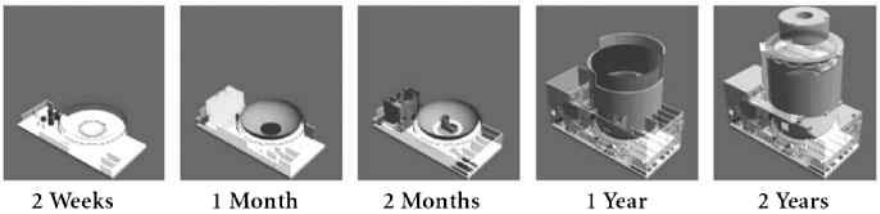


FIG. 15A.9 ILLUSTRATION OF AP1000 PLANT BUILDING MODULARIZATION (*Source*: Westinghouse Electric Company, LLC)

TABLE 15A.6 AP1000 PLANT STRESS CRITERIA FOR ASME CODE SECTION III CLASS 1, CORE SUPPORT STRUCTURES, AND COMPONENT SUPPORTS (*SOURCE*: WESTINGHOUSE ELECTRIC COMPANY, LLC)

Service level	Vessel/tanks/ pumps	Pipe	Core supports	Valves	Component support
A	NB-3221 NB-3222	NB-3652	NG-3221 NG-3222 NG-3231 NG-3232	NB-3520 NB-3525	NF
B	NB-3223	NB-3654	NG-3223 NG-3233	NB-3525	NF
C	NB-3224	NB-3655	NG-3224 NG-3234	NB-3526	NF
D	NB-3225	NB-3656	NG-3225 NG-3235	special	NF

without reactor trip or steam-dump system actuation, provided that the rated power level is not exceeded. The **AP1000** plant is designed to accept 100% load rejection from full power to house loads without a reactor trip or operation of the pressurizer or SG safety valves.

15A.8 ASME CODE ASPECTS

The **AP1000** plant is designed as per the 1998 Edition of the ASME Code up to and including the 2000 Addenda. The **AP1000** plant Design Control Document (DCD) [4] and the ASME Code [5] correlation with primary equipment and piping components requirements are summarized in Table 15A.6.

15A.9 FUTURE DIRECTION ON THE AP1000 PLANT

As of the date of this publication, Westinghouse has received orders for domestic and international **AP1000** plants. The first international orders received were from China for four plants, which are currently under construction. There are also four **AP1000** plants under construction in the U.S. - two in Georgia and two in South Carolina.

Future work will involve support of the eight plants presently under construction through fuel load, plant start-up, and commercial operation. There will also be continued support to obtain NRC approval for COL applications already submitted, as well as submittal of new COL applications in the U.S. The **AP1000** plant complies with most of the requirements in the URD [6]. For those requirements where exceptions are taken, technical justification has been provided. In addition, Westinghouse's European Passive Plant based on the **AP1000** plant has received formal certification of compliance from the European Utilities Requirements (EUR) organization [7]. Regulatory design approval in each country is underway. The main challenges that remain ahead for the **AP1000** plant are successful completion of the plants under construction, obtaining additional plant orders, and achieving the design goals for a safe, reliable, and cost-effective fleet of nuclear power plants.

The **AP1000** plant also has a role in the development of Small Modular Reactors (SMR) in the U.S. and internationally. The advancements made with the **AP1000** plant passive systems design concepts, simplicity, standardization, and modularization will all be incorporated into the Westinghouse SMR. The construction, startup and operating experience that is accumulating with the eight **AP1000** plants under construction in the U.S. and internationally are providing real-world lessons learned for the SMR.

15A.10 REFERENCES

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3. Saiu, G. and Frogheri, M.L., AP1000 Nuclear Power Plant Overview, ANSALDO Energia S.p.A – Nuclear Division.
4. Westinghouse AP1000 Passive Nuclear Plant Design Control Document.
5. ASME Boiler & Pressure Vessel Code, 1998 Edition up to and including the 2000 Addenda.
6. Electric Power Research Institutes, *Advanced Light Water Reactor Utility Requirements Document (URD)*, Volume III - ALWR Passive Plant, Revision 8, March 1999.
7. European Utilities Requirements Document.

15A.11 NOMENCLATURE

ADS	automatic depressurization system
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
BWR	boiling water reactor
CCS	component cooling water
CMF	core melt frequency
CMT	core makeup tank
COD	commercial operating date
COL	combined operation license
DCD	Design Control Document
EPRI	Electric Power Research Institute
ESP	early site permit
EUR	European Utilities Requirements
I&C	instrumentation and control
HVAC	heating, ventilating, and air-conditioning
IRWST	in-containment refueling water storage tank

LRF	large release frequency
LOCA	loss of coolant accident
LWRs	light water reactors
MCR	main control room
MWe	megawatt electrical
MWt	megawatt thermal
NRC	Nuclear Regulatory Commission
PCS	passive containment cooling system
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PRHR	passive residual heat removal system
PRHR HX	passive residual heat removal heat exchanger
PSA	probabilistic safety assessment
PWR	pressurized water reactors
PXS	passive core cooling system
RCP	reactor coolant pumps
RHR	residual heat removal
RPV	reactor pressure vessel
SG	steam generator
T/C	thermocouples
SWS	service water system
UBC	uniform building code
URD	Utilities Requirement Document

15B EPR

15B.1 INTRODUCTION

The EPR is an evolutionary, 1600+ MWe (net) pressurized water reactor (PWR) design based on experience from several thousand reactor-years of operation of light water reactors (LWRs) worldwide, primarily incorporating features of the N4 and KONVOI reactors currently operating in France and Germany, respectively. The design integrates the results of decades of research and development programs performed around the world. The EPR is safer and more economical to operate than previous reactors, and it is being built now in Finland and France. The EPR design is described in this chapter using information predominantly from published sources [1, 2].

15B.2 EPR DEVELOPMENT

The French-German cooperation set up to develop the EPR brought together power plant vendors, major utilities, and the safety authorities from both countries. The design objectives for what was to become the EPR were set early in the project by the collaborators:

- **Evolutionary:** The design should be based on existing PWR construction experience, research and development, operating experience and "lessons learned."
- **Improved economics:** Generation cost should be reduced by at least ten percent as compared with the latest operating reactors. In addition, operations and maintenance should be simplified.
- **Safer:** Increase design margins, reduce reliance on operator actions, increase diversity of safety functions, and significantly reduce core damage frequency. Furthermore, severe accidents (core melt scenarios) and external hazards (including explosions and aircraft hazards) must be accommodated with no long-term local population effect.
- **Sustainability:** Reduce occupational radiation exposure, uranium usage, and generation of low level radioactive waste.

The EPR design meets these development goals and more. The designers considered the expectations of utilities as stated in the "European Utility Requirements" (EUR) [3] document and the "Utility Requirements Documents" (URD) [4] issued by the U.S. Electric Power Research Institute (EPRI). The U.S. version of EPR has been assessed against operating experience compiled by the Institute of Nuclear Power Operations in Report 06-001 [5] and the relevant lessons-learned have been incorporated.

15B.3 PLANT DESIGN

The EPR is a four-loop PWR with a power rating of 4300–4590 megawatt thermal (MWt) and a nominal net electrical output of 1600–1650 megawatt electric (MWe). The net output depends largely on the type of condenser cooling and the local ambient temperatures of the plant site. Plant structures and components have a 60-year design life. As an evolutionary design, a combination of active and passive safety systems are employed. The availability factor over the life of the plant is expected to be 92-to-94 percent, which is dependent upon whether a 12-month, 18-month, or 24-month cycle length is employed by the owner.

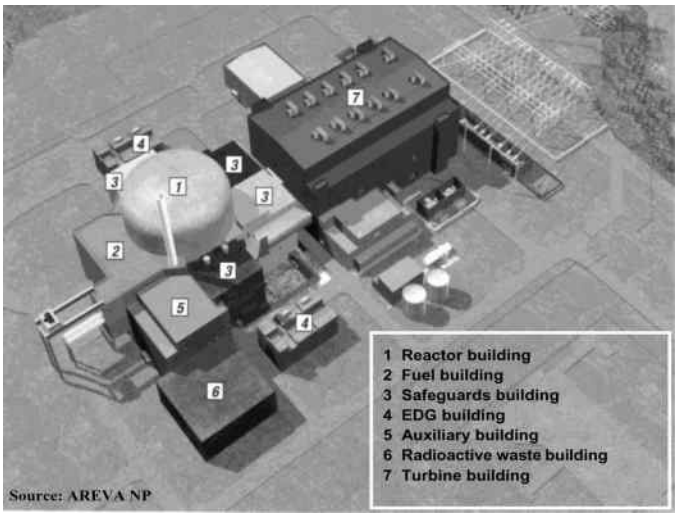


FIG. 15B.1 LAYOUT OF EPR POWER BLOCK
(*Source*: AREVA-NP)

15B.3.1 EPR Layout

Layout of the EPR offers unique resistance to external hazards, especially earthquakes and airplane crashes. To withstand a major earthquake, the entire Nuclear Island stands on a single thick, reinforced concrete base mat. Building heights have been minimized and heavy components and water tanks are located at the lowest possible levels. To withstand a large airplane crash, the Reactor Building, Spent Fuel Building, and two of the four Safeguard Buildings are protected by a shield building made of reinforced concrete. The other two safeguard buildings are protected by geographical separation. Similarly, the emergency diesel generators are in two geographically separate buildings to avoid common failures.

The footprint of the EPR is similar to a typical 4-loop PWR. Of course, the power output of the EPR is significantly greater for the same land use. The general site layout of the EPR power block is shown in Fig. 15B.1.

15B.3.1.1 Reactor Building The Reactor Building, located in the center of the Nuclear Island, houses the main equipment of the Nuclear Steam Supply System (NSSS). It consists of a cylindrical, post-tensioned concrete containment with a steel liner surrounded by a reinforced concrete shield building.

15B.3.1.2 Fuel Building The Fuel Building, located on the same common base mat as the Reactor Building and the Safeguard Buildings, houses the fresh fuel, the spent fuel in an interim fuel storage pool, and associated handling equipment. The fuel building is surrounded by a reinforced concrete shield building to protect the spent fuel and fuel building systems from external explosives or aircraft hazards.

15B.3.1.3 Safeguard Buildings Four Safeguard Buildings house the safeguard systems, such as the Safety Injection System and Emergency Feedwater System, and their support systems. Each Safeguard Building contains a separate, redundant safety division that includes a medium head safety injection system, a combined low head safety injection and residual heat removal system,

component cooling water system, emergency feedwater system, and all supporting electrical supplies, instrumentation/controls, and HVAC (healing, ventilation and air conditioning). This separation ensures that internal hazards, such as fire or flood, in one building cannot propagate to the other buildings.

Two of the safeguard buildings are surrounded by a reinforced concrete shield building to protect the systems, structures and components (SSCs) from external explosions or aircraft hazard. The main control room is in one of the shielded safeguard buildings. The safe shutdown facility is in the other shielded safeguard building.

15B.3.1.4 Diesel Buildings The two diesel buildings shelter the four emergency diesel generators and their support systems, which supply electricity to each safeguard train in the event of a complete loss of offsite electrical power. Each building is placed on opposite side of the nuclear island to minimize the likelihood that an external event could affect the emergency power supplies of all the four divisions.

15B.3.1.5 Nuclear Auxiliary Building The Nuclear Auxiliary Building (NAB) primarily houses systems that maintain reactor coolant chemistry, dissolved gas content, and concentrations of radioactive species within limits. Special laboratories for sampling systems are at the lowest level. Upper levels, designed as a radiological noncontrolled areas, maintenance and setdown areas used during refueling outages.

15B.3.1.6 Waste Building The waste building is used to collect, store, and treat liquid and solid radioactive waste.

15B.3.1.7 Turbine Building The Turbine Building houses all the main components of the steam-condensate feedwater cycle. It contains the turbine-generator set, the condenser, and their auxiliary systems. The turbine/generator (T/G) design is optimized based on regional variations in grid frequency and condenser cooling water temperatures.

15B.3.1.8 Essential Service Water System Cooling Structures The standard EPR design uses once-through cooling to remove the heat from the component cooling water system. However, the U.S. EPR design employs safety-related mechanical-draft cooling towers as the ultimate heat sink for the essential service water. Each division has a dedicated cooling tower and basin located within the protected area. The cooling towers are grouped in divisional pairs, with each pair located on opposite sides of the power block to minimize the likelihood an external event could affect the cooling of all the four divisions.

15B.3.2 Nuclear Steam Supply System

The EPR nuclear steam supply system is of the well-proven 4-loop design (see Fig. 15B.2–Source: AREVA NP). EPR main reactor components—reactor pressure vessels, pressurizer, and steam generators—feature larger volumes than similar components from previous designs to provide additional operational and safety margins. Larger water and steam volumes in the pressurizer smooth the response of the plant to normal and abnormal operating transients, allowing extended time to counteract transients. The larger volume of the steam generator secondary side results in an increased secondary water inventory, providing up to 30 min of core decay heat removal in the event of total loss of feedwater. Some characteristics of the EPR NSSS are listed in Table 15B.1.

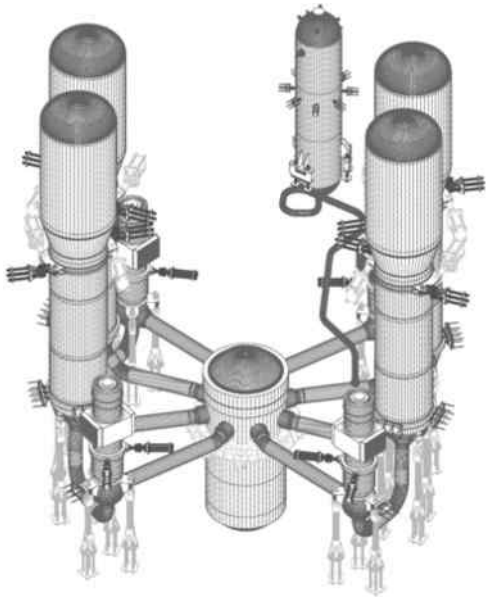


FIG. 15B.2 US-EPR NUCLEAR STEAM SUPPLY

TABLE 15B.1 NSSS CHARACTERISTICS [4]
(*SOURCE*: AREVA NP)

Parameter	Value
Design life, yr	60
Reactor power, MWt	4590
Hot leg temperature, °F	624.5
Cold leg temperature, °F	563.5
Reactor coolant flow per loop, gpm	124,730
Primary system operating pressure, psia	2250
Primary system design pressure, psia	2550
Steam generator exit pressure, psia	1109
Steam generator design pressure, psia	1450
Steam flow per loop, mLb/HR	5.11
Reactor coolant system volume, cu. ft.	16,245
Pressurizer volume, cu. ft.	2649
Steam generator secondary inventory LBM	182,000

15B.3.2.1 Reactor Pressure Vessel and Internal Structures The Reactor Pressure Vessel (RPV) contains the core. The closure head is fastened to the top of the RPV by a set of studs, which allows removal of the closure head for refueling the reactor.

The reactor pressure vessel is comprised of a number of large forgings of low alloy carbon steel. This minimizes the number of welds, which reduces the manufacturing cost and the time required for in-service inspections. In-core instrumentation is introduced through the closure head at the top of the RPV. Consequently, there are no penetrations through the lower head of the RPV.

The RPV and its closure head are made of forged ferritic steel - SA 508, Gr. 3, Cl. 1 - a material that combines adequate tensile strength, toughness, and weldability. The internal surfaces of the RPV and the closure head are clad with stainless

steel for corrosion resistance. All materials are specified with a low Cobalt content to minimize the radiation source term from corrosion products.

Significant safety margin against the risk of brittle fracture (due to material aging under irradiation) is ensured over the entire 60-year design life. The ductile-brittle transition temperature (RTNDT) of the RPV material remains lower than 86°F at the end of the design life, thanks to a stainless steel neutron reflector surrounding the core that reduces the fast neutron flux at the RPV.

The Reactor Pressure Vessel Internals (RPVI) support the fuel assemblies and keep them properly aligned and spaced to ensure free motion of the control rods and core cooling by the primary coolant under any circumstances, including postulated accidents. The RPVI allow insertion and positioning of the in-core instrumentation as well as protection against flow-induced vibrations during reactor operation.

The base material of the internals is a low-Carbon chromium-nickel stainless steel. The various connectors (bolts, pins, tie rods, etc.) are made of cold-worked Chromium-Nickel-Molybdenum stainless steel. At some locations, hard-facing materials are used to prevent fretting wear.

15B.3.2.2 Reactor Core The reactor core contains the fuel material in which the fission reaction takes place, releasing energy. The core is cooled and moderated by light water at a pressure of 2250 psia and a temperature of approximately 594°F.

The EPR core consists of 241 fuel assemblies. Fuel cycle length can vary from 12 to 24 months, with UO_2 fuel and mixed oxide fuel. The main features of the core and its operating conditions have been selected to obtain not only high thermal efficiency of the plant and low fuel cycle costs, but also extended flexibility for different fuel cycle lengths and a high level of maneuverability.

Each fuel rod bundle consists of bottom and top nozzles, 24 guide thimbles, 10 spacer grids, and 265 fuel pins. The spacer grids are vertically distributed along the assembly structure. Inside the assembly, the fuel rods are vertically arranged in a square lattice with a 17×17 array. The bottom nozzle is equipped with an anti-debris device that almost eliminates debris-related fuel failures.

The guide thimbles are used as locations for the absorber rods of the Rod Cluster Control Assemblies (RCCAs) and, when required, for fixed or moveable in-core instrumentation and neutron source assemblies.

The EPR fuel design benefits from years of experience. Each feature is currently in use in operator reactors.

15B.3.2.3 Core Instrumentation Core instrumentation consists of ex-core instruments, fixed in-core, and movable in-core instrumentation. Core power is measured using ex-core instrumentation that measures the neutron flux outside the reactor vessel. The fixed in-core instrumentation consists of self-powered neutron detectors and thermocouples that measure the neutron flux distribution in the core and the temperature distribution at the core outlet, respectively. The output of the self-powered neutron detectors is calibrated to a reference three-dimensional power distribution generated using the movable in-core instrumentation or "aeroball" system. The in-core instrumentation is inserted into the core through the reactor pressure vessel losure head, eliminating instrument nozzle penetrations in the lower RPV head.

15B.3.2.4 Control Assemblies The core has a fast shutdown control system comprising 89 Rod Cluster Control Assemblies (RCCAs). All RCCAs are of the same type. Each consists of 24 identical absorber rods, fastened to a common head assembly. These rods contain neutron-absorbing materials, and when fully inserted in the core, ensure shutdown of the fission chain reaction.

The U.S. EPR is equipped with HARMONI™ RCCAs, a proven AREVA NP design. The neutron-absorbing components are bars made of an Ag-In-Cd alloy. Each rod is composed of a stack of Ag-In-Cd bars contained in a stainless steel cladding under a Helium atmosphere (for efficient cooling of the absorbing materials).

15B.3.2.5 Control Rod Drive Mechanisms The Control Rod Drive Mechanisms (CRDMs) insert and withdraw the 89 RCCAs over the entire height of the core and hold them in any selected position so that core power may be controlled by the control system or the operator. The other function of the CRDMs is to drop the RCCAs into the core to shut down the reactor in a few seconds by stopping the chain reaction, particularly in the case of an abnormal situation. The CRDMs are of the same type as those used in the KONVOI reactors, which have an excellent operating history.

The CRDMs are bolted to adapters welded to the reactor vessel closure head. Each CRDM is self-contained and can be fitted or removed independently of the others. The CRDMs do not need forced ventilation of the coils, which saves space on the reactor head.

15B.3.2.6 Steam Generators The steam generators (SGs) are the interface between the primary water heated by the nuclear fuel and the secondary water, which provides steam to the turbine generator. The EPR steam generator is a vertical, U-tube, natural circulation heat exchanger equipped with an axial economizer (Fig. 15B.3—Source: AREVA NP). It is an enhanced version of the steam generator currently operating in the N4 units in France.

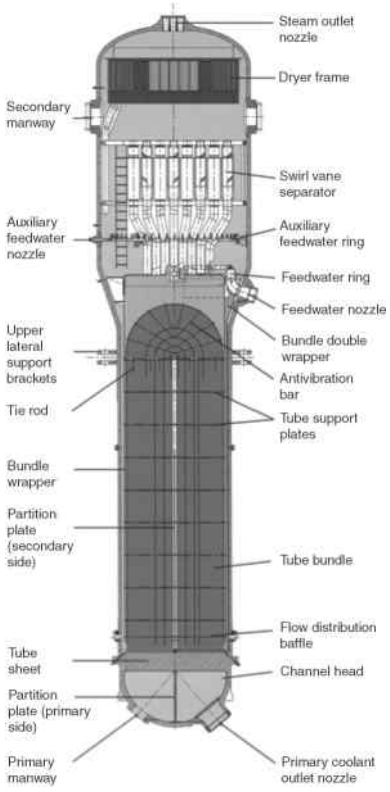


FIG. 15B.3 STEAM GENERATOR (*Source*: AREVA NP)

The EPR SG is comprised of two subassemblies:

- A lower section, or boiler, where the heat exchange process between the primary water and the secondary water takes place
- An upper section where the steam-water mixture is mechanically dried before it is routed to the turbine via the main steam lines

Increased heat exchange area as compared with existing PWRs, in conjunction with the axial economizer, make it possible to reach a steam exit pressure of 1109 psia. Heat transfer efficiency is increased by an axial economizer that directs 100% of the cold feedwater to the cold leg of the tube bundle and about 90% of the hot recirculated water to the hot leg. This increases steam pressure by about 43 psi compared to a conventional steam generator, while avoiding tube wear and water hammer experienced by early PWRs with preheat-type SGs.

The tube bundle is made of thermally treated alloy-690, a proven alloy resistant to stress-corrosion. Tube support plates and anti-vibration bars are made of stainless steel and meticulously assembled such that significant tube wear is eliminated. The SG bundle wrapper and shell are made of SA-508 steel. Extensive use of forgings for the SG shell sections reduces the number of welds requiring in-service inspection.

15B.3.2.7 Reactor Coolant Pumps The Reactor Coolant Pumps (RCPs) provide forced circulation of water through the reactor coolant system. This circulation removes heat from the reactor core to the steam generators, where it is transferred to the secondary system.

The RCP design is an enhanced version of the model used in the N4 reactors. This pump model is characterized by the very low vibration level of its shaft line due to the hydrostatic bearing installed at the end of the impeller. The pump capacity has been increased to match the EPR operating point. In addition, a new safety device called a standstill seal has been added as shaft seal back-up.

The pump contains three dynamic shaft seals made of advanced face materials to minimize wear and extend seal life. The seals are cooled by seal injection or by a low pressure water coil, each capable by itself to cool the seals. The standstill seal is a new design that prevents leakage from the pump seals if there is a total loss of cooling water, that is, seal injection and thermal barrier cooling are lost.

All parts of the reactor coolant pump are replaceable. Pump internals can be easily removed from the casing. The spool piece between the pump shaft and the motor shaft enables rapid maintenance of the controlled leakage seal with the motor in place.

15B.3.2.8 Main Coolant Lines The reactor main coolant lines convey the reactor coolant from the reactor pressure vessel to the steam generators and then to the reactor coolant pumps, which discharge it back to the reactor pressure vessel. Materials and manufacturing processes were selected to yield a high-quality, tough product, improve inspectability and significantly reduce the number of welds. Already in use on the N4 reactors at the Civaux site, the material is forged austenitic steel, which exhibits excellent resistance to thermal aging and permeability for ultrasonic testing. The hot leg is forged, with separate forged elbows. The cold leg is made using "one-piece technology" with an elbow machined out of the forging. The surge line also consists of several segments. The surge line routing was designed to avoid thermal stratification during steady state operation.

Major advances in welding processes are being implemented. For example, the homogeneous circumferential welds are made using orbital narrow gap TIG welding technology. The weld is made with an automatic TIG machine, which enables a large reduction of the volume of weld metal and an enhanced quality level. The bimetallic weld joining austenitic to ferritic parts (like reactor pressure vessel or steam generator nozzles) is made by direct automatic narrow gap welding of alloy-52. Large nozzles are integral with the main coolant lines and are machined from the forging of the piping, which improves resistance to thermal fatigue.

15B.3.2.9 Pressurizer The pressurizer (PZR) maintains the pressure of the primary circuit within prescribed limits. It is part of the primary circuit and is connected through a surge line to the hot leg of one of the four loops of that circuit.

The pressurizer contains primary water in the lower part and steam in the upper part. Compared to previous designs, the volume of the EPR pressurizer is significantly increased to smooth the response to operational transients. This improvement increases equipment life duration and time available to counteract potential abnormal situations in operation.

Relief and safety valves at the top of the pressurizer protect the primary circuit against overpressure. Compared to previous designs, the EPR features an additional set of motorized valves. In case of a postulated accident with a risk of core melting, these valves provide the operator an additional efficient means of rapidly depressurizing the primary circuit and avoiding a high-pressure core melt situation.

A number of design features have been incorporated to improve maintainability. In particular, a platform between the pressurizer head and the relief valves reduces radiological dose during valve service. All the pressurizer boundary parts, with the exception of the heater penetrations, are made of forged ferritic steel with two layers of stainless steel cladding. The steel grade is the same as that for the reactor pressure vessel. Heater penetrations are made of stainless steel.

15B.3.3 Anciliary Systems

15B.3.3.1 Chemical Volume and Control System The Chemical and Volume Control System (CVCS) performs several operational functions similar to existing PWRs:

- Continuously controls the water inventory of the Reactor Coolant System (RCS).
- Adjusts the RCS Boron concentration to control power variations, start-up or shutdown the plant, or to compensate for core burnup.
- Monitors the Boron concentration of all fluids injected into the RCS, and controls the concentration of dissolved gases in the RCS.
- Enables the adjustment of the RCS water chemistry.
- Provides seal injection to the RCP seal system.
- Provides a pressurizer auxiliary spray, if the normal system cannot perform its function

15B.3.3.2 Safety Injection System/Residual Heat Removal System The Safety Injection System/Residual Heat Removal System (SIS/RHRS) comprises Medium Head Safety Injection System (MHSI), Accumulators, Low-Head Safety Injection System (LHSI) and the In-Containment Refueling Water Storage Tank (IRWST). The system performs a dual function both during the normal operating conditions in RHR mode and in the event of an accident.

The system consists of four separate and independent trains, each providing the capability for injection into the RCS by an accumulator, an MHSI pump, and an LHSI pump, with a heat exchanger at the pump outlet. While operating in residual heat removal (RHR) mode, the system.

- Provides the capability for heat transfer from the RCS to the Component Cooling Water System (CCWS).
- Transfers heat continuously from the RCS or the reactor refueling pool to the CCWS during cold shutdown and refueling shutdown.
- In the event of a postulated accident, and in conjunction with the CCWS and the Essential Service Water System (ESWS), the SIS in RHR mode maintains core cooling at RCS temperatures less than 350°F.

The four redundant and independent SIS/RHRS trains are arranged in separate divisions in the Safeguard Buildings. Each train is connected to one dedicated RCS loop and is designed to provide the injection capability required to mitigate accident conditions. This configuration greatly simplifies the system design. In addition, the four divisions allow extended periods of online preventive maintenance or repairs because preventive maintenance may be carried out on one safety train during power operation.

In safety injection mode, the main function of the SIS is to inject water into the reactor core following a postulated loss-of-coolant accident. It would be also activated during a steam generator tube rupture or during loss of a secondary side heat removal function. The MHSI system injects water into the RCS at a pressure (<1400 psia) set to prevent lift of the secondary side safety valves in the event of steam generator tube leaks. The accumulators and the LHSI system also inject water into the RCS cold legs when the primary pressure is sufficiently low (650 psia and 305 psia, respectively).

15B.3.3.3 In-Containment Refueling Water Storage Tank (IRWST) The IRWST contains a large amount of borated water and collects water that might be discharged from the RCS to the containment. Its main function is to supply water to the SIS, Severe Accident Heat Removal System, and Chemical and Volume Control System (CVCS) pumps, and to flood the spreading area in the event of a severe accident.

The tank is located at the bottom of the containment below the operating floor, between the reactor cavity and the missile shield. During the management of a postulated accident, the IRWST content is cooled by the LHSI system.

Screens are provided to protect the SIS, CHRS, and CVCS pumps from debris that might be entrained with the IRWST fluid under accident conditions.

15B.3.3.4 Emergency Feedwater System The Emergency Feedwater System (EFWS) ensures that water is supplied to the steam generators when all other feedwater supply systems are unavailable. This system consists of four separate and independent trains, each providing injection capability through an emergency pump that takes suction from an EFWS tank housed in the safeguard building. As the name denotes, this system is only used for emergency conditions. For start-up and operation of the plant, dedicated feedwater systems, separate from EFWS, are provided for plant startup and normal operation.

15B.3.3.5 Extra Borating System The Extra Borating System (EBS) is a safety-related source of borated water to maintain shutdown of the reactor chain reaction as the plant is cooled to cold shutdown. This system consists of two separate and independent trains, each capable of injecting the total amount of concentrated boric acid required to reach the cold shutdown condition from any steady-state power operation.

15B.3.3.6 Component Cooling Water The Component Cooling Water System (CCWS) transfers heat from the safety-related systems, operational auxiliary systems and other reactor equipment to the ultimate heat sink via the Essential Service Water System (ESWS). The CCWS consists of four separate safety trains corresponding to the four divisions of the safeguard buildings.

15B.3.3.7 Essential Service Water System The ESWS consists of four separate safety trains that cool the CCWS heat exchangers with water from the ultimate heat sink during all normal plant operating conditions and during incidents and accidents. This system also includes two trains of the dedicated cooling chain for conditions associated with the mitigation of postulated severe accidents.

15B.3.3.8 Other Systems The Nuclear Sampling System takes samples of gases and liquids from systems and equipment inside reactor containment. The vent and drain system collects gaseous and liquid waste from systems and equipment so that it can be treated. The Steam Generator Blowdown System prevents build-up of contaminants in the secondary side water, and the Waste Treatment System ensures the treatment of solid, gaseous and liquid wastes.

15B.3.4 Fuel Handling and Storage

The reactor core is periodically reloaded with fresh fuel assemblies. The spent fuel assemblies are moved to and stored under water in the Spent Fuel Pool, which resides in the Fuel Building. These operations are carried out using several handling devices and systems and a fuel transfer tube that connects the containment and fuel buildings.

The temperature of the fuel pool water is controlled by the Fuel Pool cooling system, which has two independent trains that remove heat from the pool and transfers it to the CCWS. Water quality of the fuel pool is maintained by the fuel pool purification system, which is also used to purify the water in the in-containment refueling water tank, as needed.

15B.3.5 Instrumentation & Control System

A nuclear power plant, like any other industrial facility, requires a means of monitoring and controlling processes and equipment. This is performed by the plant instrumentation and control (I&C) system, which is comprised of several systems and their electrical and electronic equipment.

The I&C system is composed of sensors to transform physical data into electrical signals, programmable controllers to process these signals, and the control actuators, monitors and other means of control by plant operators.

The EPR I&C system is completely computerized and supported by the most modern digital technologies to provide operational flexibility. However, the technology is far from first-of-a-kind. AREVA NP uses a proven TELEPERM-XS™ technology for safety-related applications and a diverse technology for standard plant controls that is validated through use on industrial plants throughout the world.

15B.3.5.1 I&C Design Philosophy The I&C systems act in accordance with the "defense-in-depth" concept:

- The control system maintains the plant parameters within their normal operating ranges.
- In case a parameter leaves normal range, the limitation system generates appropriate actions to prevent protective actions from having to be initiated.
- If a parameter exceeds a protection threshold, the reactor protection system generates the appropriate safety actions (reactor trip and safeguard system actuation).

15B.3.5.2 EPR I&C Architecture A multi-level I&C structure is implemented that considers the different roles played by different I&C systems. Level 0 is Process Interface, which comprises the sensors and the switchgears. Level 1, or System Automation, includes I&C systems that perform

- Reactor protection,
- Reactor control, surveillance, and limitation functions,
- Safety automation, and
- Process automation.

Level 2, Process Supervision and Control, consists of

- workstations and display panels, which are also called the man-machine interface (MMI); and
- I&C systems that act as a link between the MMI and the "system automation" level.

The I&C systems and equipment comply with the principles of redundancy, division, and diversity applied to all of the EPR safety-related systems. There are four redundant and independent I&C channels, including power supplies and sensors. Processing equipment for the I&C in each division is contained within the corresponding safeguard building.

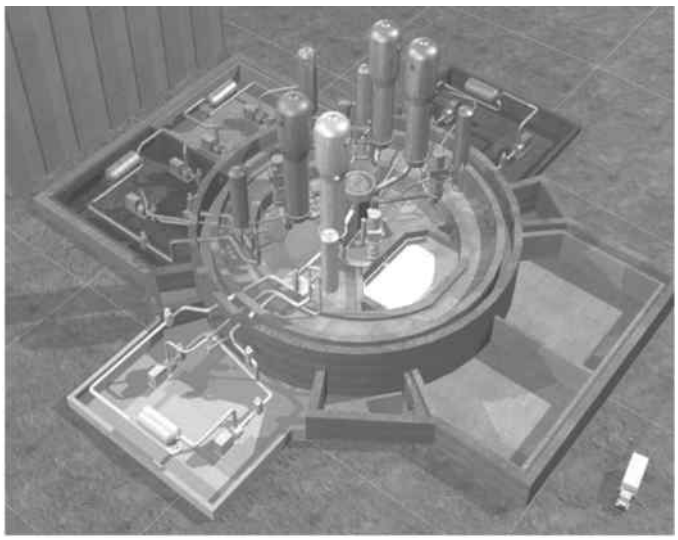


FIG. 15B.4 QUADRUPLE REDUNDANCY WITH PHYSICAL SEPARATION OF DIVISIONS (*Source*: AREVA NP)

15B.4 EPR SAFETY

All light water reactors rely on well-established principles of protective barriers and defense-in-depth to safeguard the health and safety of the public from radiological consequences. This is also true for EPR because the most important design consideration was to base the EPR on experience feedback from the 96 reactors built by AREVA NP around the world, and avoid the risk of unproven technologies.

However, additional goals were applied to the design to significantly enhance the safety of the EPR as compared with previous generations of light water reactors:

- Enhance the defense-in-depth approach, including redundancy and diversity of safety functions, to significantly reduce the probability of core melt
- Provide protection of critical systems from external hazards such as tornado missiles, explosions, or military airplane crash (recently extended to large commercial aircraft)
- Provide design features to mitigate severe accident scenarios and limit potential consequences

15B.4.1 Internal and External Hazards

The design of safeguard systems and civil works minimize the risks arising from various hazards (earthquake, flooding, fire, aircraft crash, or explosion).

The safeguard systems are generally designed on the basis of quadruple redundancy for mechanical systems, electrical supplies, and the I&C that actuate and control the systems. This means that each system is comprised of four sub-systems or "trains," each capable of fulfilling the safeguard function. The four redundant trains are physically separated, each contained within a separate safeguard building (Fig. 15B.4—Source: AREVA NP). Each division includes the following:

- Low-head and medium-head injection systems for borated water safety injection into the reactor vessel in case of loss-of-coolant accident
- An steam generator emergency feedwater system, including water tank inside the safeguard building
- The electrical systems and I&C linked to these systems

The containment building, fuel building, and safeguard buildings are given special protection against external hazards such as earthquakes and explosions. This protection is further enhanced against an airplane crash. The containment building, fuel building, and two safeguard buildings are surrounded by a reinforced concrete shield building with sufficient strength to absorb the impact of a military or large commercial aircraft. The shielded safeguard buildings contain the main control room and remote shutdown station, which is only used if the main control room is not habitable. The other two safeguard buildings that are not protected by a shield wall are remote from each other and separated by the reactor building, which shelters them from simultaneous damage. In this way, should an aircraft crash occur, at least three of the four divisions of the safeguard systems would be preserved.

15B.4.2 Simplification, Redundancy, and Diversity

The main safety systems and their support systems feature four trains, each train in a separate division. Emergency power is assured by use of Emergency Diesel Generators, one for each division.

TABLE 15B.2 EPR PROBABILISTIC RISK ASSESSMENT
(*SOURCE*: AREVA NP)

	NRC Requirement	Gen II	URD/IAEA	EPR
CDF	1×10^{-4}	5×10^{-5}	1×10^{-6}	6×10^{-7}

CDF, Core damage frequency, events per year.

Quadruple redundancy allows each train to connect to a single reactor coolant loop, minimizing cross-connects and reducing the length of pipe and number of valves compared with earlier PWRs.

Furthermore, emergency feedwater and medium head safety injection are only called to operate during accidents or incidents, which simplifies operation (only one operating mode) and reduces maintenance (reduced wear and tear). Operation of safety injection systems during postulated loss of coolant accidents is simplified by use of the in-containment refueling water storage tank, which is the sole source of injection water. This eliminates the need for the operator to switch suction sources when an external tank is dry, which is the case for Generation II PWRs.

Residual heat removal is provided by the four trains of the low-head portion of the safety injection system, which are configured to remove the residual heat in a closed loop (suction via the hot legs, discharge via the cold legs). Safety injection remains available for action in the event of a leak or break occurring in the reactor coolant system.

The design of the EPR provides diverse, back-up functions in the case of total loss of the redundant safety systems. Some examples of this approach are as follows:

- In the event of a loss of all feedwater sources, reactor coolant system cooling can be performed by "feed and bleed" cooling, using primary depressurization valves and safety injection.
- In the event medium heat safety injection is not available to mitigate loss of reactor coolant, steam generator heat removal, accumulator injection, and low head safety injection can replace MHSI.
- Similarly, complete loss of the LHSI system is backed up by the MHSI system and containment heat removal system.
- Loss of off site power with coincident failure of the emergency diesel generators (Station Blackout or SBO) is backed up by two diverse SBO diesel generators that provide power to critical loads in two safeguard divisions.

15B.4.3 Increased Reliability of Operator Action

Safety enhancements at all levels are included in the EPR, and the man-machine interface is a primary example. Advanced digital instrumentation and control (I&C) systems are used to automate most plant functions and reduce the burdens on the plant operators. The designs of the control and protection systems are such that no operator action is required prior to 30 minutes to mitigate any plant upsets. Furthermore, the plant components have been sized to slow the response to upset conditions, supporting this design objective. Relieving the time-pressure from the operator significantly enhances the overall safety of the plant by reducing error-likely situations. Furthermore, unlike other Generation III reactors that use passive safety features that cannot be turned off once they actuate, the operator maintains a certain level of control in EPR to recover the plant from complex events through use of emergency operating procedures.

15B.4.4 Reduced Probability of Core Melt

Although the probability of core melt for Generation II reactors is extremely small (approximately 5×10^{-5} per reactor year), a primary design objective for EPR is to significantly reduce this value. This is consistent with the EPRI Utility Requirements Document and International Atomic Energy Agency (IAEA) [6] requirements for advanced reactors. Specifically, the design goal for EPR is core damage frequency less than 10^{-6} per reactor year for all internal events, which is a significant reduction compared with most modern reactors in operation.

Accomplishing this goal requires detailed probabilistic safety assessments that:

- Consider a broad range of at-power and shutdown events, with special attention paid to shutdown states,
- Augment deterministic defense-in-depth evaluations to add or modify equipment capabilities to reduce the likelihood that abnormal conditions deteriorate into a core damage scenario, leading to many of the plant features described previously in this chapter, and
- Include enhanced reliability of operator actions due to increased automation and improved grace periods.

The detailed Level 1 probabilistic risk assessment (Table 15B.2) shows that the design objective was obtained, and that the EPR design represents a significant safety improvement compared with operating Generation II light water reactors. Furthermore, the sum of the core damage frequencies (CDF) for all events occurring during shutdown states is only ten percent of the total CDF.

15B.4.5 Mitigation of Severe Accidents

As early as 1993, French and German safety authorities introduced a new safety model for future nuclear power plants. Notwithstanding the extremely low likelihood of core melt scenarios, the safety authorities require features to mitigate consequences of a core melt accident. Therefore, features were incorporated into the EPR design to practically eliminate situations that could lead to large early radiological releases. Furthermore, even if a low-pressure core melt is postulated with ex-vessel progression, the approach ensures the integrity of the reactor containment by retaining and stabilizing the corium (i.e., several parallel layers of molten material arranged on top of each other) inside containment and by cooling the corium.

15B.4.5.1 Prevention of High-Pressure Core Melt In addition to the usual reactor coolant system depressurization systems in other reactors, the EPR is equipped with valves dedicated to preventing high-pressure core melt in the event of a severe accident. The relieving capacity ensures the primary system is depressurized long before the corium can melt through the vessel.

15B.4.5.2 Prevention of High-Energy Corium/Water Interaction Design of the corium retention and cooling systems preclude the possibility of an energetic corium water interaction.

15B.4.5.3 Containment Design with Respect to the Hydrogen Risk In the unlikely case of a severe accident, hydrogen could be released in large quantities inside containment. Consequently, the post-tensioned concrete containment building is designed to withstand the pressure that could result from the combustion of hydrogen. In addition, passive autocatalytic hydrogen recombiners are

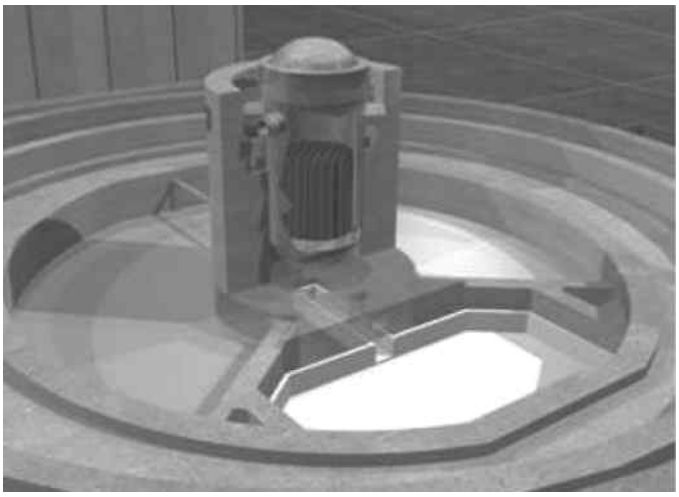


FIG. 15B.5 GENERAL ARRANGEMENT OF RV, IRWST, REACTOR PIT AND CORIUM RETENTION (*Source*: AREVA NP)

installed inside the containment to keep the average concentration below 10% at all times to avoid any risk of detonation.

15B.4.5.4 Corium Retention and Stabilization The reactor pit is designed to collect the corium in case of ex-vessel progression and to transfer it to the corium spreading and cooling area. The reactor pit surface is protected by "sacrificial" concrete, which mixes with the corium, cooling it and decreasing the viscosity of the melt.

Transfer of the corium from the reactor pit to the spreading area would be initiated by a passive melt "plug" that opens the channel between the two areas. After the corium spreads in the spreading area, the corium is passively cooled by gravity injection of water from the in-containment refueling water storage tank. The containment base mat remains cool because the cooling water is directed under the spreading area before it is directed to cooling the corium by direct contact. The arrangement of the reactor pit and corium spreading area are shown in Fig. 15B.5.

15B.4.5.5 Containment Heat Removal Steam generated by cooling the corium during a postulated severe accident would cause the containment building pressure to increase. To prevent the containment from losing long-term integrity, a dedicated spray system is provided with heat-exchangers and dedicated heat sink. This spray can cool the containment atmosphere and prevent pressure increase. Passive containment design features, such as the large containment air volume and concrete heat sinks, allow a long grace period of at least 12 hours before operators must start the spray system.

Containment heat removal system water can also be pumped into the spreading area providing active, forced cooling of the corium in the spreading area.

15B.4.6 Fukushima Event

On March 11, 2011, a magnitude 9.0 earthquake off the coast of Japan caused a large tsunami that swept through the Fukushima Daiichi nuclear site, flooding emergency power generators and switch gear, and damaging important equipment, causing a loss of cooling of three of the six reactors there. The fuel inside those reactors melted and breached the reactor vessel, causing significant radiation releases that continue at the time of this writing. This rare event clearly exceeded the plant design parameters with serious environmental consequences.

The EPR plant safety features described here are designed to handle an event just like the Fukushima earthquake and tsunami. Four redundant, seismically qualified emergency generators provide power to critical equipment required shut down and cool the reactor. The plant is situated above the highest elevation attainable by flood or tsunami. Regardless, power supplies and critical equipment are in watertight buildings with important electrical connections more than 19m above ground. Fuel supplies and electrical connections for these emergency generators are also in seismically qualified, watertight buildings. Cooling water for the emergency generators and other critical equipment, including core cooling equipment, are housed in earthquake-proof buildings completely protected from tornado missiles or other debris. Consequently, the EPR plant has sufficient on-site resources to shut down and cool the reactor for weeks without any outside assistance in case of once-in-a-lifetime natural disaster.

15B.5 CONTAINMENT DESIGN

The EPR containment building is a post-tensioned concrete building, approximately 4.3 ft. thick, surrounded by a reinforced concrete shield building that protects the containment building and all internal systems from external hazards such as explosions or aircraft hazards. A 0.25-inch thick steel liner covers the internal wall of the containment building to ensure a leak-tight barrier in case of radiation release from the reactor. The design pressure of the containment building is 62 psig, ensuring structural integrity following postulated design basis accidents or severe accident (core melt) scenarios.

A "two-room" concept is used to separate the NSSS equipment from the rest of containment. The major NSSS components inside the equipment space reside in separate compartments. In fact, concrete walls are erected between the individual coolant loops and between the hot leg and cold leg piping of each loop.

Other equipment is contained in the service compartments. Locating ancillary equipment separate from the equipment space allows personnel entry to the containment at any time during power operation to perform maintenance or prepare for refueling outages. Personnel hatches are provided for that purpose.

Air temperatures and air quality are maintained by a nonsafety related HVAC system during normal operation. During postulated pipe rupture scenarios, the containment pressure is maintained by way of passive condensation of vapor on concrete and steel structures and by long-term cooling by the residual heat removal system. There are no safety-related fan coolers or spray systems inside containment. Non-safety related sprays are available for containment cooling in case of a severe accident scenarios. A number of other features, including the reactor pit, corium retention area, and passive autocatalytic hydrogen recombiners already described in this chapter, were incorporated into the containment design to mitigate severe accident scenarios without a breach of containment.

15B.6 CONSTRUCTION

EPR plants are currently under construction in Finland, France and China. Experience gained from those projects regarding construction, procurement, and engineering are factored into the standard EPR approach such that the construction time of EPR rivals the top decile performance of Generation II and III reactors world-wide. This provides certainty necessary for investors in such large projects.

Generally, several techniques may be employed to construct an EPR, including "open-top" construction. Modular construction is employed where there is a clear advantage to the construction schedule. Other labor-saving techniques are employed such as bending pipe to fabricate a piping system, which eliminates a large number of welds, or designing concrete formwork to remain in place. Because EPRs are under construction now, a well-established supply chain is in place, which ensures the certainty of equipment and commodities for future EPR projects. The latest engineering processes, including detailed 3-D layout tools and associated equipment catalogs and part lists, streamline construction by eliminating layout conflicts and allowing for pre-engineered time-saving construction techniques.

15B.7 OPERATION AND MAINTENANCE

A main objective of the EPR design process was to provide a plant with an electricity generation cost at least 10% less than the current generation of operating units. This is approached in two ways. First, improve the capacity factor of the unit to maximize power generation. Second, reduce the operation and maintenance costs.

Extensive operating experience was used to ensure that design features were incorporated in the EPR to improve reliability of systems and components, reduce unwanted reactor trips, reduce refueling outage duration and improve the overall plant availability goal to greater than 94% average.

Single-point vulnerabilities that can lead to power reductions or reactor trips have been eliminated by increasing redundancy or diversity. EPR can accommodate a wide range of plant upsets, including partial or full load rejection, without tripping the reactor. Self-diagnostic features of the digital I&C reduces spurious reactor trips from sensor or controls failures. Use of the latest materials and technologies, proven by operation in reactors, eliminate the degradation, breakdowns or failures that require long shutdowns experienced by Generation II reactors for augmented inspection and repairs.

Most important, quadruple redundancy of the safeguards systems allows on-line maintenance and testing of the equipment in each division, one division at a time. Eliminating maintenance of emergency diesel generators, emergency feedwater pumps, safety injection systems, and supporting systems from the refueling outage window allows a standard refueling outage of less than 15 days.

With respect to plant maintenance, several features were incorporated to simplify activities and reduce costs. The majority of the cost to maintain the plant resides in the non-safety related steam conversion systems, so the following principles were applied to both the nuclear island and turbine island buildings.

The first principle is to procure reliable equipment, with a proven track record, to eliminate the time and expense of performing corrective maintenance (repairs) and to minimize preventative maintenance. Furthermore, equipment or technology that minimizes the time to perform necessary inspections are incorporated into the design. For example, welds in Class 1 and 2 systems are minimized to reduce in-service inspection time and self-checking digital I&C will reduce manual testing and trouble-shooting.

Second, plant layout ensures adequate access for inspection and maintenance of all plant equipment. Floors or permanent platforms are provided at key locations. All components except the reactor vessel can be removed and replaced using pre-engineered haul paths and lifting devices for that purpose. Regardless, laydown space is provided for in-situ maintenance or repairs of equipment, including space to allow temporary storage of components.

The largest portion of the non-fuel operating and maintenance costs of a plant is salaries and benefits for the operating staff, which include operations, maintenance, testing, training, chemistry, human resources, radiation protection, procurement, engineering, security, and administration personnel. Staffing for an EPR is projected to be significantly less than that for an existing 1000 MWe unit. Of course, due to the large output of EPR (1600 MWe), O&M costs will be significantly less than the previous generation of reactors when based on a per MWe basis.

The ALARA principle (as low as reasonably achievable) was applied to the EPR design to reduce radiation exposure to workers. Significant reductions in cobalt content of components, strict design rules to eliminate deposits within equipment, shielding of key process components, and separation of "harsh" and "mild" environments inside buildings mean the average yearly collective dose to plant personnel is less than 0.5 man-Sv (50 man-Rem).

15B.8 CODE ASPECTS

The EPR design accommodates various mechanical, electrical, and civil codes and standards around the world. For example, EPR nuclear steam supply components have been designed to the French RCC-M and ASME Codes. The U.S. version of the EPR is designed to the 2004 edition of the ASME Code, with no addenda.

15B.9 BUILDING NOW

As of the time of this writing, EPR are under construction in Finland (Olkiluoto 3, shown in Fig. 15B.6), France (Flammanville 3), and China (Taishan 1&2). The US Nuclear Regulatory Commission is reviewing the application for design certification as well as several applications for combined construction and operating licenses. In addition, the design has been reviewed by the safety authority in the United Kingdom according to their Generic Design Assessment process.



Photo Courtesy of Teollisudden Voima Oy

FIG. 15B.6 CONSTRUCTION OF OLKILUOTO3

15B.10 REFERENCES

1. *U.S. EPR*, © February 2007, AREVA NP.
2. U.S. EPR Final Safety Analysis Report, Revision 0, © 2007, AREVA NP, Inc.
3. *European Utilities Requirements (EUR) Document*, ©1994–2004, British Energy plc, Electricité de France, Fortum, Iberdrola, NRG, Rosenergoatom, SOGIN (Società Gestione Impianti Nucleari), Swissnuclear, Teollisuuden Voima Oy, Tractebel, Vattenfall, VGB Powertech.
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15C US-APWR

15C.1 INTRODUCTION

Mitsubishi Heavy Industries, Ltd. (MHI) has designed the US-APWR as an advanced pressurized water reactor (APWR), originated for utilities needs and regulatory requirements in U.S.

Basic design of the US-APWR is the same as that of the Japanese APWR whose design has been completed. The design of the Japanese APWR is based on conventional four-loop plant technology, with which MHI has accumulated significant operating experience in Japan, scaled up to achieve higher electrical outputs. In addition to adopting these proven technologies, modifications are also made to the Japanese APWR to improve economy, safety, reliability, operability, and maintainability. The US-APWR has been developed as a larger-scale version of the Japanese APWR, aiming at higher electrical outputs and improved economics, by modifying some design features of the Japanese APWR without increasing core thermal output.

The US-APWR Design Control Document (DCD) [1] was submitted on December 31, 2007 and docketed on February 29, 2008.

15C.2 US-APWR PLANT DESIGN CONCEPT

For the advancement of nuclear power technology in Japan, the Japanese APWR has been developed. The newly developed Japanese APWR is an evolutionary design based on fully tested, well verified, and well established existing PWR technologies.

The US-APWR is fundamentally based on the established Japanese APWR plant with its latest technologies to improve plant efficiency, such as the employment of large steam generator(SG)s and turbines, and other minor modifications to meet U.S. utility requirements. With increased plant safety, reliability, and performance, construction costs are reduced due to the economy of scale resulting from an increase in capacity. The Japanese APWR output of 1538 MWe is produced from the large capacities of the reactor core and other major components such as the SG, reactor coolant pump (RCP), and turbines. The US-APWR plant performance exceeds that of the Japanese APWR plant by 10%. The US-APWR is able to achieve a plant output of 1700 MWe due to its high performance and larger capacity SG and a higher performance turbine system with low pressure (LP) turbines having 70-in. class last stage blades.

Table 15C.1 shows the main differences between the current four-loop (1180 MWe) plant, the Japanese APWR (1538 MWe) plant, and US-APWR (1700 MWe) plant features. The major differences between the US-APWR and current four-loop plant are the thermal and electrical outputs, the number of fuel assemblies and trains of safety systems, and the active fuel lengths. The major differences between the US-APWR and the Japanese APWR are the electric outputs, the active fuel lengths, and the number of electrical trains of safety systems. The adoption of the four-train safety system allows the plant operator to perform online maintenance while still meeting the single failure criteria.

15C.3 OPERATIONAL TECHNOLOGY

The US-APWR is a four-loop pressurized water reactor (PWR) with a power rating of 4451 MWt and a nominal gross electrical output of 1700 MWe. The US-APWR core consists of 257 fuel

TABLE 15C.1 US-APWR FEATURE COMPARISON WITH THE JAPANESE APWR AND CURRENT FOUR-LOOP PLANT (*SOURCE*: MITSUBISHI HEAVY INDUSTRIES, LTD.)

Design Parameter	Current Four-Loop PWR	Japanese APWR	US-APWR
Electric output	1,180 MWe	1,538 MWe	1,700 MWe class
Thermal output	3,411 MWt	4,451 MWt	4,451 MWt
Core	12 ft. Fuel 193 Assys	12 ft. Fuel 257 Asseys	14 ft. Fuel 257 Assys
SG heat transfer area	52,400 ft.^{2}/SG	70,000 ft.^{2}/SG	91,500 ft.^{2}/SG
Thermal design flow rate per loop	88,500 GPM	113,000 GPM	112,000 GPM
Turbine last Stage blades	44 in.	54 in.	70 in.class
Containment vessel	PCCV	PCCV	PCCV
Safety systems	Electrical: 2 trains Mechanical: 2 trains HHSI × 2 Accumulator × 4 LHSI × 2	Electrical: 2 trains Mechanical: 4 trains HHSI × 4 Advanced Accumulator × 4 No LHSI	Electrical: 4 trains Mechanical: 4 trains HHSI × 4 Advanced Accumulator × 4 No LHSI
I&C	Safety System analog Control system: digital	Full digital	Full digital

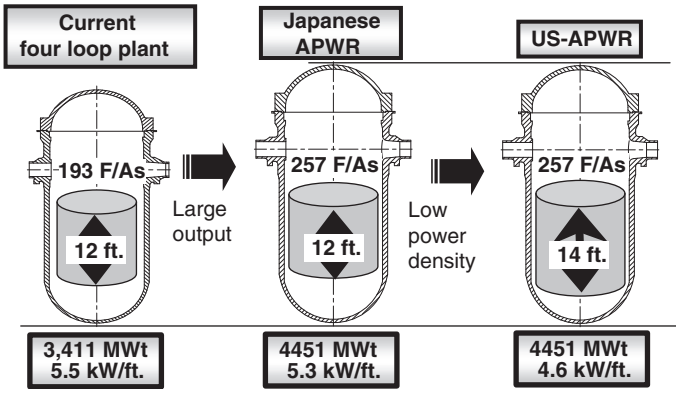


FIG. 15C.1 IMPROVEMENT OF REACTOR DESIGN
(*Source*: Mitsubishi Heavy Industries, Ltd.)

assemblies and has the active fuel length of approximately 14 ft. The fuel assemblies are surrounded by a stainless steel neutron reflector designed to improve neutron utilization, which reduces fuel cycle cost and reactor vessel irradiation compared to the conventional PWRs.

Figure 15C.1 shows a comparison of the core size for different type PWRs. Both the US-APWR and the Japanese APWR have much larger thermal outputs than the conventional PWRs. The introduction of 14-ft. fuel to the US-APWR is achieved without changing the reactor vessel size of the Japanese APWR. The resulting low linear power density, 4.6 kW/ft., allows 24-month operation with 2-batch fuel management as an equilibrium cycle under constraints of 5 wt% U-235 enrichment at the maximum and also at the well-proven maximum fuel rod burnup of 62 GWd/t.

The US-APWR employs the top-mounted incore instrumentation system instead of the bottom-mounted incore instrumentation system used in the conventional plants to eliminate nozzles attached on the reactor vessel bottom dome. Detectors are inserted using peripheral nozzles attached on the reactor vessel closure head by thimble assemblies. The illustration of top-mounted incore instrumentation system is depicted in Fig. 15C.2.

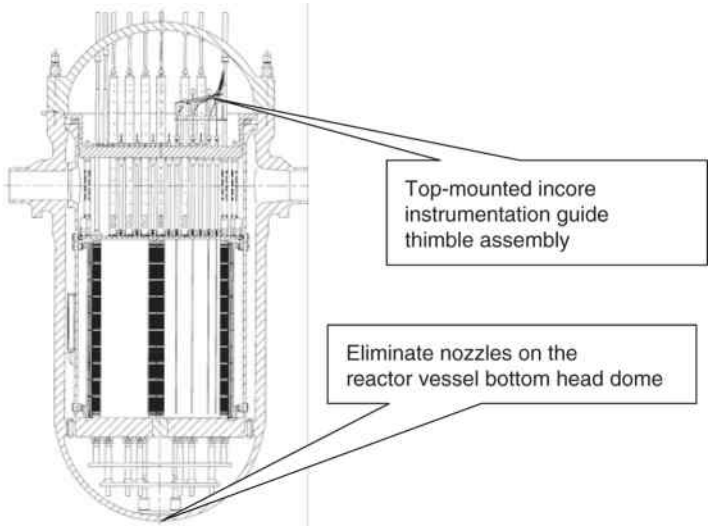


FIG. 15C.2 IMPROVEMENT OF REACTOR DESIGN
(*Source*: Mitsubishi Heavy Industries, Ltd.)

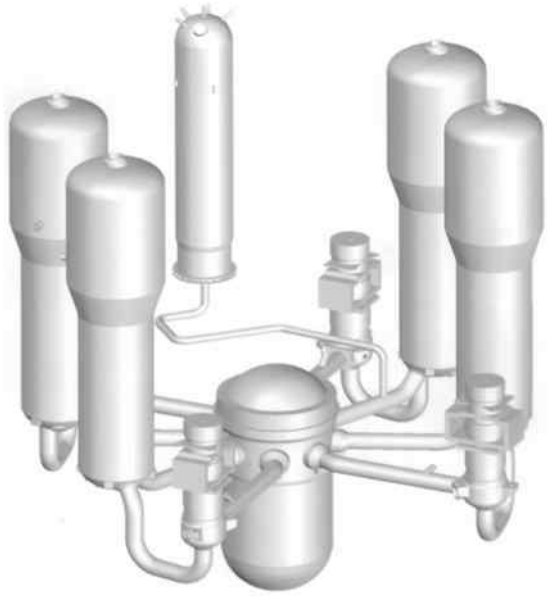


FIG. 15C.3 US-APWR REACTOR COOLANT SYSTEMS
(*Source*: Mitsubishi Heavy Industries, Ltd.)

The basic configuration of reactore cooolant system (RCS), described in Fig. 15C.3, is the same as a currently operating four-loop plant that has been proven through long-term operating experience and enhanced reliability. The main components of the RCS are enlarged in size corresponding to the large thermal output and improved plant efficiency. The pressurizer volume is increased with a larger margin to achieve a more efficient transient response. The SG design is also improved, thus realizing high efficiency and reliability. The tubes are 3/4 in. in diameter, smaller than the 7/8-in. tubes used in the existing plants. This results in a more compact SG with resistance to earthquakes, and so on. The SG tubes are made of thermally treated alloy 690. The design of the antivibration bars in the U-bend area has also been improved to reduce the flow-induced vibration risk of the tubes. Water and steam separation efficiency with the high-performance moisture separators is less than 0.1%.

One high pressure (HP) turbine and three low pressure (LP) turbines are provided in the US-APWR secondary system. Longer blades with 70 in. class for the LP turbines contribute to improvement in higher turbine efficiency. Figure 15C.4 depicts the US-APWRs turbine generator.

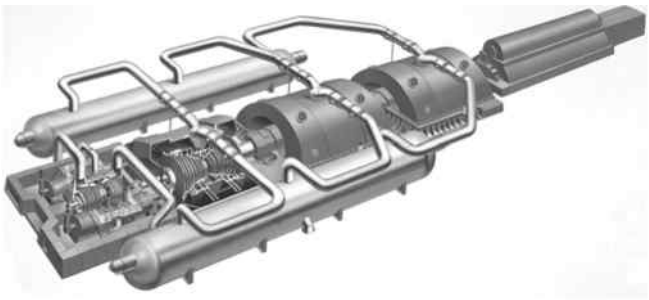


FIG. 15C.4 US-APWR HIGH-EFFICIENCY AND HIGH-RELIABILITY TURBINE GENERATOR (*Source*: Mitsubishi Heavy Industries, Ltd.)

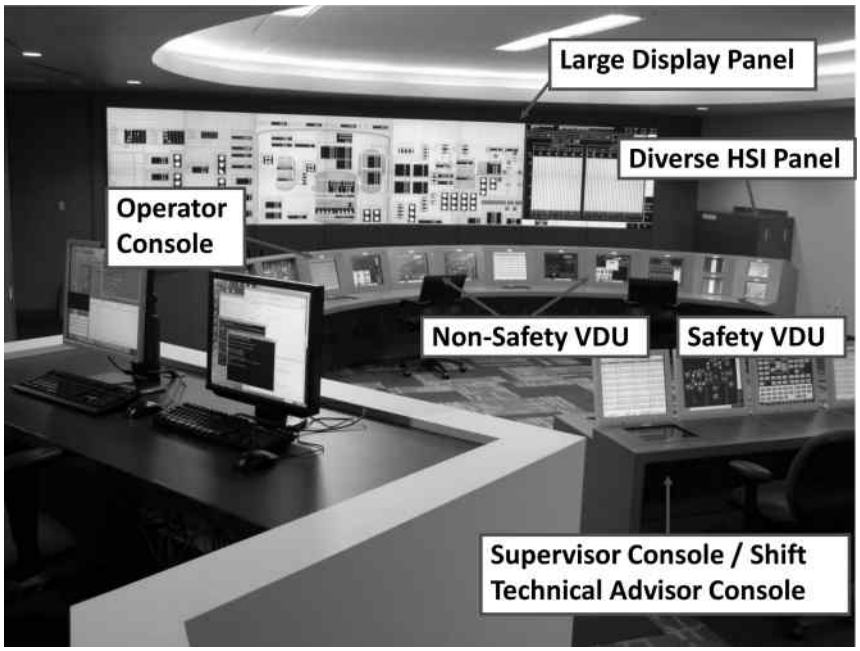


FIG. 15C.5 US-APWR COMPUTERIZED MAIN CONTROL ROOM
(*Source*: Mitsubishi Heavy Industries, Ltd.)

The moisture separator and reheater is adopted to remove the moisture and to reheat the steam between the HP turbines and the LP turbines. Seven-stage feedwater heaters are provided to heat the feedwater to the SGs.

The fully digital system is applied to the instrumentation and control (I&C) system of the US-APWR, including both safety and non-safety systems. The same digital platform has been developed and applied to PWR plants with excellent experiences in Japan, including tha Japanese APWR. Figure 15C.5 shows the main control room (MCR) employing the fully digital I&C system. This proven digital system provides significant benefits to the safety of nuclear power, such as reduction of operations and maintenance workload, which reduces the potential for human error. The design features of the I&C system includes redundancy, defense-indepth and diversity, self-diagnosis, and online maintenance.

The major design modifications of fuel assembly, depicted in Fig. 15C.6, from the Japanese APWR to the US-APWR are the fuel active length from 12 ft. to14 ft. and the number of grids from 9 to 11. All the advanced technologies incorporated into the current 17 × 17 fuel assembly for higher burnup are applied to the US-APWR fuel assembly. The fuel assembly design for the US-APWR is based on the Mitsubishi 17 × 17 fuel assembly that has demonstrated high reliability through significant irradiation experience in Japan. This fuel design improves reliability, enhances fuel economy, and enables flexible core operation.

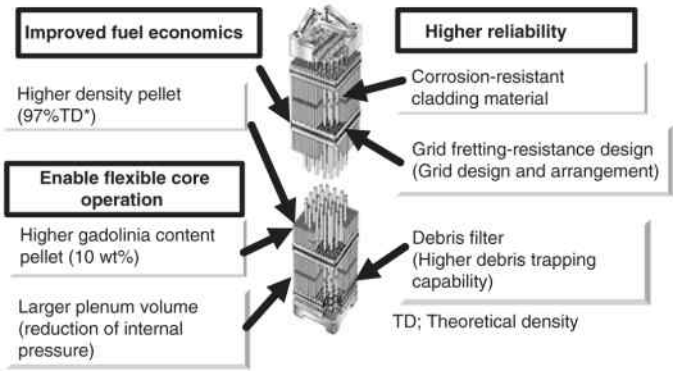


FIG. 15C.6 US-APWR FUEL ASSEMBLY
(*Source*: Mitsubishi Heavy Industries, Ltd.)

15C.3.1 Improved Reliability

- Grid spring design and adoption of an 11-grid design result in high grid fretting resistance. This grid design concept has been proven with long-term no-leakage records in Japanese PWRs for approximately 13 years.
- ZIRLO™* cladding tube demonstrates high corrosion resistance under demanding conditions. *ZIRLO™ is trademark of Westinghouse Electric COMPANY, LLC.
- An antidebris bottom nozzle with a built-in filter enhances debris-trapping capability.

The fuel assembly design for the US-APWR adopts the above features to ensure high reliability.

15C.3.2 Enhanced Fuel Economy

Pellet density of 97% theoretical density (TD), which is greater than the conventional 95% TD, improves fuel cycle cost by increasing the amount of uranium in the core.

15C.3.3 Flexible Core Operation

A higher gadolinia content of up to 10 wt% enables flexible core operation to achieve higher burnup. Furthermore, a larger rod plenum volume can produce potential margin for a rod internal pressure increase caused by fission gas release, especially under high power operation at high burnup.

The main design features of the RCS major components are listed below:

- **Reactor Pressure Vessel:**
  1. Support and encloses the reactor core internals
  2. Four inlet nozzles
  3. Four outlet nozzles
  4. Four direct vessel injection (DVI) nozzles
  5. Top-mounted incore instrumentation penetrations to eliminate penetration below the top of the reactor core

- **Reactor Internals:**
  1. Four hot leg outlet nozzles similar to the conventional plants
  2. Integrated lower core support plate similar to the conventional 14-ft. fuel plants
  3. Perforated metal ring blocks neutron reflector to eliminate bolts in high fluency region
  4. Top-mounted incore instrumentation system to eliminate reactor vessel bottom dome nozzles
  5. Diffuser plates in lower plenum to stabilize core inlet flow

- **CRDMs and Driveline:**
  1. Control rod drive mechanisms (CRDMs) are proven magnetic jack type
  2. Travel length of the rod cluster control assembly complies with 14-ft. fuel

- **Steam Generators**
  1. Four SGs employing triangular pitch tubing
  2. Alloy 690 thermally treated tube material to improve corrosion resistance
  3. Hydraulically expanded tubes in the tube sheet to reduce stress
  4. Stainless steel broached tube supports to minimize corrosion and denting
  5. Advanced antivibration bar design in U-bends to minimize vibration and wear
  6. Improved moisture separators

- **Reactor Coolant Pumps**
  1. The US-APWR RCP has achieved a larger capacity and higher efficiency (over 85%) by improving the impeller and diffuser configuration.
  2. Leakage along the RCP shaft is normally controlled by three shaft seals arranged in series so that any reactor coolant leakage to the containment is essentially reduced to zero.
  3. The advanced seal design of the US-APWR RCP contributes to its longer life and stabilization of No. 1 seal leakage characteristics.
  4. The pump shaft, bearing, seal housing, main flange and thermal shield, diffuser, and impeller of the RCP can be removed from the casing as a unit without disturbing the reactor coolant piping.
  5. All parts of the pump in contact with the reactor coolant are made of stainless steel except for the seals, bearings, and special parts.

- **Pressurizer**
  1. The largest type of the Mitsubishi design (2900 cu ft.)
  2. Enhanced plant control with greater margin for transients

- **Fuel**
  1. 257 fuel assemblies with zircaloy grids
  2. 14-ft. 17 × 17 fuel assembly
  3. Higher burnup features
  4. Antidebris bottom nozzle

- **Incore Instrumentation System**
  1. Top-mounted incore instrumentation

- **Thermocouple Instrumentation**
  1. Thermocouples provided in reactor internals similar to conventional Westinghouse plants.

15C.4 SAFETY FEATURES

The US-APWR incorporates the following safety features (Fig. 15C.7):

1. Four independent safety trains
2. Advanced accumulator system and elimination of low-head safety injection (LHSI) pumps
3. In-containment refueling water storage pit (RWSP)
4. Full digital I&C system
5. MCR emergency habitability system
6. Core debris cooling under severe accident conditions
7. Combustible gas control

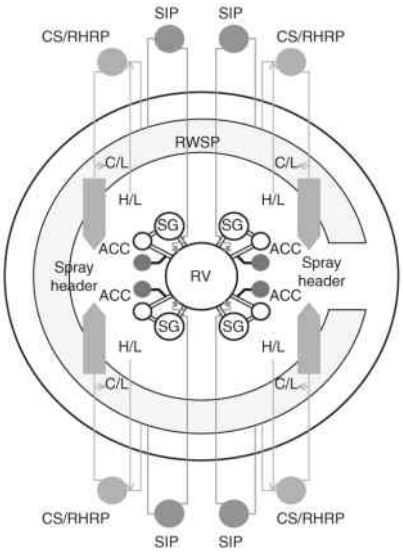


FIG. 15C.7 US-APWR DISTINCTIVE SAFETY SYSTEM RV, REACTOR VESSEL; SG, STEAM GENERATOR; ACC, ADVANCED ACCUMULATOR; SIP, SAFETY INJECTION PUMP; CS/RHRP, CONTAINMENT SPRAY/RESIDUAL, HEAT REMOVAL PUMP (*Source*: Mitsubishi Heavy Industries, Ltd.)

15C.4.1 Four Independent Safety Trains

15C.4.1.1 Four Mechanical Trains – Safety Injection System and Containment Spray System The engineered safety features of the US-APWR employ a four-train system to perform required safety functions following an accident assuming a single failure in one train with a second train out of service for maintenance.

The safety injection (SI) system consists of the high-head injection system (HHIS) and the accumulator system. The HHIS consists of four independent trains, each containing a safety injection pump (SIP). The HHIS is automatically actuated on receipt of an emergency core cooling system (ECCS) actuation signal. The SIP motor is connected to a safety bus, so that the gas turbine generator (GTG) can supply electrical power in case of a loss of off-site power. The SIPs take suction from the RWSP and the stop valve at the inlet line is always open during reactor operation. The HHIS adopts DVI. The four-train DVI system configuration increases redundancy and independency and enhances safety and reliability. The DVI system is a simple and compact safety system, enabling it to reduce the capacity of each train from 100% to 50%. Interconnecting piping between each train is also eliminated.

The US-APWR provides defense-in-depth through the fuel pellet, fuel cladding, reactor coolant pressure boundary, and the containment to prevent fission product release in the event of an accident, in addition to equipment to mitigate fission product release. When an accident that involves a large release of radioactive materials into the containment (ex- loss-of-coolant accident (LOCA)) occurs, radioactive nuclides in the containment atmosphere are removed by the containment spray system (CSS), with the exception of noble gases. Sodium tetraborate decahydrate (NaTB) baskets in the containment maintain the desired postaccident pH conditions in the recirculation water. This equipment helps to prevent re-evolution of iodine. Furthermore, if containment leakage occurs, fission products will be filtered before they are released to the environment through the annulus emergency exhaust system.

The CSS consists of four independent trains, each containing a containment spray/residual heat removal (CS/RHR) heat exchanger, a CS/RHR pump, and valves. The CS/RHR heat exchangers and the CS/RHR pumps are used for both CSS and residual heat removal system (RHRS) functions. The CSS is automatically actuated on receipt of a CS signal. When the signal is received, the CS/RHR heat exchanger outlet valves open and the CS/RHR pumps start. The CS/RHR pump motor is connected to a safety bus, so that the GTG can supply electrical power in case of a loss of off-site power. The CS/RHR pumps take suction from the RWSP and the stop valve at the inlet line is always open during reactor operation. The water in the pit is cooled by the CS/RHR heat exchangers and is delivered to the spray headers located at the top of the containment vessel.

15C.4.1.2 Four Electrical Trains – Electrical Power System and Gas Turbine Generator Safety-related electrical power systems consist of four 50% systems. That is, only two trains are required for safe shutdown of the plant. Each safety-related load is connected to a Class 1E bus. This configuration with four Class 1E power systems allows online maintenance of the GTGs.

Each safety-related electrical power train consists of an alternating current (ac) power system and direct current (dc) power system. Each ac power system consists of 6.9kV ac medium voltage switchgear, 480V ac low voltage buses (Load Centers, Motor Control Centers) and other low voltage distribution. Each safety-related ac medium voltage bus is normally supplied from offsite power, and back-up power is provided by the Class 1E GTGs under a Loss Of Offsite Power (LOOP). Each dc power system consists of a battery charger, a battery and dc buses. Even if the input ac power or battery charger is lost, dc loads can be supplied from the battery without interruption.

The gas turbine is a very simple rotating engine and a GTG system consists of a GTG package, a fuel transfer system, a starting system, an intake, exhaust and ventilation system, and a control/instrument system. There are several advantages to select a GTG in lieu of a diesel generator, which include no cooling water system, easy maintenance, small footprint, and fewer auxiliary systems. The GTG can be applied to US-APWR because the advanced accumulator with LHSI allows a starting time consistent with GTG performance.

15C.4.2 Advanced Accumulator System and Elimination of Low-Head Safety Injection System

The accumulator system consists of four advanced accumulators and associated valves and piping, with one advanced accumulator for each RCS loop. Figure 15C.8 illustrates the US-APWR advanced accumulator. The system is connected to the cold legs of the reactor coolant piping and injects borated water when the RCS pressure falls below the accumulator operating pressure. Pressurized nitrogen gas forces borated water from the advanced accumulators into the RCS. The advanced accumulators incorporate internal passive flow dampers, which function to switch between an initial large flow injection mode and a small flow injection mode. The advanced accumulators inject at a large flow rate to refill the reactor vessel in the first stage of injection and then passively switch to small flow injection as the water level in the accumulator drops.

When the water level is above the top of the standpipe, water enters the flow damper through both the top of the standpipe and the side of the flow damper and thus water is injected at high flow rates. When the water level drops below the top of the standpipe, water enters the damper only through the side inlet and water is injected at relatively low flow rates. The advanced accumulators perform large flow injection to quickly refill the reactor vessel downcomer and lower plenum and then perform a small flow injection to maintain downcomer level during core reflooding in combination with the SIPs. The combined performance of the accumulator system and the HHIS eliminates the need for a conventional LHSI system.

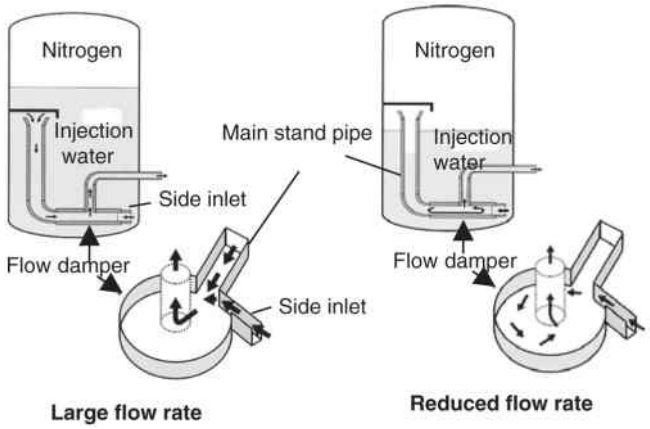


FIG. 15C.8 US-APWR ADVANCED ACCUMULATOR
(*Source*: Mitsubishi Heavy Industries, Ltd.)

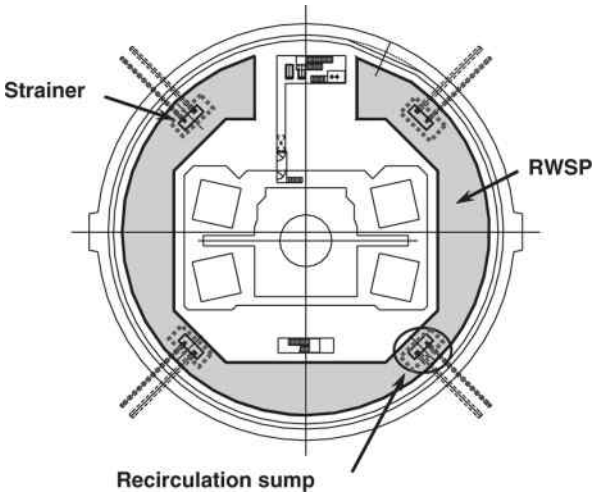


FIG. 15C.9 US-APWR IN CONTAINMENT REFUELING WATER STORAGE PIT (RWSP) (*Source*: Mitsubishi Heavy Industries, Ltd.)

15C.4.3 In-containment Refueling Water Storage Pit

The RWSP of the US-APWR is shown in Figure 15C.9. The RWSP is located at the lowest elevation of containment and includes four recirculation sumps installed at the bottom of the RWSP. Following a LOCA, the recirculation water in the containment is transferred to the RWSP. The containment recirculation pathways include large flow areas, buffer volumes, and debris interceptors to prevent blockage from large debris and promote debris settling in the recirculation path.

The RWSP sumps include strainers to protect downstream components from the effects of post-LOCA debris.The strainers consist of a stacked disc arrangement to provide large surface areas to limit head loss across the strainers and maintain sufficient net positive suction head (NPSH) for the SIP and CS/RHR pumps. This configuration provides a continuous suction source for the SIPs and CS/RHR pumps, thus eliminating the realignment from a conventional refueling water storage tank outside containment to the containment recirculation sump inside containment.

15C.4.4 Full Digital I&C

The US-APWR utilizes a fully digital I&C system with design features that improve plant reliability and operability. Each safety-related I&C system has four separate trains. Duplex redundant digital architecture reduces the likelihood that any one subsystem or component failure will cause a plant disturbance or disable plant safety systems. Self-diagnostic features enable the detection of failed components, including central processing units, input/output modules, and communication modules.

Defense-in-depth and diversity features are applied that provide countermeasures for common cause failures of the digital safety systems. Redundant components are arranged in configurations for continuous parallel operation or standby operation. For stand-by operation, self-diagnostic features automatically switch to redundant stand-by components in case of failure. A fully analog diverse actuation system is provided in case of common cause failure in the digital systems.

Non-safety visual display units (VDUs) are also used for control of safety-related systems and components. This feature enables one reactor operator to control the plant using a non-safety VDU without walking trough between safety and non-safety VDU. This feature also enables to provide all associated plant information and controls in a non-safety VDU. Thus that design feature reduces operator's workload and potential human errors and improves operator's plant control and situational awareness.

15C.4.5 Main Control Room Emergency Habitability System

The MCR heating, ventilation, and air-conditioning system includes two 100% capacity MCR emergency filtration units to maintain the control room within safe habitability limits during emergency pressurization mode and emergency isolation mode. This system establishes the control room envelope (CRE) pressure higher than that of adjacent areas during a radiological accident. Depending on the radiological concentration in the air intake, the MCR operator may select the train of MCR emergency filtration train that would minimize exposure to the CRE. The CRE consists of leak-tight equipment so that unfiltered leakage is maintained at a low value.

15C.4.6 Core Debris Cooling under Severe Accident Conditions

The US-APWR is designed to mitigate hypothetical severe accidents such as reactor vessel failure. The fundamental concept of the US-APWR for severe accident mitigation is to flood the reactor cavity with coolant water and to keep the molten fuel within the reactor cavity. To achieve this, the US-APWR provides reliable reactor cavity flooding features which include two diverse independent coolant water supply systems. Molten fuel behavior under postulated reactor vessel failure was analyzed using a computational code. The calculation result shows that the molten fuel spreads out on the flooded reactor cavity floor and the debris deposition is adequately thin and evenly distributed. Therefore, core debris coolability is sufficient for severe accident mitigation. Analysis was also performed for challenges to containment integrity due to a postulated ex-vessel steam explosion. Containment integrity is maintained with a considerable safety margin and the risk associated with the challenge to containment integrity is negligibly small and acceptable.

The result of calculation for the US-APWR core damage frequency (CDF) (Table 15C.2) meets the U.S. Nuclear Regulatory Commission goal and the Utility Requirement Document (URD) goal [2].

15C.4.7 Combustible Gas Control

The US-APWR systems for combustible gas control include a hydrogen monitoring system and hydrogen ignition system. The hydrogen monitoring system consists of a hydrogen monitor located outside containment to sample containment air extracted through the post-accident radiation monitoring system. The hydrogen ignition system consists of twenty hydrogen igniters located throughout containment.

The hydrogen ignition system is designed to continuously burn hydrogen at a low concentration to prevent significant hydrogen accumulation following a severe accident involving core damage.

TABLE 15C.2 US-APWR PROBABILISTIC RISK ASSESSMENT METRICS (*SOURCE*: MITSUBISHI HEAVY INDUSTRIES, LTD.)

	NRC Requirement	URD Requirement	US-APWR PRA
CDF	1×10^{-4}	1×10^{-5}	3×10^{-6}

The igniters are simple and robust components utilized at conventional PWRs. The US-APWR is designed to control hydrogen which may result from a steam-cladding reaction consisting of 100% of the active length of fuel cladding. The US-APWR containment vessel is designed with large and open volumes to prevent significant hydrogen accumulation. The igniters are powered by either non-safety electrical bus, with cross-connection capabilities to either bus or the alternate ac GTGs. In addition, selected igniters are also provided with dc battery-backup power to ensure their availability for at least twenty-four hours following a loss of all on-site and off-site ac power.

15C.5 BUILDING CONFIGURATION

The equipment layout within the US-APWR buildings is determined to facilitate plant operation and maintenance and minimize personnel radiation exposure. Provisions including redundant train separation and segregation barriers have been made to assure that the functions of the safety-related systems are maintained in the event of postulated incidents such as fires, floods, and high-energy pipe break events. Within the buildings, access control zonings are established to restrict access to radiation areas and to define the required radiation shielding and monitoring during operation, shutdown, and accident conditions.

The US-APWR plant has the following principal buildings, as shown in Fig. 15C.10.

- Reactor building (R/B) (seismic category I)
- Power source buildings (PS/B) (seismic category I)
- Auxiliary building (A/B)
- Access building (AC/B)
- Turbine building (T/B)

The R/B and the small PS/Bs are designed and constructed as safety-related structures to the requirements of seismic category I, as defined in RG 1.29 [3]. The symmetrical arrangement for safety equipment efficiently reduces the required space in the R/B. These design features provide less building volume and cost improvement compared to conventional PWR plants.

Radioactive equipment and piping in all buildings is arranged and shielded to minimize radiation exposure. Pathways through the plant are designed to accommodate equipment maintenance and equipment removal from the plant. The size of the pathways is determined by the largest piece of equipment that may have to be removed or deployed after initial installation. Where required, lay-down space is provided for disassembling large pieces of equipment to facilitate the removal or installation process. Adequate space is provided for equipment maintenance, laydown, removal, and inspection. Hatches, monorails, hoists, and removable shield walls are provided to facilitate maintenance.

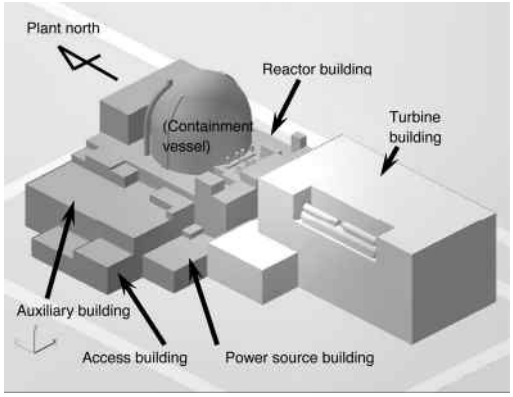


FIG. 15C.10 US-APWR COMPACT ARRANGEMENT OF POWER BLOCK (*Source*: Mitsubishi Heavy Industries, Ltd.)

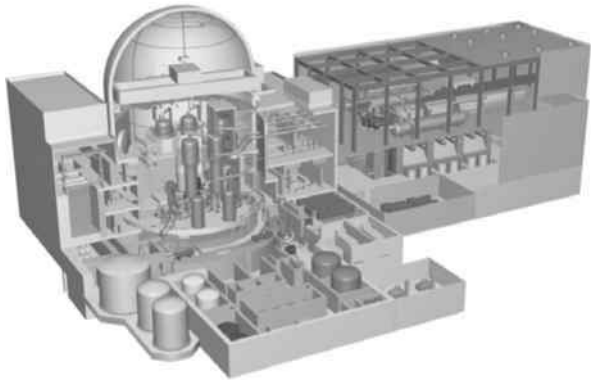


FIG. 15C.11 US-APWR PLANT
(*Source*: Mitsubishi Heavy Industries, Ltd.)

The containment facility is comprised of the prestressed concrete containment vessel (PCCV) and the annulus enclosing the containment penetration area, and provides an efficient leak-tight barrier and radiation protection under all postulated conditions including LOCA. The PCCV is designed to withstand the peak pressure under LOCA conditions. Tendon gallery is provided for periodic inspection and testing of circumferential and axial prestressing tendons. Figure 15C.11 shows a sectional view of the US-APWR power block buildings.

For ease of access during operation, maintenance, repair, and refueling, the following means to access the PCCV are also established: two personnel airlocks at different elevations and a large equipment hatch on the operating floor of the containment. The dimensions of the equipment hatch are determined to allow the future replacement of SGs without cutting through the containment. These features significantly improve the maintainability of equipment and accessibility to the containment during outages.

The US-APWR safety-related structures, systems, and components (SSCs) are designed as required by General design Criteria (GDC) 2 of 10 CFR 50, Appendix A [4] to withstand the effects of natural phenomena, including earthquakes, without jeopardizing the plant safety. The SSCs are assigned to one of the three seismic categories (seismic category I, seismic category II, or nonseismic) depending on the nuclear safety function of the particular structure, system, and component (SSC). The US-APWR standard plant seismic design is based on the safe shutdown earthquake (SSE) and the operating-basis earthquake (OBE). The certified seismic design response spectra (CSDRS) define the site-independent SSE for the seismic design of the US-APWR standard plant. The peak ground acceleration (PGA) of the CSDRS is 0.3 g ground acceleration for the two horizontal directions and the vertical direction. The PGA of the OBE is set at 1/3 of the SSE (CSDRS), and then no design analysis is required to address the OBE loads for the seismic category I SSCs.

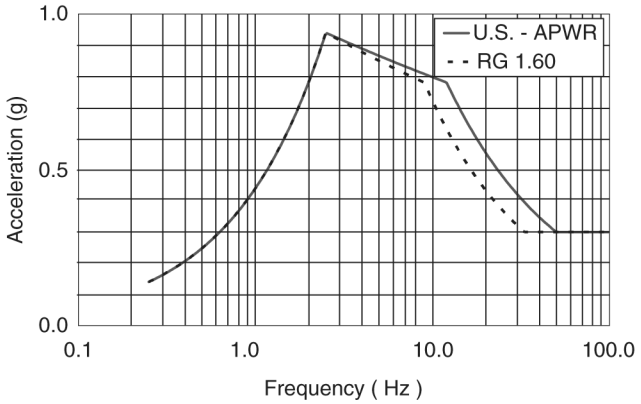


FIG. 15C.12 THE CSDRS (HORIZONTAL. DAMPING 5%)
(*Source*: Mitsubishi Heavy Industries, Ltd.)

The CSDRS are derived from RG 1.60 [5] spectra by scaling the spectra contained in RG 1.60 from 1.0 g to 0.3 g zero period acceleration (ZPA) values. The RG 1.60 spectral values are based on deterministic values for earthquakes in the western United. States. However, recent seismic research, including recently published attenuation relations, indicate that earthquakes in the central and eastern United States have more energy in the higher frequency range than those in the western United States. Thus, the RG 1.60 spectra control points have been modified by shifting the control points at 9 Hz and 33 Hz to 12 Hz and 50 Hz, respectively, for both the horizontal and the vertical spectra, as shown in Fig. 15C.12. The modified RG 1.60 spectra used for the CSDRS are expected to cover many sites in the central and the eastern United States to apply the US-APWR standard plant design as widely as possible.

The design of the US-APWR R/B complex is based on the analyses of the seismic responses of a dynamic model, considering the effects of soil-structure interaction (SSI) and structure-soil-structure interaction (SSSI). The R/B complex consists of the R/B, the PCCV, the containment internal containment internal structure (CIS) including the reactor coolant loop (RCL), the East PS/B, the West PS/B, the A/B, and the essential service water pipe chase (ESWPC), all on a common basemat. The RCL represents the stiffness and mass inertia properties of the major equipment and pipe supports by the CIS. All structures on the basemat are seismic category I structures with the exception of the A/B which is a seismic category II structure. The SSSI analysis is for the seismic response of the R/B complex considering its potential interaction with the T/B. The T/B is a seismic category II structure. Two different levels of stiffness and damping properties are assigned to the dynamic finite element model in order to capture variations of the material properties of the structural members due to cracking. The first level represents the full stiffness (uncracked concrete) of the structures corresponding to low stress levels, and the second level represents the reduced stiffness (cracked concrete) level of the structures corresponding to high stress levels. OBE damping values are assigned to the model with full stiffness. SSE damping values are assigned to the model with reduced concrete properties. Two SSI analyses of the R/B complex are performed for each soil profile corresponding to each of the two bounding levels of stiffness and damping. The site-independent SSI analyses are conducted considering six generic subgrade conditions: (1) Two profiles of soft soil (nominal shear wave velocity of 270 m/s) with depths of 200 ft and 500 ft above rock foundations, (2) Stiff soil profile (nominal shear wave velocity of 560 m/s) with a depth of 500 ft, (3) Two soft rock profiles (nominal shear wave velocity of 900 m/s) with depths of 100 ft and 200 ft, and (4) Firm rock profile (nominal shear wave velocity of 2032 m/s) with a depth of 100 ft. A total of 12 cases are analyzed for the R/B complex (SSI) and eight cases for the combined model the of R/B complex and T/B (SSSI).

For development of design basis in-structure response spectra (ISRS), the results from the 20 SSI and SSSI analyses are enveloped and broadened by 15%. For seismic analysis of seismic category I subsystems, modal response spectra analysis, time history analysis, or equivalent static load analysis methods are used.

15C.5.1 Reactor Building Complex

The R/B, the PS/Band the A/B are founded on the common reinforced concrete basemat and compose a structurally integrated building, which is termed Reactor Building Complex.

15C.5.1.1 Reactor Building The R/B contains equipment important to safety, except the emergency power sources. The equipment includes safety-related pumps, heat exchangers, control room, and associated electrical, I&C panels.

15C.5.1.2 Power Source Buildings Each PS/B contains two identical emergency power sources, which are separated from each other by physical barriers. The electrical, I&C and heating, ventilation and air-conditioning equipment related to the emergency power sources are also contained in these buildings.

15C.5.1.3 Auxiliary Building The A/B contains the main components of the waste disposal systems and the non safety-related electrical area. This area is normally a nonradioactive zone and is completely separated from the radioactive zones of the building.

15C.5.2 Access Building

The AC/B houses the access control facilities, the chemical sampling, and laboratory area.

15C.5.3 Turbine Building

The T/B houses the non safety-related equipment of the turbine generator and its auxiliary systems (main condenser, feedwater heaters, moisture separator reheaters, etc.). The building is principally made of steel structure, which is designed to withstand all loads including the load of the overhead traveling crane. The basemat of the building is a reinforced concrete structure.

15C.6 MODULARIZATION AND CONSTRUCTION

MHI has constructed 24 PWR nuclear plants over a period of the last 30 years in Japan. MHI was responsible for the construction of both the nuclear island and the conventional island. MHI has gained valuable experience, which has enabled us to reduce the construction period target to 41 months from the first concrete to the first core loading.

The construction period of Ohi Unit 3 commercial operation (C/O: Dec, 1991) was less than 42.5 months from the first concrete to fuel loading.

The main features of these innovative construction methods to be used at the Japanese APWR are as follows:

- Use of super heavy duty crane (1000 ton class)
- Application of steel concrete (SC) structure in all parts of internal concrete structure
- Large PCCV liner block (one piece for dome liner and two pieces for cylinder liner)
- Direct carry-in of heavy components inside containment vessel by super heavy duty crane
- Large equipment module

The construction period of the US-APWR is expected to be 41 months from the first concrete to the first core loading by application of these innovative construction methods.

Examples of SC structures for the inner concrete and large equipment module for the main steam line and feedwater line piping are in Figs. 15C.13 and 15C.14, respectively.

The US-APWR offers features as described below to improve plant operability and maintainability.

15C.7 OPERATION AND MAINTENANCE

1. Online maintenance afforded by 4 × 50% safety trains. It results in about a 30% reduction in total work hours during refueling outage.
2. Fully digital I&C provides redundancy, diversity, self-diagnostics, and online repair capabilities which will substantially reduce I&C maintenance costs.
3. The US-APWR is compatible with the unique ISI devices described below. These inservice inspection (ISI) devices are currently employed at conventional Japanese PWRs and can significantly shorten ISI work time.

   (a) A-UT machine, an advanced ultrasonic testing machine for reactor vessel.

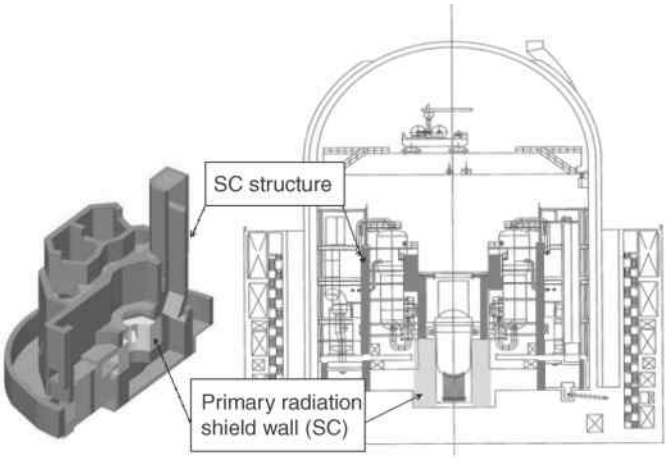


FIG. 15C.13 ILLUSTRATION OF US-APWR STEEL CONCRETE STRUCTURE MODULE (*Source*: Mitsubishi Heavy Industries, Ltd.)

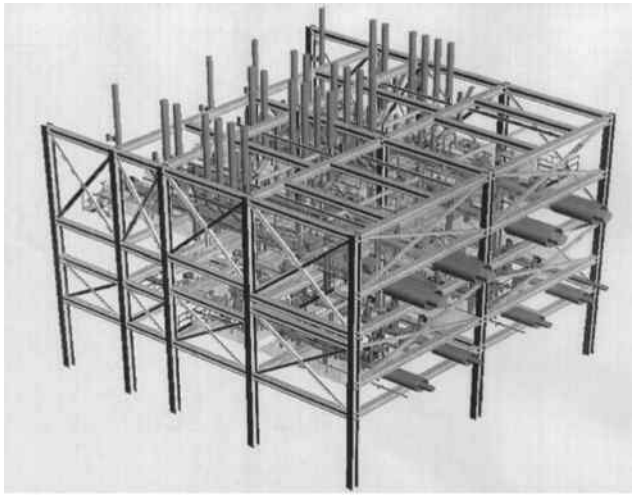


FIG. 15C.14 ILLUSTRATION OF US-APWR LARGE EQUIPMENT MODULE (*Source*: Mitsubishi Heavy Industries, Ltd.)

   (b) SG-MR III, a robot tube eddy current test (ECT) machine with twice the inspection speed compared with the conventional type machine.

It is estimated that these US-APWR operation and maintenance features will reduce occupational radiation exposure to approximately half of that in the current PWRs.

15C.8 ASME CODE ASPECTS

The US-APWR is designed to the 2001 Edition, Section III of the American Society of Mechanical Engineers (ASME) Code up to and including the 2003 Addenda. The correlation of the US-APWR DCD [1] stress criteria with the ASME Boiler & Pressure Vessel Code [6] stress criteria is summarized in Table 15C.3.

TABLE 15C.3 STRESS CRITERIA FOR ASME CODE SECTION III, CLASS 1, COMPONENT AND SUPPORTS AND CLASS CS CORE SUPPORTS (*SOURCE*: MITSUBISHI HEAVY INDUSTRIES, LTD.)

Service level	Vessel/ tanks/ pumps	Piping	Core supports	Valves	Component supports
A	NB-3221 NB-3222	NB-3652	NG-3221 NG-3222 NG-3231 NG-3232	NB-3520 NB-3525	NF
B	NB-3223	NB-3654	NG-3223 NG-3233	NB-3525	NF
C	NB-3224	NB-3655	NG-3224 NG-3234	NB-3526	
D	NB-3225	NB-3656	NG-3225 NG-3235	special	NF

15C.9 FUTURE DIRECTION OF THE US-APWR

The US-APWR is currently pursuing a Design Certification from the NRC. The US-APWR standard design may evolve further through minor variations driven by site-specific conditions through the Combined License (COL) process, as well as continued improvement and evolution from Japanese and US operating experience. Application of the US-APWR standard design technology to as large a fleet as possible will have broad appeal in the United States with its emphasis on proven evolutionary improvements in safety, economics, and realibility.

15C.10 REFERENCES

1. US-APWR Design Certification Document (US-APWR DCD).
2. Electric Power Research Institutes, Utilities Requirements Document, Volume 1, 2008.
3. Regulatory Guide 1.29, Seismic Design Classification.
4. 10CFR Part50 Appendix A General Design Criteria for Nuclear Power Plants, Criterion 2.
5. Regulatory Guide 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants.
6. ASME Boiler & Pressure Vessel Code, 2001 Edition up to and including the 2003 Addenda.

15C.11 NOMENCLATURE

A/B	auxiliary building
ac	alternating current
AC/B	access building
APWR	advanced pressurized water reactor
ASME	American Society of Mechanical Engineers
CDF	core damage frequency
CIS	containment internal structure
COL	Combined License
CRDM	control rod drive mechanism
CRE	control room envelope
CS	containment spray
CS/RHR	containment spray/residual heat removal
CSDRS	certified seismic design response spectra
CSS	containment spray system
dc	direct current
DCD	Design Control Document
DVI	direct vessel injection
ECCS	emergency core cooling system
ESWPC	essential service water pipe chase
F/A	fuel assembly
GDC	General Design Criteria
GTG	gas turbine generator
GPM	gallon per minute
GWd/t	gigawatt day per ton
HHIS	high-head injection system
HP	high pressure
I&C	instrumentation and control
ISI	inservice inspection
ISRS	in-structure response spectra
LHSI	low-head safety injection
LOCA	loss-of-coolant accident
LP	low pressure
MCR	main control room
MHI	Mitsubishi Heavy Industries, Ltd.
MWe	megawatt electrical
MWt	megawatt thermal
NaTB	sodium tetraborate decahydrate
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
OBE	operating-basis earthquake
PCCV	prestressed concrete containment vessel
PGA	peak ground acceleration
PS/B	power source building
PWR	pressurized water reactor
R/B	reactor building
RCL	reactor coolant loop
RCP	reactor coolant pump
RCS	reactor coolant system
RHRS	residual heat removal system
RG	Regulatory Guide
RWSP	refueling water storage pit
SC	steel concrete
SG	steam generator
SI	safety injection
SIP	safety injection pump
SSC	structure, system, and component
SSE	safe-shutdown earthquake
SSI	soil-structure interaction
SSSI	structure-soil-structure interaction
T/B	turbine building
TD	theoretical density
URD	Utility Requirement Document
VDU	visual display unit

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CHAPTER

16

NEW GENERATION OF BWRS

Hardayal S. Mehta[1]

16.1 INTRODUCTION

Nuclear energy plays a major role in meeting the world's energy needs. At the end of 2005, there were 443 nuclear power plants operating in 32 countries, with 25 more units under construction. These plants account for 17% of world's electricity. In a nuclear power plant, steam to turn the turbine and in turn the generator to produce electricity is produced through a controlled nuclear fission reaction. The steam producing part of a nuclear power plant, including the supporting systems, is called the nuclear steam supply system (NSSS). Beyond the NSSS, the remaining part of a nuclear power plant, the turbine/generator and remainder of the steam cycle, is called the balance of plant (BOP). In a boiling water reactor (BWR) NSSS, the steam is directly produced in the reactor pressure vessel (RPV). In the pressurized water reactors (PWRs), the steam is produced in steam generators that are connected to RPV. Both the BWRs and PWRs are classed as light water reactors (LWRs) since they use light water (as opposed to heavy water, D_2O) as coolant and moderator. In the United States and many countries of the world, the RPV and the most of the NSSS components are designed, fabricated, tested, and inspected during service using the rules of ASME Boiler & Pressure Vessel Code. Specifically, Section II (for material selection and allowable stresses), Section III (for design and analysis), Section IX (for welding), and Section XI (for in-service inspection) of the Code are used. The overall objective of this chapter is to provide a description of the evolution of the BWR product line, including the current offerings (the Advanced Boiling Water Reactor, ABWR, and the Economic Simplified Boiling Water Reactor, ESBWR), along with the discussion on the role of ASME Code in the material selection, fabrication, design, and in-service inspection (ISI) of the BWR NSSS system.

The first section provides a general background of the development of the BWR product lines. This includes the description of the reactor and reactor system design, safety system design, and the containment design [1, 2]. The next section deals with the key features of the ESBWR, including the natural circulation design, operating domain, and passive safety features [3]. The ASME Code aspects are covered next, including the ASME Code versions, treatment of environmental fatigue issues, material selection, and others. Future directions in terms of fabrications, modularization, and others are discussed next. The last section provides a summary.

16.2 EVOLUTION OF BWR PRODUCT LINE FROM BWR/1 THROUGH ESBWR

The BWR nuclear plant, like the PWR, has its origins in the technology developed in the 1950s for the U.S. Navy's nuclear submarine program. The first commercial BWR nuclear plant to be built was the 5-MWe Vallecitos plant (1957) located near San Jose, California. The Vallecitos plant confirmed the ability of the BWR concept to successfully and safely produce electricity for a grid. The first large-scale BWR, Dresden 1 (1960), then followed. The BWR design has subsequently undergone a series of evolutionary changes with one purpose in mind – simplify.

The BWR design has been simplified in two key areas – the reactor systems and the containment design. Table 16.1 chronicles the development of the BWR.

16.2.1 General Progression of BWR Designs

Figure 16.1 illustrates the evolution of the reactor system design. Interestingly enough, Dresden 1 was not a true BWR. The design was based upon dual steam cycle, not the direct steam cycle that characterizes BWRs. Steam was generated in the reactor but then flowed to an elevated steam drum and a secondary steam generator before making its way to the turbine. The first step down the path of simplicity that ultimately led to the ESBWR was the elimination of the external steam drum by introducing two technical innovations – the internal steam separator and the steam dryer (KRB, 1962). The first large direct cycle BWRs (Oyster Creek and Nine Mile Point Unit 1) appeared in the mid-1960s and were characterized by the elimination of the steam generators and the use of five external recirculation loops to provide forced circulation flow through the core. Later, reactor systems were further simplified by the introduction of jet pumps inside the vessel for driving the core flow. The use of internal jet pumps allowed two external recirculation loops to drive the core flow, down from the five loops used in the large BWR/2 plants, thus reducing the associated piping, valves, pumps, and large vessel nozzles. This change first appeared in the Dresden 2 BWR/3 plant.

The use of reactor internal pumps in the ABWR design took this process of simplification another step further. By using internal pumps attached directly to the vessel itself, the jet pumps and the external recirculation systems, with all the associated large pumps,

[1]Daniel C. Pappone was the coauthor for this chapter for the first and second editions. Subsequent third edition and the current chapter are updated by Hardayal S. Mehta. – Editor

TABLE 16.1 EVOLUTION OF THE GE BWR

Product Line	First Commercial Operation date	Representative Plant/ Characteristics
BWR/1	1960	Dresden 1 Initial commercial-size BWR Dual cycle
BWR/2	1969	Oyster Creek Plants purchased solely on economics Large direct cycle Forced circulation Variable speed pumps for recirculation flow control
BWR/3	1971	Dresden 2 Internal jet pump application Improved ECCS: spray and flood capability
BWR/4	1972	Vermont Yankee Increased power density (20%)
BWR/5	1977	Tokai 2 Improved ECCS Valve flow control
BWR/6	1978	Cofrentes Compact control room Solid-state nuclear system protection system
ABWR	1996	Kashiwazaki-Kariwa 6 Reactor internal pumps Fine-motion control rod drives Advanced control room, digital and fiber optic technology Improved ECCS: high/low pressure flooders
ESBWR	Final safety evaluation report and final design approval issued by the NRC on March 9, 2011	Natural circulation Passive ECCS

valves, piping, and snubbers, have been eliminated altogether. The development of the ABWR took place during the 1980s under the sponsorship of Tokyo Electric Power Company (TEPCO). In 1988, TEPCO announced that the next Kashiwazaki-Kariwa units (K-6 and 7) to be constructed would be ABWRs. The licensing activities for the K-6 and 7 were conducted with the Japanese regulatory agency, Ministry of International Trade and Industry (MITI), in parallel with the review of the ABWR in the United States by the Nuclear Regulatory Commission (NRC). K-6 entered commercial operation in 1996 and K-7 in 1997. Two more ABWRs entered commercial operation in Japan – Hamaoka-5 in 2005 and Shika-2 in 2006. In addition to these four units in Japan, two more ABWRs are being constructed for the Taiwan Power Company (TPC) at TPC's Lungmen site.

In the United States, the ABWR First-of-a-Kind Engineering (FOAKE) program was completed in September 1996. FOAKE represented a major step toward one of the U.S. industry's goals - to have a certified design that is 90% engineered prior to the start of construction. The ABWR Design Certification was signed into law on May 2, 1997 by the then Chair of the NRC, Shirley M. Jackson. In September 2007, NRG Energy submitted to the NRC a combined construction permit – operating license application (COLA) to build two ABWR units at the South Texas Project site in Texas.

The ESBWR and its smaller predecessor, the Simplified Boiling Water Reactor (SBWR), took the process of simplification to its logical conclusion with the use of a taller vessel and a shorter core to achieve natural recirculation without the use of any pumps. Following the Three Mile Island accident in 1979, there was significant interest in developing a reactor with passive safety features and less dependence on operator actions. Utilities also took this opportunity to request a reactor that was simpler to operate, had fewer components, and no dependence on diesel generators for

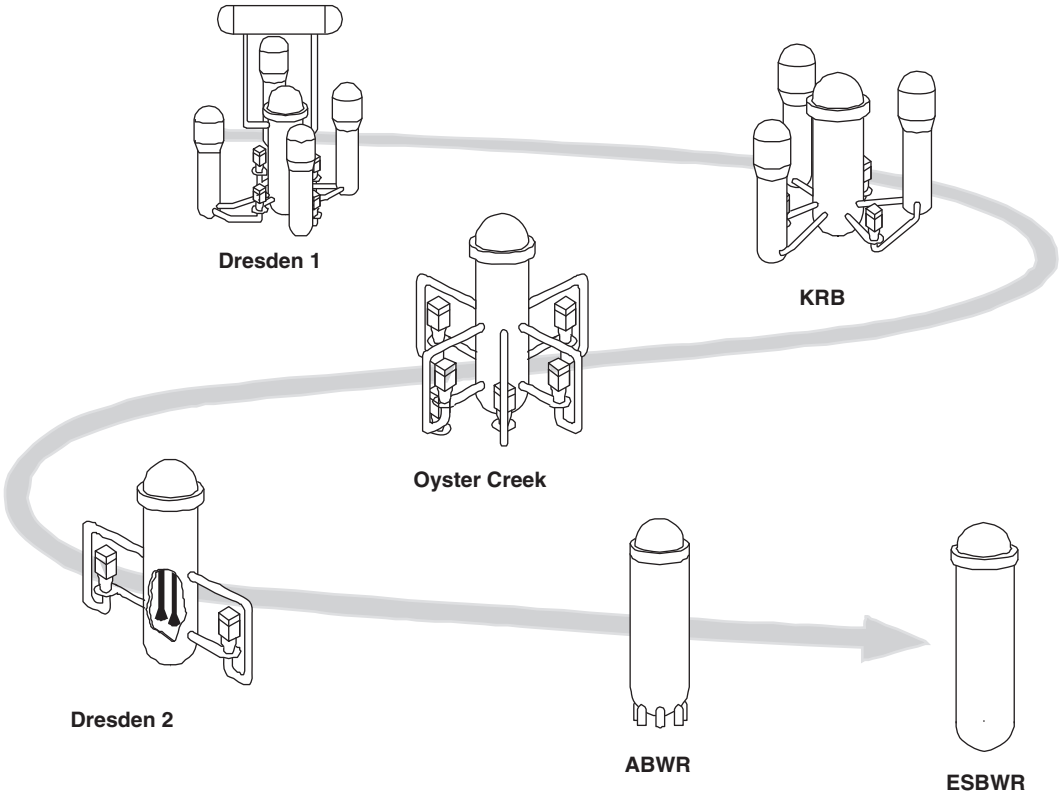


FIG. 16.1 EVOLUTION OF THE BWR REACTOR SYSTEM DESIGN [2]

safety actions. GE began an internal study of a new BWR concept based on these principles and the SBWR was developed in the early 1980s. This concept attracted development support from the U.S. Department of Energy (DOE), EPRI, and a number of U.S. utilities. Key new features, such as the gravity-driven cooling system (GDCS), depressurization valves (DPV), and leak-tight wet well/dry well vacuum breakers were tested. As interest grew, an international team was formed to complete the design, and additional separate effects, component and integrated system tests, particularly of the innovative new feature, the passive containment cooling system (PCCS), were run in Europe and Japan. A Design Certification Program was begun in the late 1980s with the objective of obtaining a standardized license, similar to that obtained for ABWR. However, as more of the design details became known, it became clear that at 670 Mwe, the SBWR was too small to generate the right economics for a newly build project. The certification program was stopped, but efforts continued to make the SBWR attractive for power generation. With European utility support, the SBWR was uprated gradually to its current power level of approximately 1550 Mwe. This was made possible by staying within the RPV size limit established by the ABWR and by taking advantage of the modular approach to passive safety afforded by isolation condensers (ICs) and PCCS.

The Design Certification application for the ESBWR was submitted to the U.S. NRC in August 2005 and was formally accepted for docketing in 3 months. The NRC's new plant review and licensing process has been improved, including allowance for parallel review of both the Design Certification and the COLA, with a focus on standardization and reducing and eliminating rereviews of the same open items. GE is working with a number of customers who have selected the ESBWR technology and is participating in the U.S. Department of Energy's Nuclear Power 2010 program, which was established by the DOE to act as a catalyst for the newly built nuclear energy in the United States.

16.2.2 Reactor System Design

The first LWRs were pressurized to prevent the water from boiling in the core or turning to steam. The conventional wisdom was that steam bubbles would somehow affect the behavior of the neutrons and cause the reactor to behave erratically and possibly overheat. Samuel Untermyer, a scientist at Argonne National Laboratory, postulated that if water bubbled or steamed in an overheating reactor core, the chain reaction would slow down [4]. This concept of a negative void reactivity coefficient proved to be fundamental to the successful design and operation of the BWRs. Untermyer initiated the Boiling Water Reactor Experiment (BORAX) series of test reactors at the National Reactor Testing Station in Idaho. In 1953, the first test reactor in the series, BORAX-1, demonstrated two theories: (1) boiling water in a reactor was a stable condition, and (2) the void coefficient can control the power increases. Argonne modified the BORAX reactor design several times while conducting experiments to develop an understanding of the parameters necessary for operating a BWR safely.

Argonne's ultimate goal was to evolve a reactor useful for electrical generation. The early experiments with the BORAX reactors demonstrated the inherent safety and stability of the BWR. Using a turbine generator scrounged from an old sawmill, the BORAX-III reactor lit the town of Arco, Idaho, on July 17, 1955 with nuclear power for the first time in history. The first

BWR power plant, EBWR (Experimental BWR), built by Argonne Laboratory, was designed for 20 MWe. The plant ran from 1956 to 1967, gradually increasing its power level and reliability from the point where it supplied electricity to the entire Argonne Lab.

The main characteristic of the BWR is the fact that bulk boiling takes place in the reactor core. Three configurations have been used for the power cycle design of the BWR plant. In the direct cycle BWR, the simplest design, the steam is passed directly from the reactor vessel to the turbine. In the indirect cycle design, the steam–water mixture passes through a steam generator; the steam produced on the secondary side of the steam generator is then passed to the turbine. The indirect cycle design has the advantage of isolating the radioactive contaminants within the primary system; however, this advantage is offset by the increased cost and maintenance associated with the steam generators. The dual cycle design is a combination of both the direct and indirect cycles, with high-pressure steam being passed directly to the high-pressure end of the turbine and lower pressure steam from the steam generator entering the turbine at an intermediate stage. The dual cycle combined reliability, stability, a fairly high power density, and a well-controlled reactor response to changes in load demand. The BWR designs can be further classified by the means used to drive the coolant through the core. In a forced circulation design, the core flow is driven by pumps external or internal to the reactor vessel. In a natural circulation design, the difference in density between the single-phase fluid in the downcomer region and the two-phase mixture in the core provides the driving force [5].

GE selected the BWR as the most promising nuclear power concept because of its inherent advantages in control and design simplicity. GE established an atomic power equipment business in 1955 to offer the BWR commercially. The first GE BWR, the Vallecitos BWR, was built in 1957. This 1000-psi reactor powered a 5-MWe generator and provided power to the Pacific Gas and Electric Company grid through 1963. The VBWR was constructed so that it could be operated in either a direct cycle mode or a dual cycle mode using either forced or natural circulation.

The advantages of the BWR compared to the PWR are as follows:

- The reactor vessel and associated components operate at a substantially lower pressure (about 1000 psig) compared to a PWR (about 2200 psig).
- There are no steam generators and no pressurizer vessel.
- Lower risk (probability) of a rupture causing loss of coolant compared to a PWR, and lower risk of a severe accident should such a rupture occur. This is due to fewer pipes, fewer large diameter pipes, fewer welds, and no steam generator tubes.
- The distance between the core and the vessel wall is greater; therefore, the pressure vessel is subject to significantly less irradiation compared to a PWR and so does not become as brittle with age.
- The fuel operates at a lower temperature.
- The single reactor vessel makes emergency conditions simpler to diagnose and emergency actions simpler to execute.
- A BWR may be designed to operate using only natural circulation so that recirculation pumps are eliminated entirely.

The disadvantages of a BWR are as follows:

- The core nuclear and thermal hydraulic calculations are more complex when considering two-phase flow.
- The RPV is much larger than that of a PWR of similar power. However, the overall cost is reduced because a modern BWR has no main steam generators or pressurizers.
- The primary coolant passes through the turbine, contaminating it with short-lived activation products. Therefore, radiation exposure must be managed in the vicinity of the steam piping and turbine.

The first commercial BWRs were small demonstration plants for evaluating various approaches to reactor and containment design and for demonstrating key system design features. These plants are referred to as the BWR/1 product line, even though they were custom designs. Dresden 1 was the first commercial BWR. Dresden 1 was based upon dual cycle design and used forced circulation. The plant used a spherical dry containment. Steam was generated in the reactor but then flowed to an elevated steam drum and a secondary steam generator before making its way to the turbine. The dual steam cycle system was employed to assure overall plant stability between the reactor and turbine generator during normal operation and operational transients. Dresden 1 was the model for several other dual cycle plants (Garigliano, KRB, Tarapur). Humboldt Bay and Big Rock Point were the first commercial direct cycle plants.

Table 16.2 provides a comparison of the key features of the commercial BWRs. The first standardized BWR design was the BWR/2 (Oyster Creek and Nine Mile Point 1). The BWR/2 direct cycle design used the internal steam separator and steam dryer demonstrated at KRB. This simplified the reactor design by eliminating the external steam drum and steam generator pressure vessels. The steam separator and dryer assemblies are removed to allow access to the core during refueling. The control blades enter the core from the bottom of the vessel. Control rod entry from the bottom of the core provides the best axial flux shaping and resultant fuel economy for the BWR. The bottom entry drives do not interfere with refueling operations. The piston drive and high-pressure scram accumulators provide high scram forces and ensures rapid rod insertion.

The BWR/2 design also standardized the use of forced recirculation core flow. Oyster Creek and Nine Mile Point 1 passed the entire core flow through five external recirculation loops with pumps. Forced recirculation core flow provides a second means of controlling core power in addition to the control rods. Forced recirculation allows the core power to be controlled by changing recirculation flow by exploiting the negative void reactivity characteristics of the BWR core design. An increase in the core flow increases the liquid in the core, which increases the neutron moderation and power generation. The core stabilizes at a higher power level. The ability to change power gradually by using core flow also reduces the thermal mechanical duty on the fuel. The control rod drives (CRDs) move the control blades in finite increments, which may result in a significant local power increase near the tip of the control blade. Varying the core flow also varies the boiling boundary in the core. This allows spectral shift core management schemes to be employed. Early in the cycle, the core flow is kept at low, lowering the axial flux shape and boiling boundary in the core, which increases the voiding in the top of the core. This voiding hardens the neutron spectrum in the upper part of the core resulting in the breeding of plutonium. At the end of the cycle when the reactivity in the lower part of the core is exhausted, the core flow is increased, shifting the axial flux shape upward and burning the plutonium generated in the upper part of the core early in the cycle. Thus, the ability to control core power

TABLE 16.2 COMPARISON OF KEY FEATURES OF GE BWRs

Parameter	BWR/2	BWR/4	BWR/6	ABWR	ESBWR
Power (MWt/MWe)	1930/670	3293/1098	3900/1360	3926/1350	4500/1550
Vessel height/diameter (m)	19.5/5.4	21.9/6.4	21.8/6.4	21.1/7.1	27.7/7.1
Fuel bundles, number	560	764	800	872	1132
Active fuel height (m)	3.7	3.7	3.7	3.7	3.0
Power density (kW/L)	40.5	50	54.2	51	54
Recirculation pumps	5 (external)	2 (external)	2 (external)	10 (internal)	0
Number/type of CRDs	137/LP	185/LP	193/LP	205/FM	269/FM
Safety system pumps	12	9	9	18	0
Safety diesel generators	2	2	3	3	0
Alternate shutdown	2 SLC pumps	2 SLC pumps	2 SLC pumps	2 SLC pumps	2 SLC accumulators
Control and instrumentation	Analog single channel	Analog single channel	Analog single channel	Digital multiple channel	Digital multiple channel
Core damage (freq/yr)	10^{-5}	10^{-5}	10^{-6}	2×10^{-7}	3×10^{-8}
Safety bldg vol (m^3/Mwe)	110	120	170	180	130

using recirculation flow ultimately results in better fuel cycle economics for the plant.

The next significant simplification introduced in the reactor system was the internal jet pump in the BWR/3 design. These pumps sufficiently boosted recirculation flow so that only two external recirculation loops were needed. This change was first incorporated in the Dresden 2 plant. The use of internal jet pumps resulted in the elimination of several of the recirculation lines and pumps used previously in the BWR/2 reactors. Savings in investment for recirculation lines and pumps were partially offset by the higher power requirements due to the lower efficiency of the jet pump. More notably, the use of jet pumps gives some safety advantages in that the number and size of major nozzle penetrations on the vessel is reduced and the reactor internal arrangement allows the capability of reflooding the vessel and maintaining coolant level in the core even if there is a complete severance of the recirculation line. Increased natural circulation capability was also gained with the jet pump system.

The basic jet pump BWR design was carried through most of the plants comprising today's BWR operating fleet. The BWR/4 design (Browns Ferry and Peach Bottom) introduced improved ECCS and higher core power densities. The BWR/5 design (Tokai 2) introduced constant speed recirculation pumps and flow control valves used to control the reactor core flow and improved ECCS. The change from variable speed recirculation pumps to constant speed pumps with valve control allowed the plants to follow more rapid load variations and reduced the capital cost of the overall control system. The BWR/6 design (Cofrentes) incorporated a five-hole nozzle design in the jet pump that increased the pumping efficiency and allowed the use of smaller jet pumps. With smaller jet pumps, the size of the core could be increased, increasing the reactor output for the same size vessel.

The ABWR design (Kashiwazaki-Kariwa 6) incorporated reactor internal pumps to drive the core flow. By using pumps attached directly to the vessel itself, the jet pumps and the external recirculation systems, with all their pumps, valves, piping, and snubbers, have been eliminated altogether. With the elimination of the large external recirculation piping, there were no large pipes attached to the vessel below the top of the core. This allowed the ABWR to be designed to keep the core submerged and cooled during the break of any pipe forming the reactor coolant pressure boundary. Fine motion CRDs permit small power changes, improved start-up times, and improved power maneuvering.

The ESBWR design uses natural circulation to provide the driving force for the core flow, eliminating the recirculation pumps altogether. Building on the basic ABWR vessel design, the height of the vessel has been increased to provide the additional driving head necessary to achieve the core flows and power levels necessary for a modern reactor. Variable feedwater temperature control has been added to provide a second means of reactivity control in addition to the fine motion CRDs. Figure 16.2 shows the direct cycle power conversion system used in most BWRs.

16.2.3 Safety System Design

The loss-of-coolant accident (LOCA) has dominated the design of the safety systems for BWRs. A LOCA is defined as a breach in

the primary coolant system pressure boundary. The design basis accident (DBA) was specified to be the instantaneous double-ended guillotine break of the largest pipe attached to the RPV. However, the safety systems must also be designed to mitigate the consequences of the full spectrum of potential break sizes and locations anywhere in the primary coolant piping, as well as equipment failures such as a stuck-open relief valve that result in a an uncontrolled loss of primary system coolant. The emergency core cooling system (ECCS) is designed to provide cooling water to the core terminating any heat up of the core and to provide long-term removal of the core decay heat. The containment provides the final barrier to prevent the release of fission products from the fuel. The suppression pool in the containment provides a heat sink and internal water source for core cooling. The containment heat removal systems transfer the decay heat to the ultimate heat sink. In addition to providing for core and containment cooling, the incorporation of the LOCA affected the structural design of the plant. The vessel and piping structures had to be designed to withstand the jet reaction and pipe whip forces from the broken pipe. Structures and systems had to be protected against the impingement of the jet from the broken pipe. Systems had to be designed to mitigate the hydrogen generated by the reaction of the zirconium fuel cladding with steam at high temperatures. The ECCS, containment, and supporting systems designed for mitigating the consequences of a LOCA have resulted in a network of safety system with the capacity and redundancy to handle a wide range of transient and accident events.

The BWR ECCS design has evolved along with the BWR product generations. The first generation of BWRs were designed without ECCS, but rather made use of highly reliable feedwater systems. With the increase in core power associated with the first commercial scale reactors (the BWR/2 design), concerns were raised with respect to providing adequate core cooling during a LOCA and preventing a core meltdown that would threaten containment integrity. In the late 1960s, the Report of the Advisory Task Force on Power Reactor Emergency Cooling led to the requirement that all nuclear plants must have ECCS [6]. Some forms of emergency core cooling, typically a core spray and high-pressure coolant injection (HPCI), were retrofit to the BWR/1s. The BWR/2s, BWR/3s, and BWR/4s were under design and construction during this time frame and a separate ECCS were incorporated into those reactor designs.

The BWR/2 recirculation loop design took water from the downcomer region and pumped it into the lower plenum region of the vessel. The limiting pipe break LOCA for the BWR/2 was in the recirculation discharge pipe where it attached to the vessel. A break at this location would leave a large rupture in the bottom of the system that would prevent reflooding the vessel. Therefore, it was decided that the best means of cooling the core would be with a spray system that would wet and cool the fuel from above. The core spray consisted of ring spargers around the periphery of the core, just above the top of the fuel bundles. The ring spargers do not interfere with the core flow during normal operation or fuel bundle movement during refueling. Two completely separate systems (electrical power, pumps, valves, piping, etc.) were provided for redundancy. Because the core spray system was designed for the large break LOCA, the core spray pumps are low-pressure, high-flow capacity pumps. These pumps cannot inject into the vessel at normal operating pressures. To address breaks that are so small that the vessel will not depressurize through the break, logic was added to some of the vessel pressure relief valves. When the logic detected the LOCA conditions, low reactor water level and high containment drywell pressure, and sensed that the core spray pumps were running, the logic would open the relief valves and depressurize the vessel, effectively making the small break into a large break. This logic is known as the automatic depressurization system (ADS). For the long-term recovery from the accident, provisions were made to flood the containment to a level above the top of the core. In addition to the ECCS network, the BWR/2 design includes ICs to provide decay heat removal from the vessel in the event that the main steam line isolation valves are closed and the

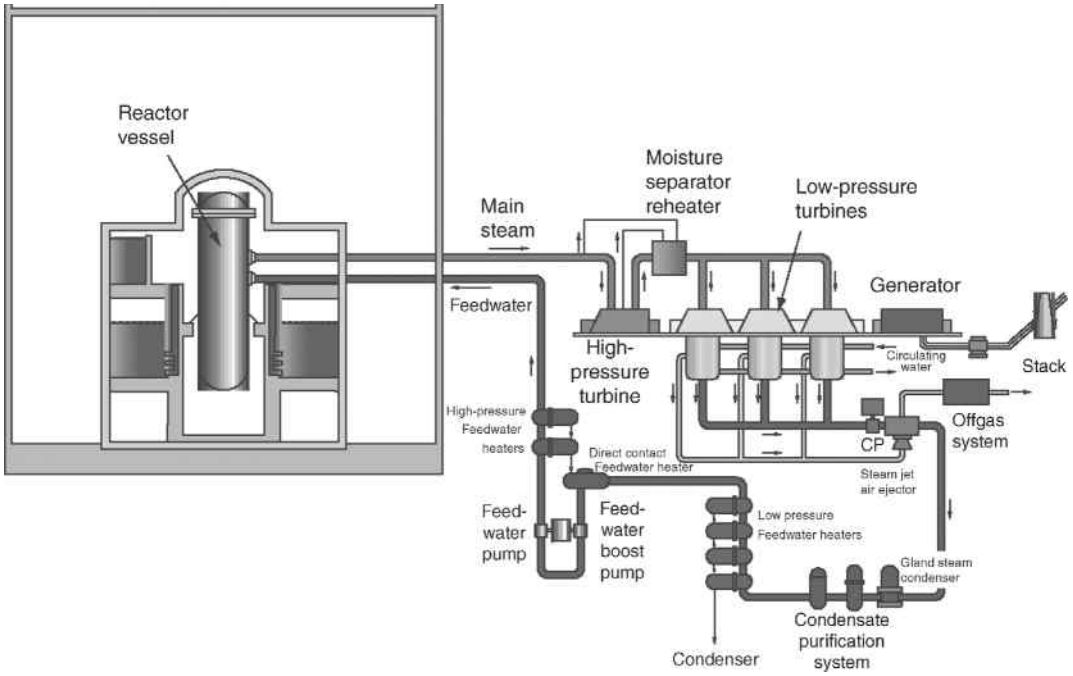


FIG. 16.2 ESBWR STEAM AND POWER CONVERSION SYSTEM [2]

main condenser is unavailable as a heat sink. The ICs are simply passive heat exchangers located in pools of water above the vessel and outside the containment. Steam from the reactor vessel is passed through the heat exchanger tubes, condensed, and the condensate is returned to the vessel. The water on the shell side of the heat exchange is boiled and vented to the atmosphere.

The BWR/2 plant design also marked the standardization of the pressure suppression containment design. In the pressure suppression containment design, steam released from the reactor vessel is directed into the suppression pool where it is condensed. The containment cooling system, which takes water from the suppression pool, passes it through a heat exchanger where it is cooled, then returns the cooled water to the containment, either back to the pool or through sprays in the drywell and suppression chamber airspace.

The ECCS network design used for the BWR/3 and BWR/4 product lines are similar. The two core spray systems and the ADS system were carried forward from the BWR/2. The jet pump design introduced in the BWR/3 eliminated the large recirculation pipe connection to the bottom head of the vessel. It now became possible to reflood the core region of the vessel up to the top of the jet pumps. The containment cooling system described above grew in scope and became the residual heat removal (RHR) system. The RHR system was connected to the reactor vessel to provide decay heat removal when the reactor is shut down. During the beginning portion of the accident, the flow from the four RHR pumps is directed into the recirculation discharge lines and injected through the jet pumps into the core shroud region of the vessel. This mode is called the low pressure coolant injection (LPCI) mode. Once the core is reflooded, the RHR pumps are realigned into the containment cooling mode. The two core spray systems are dedicated to core cooling. In addition, a turbine-driven large-capacity HPCI pump was added to the ECCS network. This pump provides inventory makeup for small breaks with the vessel at operating pressure. The improved core cooling provided by the ECCS network allowed larger plants with higher power cores to be designed. With the higher core powers, however, the size of the IC became impractical. In place of the ICs, the later BWR/3s and all the BWR/4s used a second nonsafety turbine-driven injection pump to provide inventory makeup when the vessel is isolated. The reactor core isolation cooling (RCIC) system is similar to the HPCI but smaller in capacity because it is sized to make up only the boiloff due to decay heat. The control valves and instrumentation for the HPCI and RCIC systems are powered from the station emergency batteries, allowing them to function in station blackout situations where no power is available from off-site or the station emergency diesel generators.

At the time the BWR/2, BWR/3, and BWR/4 ECCS were designed, there were no regulations defining the ECCS performance acceptance criteria. The design intent of the ECCS was to prevent the fuel cladding from melting and to keep the core in a coolable geometry during a LOCA. GE designed the ECCS for these plants to limit the peak cladding temperature below 2700°F, which provided some margin to the melting point of approximately 3400°F. In 1973, 10CFR50.46 was issued, which defined the ECCS performance acceptance criteria. In these new regulations, the peak cladding temperature was limited to 2200°F. More sophisticated analytical models, combined with a transition in fuel design from a 7×7 lattice to an 8×8 lattice with the fuel rods operating at lower powers, allowed the plants to minimize the impact of the new regulations on the plant power output.

The BWR/5 product line was designed during the time frame when the ECCS performance issues were being raised. The ECCS network incorporated in the BWR/5 product line improved the performance and reliability of the ECCS over the BWR/3 and BWR/4 designs. The network consists of three electrical divisions, of which two divisions contain two ECCS pumps each, an RHR pump that can be used for LPCI injection or containment cooling and either a low-pressure core spray system or a second LPCI pump dedicated to vessel injection. The third electrical division has a high-pressure core spray (HPCS) system powered by a dedicated diesel generator, which replaces the turbine-driven HPCI. The HPCI turbine would trip off when the vessel depressurized below about 100 psi, whereas the electrically driven HPCS operates through the full vessel pressure range. Also, the HPCI injects water through the feedwater line into the vessel downcomer region. With a large recirculation line break, the water injected by the HPCI would be lost through the break and not reach the core region. The HPCS injects directly into the core region through one of the two core spray spargers. The LPCI flow path was rerouted from the recirculation discharge line to dedicated lines allowing the LPCI to inject directly into the core region inside the core shroud. In the earlier BWR/3 and BWR/4 designs, a break of the recirculation discharge line also disabled the injection flow path for the LPCI injecting into that division. The RCIC was retained to provide makeup when the vessel is isolated and for station blackout events. The BWR/5 design was carried forward into the BWR/6 product line with the capacities increased to accommodate the higher BWR/6 core power levels. The ECCS network design was able to meet the requirements imposed by 10CFR50.46 without any impact on plant operations.

The internal recirculation pumps in the ABWR eliminated the large external recirculation loop piping. The ABWR was the first BWR designed after the adoption of the 10CFR50.46 limits. With the elimination of the large pipes attached to the lower section of the vessel, it was now possible to design the ECCS so that the core would remain covered during the design basis LOCA, thus assuring adequate core cooling throughout the event. It was possible to significantly downsize ECCS equipment as a result of eliminating large vessel nozzles below the top of the core. Capacity requirements are sized based on operating requirements – transient response and shutdown cooling – rather than on the need for large reflood capability. Inside the reactor vessel, core spray spargers were eliminated, since no postulated LOCA would lead to core uncovery. For transient response, the initiation water levels for RCIC and the high-pressure core flooder were separated so that there is reduced duty on the equipment relative to earlier BWRs. There are three complete shutdown cooling loops, including dedicated vessel nozzles. Complex operating modes of the RHR systems, such as steam condensing, were eliminated. Finally, heat removal, in addition to core injection, was automated so that the operator no longer needs to choose which mode to perform during transients and accidents.

Like the ABWR, the ESBWR is designed to keep the core covered and cooled during a LOCA. However, the ESBWR core and containment cooling systems represent a radical departure from those of the earlier BWR product lines in that the cooling systems are passive and do not rely on electrically driven pumps. The ESBWR passive safety systems are discussed in more detail in Section 16.3.3.

16.2.4 Containment Design

The containment is essentially a pressure vessel housing the reactor that provides a safety barrier to protect personnel and the public in the event of a reactor accident. Figure 16.3 illustrates the evolution of

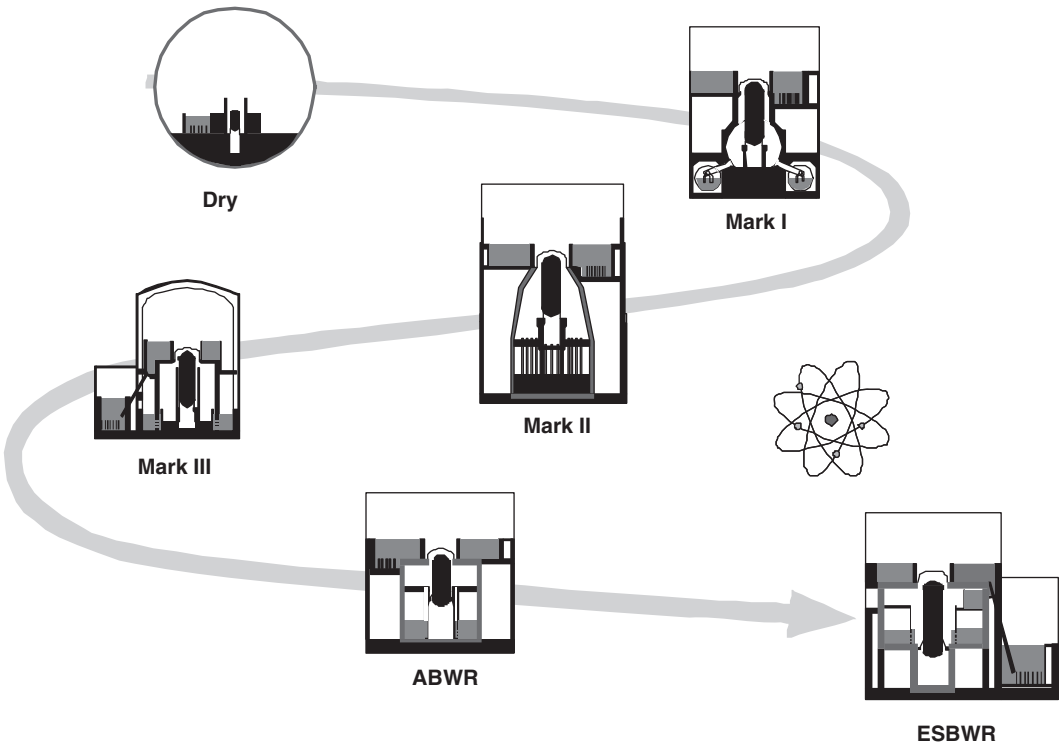


FIG. 16.3 EVOLUTION OF THE BWR CONTAINMENT DESIGN [2]

the BWR containment from the earliest versions to today's ESBWR design. Most of the initial BWR/1 plants used spherical dry containments. The containment vessel was sized to be able to hold the sensible energy content of the steam and hot water in the reactor coolant system and limit the pressure rise to within the design value of the vessel. Larger reactor sizes could be accommodated by increasing the volume of the containment vessel and by increasing the pressure rating of the vessel. However, because of the higher energy content in the BWR vessel as compared to a similar PWR, dry containments could not be designed that were economically competitive with PWRs. Therefore, GE selected the pressure suppression containment for the standard BWR plants [7].

Table 16.3 provides a comparison of the key features of the pressure suppression containments used in the BWR plants. In a pressure suppression containment, the reactor and primary system piping are contained in one chamber, the drywell, and the suppression pool is contained in a separate chamber, the wetwell. A system of vents provides a flow path from the drywell to the wetwell, with the vents discharging below the surface of the suppression pool. In the event of a LOCA, the steam and water from the vessel, as well as the air in the drywell, are driven through the vents into the suppression pool where the water in the pool quenches the steam. The advantages of a pressure suppression containment are as follows:

- High heat capacity
- Lower design pressure
- Superior ability to accommodate rapid depressurization
- The pool has the ability to filter and retain fission products
- A large source of readily available makeup water in the case of accidents
- Simplified, compact design

The Mark I containment was the first of the pressure suppression containment designs. The Mark I design has a characteristic light bulb configuration for the drywell, surrounded by a steel torus that houses a large water pressure suppression pool. The light bulb design came from the need to have a removable closure at the top for reactor servicing and refueling and sufficient room at the bottom for the recirculation piping. The torus design provided a large surface area for the vents. The structural analyses of the drywell and the torus were also simplified because closed-form solutions were available for these simple shapes (the Mark I design was developed in an era of limited computing power). The drawbacks of the Mark I design was the difficulty of its construction and the construction of the reactor building around it and the limited room inside the drywell for construction of the primary system piping and maintenance of components. The Mark I containment was used with the BWR/2, BWR/3, and BWR/4 product lines.

The Mark II over-under configuration was designed to address the construction issues associated with the Mark I design. The main advantages of the Mark II design were (1) more volume in the drywell to allow better access to the steam and ECCS piping, (2) simpler vent configuration using straight pipes, (3) the potential to use different construction materials, and (4) a smaller reactor building. The Mark II containment design was introduced with the BWR/5 product line but was also used for a couple of the late BWR/4 plants.

The Mark III containment design, introduced with the BWR/6 product line, represented a major improvement in simplicity. Its containment structure is a right circular cylinder that is easy to construct, and provides access to equipment and ample space for maintenance activities. The large volume allowed a reduction in the design pressure. Other features of the Mark III include horizontal

TABLE 16.3 COMPARISON OF KEY FEATURES OF GE BWR CONTAINMENTS

Parameter	Mark I	Mark II	Mark III	ABWR	ESBWR
Power level (MWe)	1100	1100	1220	1371	1600
Reactor pressure vessel inside diameter (m)	6.4	6.4	6.0	7.1	7.1
Drywell					
Free volume (m^3)	4672	7872	7929	7350	7206
Design pressure (MPa)	0.43	0.31	0.17	0.31	0.31
Wetwell					
Free volume (m^3)	4834	5318	32904	5960	5467
Water volume (m^3)	3480	3268	4332	3580	4383
Design pressure (MPa)	0.43	0.31	0.10	0.31	0.31
Vents					
Orientation	Vertical	Vertical	Horizontal	Horizontal	Horizontal
Size (m)	0.6	0.6	0.7	0.7	0.7
Number	76	70	117	30	30

vents to reduce overall loss-of-coolant (LOCA) dynamic loads and a freestanding all-steel structure to ensure leak tightness.

The ABWR containment is significantly smaller than the Mark III containment because the elimination of the recirculation loops translates into a significantly more compact containment and reactor building. The structure itself is made of reinforced concrete with a steel liner from which it derives its name – reinforced concrete containment vessel (RCCV). The ESBWR containment is similar in construction to the ABWR, but slightly larger to accommodate the passive ECCS systems.

16.3 KEY FEATURES OF ESBWR

16.3.1 Natural Circulation Design

Natural circulation in BWRs is a proven technology [8, 9]. Some of the early GE BWRs employed natural circulation. These were small plants (e.g., Dodewaard at 183 MWt and Humboldt Bay at 165 MWt), but they clearly demonstrated the feasibility of the BWR and provided valuable operating data and experience. GE moved to forced circulation plants to achieve higher power ratings in a compact pressure vessel. Pressure vessel fabrication capability at the time was a factor in this decision. Now, after several decades, GE is returning to natural circulation for the ESBWR.

Natural circulation provides major simplification by removal of the recirculation pumps and associated piping and heat exchangers and controls. It is also synergistic with two other requirements that GE considered to be important in the design of a new reactor: large safety margins with a very reliable passive ECCS and avoidance of safety/relief valve (SRV) opening for pressurization transients such as turbine trips or main steam line isolation events. Both of these features need a tall pressure vessel with large water volumes. The tall vessel leads to enhanced natural circulation flow, so the natural circulation capability comes with no additional cost.

The ESBWR builds on the design features of operating BWRs. Figure 16.4 shows a cutaway of the ESBWR RPV. Most components in the ESBWR are standard BWR components that have been operating in the field for years (steam separators, control rods and guide tubes, core support structure, etc.). The core consists of conventional BWR fuel bundles, shortened from 12 ft. to 10 ft. to improve pressure drop and stability characteristics. The absence of hardware in the downcomer (jet pumps or internal pumps) reduces flow losses and further enhances natural circulation. The main difference is the taller reactor vessel with the addition of a partitioned chimney above the core and a correspondingly taller downcomer annulus. The fluid in the taller downcomer provides the additional driving head for natural circulation flow through the core, as well as a large water inventory for a LOCA. Steam in the chimney also provides a cushion to dampen void collapse in the core during pressurization transients, leading to a softer response with no SRV discharges.

16.3.2 Operating Domain

Valuable operating experience was gained from the early natural circulation BWRs. It was demonstrated that BWRs could operate in natural circulation without problems. The plants were extremely stable and presented no unusual characteristics relative to noise in the instrumentation. Power was raised by control rod withdrawal. The ESBWR will also adjust output using control rods, but with electrically driven CRDs that move slower and have finer positioning capability than the locking piston design for conventional BWRs. Because of its size, ESBWR will not normally be operated in a load follow mode. The FMCRDs can accommodate a duty corresponding to daily load following cycles for 10 years. Variable feedwater temperature control has been added to provide a second means of reactivity control in addition to the fine motion CRDs.

The present-day BWRs can operate at about 50% of rated power in natural circulation; however, stability considerations prevent

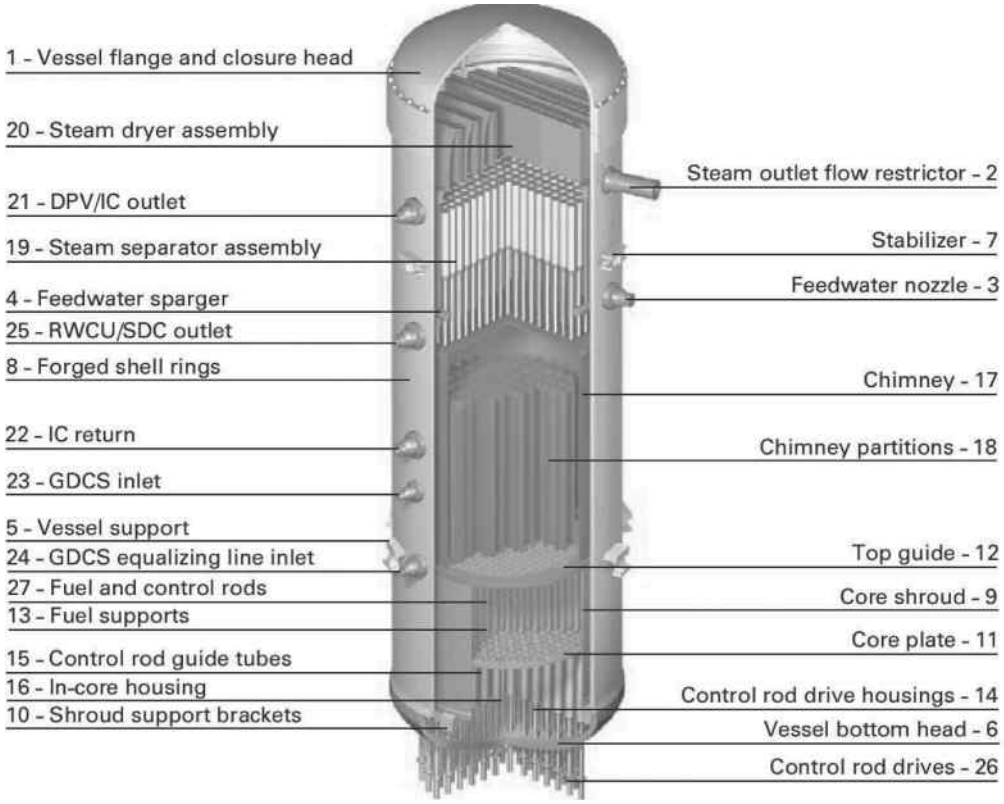


FIG. 16.4 ESBWR REACTOR ASSEMBLY [2]

steady operation in this region. There have been recirculation pump trip events in operating plants, which led to a natural circulation state at around 50% of rated power. The operating conditions in the present-day BWRs (power, flow, power distribution) in natural circulation following the pump trip were well predicted by the calculational models used for ESBWR performance analysis.

The operating parameters for the ESBWR, such as the power density, steam quality, void fraction, and void coefficient are within the range of operating plant data. Figure 16.5 shows a comparison of the ESBWR power–flow operating map with those of operating BWRs. This figure is based on the power per bundle and flow per bundle so that a meaningful comparison can be made. The power per bundle and flow per bundle for the ESBWR are both lower than for a modern jet pump plant at rated operating conditions, but the ratio of power to flow is similar to that for an uprated BWR at Maximum Extended Load Line Limit Analysis Plus (MELLLA+) conditions. This means that the core exit steam quality (ratio of steam flow to core flow) is also similar.

16.3.3 Passive Safety Features

The ESBWR safety systems design incorporates four redundant and independent divisions of the passive GDCS, the ADS and a PCCS. These systems are shown in Fig. 16.6. Heat removal and inventory addition are also provided by the isolation condenser system (ICS) and the standby liquid control system (SLCS).

The RPV has no external recirculation loops or large pipe nozzles below the top of the core region. This, together with a high capacity ADS, allowed the incorporation of an ECCS driven solely by gravity, not needing any pumps. The water source needed for the ECCS function is stored in the containment upper drywell, with sufficient water to insure core coverage to 1 m above the top of active fuel as well as flooding the lower drywell.

The PCCS heat exchangers are located above and immediately outside of containment. There is sufficient water in the external pools to remove decay heat for at least 72 h following a postulated design basis accident, and provisions exist for external makeup beyond that, if necessary.

As a result of these simplifications in the ESBWR safety systems, there is an increase in the calculated safety performance margin of the ESBWR over earlier BWRs. This has been confirmed by a Probabilistic Risk Assessment (PRA) for the ESBWR, which shows that the ESBWR is a calculated factor of about 5 lower than ABWR and 50 better than BWR/6 in avoiding possible core damage from degraded events.

16.3.3.1 Gravity-Driven Core Cooling System The GDCS is composed of four divisions. A single division of the GDCS consists of three independent subsystems: a short-term cooling (injection) system, a long-term cooling (equalizing) system, and a deluge line. The short-term and long-term systems provide cooling water under force of gravity to replace RPV water inventory lost during a postulated LOCA and subsequent decay heat boiloff. The deluge line connects the GDCS pool to the lower drywell. A schematic of the GDCS is shown in Fig. 16.7.

Each division of the GDCS injection system consists of one 200-mm pipe exiting from the GDCS pool. A 100-mm deluge line branches off and is terminated with three 50-mm squib valves and deluge line tailpipes to flood the lower drywell. The injection line

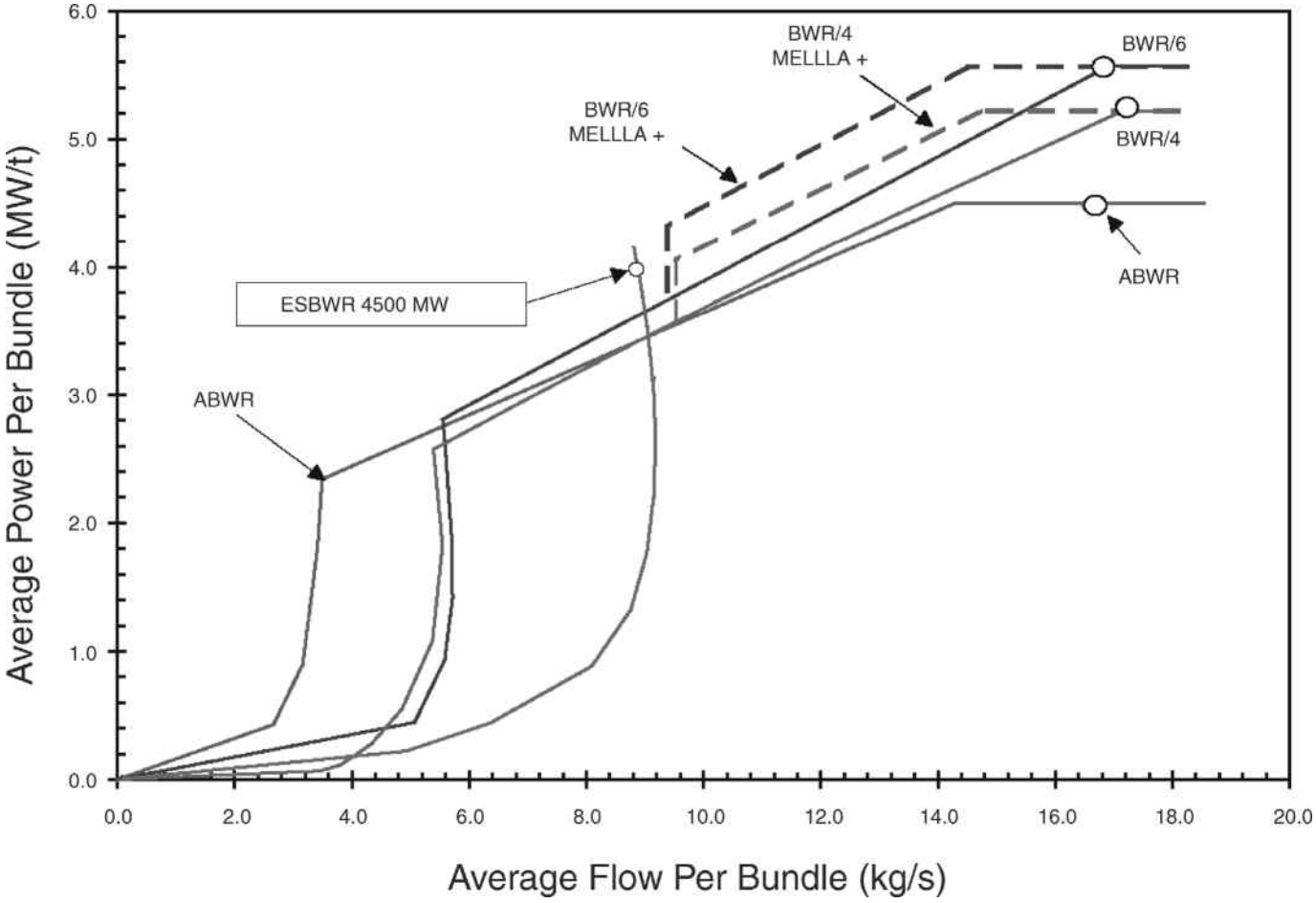


FIG. 16.5 COMPARISON OF ESBWR OPERATING POWER/FLOW MAP WITH OPERATING BWRs [2]

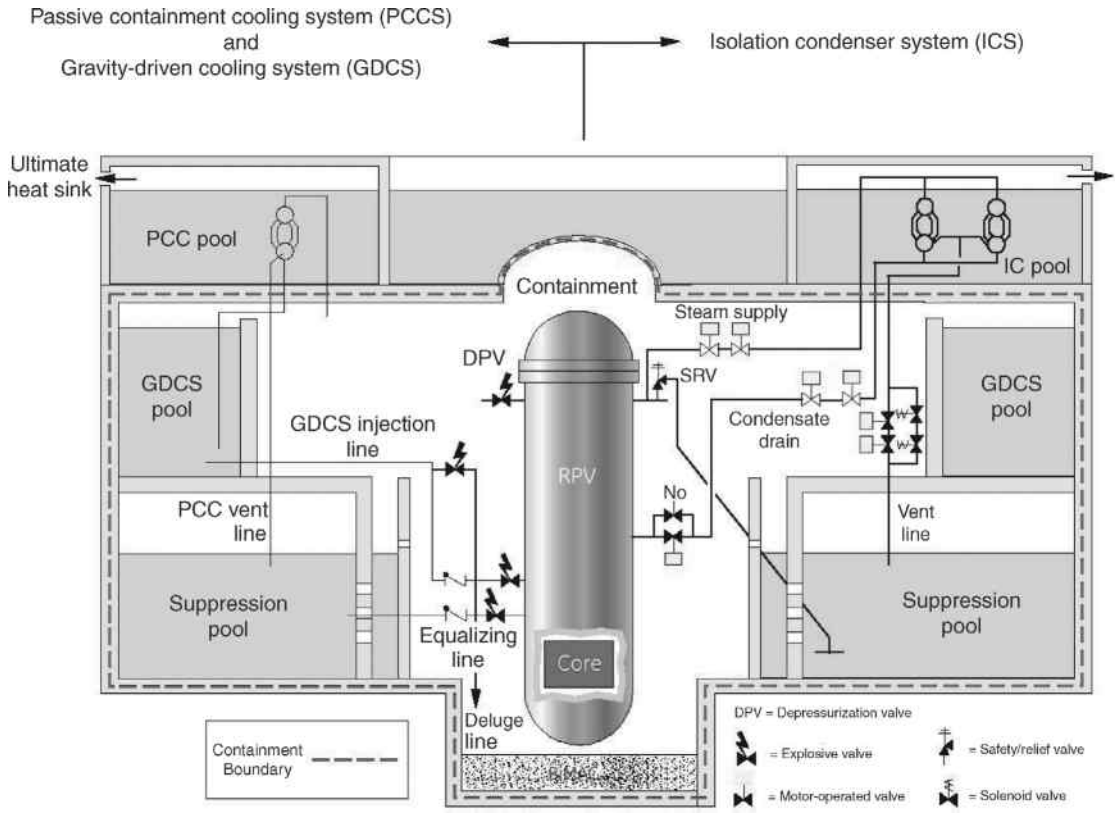


FIG. 16.6 ESBWR KEY SAFETY SYSTEMS [2]

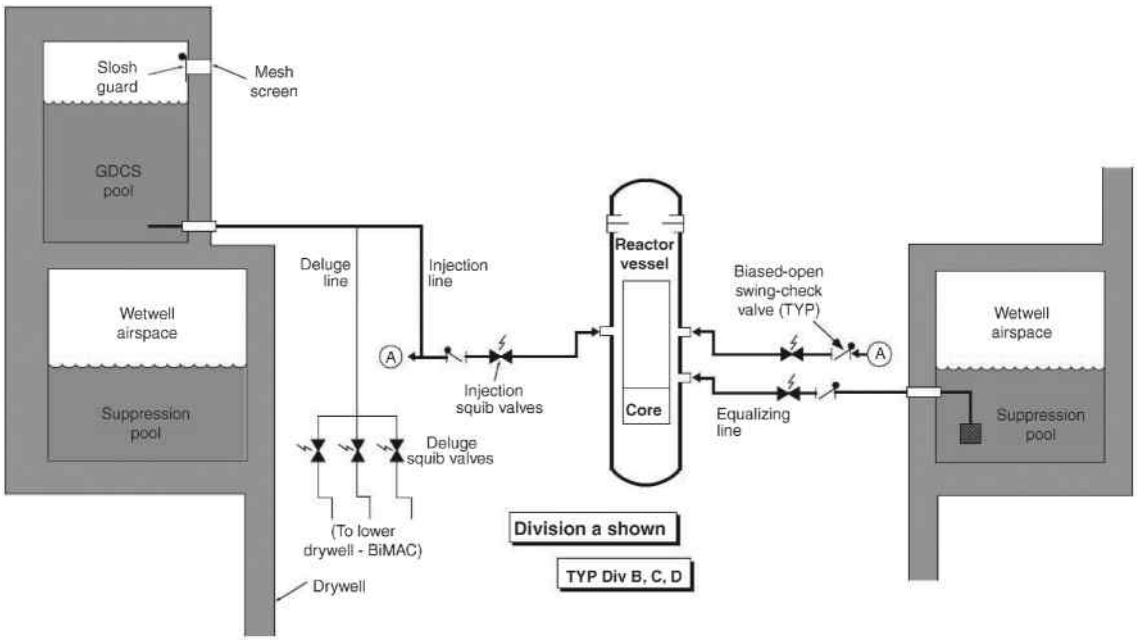


FIG. 16.7 ESBWR GRAVITY-DRIVEN COOLING SYSTEM [2]

continues after the deluge line connection from the upper drywell region through the drywell annulus where the line branches into two 150-mm branch lines, each containing a biased-open check valve and a squib valve.

Each division of the long-term system consists of one 150-mm equalizing line with a check valve and a squib valve, routed between the suppression pool and the RPV. All piping is of stainless steel and rated for reactor pressure and temperature. The RPV injection line nozzles and the equalizing line nozzles all contain integral flow limiters.

In the injection lines and the equalizing lines, there exists a biased-open check valve located upstream of the squib-actuated valve. The GDCS squib valves are gas propellant-type shear valves that are normally closed and which open when a pyrotechnic booster charge is ignited. During normal reactor operation, the squib valve is designed to provide zero leakage. Once the squib valve is actuated, it provides a permanent open flow path to the vessel.

The check valves mitigate the consequences of spurious GDCS squib valve operation and minimize the loss of RPV inventory after the squib valves are actuated and the vessel pressure is still higher than the GDCS pool pressure including (its gravity head). Once the vessel has depressurized below the GDCS pool surface pressure and its gravity head, the differential pressure opens the check valve and allow water to begin flowing into the vessel.

The GDCS deluge lines provide a means of flooding the lower drywell region with GDCS pool water in the event of a postulated core melt sequence that causes failure of the lower vessel head and allows the molten fuel to reach the lower drywell floor. A core melt sequence would result from a common mode failure of the short-term and long-term systems, which prevents them from performing their intended function. Deluge line flow is initiated by thermocouples, which sense high lower drywell region basemat temperature indicative of molten fuel on the lower drywell floor. Squib-type valves in the deluge lines are actuated upon detection of high basemat temperatures. The deluge lines do not require the actuation of squib-actuated valves on the injection lines of the GDCS piping to perform their function.

The deluge valves are opened based on very high temperatures in the lower drywell, indicative of a severe accident. Once the deluge valve is actuated, it provides a permanent open flow path from the GDCS pools to the lower drywell region. Flow then drains to the lower drywell via permanently open drywell lines. This supports the BiMAC core catcher function.

The GDCS check valves remain partially open when zero differential pressure exists across the valve. This is to minimize the potential for sticking in the closed position during long periods of nonuse.

Suppression pool equalization lines have an intake strainer to prevent the entry of debris material into the system that might be carried into the pool during a large break LOCA. The GDCS pool airspace opening to DW is covered by a mesh screen or equivalent to prevent debris from entering pool and potentially blocking the coolant flow through the fuel. A slosh guard is added to the opening to minimize any sloshing of GDCS pool water into the drywell following dynamic events.

The GDCS equalizing lines perform the RPV inventory control function in the long term. By closing the loop between the suppression pool and the RPV, liquid inventory that is transferred to the suppression pool either by PCCS condensation shortfall or by steam condensation in the drywell (which eventually spills back to the suppression pool) can be added back to the RPV.

16.3.3.2 Passive Containment Cooling System The PCCS maintains the containment within its pressure limits for DBAs. The system is designed as a passive system with no components that must actively function, and it is also designed for conditions that equal or exceed the upper limits of containment severe accident capability. The PCCS consists of six low-pressure, totally independent loops, each containing a steam condenser (passive containment cooling condenser), as shown in Fig. 16.8. Each PCCS

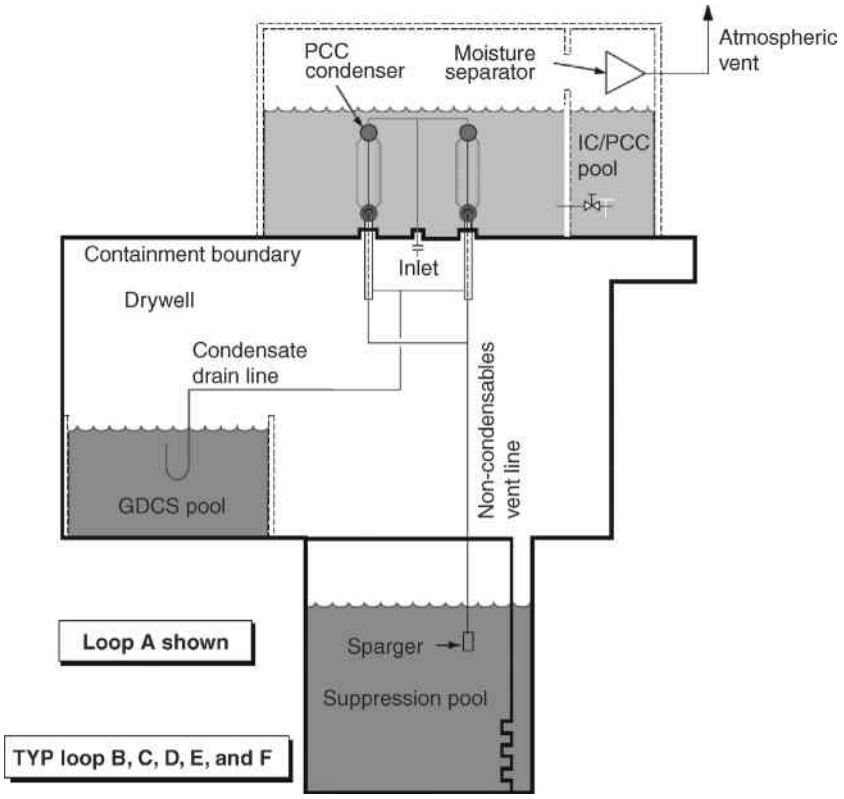


FIG. 16.8 ESBWR PASSIVE CONTAINMENT COOLING SYSTEM [2]

condenser loop is designed for 11-MWt capacity and is made of two identical modules. Together with the pressure suppression containment, the PCCS condensers limit containment pressure to less than its design pressure for at least 72 h after a LOCA without makeup to the IC/PCC pool and beyond 72 h with pool makeup. The PCCS condensers are located in a large pool (IC/PCC pool) positioned above, and outside, the ESBWR containment (DW).

Each PCCS condenser loop is configured as follows. A central steam supply pipe is provided, which is open to the containment at its lower end and it feeds two horizontal headers through two branch pipes at its upper end. Steam is condensed inside vertical tubes and the condensate is collected in two lower headers. The vent and drain lines from each lower header are routed to the DW through a single containment penetration per condenser module as shown in the diagram. The condensate drains into an annular duct around the vent pipe and then flows in a line that connects to a large common drain line, which also receives flow from the other header, ending in a GDCS pool.

The noncondensable vent line is the pathway by which drywell noncondensables are transferred to the wetwell. This ensures a low noncondensable concentration in the steam in the condenser, necessary for good heat transfer. During the periods in which PCCS heat removal is less than decay heat, excess steam also flows to the suppression pool via this pathway.

The PCCS loops receive a steam–gas mixture supply directly from the DW. The PCCS loops are initially driven by the pressure between the containment DW and the suppression pool during a LOCA and then by gravity drainage of steam condensed in the tubes, so they require no sensing, control, logic, or power-actuated devices to function. The PCCS loops are an extension of the safety-related containment and do not have isolation valves.

Spectacle flanges are included in the drain line and in the vent line to conduct postmaintenance leakage tests separately from Type A containment leakage tests. Located on the drain line and submerged in the GDCS pool, just upstream of the discharge point, is a loop seal. It prevents backflow of steam and gas mixture from the DW to the vent line, which would otherwise short circuit the flow through the PCCS condenser to the vent line. It also provides long-term operational assurance that the PCCS condenser is fed via the steam supply line.

Each PCCS condenser is located in a subcompartment of the IC/PCC pool, and all pool subcompartments communicate at their lower ends to enable full use of the collective water inventory independent of the operational status of any given IC/PCCS subloop. A valve is provided at the bottom of each PCC subcompartment that can be closed so that the subcompartment can be emptied of water to allow PCCS condenser maintenance.

Pool water can heat up to about 101°C (214°F); steam formed, being nonradioactive and having a slight positive pressure relative to station ambient, vents from the steam space above each PCCS condenser where it is released to the atmosphere through large-diameter discharge vents. A moisture separator is installed at the entrance to the discharge vent lines to preclude excessive moisture carryover and loss of IC/PCC pool water. IC/PCC pool makeup clean water supply for replenishing level is normally provided from the makeup water system.

Level control is accomplished by using an air-operated valve in the makeup water supply line. The valve opening and closing is controlled by water level signal sent by a level transmitter sensing water level in the IC/PCC pool. Cooling and cleanup of IC/PCC pool water is performed by the fuel and auxiliary pools cooling system (FAPCS). The FAPCS provides safety-related, dedicated

makeup piping, independent of any other piping, which provides an attachment connection at grade elevation in the station yard outside the reactor building, whereby a post-LOCA water supply can be connected. There have been extensive qualification tests of the PCCS, including full-scale component tests and full height scaled integral tests.

16.3.3.3 Standby Liquid Control System The SLCS provides a backup method to bring the nuclear reactor to subcriticality and to maintain subcriticality as the reactor cools. The system makes possible an orderly and safe shutdown in the event that not enough control rods can be inserted into the reactor core to accomplish shutdown in the normal manner. The SLCS is sized to counteract the positive reactivity effect of shutting down from rated power to cold shutdown condition. It also adds additional inventory to the RPV after confirmation of a LOCA.

The SLCS is automatically initiated in case of signals indicative of LOCA or anticipated trips without scram (ATWS). It can also be manually initiated from the main control room to inject the neutron-absorbing solution into the reactor.

The SLCS is a two-division passive system using pressurized accumulators to inject borated water rapidly and directly into the bypass area of the core. Each division is of 50% capacity. Injection will take place after either of two squib valves in each division fires upon actuation signal from the SSLC. Figure 16.9 illustrates the SLCS configuration.

In addition to the accumulators and injection valves, supporting nonsafety grade equipment includes a high-pressure nitrogen charging system for pressurization and to make up for losses and a mixing and boron solution makeup system. The boron absorbs thermal neutrons and thereby terminates the nuclear fission chain reaction in the fuel. The specified neutron absorber solution is sodium pentaborate using 94% of the isotope B10 at a concentration of 12.5%. This combination not only minimizes the quantity of liquid to be injected, but also assures no auxiliary heating is needed to prevent precipitation of the sodium pentaborate out of solution in the accumulator and piping. At all times, when it is possible to make the reactor critical, the SLCS will be able to deliver enough sodium pentaborate solution into the reactor to assure reactor shutdown.

Upon completion of injecting the boron solution, redundant accumulator level measurement instrumentation using two out of four logic closes the injection line shut-off valve in each SLCS division. Closure of these valves prevents injection of nitrogen from the accumulator into the reactor vessel that could interfere with ICS operation or cause additional containment pressurization. As a backup, the accumulator vent valves are also opened at the same time.

16.3.3.4 Isolation Condenser System The primary function of the ICS is to limit reactor pressure and prevent SRV operation following an isolation of the main steam lines. The ICS, together with the water stored in the RPV, conserves sufficient reactor coolant volumes to avoid automatic depressurization caused by low reactor water level. The ICS removes excess sensible and core decay heat from the reactor, in a passive way and with minimal loss of coolant inventory from the reactor, when the normal heat removal system is unavailable. The ICS is designed as a safety-related system to remove reactor decay heat following reactor shutdown and isolation. It also prevents unnecessary reactor depressurization and operation of ECCS, which can also perform this function.

The ICS consists of four totally independent trains, each containing an IC that condenses steam on the tube side and transfers heat to a large IC/PCCS pool positioned immediately outside the containment, which is vented to the atmosphere as shown in the ICS schematic (Fig. 16.10). The IC, connected by piping to the RPV, is placed at an elevation above the source of steam (vessel) and, when the steam is condensed, the condensate is returned to the vessel via a condensate return pipe. The steam side connection between the vessel and the IC is normally open and the condensate line is normally closed. This allows the IC and drain piping to fill with condensate, which is maintained at a subcooled temperature by the pool water during normal reactor operation. The IC is brought into operation by opening

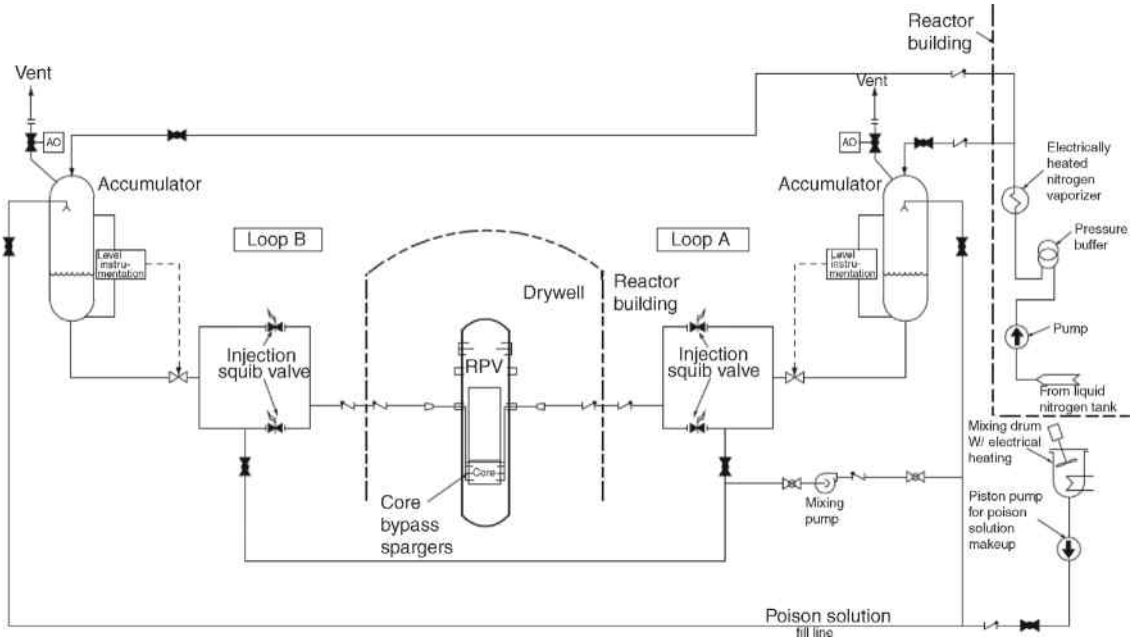


FIG. 16.9 ESBWR STANDBY LIQUID CONTROL SYSTEM [2]

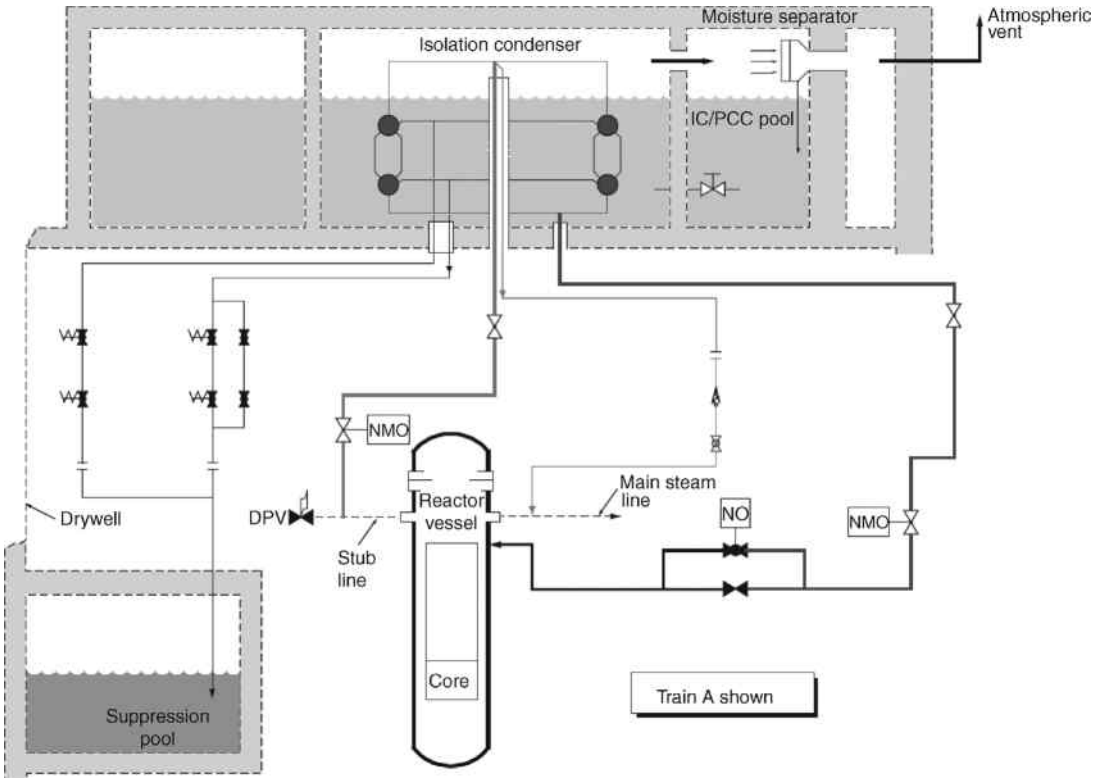


FIG. 16.10 ESBWR ISOLATION CONDENSER SYSTEM [2]

condensate return valves and draining the condensate to the reactor, thus causing steam from the reactor to fill the tubes that transfer heat to the cooler pool water. Each IC is made of two identical modules.

The steam supply line (properly insulated and enclosed in a guard pipe that penetrates the containment roof slab) is vertical and feeds two horizontal headers through four branch pipes. Each pipe is provided with a built-in flow limiter, sized to allow natural circulation operation of the IC at its maximum heat transfer capacity while addressing the concern of IC breaks downstream of the steam supply pipe. Steam is condensed inside vertical tubes and condensate is collected in two lower headers. Two pipes, one from each lower header, take the condensate to the common drain line that vertically penetrates the containment roof slab.

A vent line is provided for both upper and lower headers to remove the noncondensable gases away from the unit during the IC operation. The vent lines are routed to the containment through a single penetration.

A purge line is provided to assure that during the normal plant operation (IC system standby conditions), the excess of hydrogen (from hydrogen water chemistry control additions) or air from the feedwater does not accumulate in the IC steam supply line, thus assuring that the IC tubes are not be blanketed with noncondensables when the system is first started. The purge line penetrates the containment roof slab.

Containment isolation valves are provided on the steam supply piping and the condensate return piping.

Located on the condensate return piping just upstream of the reactor entry point is a loop seal and a parallel-connected pair of valves: (1) a condensate return valve (motor-operated, fail as is) and (2) a condensate return bypass valve (nitrogen piston-operated, fail open). These two valves are closed during normal station power operations. Because the steam supply line valves are normally open, condensate forms in the IC and develops a level up to the steam distributor, above the upper headers. To bring an IC into operation, the motor-operated condensate return valve is opened, whereupon the standing condensate drains into the reactor and the steam—water interface in the IC tube bundle moves downward below the lower headers to a point in the main condensate return line. The fail-open nitrogen piston-operated condensate return bypass valve opens if power is lost or on low reactor water level signal.

The loop seal assures that condensate valves do not have hot water on one side of the disk and ambient temperature water on the other side during normal plant operation, thus affecting leakage during system standby conditions. Furthermore, the loop seal assures that steam continues to enter the IC preferentially through the steam riser, irrespective of water level inside the reactor, and does not move countercurrent back up the condensate return line.

During ICS normal operation, any noncondensable gases collected in the IC are vented from the IC top and bottom headers to the suppression pool. During ICS standby operation, discharge of noncondensable gases is accomplished by a purge line that takes a small stream of gas from the top of the IC and vents it downstream of the RPV on the main steam line upstream of the MSIVs.

Radiation monitors are provided in the IC/PCC pool steam atmospheric exhaust passages for each IC loop. The radiation monitors are used to detect IC loop leakage outside the containment and cause either alarms or automatic isolation of a leaking IC. The IC has undergone engineering development testing using a prototype to demonstrate the proper operability, reliability, and heat removal capability of the design.

16.4 MATERIALS, FABRICATION, AND APPLICABLE ASME CODE EDITION

This section describes the thought process and the technical basis used in selecting materials and fabrication processes used in GE-designed ABWR and ESBWR. Additionally, the ASME Code edition applicability is briefly discussed.

16.4.1 RPV Design

Figure 16.4 shows the ESBWR reactor assembly. The materials and fabrication techniques mostly are commonfor ABWR and ESBWR. The RPV closure head is fabricated of low alloy steel, as per ASME SA-508, Grade 3, Class 1. The ABWR closure head is elliptical and the ESBWR RPV closure head is torispherical. The ABWR closure head is secured to the RPV by 80 fasteners (studs and nuts). The ESBWR has 84 fasteners. The studs are fabricated from SA-540 B23 or B24. The nuts are tightened in groups of (typically) four at a time, using an automatic or semi-automatic four-stud tensioner device.

There are three feedwater nozzles for each of the two feedwater lines, which utilize double thermal sleeves welded to the nozzle. The double thermal sleeve protects the vessel nozzle inner blend radius from the effects of high frequency thermal cycling. A schematic of the feedwater nozzle is shown in Fig. 16.11.

The ABWR vessel support has a skirt-type geometry. The ESBWR vessel supports are of the sliding block-type geometry and are provided at a number of positions around the periphery of the vessel. Multiple vessel ESBWR supports along with the corresponding pedestal RPV support brackets provide

- openings to permit communication between the upper to lower drywell
- access for ISI of the core beltline-to-bottom head weld

The vessel bottom head consists of a spherical bottom cap, made from a single forging, extending to the toroidal knuckle between the head and the vessel cylinder and encompassing the CRD penetrations. With a thickness of approximately 260 mm, the bottom head meets the ASME Code allowables for the specified design loads. The main advantage of using a single forging for the bottom head is that it eliminates all RPV welds within the CRD pattern, thus reducing future ASME Section XI ISI requirements. Both the ABWR and ESBWR RPVs utilize rings forged from low alloy steel, adjacent to and below the core belt line region. The flanges and large nozzles are also low alloy steel. The shell rings above the core belt line region and the RPV closure head are made from low alloy steel forgings or plate as per ASME SA-533, Type B, Class 1. The specified maximum reference nil ductility temperature, RT_{NDT}, of the vessel forging material is –20ºC. The corresponding specified maximum RT_{NDT} of the upper shell courses are –12ºC. Figure 16.12 shows one of the forged RPV shell rings during fabrication of an ABWR vessel.

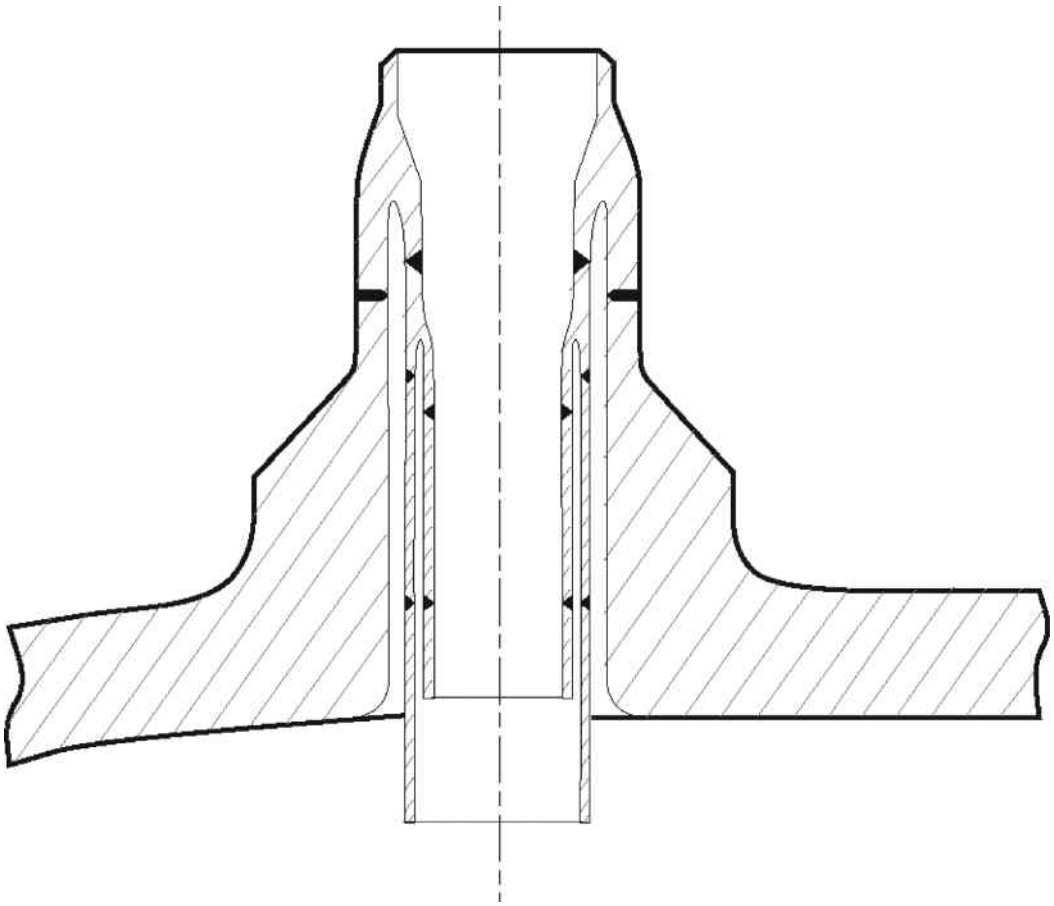


FIG. 16.11 ABWR/ESBWR RPV FEEDWATER NOZZLE [1, 2]

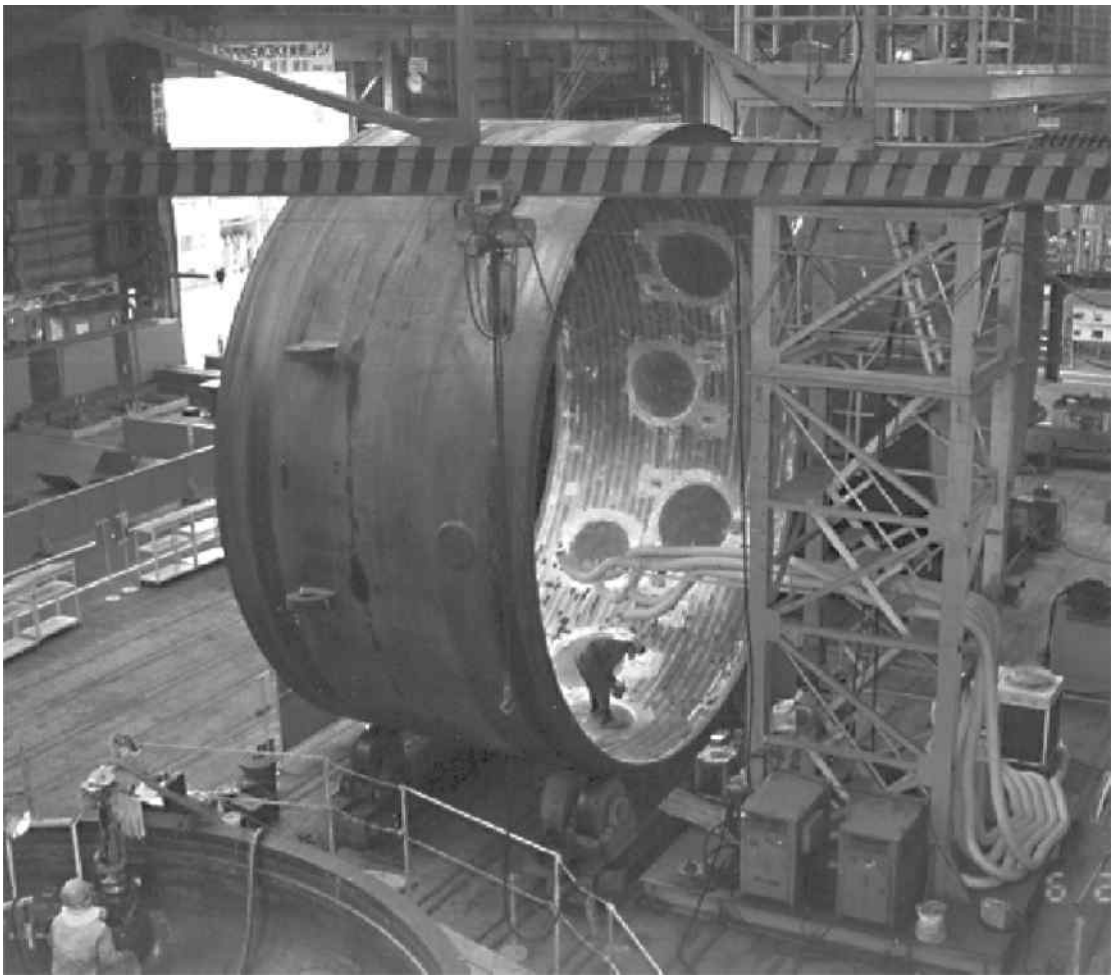


FIG. 16.12 ABWR RPV FORGED STEEL RING [1]

16.4.2 Materials Selection and Water Chemistry Controls

From the experience gained from the operating BWR fleet, the understanding of both the materials of construction and the degradation mechanisms has increased significantly. This understanding has been used to make ABWR/ESBWR materials selection. The ABWR/ESBWR makes use of austenitic stainless steels and nickel-base alloys as well as low alloy and carbon steel for all the major components. The plant design takes into account the potential effects of stress corrosion cracking (SCC), irradiation embrittlement, erosion/corrosion, and radiation buildup in the careful application of these materials. This application of materials is made in conjunction with good fabrication practice and strict operating control of the coolant environment chemistry to minimize the potential for long-term degradation and radiation buildup. A more detailed explanation of each area is given in the next section.

16.4.2.1 Austenitic Stainless Steel Materials for Internals and Components Austenitic stainless steels, because of high general corrosion resistance, high toughness, ease of fabrication, and acceptable strength, have been commonly used for reactor internals and some piping systems. In the ABWR, the primary consideration in the use of these materials is the development of resistance to intergranular stress corrosion cracking (IGSCC) both in low and high fluence locations. Based on field and laboratory efforts, this resistance is tied to the control of the material's composition, control of the fabrication processes, and control of the coolant environment.

The extensive understanding has now thoroughly demonstrated that reduction of carbon content in austenitic stainless steel reduces susceptibility to IGSCC. Mainly four austenitic materials are being used: Type 316NG/316L and 304NG/304L wrought materials, CF3M cast materials, and XM-19 high strength stainless steel.

For the majority of the reactor internal structures, resistance to sensitization for the ABWR and ESBWR is achieved by using special nuclear grade (NG) Type 316 and 304 materials. These alloys have carbon restricted to a maximum 0.020% by weight to prevent sensitization, have nitrogen additions up to a maximum of 0.12% to maintain the desired strength levels, and have specific fabrication and processing controls to increase the resistance to any crack initiation. Alternately, where design does not need the mechanical strength of Type 316 or 304, Type 316L or 304L is used with the same carbon limit and controls on fabrication processes. Types 308L/316L weld metal and CF3M austenitic stainless steel castings are also used in the reactor as well as for

many of the complex-shaped components such as valve body castings. These alloys have a microstructure that has been found to have high resistance to IGSCC. Their IGSCC resistance is maximized by again limiting the carbon content to less than 0.03%. All austenitic stainless steel weld filler materials are required by specification to have an average minimum delta ferrite content of 8 FN (ferrite number) and a maximum of 20 FN for 308L and 16 FN for 316L as determined on undiluted weld pads by magnetic measuring instruments calibrated in accordance with AWS Specification A4.2.

For any highly irradiated stainless steel in-core components such as control rods and instrument tubes, it is desirable to provide additional potential for the component to reach the intended design life. Consequently, for the ABWR and ESBWR, both the component design and materials of construction have been altered to provide this higher resistance against irradiation-assisted stress corrosion cracking for IASCC. The ABWR and ESBWR designs are crevice-free and incorporate control of trace element chemistry such as sulfur and phosphorus that provide this resistance.

The final material selected for specialized ABWR and ESBWR applications is XM-19. This is a high chromium, high manganese austenitic stainless steel alloy that is strengthened with specific nitrogen addition (as opposed to carbon). It has an established record of excellent performance in demanding applications in BWR service where both high strength and high resistance to IGSCC are required. Example applications in the ABWR include components in the FMCRD as well as core plate and top guide bolting.

16.4.2.2 Nickel Base Alloys for ABWR/ESBWR Application Nickel base alloys, particularly Alloy 600 and X-750, are also used in BWRs. In addition to their excellent corrosion resistance, nickel base alloys have a thermal expansion coefficient more similar to the low alloy steel used in the construction of the RPV and nozzles. This feature has led to the application of niobium modified Alloy 600 for several parts of the core internals, including the shroud support structure as a transition material placed between the alloy steel reactor vessel and the stainless steel internals. The other desirable feature of niobium modified Alloy 600 is that it is resistant to stress corrosion crack initiation in the post weld heat-treated condition, thereby allowing attachment to low alloy steel prior to stress relief. For the ABWR and ESBWR, to add margin against IGSCC, these alloys and their weld metals have been modified with stabilizing additions of niobium to reduce the potential for chromium depletion. For the wrought structures, the ABWR and ESBWR employ an Alloy 600 (designated as 600M) that has a niobium content on the order of 1–3%. For weld metal, Alloy 82 with high stabilizing ratios is used, leading to high IGSCC resistance as well.

Alloy X-750 is also used to a limited extent in the ABWR where high strength is required. Alloy X-750 is a precipitation hardening high strength nickel-base alloy that will perform well in the ABWR environment under the proper application. To improve SCC resistance for the ABWR, both the heat treatment and stresses of Alloy X-750 components are controlled, based on the extensive operating plant experience and material understanding.

16.4.2.3 Component Fabrication and Design Considerations Aside from selection of materials that are intrinsically resistant to IGSCC, the fabrication of components will be controlled to ensure that this high resistance is maintained in the finished part. Low heat input welding processes are used to decrease the likelihood of any sensitization due to the welding process. The margin of IGSCC resistance will be reduced even for the intrinsically resistant materials by abusive fabrication practices such as excessive cold working. Postmanufacturing surface processing such as polishing can be applied to the weld heat-affected zones to remove surface cold work and residual stresses and strains, thereby further increasing the resistance to IGSCC initiation. Contamination with in-process materials having high levels of species such as chlorine, fluorine, and sulfur can degrade performance. Consequently, to protect the high level of resistance obtained by using materials such as described above for the ABWR, the entire fabrication and installation process is controlled to prevent detrimental practices.

A final consideration in control of IGSCC is the design itself. Crevices have been eliminated where possible and the number of welds has been reduced. The top grid structure, for example, is manufactured from a single solution annealed plate, thereby eliminating the risk of IGSCC. The core shroud is constructed in a manner to locate all welds away from the highest fluence locations.

16.4.2.4 Water Chemistry Control With respect to materials performance in the BWR, a substantial body of data now exists that shows that water chemistry is a key factor in material degradation as well as radiation buildup processes, especially for core internal components. It has become very clear that the presence of oxidizing species in the high purity coolant (such as oxygen and hydrogen peroxide), as well as anionic species that contribute to the coolant conductivity, can be correlated with incidence of IGSCC cracking as well as the rate of progression of any initiated cracks. Events such as resin intrusions can also reduce the resistance to SCC initiation. The benefits of operating with good water chemistry are very clear and the owners of operating BWRs (even plants that have not experienced severe degradation in water chemistry such as resin intrusions) have adopted practices to obtain low conductivity. Thus, the Electric Power Research Institute (EPRI) has developed guidelines for water chemistry control that provide specific recommended limits on overall conductivity as well as specific species. For the ABWR, recommended water chemistry is applied such that the units operate at or below a target conductivity of 0.1 μS/cm whenever the reactor system is greater than 200°F (93°C).

These guidelines also recommend the application of hydrogen water chemistry (HWC) when possible. The main function of HWC is to inject sufficient hydrogen into the condensate to reduce oxidizing species and maintain the electrochemical potential (ECP) of the reactor water below –0.23 V standard hydrogen electrode (SHE). The addition of hydrogen has been documented to effectively control SCC. Although HWC can result in additional main steam line radiation, the use of noble metal technology such as noble metal chemical addition (NobleChem^{TM}) can reduce the hydrogen needed for SCC control through catalytic action while limiting any steam line radiation issues.

16.4.2.5 Material Considerations for 60-Year Design Life The reactor vessel is also a very important component where 30 years of BWR operating experience and materials understanding have been used in the ABWR. The vessel draws from the understanding of material degradation mechanisms and fabrication experience. Of key interest are the effects of neutron irradiation over the life of a reactor vessel beltline region (the region immediately around the core), which results in a progressive loss of fracture toughness. This shift in RT_{NDT} to higher temperatures can influence reactor operation with respect to such items as bolt-up

temperature and hydrostatic test temperature. Consequently, it is advisable to start with a low RT_{NDT} and use material resistant to neutron radiation damage. Copper and phosphorus have been identified as detrimental elements in alloys steels with respect to neutron damage, and nickel is considered to also be a factor. The corrosion behavior of reactor vessel steels is also well understood. There is significant experience with these steels to assure that there is high resistance to any SCC processes under the ABWR operating coolant environment.

For the ABWR reactor vessel, high toughness and retention of that toughness in service is provided. Strict controls are specified on initial fracture toughness of vessel components. Reactor vessel forging shell courses are required to have RT_{NDT} of –20°C or less. In addition, copper content is controlled to 0.05% maximum for base metal and weld metal. Phosphorus is limited to 0.006 and 0.008%, respectively. With these very low levels of copper, the shift in RT_{NDT} for the ABWR and ESBWR reactor vessels is expected to be very small over the operating life of the units. The estimated shift in ABWR RT_{NDT} is less than 11°C for a 60-year design life. Due to the core being closer to the vessel wall, the estimated shift in ESBWR is 37ºC for beltline forgings and 20ºC for the welds.

Low alloy steels are also used in many piping applications. The reduced corrosion rates make it attractive for several systems. However, the ABWR also employs carbon steel piping in some systems. This selection has been made to aid in plant fabrication while taking advantage of the steel's inherent toughness. Although erosion–corrosion in carbon steel power plant piping systems has been experienced in some units, oxygen injection is used for the ABWR to minimize this concern. Corrosion allowances for 60 years operation are included in the piping design.

16.4.3 Environmental Fatigue Rules

Since the early 1980s, the effects of high temperature water on the fatigue cyclic life of LWR components have been extensively discussed by numerous researchers. References [10]–[12] are some of the examples. The Subgroup on Fatigue Strength of the ASME Boiler & Pressure Vessel Code is currently working on a Code Case that would provide procedures for incorporating the reactor water environmental effects in the fatigue evaluation conducted as per the guidelines in Section III Paragraphs NB-3200 and NB-3600 [13].

Recently, the NRC has published Regulatory Guide 1.207 to provide guidance for determining the acceptable fatigue life of ASME pressure boundary components, with consideration of LWR environment [14]. The associated detailed guidance document is NUREG/CR-6909 [12]. NUREG/CR-6909 adopted the environmental fatigue correction factor method or F_{en} method to account for the environmental fatigue effects. F_{en} is defined as the ratio of fatigue initiation life in air at room temperature to that in reactor water at the service temperature. The regulatory guides are not mandatory. However, the NRC is likely to ask applicants for certification of new reactor designs for the technical approach they plan to follow to address environmental fatigue effects.

Reference [15] describes the results of the application of Regulatory Guide 1.207 methodology to an ABWR plant piping system. The system chosen was feedwater piping inside the containment. This system is typically classified as Class 1 as per the ASME Code classification.

Figure 16.13 schematically shows the feedwater piping system. The piping system delivers the feedwater to the reactor. It also receives water from RHR and RCIC systems. The portion of the piping between the reactor nozzle and the header at the containment penetration is designed as per ASME Class 1 requirements. Piping thickness is as per Schedule 80. The specified design pressure and temperature for this piping are 1250 psi and 550°F, respectively. The feedwater temperature during normal operation is 420°F.

Table 16.4 provides a summary of the calculated values of cumulative fatigue usage factors at two locations. For the feedwater nozzle location, usage factors are provided for both the nozzle side (low alloy steel) and the safe end side (carbon steel). It is seen that there is a modest impact on the calculated fatigue usage

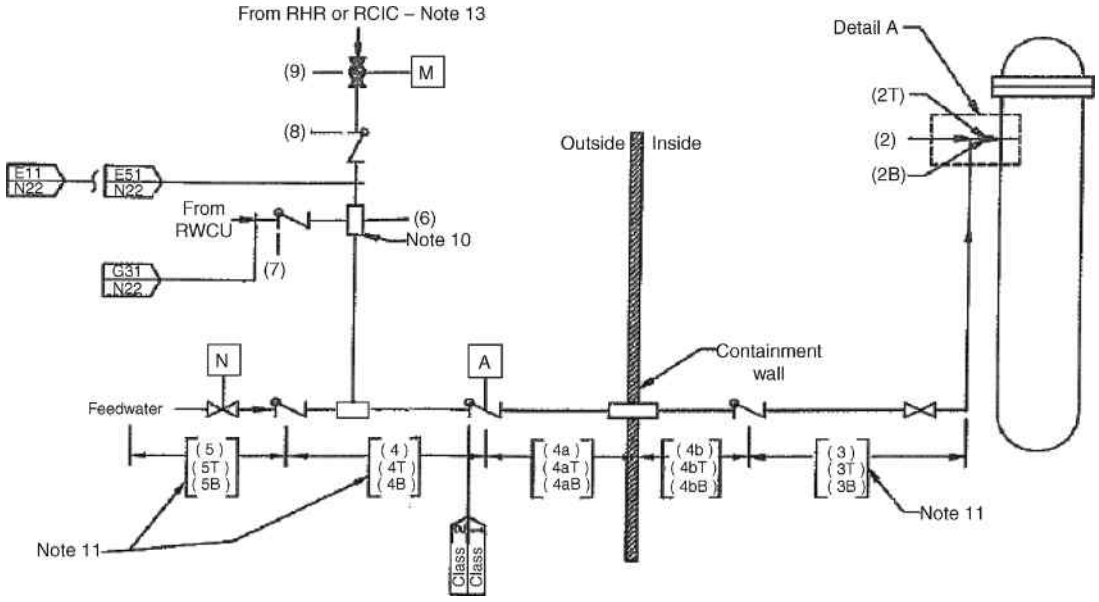


FIG. 16.13 SCHEMATIC OF AN ABWR FEEDWATER PIPING SYSTEM [15]

TABLE 16.4 CURRENT CODE AND ENVIRONMENTAL FATIGUE USAGE FACTORS FOR AN ABWR FEEDWATER LINE [15]

Node/location/material	Fatigue usage by current code	Fatigue usage by NUREG/CR-6909
Node 26/header/CS	0.083	0.117
Node 48/nozzle/LAS	0.085	0.302
Node 48/safe end/CS	0.085	0.086

factors when reactor water environmental effects are factored in. At the safe end location, the reduction in air fatigue usage through the use of NUREG/CR-6909 S–N curves essentially offset the increase due to the use of F_{en}.

The increase in calculated fatigue usage when environmental fatigue effects are taken into account was modest for the feedwater piping considered in this evaluation. One of the reasons is that the normal operating temperature for the feedwater line (240°C) is comparatively lower than the typical operating temperatures for the primary piping in LWRs. In the case of carbon and low alloy steel piping systems, the increase due to the use of F_{en} is significantly offset by the advantage gained through the use of air S–N curves provided in NUREG/CR-6909. This would not be the case for stainless steel piping systems where the air S–N curves in NUREG/CR-6909 predict higher usage factor than the Code curve.

In general, one would expect several fold increase in the calculated fatigue usage factor when F_{en} is used. This would have implications in terms of number of locations where hypothetical pipe breaks need to be postulated. Currently, the NRC Branch Technical Position MEB 3–1 [16] is used for postulation of breaks in high energy lines. MEB 3–1 requires postulation of a break at an intermediate locations if the fatigue usage at a location exceeds 0.1 or the primary plus secondary stress range exceeds 2.4 S_m. The calculated primary plus secondary stress range is not impacted by the use of F_{en} but the fatigue usage factor is. The use of F_{en} results in more locations where cumulative fatigue usage factor would exceed 0.1. More break locations means more pipe whip restraints to meet the requirements of General Design Criterion 4 of 10CFR50 [17]. However, the presence of more pipe whip restraints adversely affects the ability to conduct piping ISIs and thus have a negative impact on piping reliability during operation. The 0.1 fatigue usage threshold was based on engineering judgment and perhaps can be revised upward to say 0.4 or 0.6 to avoid this situation. The revision could be justified through a piping reliability analysis somewhat similar to that conducted in support of revised Appendix L in ASME Section XI Code [18].

16.4.4 Applicable ASME Code Edition

For ABWR, 1989 Edition of Section III of ASME Code was used for plant design and fabrication. The ESBWR uses two different Editions of Section III. The 2001 Edition including Addenda through 2003 Edition is used for all of the plant designs except for building construction. For building construction, 2004 Edition is used.

The ASME Section XI Edition committed to the ESBWR Design Certification Document (DCD) is 2001 Edition with Addenda through 2003. For licensing for specific site, the plant owner would select based on the permit date.

16.5 FUTURE DIRECTION – FABRICATION AND MODULARIZATION

Modularization techniques are implemented to reduce costs and improve construction schedules. These techniques are applied to such reactor fuel building items as (1) building reinforcing bar assemblies, (2) structural steel assemblies, (3) steel liners for the containment and associated water pools, (4) selected equipment assemblies, and (5) drywell platform and piping supports.

16.6 SUMMARY

The ESBWR represents an entirely new approach to the way nuclear plant projects are undertaken, modeled after the successful process used for ABWR. The ABWR was licensed and designed in detail even before construction began. Once construction did begin, it proceeded smoothly from start to finish in just 4 years.

Natural circulation is a proven technology that provides numerous benefits. Natural circulation allows the elimination of several systems, including recirculation pumps and associated piping, valves, heat exchangers, motors, adjustable speed drives, and controllers. The larger RPV employed for natural circulation provides synergy with the use of passive ECCS and improves the response to operational transients and increased safety margins. Flow transients resulting from recirculation pump anomalies are not present; that is, no runbacks or trips that would challenge stability.

The successful design, licensing, construction, and operation of the ESBWR nuclear power plant will usher in a new era of safe, economic, and environment-friendly nuclear electricity. The ESBWR is the first of a new generation of nuclear plants equipped with advanced technologies and features that raise plant safety to new levels, which significantly improve the economic competitiveness of this form of generation.

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CHAPTER

17

FUTURE CODE NEEDS FOR VERY HIGH TEMPERATURE GENERATION IV REACTORS

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ABSTRACT

This chapter: (1) identifies the structural integrity issues in the ASME Boiler & Pressure Vessel Code, including Section II, Section III, Subsection NH (Class 1 Components in Elevated Temperature Service), Section VIII, and Code Cases that must be resolved to support licensing of Generation IV (Gen IV) nuclear reactors, if for very high temperature gas-cooled reactors; and (2) describes how the Code addresses these issues; and (3) identifies the needs for additional criteria to cover unresolved structural integrity concerns for very high temperature service.

17.1 BACKGROUND

In the late 1960s, the U.S. Department of Energy (DOE) recognized that structural design methods used for light water reactor (LWR) systems would not be adequate for the licensing of high-temperature liquid metal reactor systems. Although non-nuclear systems such as chemical process plants operate routinely at high temperatures, they do not have the demonstrated reliability required for long-term nuclear service with limited inspection. A program was thus initiated by the DOE and continued for about 15 years to develop the basis for high-temperature structural design and licensing of liquid metal fast breeder reactor (LMFBR) systems.

A key feature of the program is that it was carried out simultaneously with design and construction of the fast flux test facility (FFTF) plant and with design of the Clinch River breeder reactor (CRBR) plant. Project design needs were factored into the development program continuously and the results were used in ongoing design and evaluation.

Since design temperatures of LMFBR systems are significantly above those of the LWR systems more familiar to the Nuclear Regulatory Commission (NRC), close scrutiny was given to elevated temperature effects as they relate to structural integrity and safety. The NRC identified a number of concerns in two major areas: (1) Code design limits and (2) design evaluation procedures. Specific development programs were identified to be completed prior to issuance of a plant operating license. The review, which included input from U.S. national laboratories, manufacturers, and independent consultants, represented essentially an open forum assessment of the state-of-the-art elevated temperature structural design. As a result of the extensive review and with a plan agreed upon for resolution of the NRC concerns, NRC and Advisory Committee for Reactor Safeguards (ACRS) formally recommended issuance of a construction permit for CRBR.

Subsection NH [1] of Section III was originally developed to provide structural design criteria and limits for elevated temperature design of LMFBR systems and some gas-cooled systems. The U.S. NRC and its ACRS reviewed the design limits and procedures in the process of reviewing the CRBR for a construction permit in the late 1970s and early 1980s and identified issues that needed resolution. Since then, the NRC, DOE, and various contractors have evaluated the applicability of the ASME Code and Code Cases to high-temperature reactor designs, such as the very high temperature gas-cooled reactors (VHTGRs), and identified issues that need to be resolved to provide a regulatory basis for licensing.

17.2 SUMMARY

Since the 1980s, the ASME Code has made numerous improvements in elevated temperature structural integrity technology. These advances have been incorporated into Section II, Section VIII, Code Cases, and particularly Subsection NH of Section III of the Code, "Components in Elevated Temperature Service" [1]. The current need for designs for very high temperature reactors and for Gen IV systems requires the extension of operating temperatures from about 1400°F (760°C) to about 1742°F (950°C), where creep effects limit structural integrity, safe allowable operating conditions, and design life.

Materials that are more creep and corrosive-resistant are needed for these higher operating temperatures. Material models are required for cyclic design analyses. Allowable strains, creep-fatigue and creep-rupture interaction evaluation methods are needed to provide assurance of structural integrity for such very

high temperature applications. Current ASME Section III design criteria for lower operating temperature reactors are intended to prevent through-wall cracking and leaking.

Section 17.7 describes the U.S. NRC and ACRS work on elevated temperature structural integrity licensing issues subsequent to CRBR. Source documents for the NRC and NRC sponsored work are References [15]–[21], [23], and [24] of this chapter. NRC has issued a number of definitive reports (see References [16]–[19], [23], and [24]). Oak Ridge National Laboratory (ORNL), Argonne National Laboratory (ANL), and Idaho National Engineering and Environmental Laboratory (INEEL)[1] have performed the other studies and evaluations cited herein. DOE sponsored an Independent Technical Review Group (ITRG) of Technology alternatives for meeting the functional objectives of the next generation nuclear plant (NGNP)[22]. A list of materials and design basis issues cited in a 1993 ORNL Report [15] is given in Section 17.6.1.

ANL provided two reports in 2003, describing a review and assessment of the material behavior issues, and the Codes and Procedures for high-temperature gas-cooled reactors (HTGRs). They state that Subsection NH is considered to be applicable to HTGR components that will operate at relatively low temperatures, and that the scope of Subsection NH needs to be expanded to include materials with higher allowable temperatures and other materials of interest. They cite Alloy 617, 9 Cr-1M0-V steel, and Hastelloy X as candidates for core support structures and vessel internals. Their major findings are given in Sections 17.6.4 and 17.6.5.

DOE authorized INEEL to conduct a review of technology alternatives for the NGNP. Their report-Reference–[22]–was published on June 30, 2004. Their recommendations are relevant to structural design criteria and code development. The NGNP is to be designed, constructed, licensed, and operated by no later than 2020, with a target date for initial operation of 2017. INEEL believes that meeting these objectives will require technology stretch, and warns against attempting too great a stretch. Several nuclear system concepts for a very high temperature reactor (VHTR) for the NGNP were reviewed. These include the helium-cooled prismatic reactor, the helium-cooled pebble bed reactor, and the molten salt-cooled prismatic reactor. Based on construction time objectives and material development requirements, INEEL recommended that maximum metal temperatures be limited to 900°C (1652°F). This corresponds to a maximum core average outlet temperature of 900–950°C (1652–1742°F). Even at 900°F (1652°F) metal temperature, they state that some reactor core subassemblies might require replacement during the 60-year design plant life.

The NRC prepared a presentation on "NGNP Technical Issues Safety Research Needs" in June 2006 [23]. This presentation, described in Section 17.6.7, discusses the licensing framework and related components, qualifications, fabrication, and testing issues. The major metallic component technical issues, as quoted, still requiring resolution include the following:

- Fatigue, creep, and creep-fatigue interaction
- Coolant impurities and crevice concentration impacts
- Metal carburization, decarburization, and oxidation
- Sensitization of austenitic steels
- Alloy aging behavior at elevated temperatures
- The adequacy of in-service inspection
- The applicability/adequacy of the ASME Code database

The design lifetime of Gen IV Reactors is expected to be 60 years. Additional materials including Alloy 617 and Hastelloy X need to be fully characterized. Environmental degradation effects, especially impure helium and those noted herein, need to be adequately considered. Since cyclic finite element creep analyses will be used to quantify creep rupture, creep fatigue, creep ratcheting, and strain accumulations, creep behavior models and constitutive relations are needed for cyclic creep loading. Such strain- and time-hardening models must account for the interaction between the time-independent and time-dependent material response.

The manner in which structural integrity and licensing issues for the structural design of VHTR and Gen IV systems are addressed in the current ASME Subsection NH and Code Cases is described in Section 17.7. The material creep behavior, creep fatigue, and environmental effects are addressed in Subsection NH and Code Cases largely in terms of design criteria and allowable stress and strain values. The detailed material properties needed for cyclic finite element creep design analyses are generally not provided in the Code. The minimum strength properties given in the Code are used as anchor values for the more comprehensive material suppliers' average properties. The NRC perspective is that the Code and/or Code Cases currently do not adequately cover the material behavior under cyclic loads in the creep regime and creep-fatigue-creep-rupture damage interaction effects.

Subsection NH has rules for the design of welded joints separated into Categories A–D. The permissible types of welded joints and their dimensional requirements are specified. The Code includes requirements for the design and location of all pressure-retaining welds operating at temperatures where creep effects are significant. Reduction factors for creep stress rupture are given as a function of time and temperature. Permissible weld metals are limited and special examination requirements are imposed.

Probably the most restrictive Subsection NH requirements for welds are that the inelastic accumulated strains are limited to one-half the allowable strain limits for the base metal. This has forced designers to keep welds out of high-stress areas. The allowable fatigue at weldments is limited to one-half the design cycles allowed for the base metal. The allowable creep rupture damage at weldments is limited in NH by requiring that the rupture strength be reduced by the weld strength reduction factor when determining the time to rupture. The Code also imposes additional examination requirements on Categories A–D welded joints. The adequacy of these and other Code weldment structural design requirements, and even for the temperatures currently covered, which are lower than the VHTR and Gen IV high-temperature systems, has been questioned by the NRC.

Section 17.8 herein describes the material models, design criteria, and analyses methods, which the NRC has indicated need to be covered in the ASME Code under Regulatory Issues for Very High Temperature Service. These needs for which Code technical committees must be involved are listed hereunder—:

1. Material cyclic creep behavior, creep-rupture–creep-fatigue interaction, and environmental effects

[1] On February 1, 2005, the Idaho National Engineering and Environmental Laboratory and Argonne National Laboratory-West became the Idaho National Laboratory (INL).

2. The structural integrity of welds
3. The development of extended simplified design analysis methods (to avoid dependence on "black box" finite element analysis (FEA) for cyclic creep)
4. Test verification of 1, 2, and 3

17.3 STRUCTURAL INTEGRITY EVALUATION APPROACH

17.3.1 Modes of Failure

Elevated temperature CRBR systems and components were designed to meet the limits of the ASME Boiler & Pressure Vessel Code, Section III, Case N-47 (1981) [2], the forerunner of Subsection NH, which applies for ferritic steels at temperatures above 700°F (371°C) and for austenitic stainless steels above 800°F (427°C). Failure is prevented by (1) identifying each possible failure mode, (2) determining the damage criterion for each failure mode, and (3) establishing design rules that appropriately separate design limits from initiation of failure. Other rules rely on control of geometry, design rules to specify details, and design factors based on experience to avoid failure, but do not treat each failure mode explicitly.

Code Case N-47 is based primarily on design by analysis since it was not possible to develop simple, generally applicable formulas to represent the time-dependent response of complex structures. However, it did include a number of simplified limits and bounding methods. The latter were based on elastic and short-time plastic analyses, which, although generally conservative, if satisfied, could avoid more detailed, time-dependent, inelastic, and creep analyses. The cost of analysis was a consideration. The modes of structural failure considered in CRBR design include the following:

- Ductile rupture from short-term loads
- Creep rupture from long-term loads
- Creep fatigue failure
- Gross distortion due to incremental collapse and ratcheting
- Loss of function due to excessive deformation
- Buckling due to short-term loads
- Creep buckling due to long-term loads

17.3.2 Stress Categories

In Code Case N-47, stresses and strains are categorized as primary (P), secondary (Q), or peak (F), and in applying the limits, distinction is made between two types of quantities: (1) load-controlled and (2) deformation-controlled. The load-controlled quantities result from equilibrium with applied loads during plant operation. Primary stress intensities are load-controlled quantities. Deformation-controlled quantities are stresses, strains, and deformations that result from deflection and/or strain compatibility. These quantities generally vary both with time and applied loads, and creep effects may be a major influence. Thus, accurate, analytical evaluation of deformation-controlled quantities generally requires inelastic stress analysis when creep effects are significant.

17.3.3 Materials Representations

Modeling of time-dependent materials behavior in multidimensional states of stress is fundamental to the accurate prediction of component response to service loads and to comparison with design limits.

For CRBR, the materials models (constitutive equations) were developed by the ORNL and are described in Reactor Development & Technology (RDT) Standard F9-5T [3]. The constitutive relations [4] are based on observations largely from uniaxial test data for Type 304 stainless steel and are applicable to 304 SS, 316 SS, and 2¼ Cr-1 Mo steel. For time-independent, elastic-plastic calculations, the von Mises yield criterion, its associated flow rule, and the linear kinematic hardening rule were used. For consistency, this requires use of an assumed bilinear uniaxial stress-strain relationship. Creep behavior is represented in the form of a creep law that includes both primary and secondary creep. This includes all the basic elements (elastic, plastic, primary, and secondary creep strains) and the effects of plastic yielding and flow, cyclic plasticity, plastic strain hardening, creep strain hardening, and creep load reversal.

Small strain theory was used since the Code strain limits essentially limit design strains to the range where small strain theory is valid. The effects of prior plastic deformation on subsequent creep were neglected, and, except for hardening due to prior creep strains, the effects of prior creep deformation on subsequent elastic-plastic behavior were neglected.

17.4 STRUCTURAL INTEGRITY EVALUATION METHODS

At the time the CRBR was designed, the finite element method of structural analysis was already well established. Solutions for linear elastic problems could be obtained readily and accurately for relatively complex (three-dimensional) geometries and loading conditions. The solution of nonlinear elastic–plastic creep problems was less well established. It was impractical to do a full three-dimensional inelastic analysis of a complete reactor system. However, neither was it necessary to do detailed analysis over extended regions of the system. Only part of the system operates at elevated temperatures, and many components see elevated temperatures only for brief periods. Also, for the components that operate at elevated temperatures, the magnitude of inelastic strain accumulation is critical only in local regions, such as nozzles, elbows, flanges, connections, and so on. So the general approach to design analysis was to determine interaction loads by equilibrium and compatibility considerations, and then analyze the highly stressed local regions in significant detail.

17.4.1 Simplified Analysis Method

Simplification in structural analyses took the form of simplification of geometry, material model, loading conditions, or some combinations thereof. For the solution of nonlinear, elastic-plastic creep problems, a number of special purpose computer programs were written to implement the ORNL materials models for specific geometries such as one-dimensional and plane (two-dimensional) thick cylinders and axisymmetric and two-dimensional nozzles [5, 6]. Programs were written using simplified material models to address specific failure modes such as creep ratcheting and creep buckling. The ORNL materials models were also incorporated into the general purpose finite element programs, MARC and ANSYS, to address more complex geometries and loading conditions [7].

17.4.2 Detailed Analysis of Localized Areas

For CRBR, the design evaluation process proceeded from simple to complex. The design Code Case N-47 includes the so-called screening rules that give limits for controlled quantities calculated elastically. The rules are conservative in most cases but if they can be met, more detailed inelastic analysis is not

required. A large part of the design was confirmed using the screening rules. If the screening rules cannot be met, then inelastic analysis is required. However, a "simplified" inelastic analysis may suffice. It may be possible to show, using simplified representations of the structure, that stresses or strains are bounded and within design limits. If "simplified" methods fail, a "detailed" analysis is necessary. But the detailed analysis could generally be limited to very localized regions when proper account was taken of the gross behavior of the structure. It is not necessary, for example, to do an inelastic analysis of a complete pipeline when only the elbows are loaded inelastically [8].

17.4.3 Models and Tests

To validate the combination of material model, geometrical approximation, and computer implementation, a number of model and full-scale tests were run and analyzed using simplified and detailed analyses [9]. Full-scale tests were run on piping elbows, nozzle to cylinder attachments, and cylinders rotated between two opposing sodium jets [10]. The elbows were loaded to measure time-dependent plastic buckling, creep deformation, creep ratcheting, creep relaxation, and creep buckling. The nozzle [FFTF intermediate heat exchanger (IHX) nozzle] was loaded to measure creep ratcheting and creep rupture. The rotating cylinder was also loaded to measure response to thermal striping. Tests on models included nozzles, cylinders, spheres, and plates (thermal striping). The test results were used to sharpen the analytical techniques and to gain expertise with their use in structural analysis of CRBR.

17.5 REGULATORY ISSUES

17.5.1 NRC Licensing Review

In the Safety Evaluation Report, NUREG-0968 [11], related to construction of the CRBR, the NRC described the complicating effects of elevated temperature service as follows:

> *Systems and components in service at elevated temperatures are subjected to larger temperature variations and differentials than LWR hardware. Moreover, the materials have lower strength at elevated temperatures. The resulting higher thermal strain ranges and increased inelastic strain concentrations tend to accelerate fatigue damage. In addition, the materials are susceptible to creep-rupture damage that results from both applied and residual stresses persisting after transient conditions. Relaxation of such stresses tends to cause ratcheting on subsequent load cycles. The effective microscopic ductility of many of the materials and product forms is reduced by concentration of creep strains in grain boundaries. Consequently, cracking can occur at accumulated strain levels that would cause no problems at temperatures below the creep regime.*

17.5.2 Structural Integrity Licensing Concerns

Based on a review of the material presented by the CRBR Project, the NRC (with ACRS) identified concerns in nine areas:

1. Weldment cracking
2. Notch weakening
3. Material property representation for inelastic analysis
4. Steam generator tube sheet evaluation
5. Elevated temperature seismic effects
6. Elastic follow-up in piping
7. Creep fatigue evaluation
8. Plastic strain concentration factors
9. Intermediate piping transition weld.

17.5.2.1 Weldment Cracking Weldment cracking, particularly in components subjected to repeated thermal transient loads, was identified by the NRC as the foremost structural integrity concern for CRBR. It is well known that when structural failure occurs, it is generally at weldments.

The design approach to weldment integrity was primarily to ensure that weldments are at least as strong as the parent metal. Weldment configuration and processes were controlled, and the amount of delta ferrite that may transform into a brittle sigma phase was limited. In addition, reduced strain limits were specified that encouraged the placement of weldments in lower stressed regions. Code Case N-47 specified the use of parent metal properties to represent weldment behavior in life assessment procedures, the complex interaction between stress and strain at weldments was not taken into consideration.

The NRC assessment was that because of the importance of weldment cracking as a failure mode, the designer should have a better understanding of the metallurgical interactions that take place in weldments and their effects on weldment life. Specifically, the NRC was concerned with (1) early crack initiation at the inside wall surface in the heat-affected zone (HAZ) where the weldment is exposed to thermal cycling; (2) the effects of large variations in material properties within the weldment on creep-fatigue and creep-rupture damage; and (3) the effects of time rate, cycle rate, and hold time on the propagation of long shallow cracks in the HAZ of a weldment. The NRC was also concerned about creep enhancement of crack growth in a cracked weldment, specifically, enhanced creep in the remaining uncracked wall caused by residual stress and thermal cycling, and effects of creep on stability of the remaining uncracked wall ligament. The NRC felt that as a minimum, these effects must be considered and quantitatively evaluated to determine the safety margins of weldments in elevated temperature components.

The basic requirements identified by NRC were as follows:

- Evaluate potential for premature crack initiation at weldments due to thermal fatigue, residual stresses, and damage caused by the welding process.
- Confirm adequacy of creep rupture and creep fatigue damage evaluation procedures at weldments.
- Assess growth behavior of cracks in the HAZ of weldments.
- Evaluate consequences of enhanced creep in uncracked ligaments.
- Assess stability of uncracked ligaments for creep conditions.
- Define effects of long-term elevated temperature service on crack initiation.
- Evaluate effects of loading sequence on creep fatigue behavior.

It was required that these investigations be completed prior to issuance of a plant operating license.

17.5.2.2 Notch Weakening Cracking at notches and other local structural discontinuities in components was another area of major concern to the NRC. The situation is similar to that at weldments where material discontinuities lead to high local stresses. In the case of notches, the geometrical configurations lead to local stress concentrations and the potential for inelastic strain concentrations

that may exhaust material ductility. Notches, small radius fillets, and localized structural discontinuities are regions observed in practice, besides weldments, where cracks tend to initiate.

The CRBR approach to avoid cracking was to avoid use of sharp geometrical discontinuities and to place structural transitions in low stress regions. There were no special rules in Code Case N-47 that apply to notches. They were not considered in application of the load-controlled limits but were considered in application of the Appendix T Strain Limits (T-1300) and the Creep Fatigue Limits (T-1400). Separate limits were provided for elastic and inelastic analysis. If the elastic limits could be met, then inelastic analysis was unnecessary. However, for the CRBR, most regions with significant structural discontinuities had to be modeled inelastically. In fact, most of the inelastic analysis performed for the CRBR plant was to ensure compliance with Code Case N-47 Appendix T rules at structural discontinuities.

The major concern of the NRC was that the design limits for fatigue and creep rupture were based on tests of smooth-sided specimens that did not include possible effects of stress gradients in notches. The NRC was also concerned about loss of ductility under long-term loads due to prior cyclic and monotonic straining. The NRC concerns are described as follows in the Safety Evaluation Report, NUREG-0968 [11]:

> *The basic allowable stress limits of the Code are based on unnotched creep specimen test data. Stress raisers influence the creep behavior of the entire wall in two basic ways. They introduce a constraint against inelastic flow by inhibiting slip line development. This is manifested in a reduction in the average stress intensity in the net section (a notch strengthening effect). Stress raisers also introduce a site where creep-rupture damage could cause early crack initiation and more rapid crack propagation (a notch weakening effect). Although the combined effect is notch strengthening in most cases, an evaluation is needed to determine what geometric, loading, and material parameters could cause significant notch weakening, particularly for long-term loads at elevated temperatures. Loading conditions such as transverse shear do not introduce any notch strengthening and have contributed to weldment cracking at structural discontinuities.*

A confirmatory program was developed jointly between the NRC and the CRBR project to address these concerns. The basic elements of the program are summarized as follows:

- Extend the elastic-constraint damage evaluation method to include cyclic and bending loads.
- Implement effects of material ductility in the damage evaluation procedure.
- Apply the extended method to "worst case" geometric notches in CRBR components.
- Compare effects of tensile stress versus stress intensity on creep rupture.
- Develop cyclic creep strain concentration factors for notches in creep fatigue and perform trial applications.

It was required that these investigations be completed prior to issuance of a plant operating license.

17.5.2.3 Material Property Representation for Inelastic Analysis The NRC reviewed analysis methods and applicable design criteria used for CRBR design. Concerns were expressed on the impact of new technology developments on safety, the verification of computer programs for use in inelastic analysis, and use of alternative strain limits in the DOE Office of Nuclear Energy (NE) Standard F9-5T. These were resolved by project commitments to assess the potential CRBR safety implications of new developments, provide verification and qualification of computer programs used in the design, and to avoid the use of strain limits based on elastic analysis in the final design justification.

An NRC issue that required a confirmatory program to be completed prior to application for an operating license concerned the suitability of using material average properties for inelastic analysis.

The CRBR project approach to inelastic analysis followed the guidance provided by NE Standard F9-4T, which states that

> *When inelastic analysis is used in preparation for a creep-fatigue or inelastic strain evaluation, the plasticity and thermal creep properties used in the analysis shall be average (or conservative). It is intended that the results of analysis based on "average" properties be compared to the Code supplied stress-rupture and fatigue limits.*

This applies to the strain and creep fatigue limits of Code Case N-47, but not to the buckling limits where the use of minimum strength properties is required. The rationale, which was established and affirmed by a strong national consensus, was that it is impractical to determine the worst case combination of minimum and/or maximum strength and deformation properties for each load combination. Nor would it be representative of actual material behavior because worst case combinations are not physically consistent. It was considered that material variations from the "average" are covered by Code design margins.

The NRC concern was that creep rupture damage calculated using average properties may be too low when compared to the considerable strain and cyclic hardening that occurs during fabrication and operation, and that the fatigue damage and accumulated strains may be too low if the actual yield strength is below the average value used in design analysis.

The confirmatory program identified to resolve these concerns required an evaluation of the significance of material property variations, where inelastic analysis is used to evaluate elevated temperature components containing radioactive sodium. The following requirements were imposed:

- Minimum yield strength and minimum creep deformation strength (80% of the average isochronous plots) properties shall be used to evaluate fatigue damage, as represented by the use fraction, and the accumulated inelastic strains.
- The fatigue damage fraction and the creep rupture damage, represented by the time fraction, are to be reported to the NRC for both minimum and average material properties using the method of Code Case N-47.
- The creep portions of the total accumulated inelastic strains (membrane, bending, and peak) are to be reported using the method of Code Case N-47.
- Structural adequacy of the components shall be demonstrated using these calculated values of damage and inelastic strain.
- Minimum and average properties shall be considered in performing the other confirmatory programs on Weldment Safety Evaluation, Notch Weakening, and the Steam Generator.

17.5.2.4 Steam Generator Tube Sheet Evaluation The NRC review of the CRBR steam generator design procedures was

conducted prior to project completion of design evaluation. The planned evaluation included mechanical property, feature, and prototypic tests to verify and supplement analysis methods and Code design procedures. As part of the confirmatory program, the project committed to completion of the planned test program, including an hydraulic test model, large leak tests, tube tests, departure from nuclear boiling tests, tube support wear tests, modular steam generator tests, single-tube performance tests, stability and interaction tests, tube-to-tube sheet weld tests, scaled hydraulic model feature tests, and flow-induced vibration tests.

The major NRC concern relative to the steam generator was assurance of adequacy of the tube sheet for the design life of the component. Specifically, the concern was adequate calculation of the highly localized, inelastic stress in the outer row of ligaments due to radial thermal gradients and bulk temperature difference between the perforated and unperforated regions. Section III of the ASME Code provides a simplified method of analysis based on the equivalent solid plate concept. However, this method was not applicable for the CRBR steam generator tube sheet, where the loading is dominated by large thermal gradients and deformations are inelastic. The CRBR project plan was to use detailed inelastic finite element analysis of sectors of the tube sheet in conjunction with the strain and creep fatigue limits for inelastic analysis in Code Case N-47 for elevated temperature design.

The NRC had concerns with this approach because of the difficulties in modeling ligaments and the complex thermal-structural interaction with the rim and the tubes. Their approach essentially was to extend the Section III design procedure based on the equivalent solid plate concept to include the effects of thermal gradients, plasticity, and creep.

The specific confirmatory program that the project agreed to carry out was stated as follows:

- Develop effective properties of the perforated region for use in design inelastic analysis.
- Evaluate the effects of thermal gradients and equivalent material property variations on ligaments near the periphery of the perforated region.
- Extend existing Appendix A-8000 Code methods for calculating the linearized membrane, shear, and in-plane bending stresses in the ligaments using the equivalent solid plate stresses. Include all of these nominal stresses in the comparison with allowable primary membrane plus bending and primary plus secondary allowables.
- Develop methods of evaluating local cyclic plastic and creep strain concentration effects based on equivalent solid plate stresses for use in the fatigue evaluation.
- Evaluate elastic follow-up in the outermost ligaments: (1) reclassify the portion of the discontinuity stresses caused by pressure and mechanical loads as “primary” in accordance with the associated amount of elastic follow-up that occurs during thermal transients, and (2) reclassify the portion of thermal stresses as “primary” in accordance with the amount of elastic follow-up that occurs during thermal transients.
- Develop ratcheting evaluation methods for the outermost ligaments based on elastic equivalent solid plate stresses reclassified as above and including nominal membrane, shear, and in-plane bending stresses.
- Develop creep rupture damage evaluation methods for the outermost ligaments based on equivalent solid plate stresses. The effects of elastic follow-up will reduce the amount of stress relaxation and increase the creep rupture damage.
- Perform detailed tube-to-tube sheet joint analysis for tubes in the high radial thermal gradient region at the periphery of the perforated region and include local thermal effects.

This extensive program was to be completed prior to issuance of a plant operating license.

17.5.2.5 Elevated Temperature Seismic Effects This issue concerns the possible enhancement of creep strain accumulation and creep rupture damage resulting from seismic events.

Code Case N-47 imposed limits on accumulated inelastic strain and creep fatigue damage, but did not provide guidance on cyclic load history modeling of combined events. Seismic events impose short-term primary stresses on structures that affect the inelastic strain accumulation by changing residual stress distributions. Seismic loads may also produce plastic strain accumulation by ratcheting if the event is sufficiently severe. Relaxation of the increased residual stresses that exist after a seismic event may produce enhanced creep during subsequent service at elevated temperatures. Consequently, the sequence of loading becomes important in the creep regime.

This issue was resolved by a project commitment to take into account any enhanced creep (ratcheting) and any creep rupture damage resulting from residual stresses at local stress raisers following seismic events. This was accomplished practically using an approximate procedure to simulate dynamic seismic loading as an equivalent static load for inelastic analysis. The procedure, developed under the LMFBR Program and reported in ASME Paper 82-PVP-28 [13], utilizes the results of a linear seismic response spectrum analysis to calculate external loads. These statically equivalent loads are selected such that they produce internal forces and moments comparable to those predicted by the linear response spectrum analysis. The equivalent static load for the seismic event is applied after the first system heat-up, when it is most damaging because the stresses have not yet relaxed during creep hold time. This procedure accounts conservatively for enhancement of accumulated strain and creep rupture damage due to seismic loads.

17.5.2.6 Elastic Follow-Up in Piping This issue concerns categorization of thermal expansion stresses as secondary for evaluation of hot leg piping. During creep relaxation, a portion of the elastic strain is converted to creep strain. Areas of piping that are more highly stressed are subjected to additional cyclic strain and strain accumulation resulting from elastic follow-up. To provide adequate safety margins, Code Case N-47 required that secondary stresses with a large amount of elastic follow-up be treated as load-controlled quantities. However, Code Case N-47 did not provide criteria that determine when elastic follow-up is considered large.

This issue was resolved by agreement between the NRC and the project on a method for quantifying elastic follow-up and a criterion for determining the portion of thermal expansion stress to be treated as primary. A simplified elastic analysis procedure to estimate the amount of elastic follow-up due to thermal expansion stress in a thin-walled piping system was developed under the LMFBR program and reported in Reference [14]. The reduced elastic modulus concept was used to represent creep, and elastic follow-up was quantified relative to the Code Case N-47 primary stress limit. The simplified method was validated by comparison with results of detailed inelastic analysis.

17.5.2.7 Creep Fatigue Evaluation The NRC identified three concerns relative to creep fatigue evaluations. The first was a

modification of the creep fatigue damage rule of Code Case N-47 when applied to austenitic stainless steel types 304 and 316 for components not to be Code stamped. The Code required that creep damage during compressive hold periods be taken equal to the creep damage during tensile hold periods for stresses of equal magnitude. The project modification took creep damage in compressive hold to be 20% of that in tensile hold. This was accepted by NRC upon proper documentation of the experimentally based justification.

The second NRC concern was the treatment of high-cycle fatigue due to thermal fluctuations and flow-induced vibrations that require evaluation beyond the Code Case N-47 design curve limit of 10^6 cycles for stainless steels. The project extrapolated the fatigue curve beyond 10^6 cycles using a slope of -0.12 on cycles for load-controlled situations and developed a special purpose high-cycle fatigue criterion for strain-controlled situations. The concern was resolved by demonstration that the extrapolation is more conservative at 800°F (427°C) than the high-cycle fatigue design curve up to 10^{11} cycles adopted by the Code in 1982 and by implication from additional elevated temperature data. The project also provided data to support the special limit used for strain-controlled situations.

The third concern was fatigue design limits for 2¼ Cr-1 Mo steel, which was resolved by a commitment to meet the elevated temperature fatigue design limits that had been recently approved by the ASME Code Committees.

17.5.2.8 Plastic Strain Concentration Factors For simplified elastic-plastic analysis, Section III of the Code allows the plastic strain concentration factor, K_e, to be taken as unity until the range of primary plus secondary stress intensity exceeds 3 S_m. The NRC concern was that this factor actually begins to exceed unity when the local maximum stress range, including the elastic stress concentration factor, exceeds 2 S_y. Also, strain multipliers for the concentration of plastic strain on the weaker side of a product form or material interface are not included in formulas for K_e in the Code.

This concern was resolved by a commitment to determine the actual plastic strain concentration, or to use a conservative approximation of concentration effects and the resulting fatigue design life when the local maximum stress range exceeds 2 S_y.

17.5.2.9 Intermediate Piping Transition Weld The intermediate heat transport system transition weld reference design was a trimetallic joint consisting of Type 316H stainless steel, Alloy 800H, and 2¼ Cr-1 Mo steel. Due to its complexity, the transition weld was evaluated in detail using the procedures of Code Case N-47 and applicable DOE Standards. The effects of creep, residual stress, and differences in properties between the component materials were modeled using inelastic analysis.

Although demonstration of design life had not been completed, the NRC was concerned about the minimum expected carbon content of 0.05% at 936°F (502°C), the importance of variation in properties between the different materials, and the possible increase in creep rupture damage resulting from the higher yield strength properties produced by hardening in a multipass welding process.

Resolution of the NRC concern was achieved by commitment to perform analyses using the methods and criteria to be developed under the confirmatory programs to address issues relating to weldment cracking and material property representation for inelastic analysis.

17.6 CURRENT REGULATORY ISSUES FOR STRUCTURAL DESIGN OF VHTR AND GEN IV SYSTEMS

Since the NRC and DOE licensing review of the CRBR during the late 1970s and early 1980s, NRC and DOE have continued to identify and investigate safety issues relative to structural design of high-temperature advanced reactor systems.

17.6.1 Materials and Design Bases in ASME Code Case N-47, NUREG/CR-5955

In anticipation of next generation advanced power reactors for utilities, NRC sponsored an ORNL evaluation of the design bases (principally ASME Code Case N-47) for the design and operation of reactors at elevated temperatures where the time-dependent effects of creep are significant and must be considered in the design process [15]. The reactor systems contemplated include advanced liquid-metal reactors, gas-cooled reactors, and possibly the Canada Deuterium Uranium (CANDU) reactors. This evaluation was not design specific, nor did it address specific reactor components such as transition joints, tube sheets, and bellows. Its main objective was to identify and summarize the issues that must be resolved to avoid the creep-induced failure modes of creep rupture, creep fatigue, creep ratcheting, and creep buckling.

A total of 23 issues were identified and described. They are characterized and classified by (1) type–safety or economical; (2) bases–material and database, design bases, or both; and (3) level—used to further delineate the issues into six categories based on a number of factors, depending on considerations of plant safety, plant economics, expected cost to resolve the issue, expected calendar time required to resolve the issue, whether Code rules must be extended if they are to be used as the design bases for future 60-year high-temperature plants, and so on. All but two of the issues were safety related. The 23 issues are listed here, and the 10 considered most important are identified by an asterisk:

1. Lack of material property allowable design data/curves for 60-year design life*
2. Degradation of material properties at high temperatures due to long-term irradiation*
3. Degradation of material properties due to long-term thermal aging
4. Degradation of material properties due to corrosion phenomena*
5. Lack of property allowables based on current melting and fabrication practices
6. Degradation effect of small cyclic stresses
7. Creep-induced failures at temperatures below Code Case N-47 limits
8. Use of average versus minimum material properties in design
9. Lack of a design methodology for Modified 9 Cr-1 Mo steel
10. Lack of understanding/validation of effects of short-term overload events on subsequent material properties
11. Lack of validated thermal striping materials and design methodology*
12. Lack of reliable creep fatigue design rules*
13. Difficult, overly conservative ratcheting design rules
14. Lack of a validated weldment design methodology*
15. Lack of flaw assessment procedures*
16. Uncertainty of multiaxial stress state effects

17. Uncertainty of nonradial (non-proportional) loading effects
18. Lack of understanding/validation of notch weakening effects*
19. Lack of conservatism in Code rules for simplified fatigue evaluation based on plastic strain concentration factors
20. Lack of validated rules/guidelines to account for seismic effects at elevated temperatures*
21. Lack of inelastic design procedures for piping*
22. Overly conservative buckling rules
23. Need for thermal stratification design guidelines

All issues except numbers 9 and 13 are considered to be safety related. The issues were described and elaborated but detailed plans for their resolution were not offered.

17.6.2 Safety Evaluation of the Power Reactor Innovative Small Module (PRISM) Liquid-Metal Reactor

The PRISM reactor design proposed by DOE was for a small, modular, pool-type, liquid-metal (sodium)-cooled reactor producing 471 MW_t power. The standard plant design consists of three PRISM modules with a total electrical output rating of 1395 MW_e. The primary and intermediate sodium outlet temperatures are 905°F (485°C) and 830°F (443°C), respectively, but under certain transient conditions, the reactor vessel wall may reach core outlet temperatures that increase to between 1100°F (593°C) and 1300°F (704°C). Thus, the design temperatures are not significantly greater than for CRBR. However, the design life was for 60 years compared to 30 years for CRBR, which introduced some additional material degradation issues.

The NRC staff performed a preapplication safety evaluation of PRISM and published their findings in NUREG-1368 [16] dated February 1994. The objective was to provide at least the level of safety that is required for current generation LWRs. The Preapplication Safety Evaluation Report did not result in design approval, but identified key safety issues and assessed the adequacy of the applicant's research and development programs. The overall conclusion was that there are no major impediments to licensing of the design.

Safety issues identified by NRC requiring resolution concerned primarily inelastic and limit analysis, Code Case N-47 (forerunner of Subsection NH) and other elevated temperature Code Cases, load combinations, and environmental effects associated with extrapolation of Code Case N-47 applicability from 34 to 60 years. It was pointed out that the NRC staff has not endorsed Code Case N-47 and, in general, has not accepted the application of inelastic stress and deformation limits in the initial design evaluations. Further review and justification are needed for the definition of load combinations, the application of inelastic and limit analysis in conjunction with the dynamic analysis, and the consideration of all types of time-dependent failure modes detailed in Code Case N-47.

Environmental effect issues included stress corrosion, flowing sodium effects, and neutron embrittlement. Stress corrosion was considered an issue because Type 316, used for the reactor vessel, is an austenitic sensitized stainless steel and subject to stress corrosion cracking (SCC) at the higher temperatures associated with certain transients. An area of particular concern was the weld between the core support structure and the reactor vessel. In a dynamic sodium environment, the concern was that the vessel could experience two types of degradation: erosion-corrosion and property changes. Erosion-corrosion decreases the effective load-carrying thickness and property changes can decrease time-independent and time-dependent strength properties. Neutron embrittlement was a concern because the reactor vessel is designed for a 60-year lifetime and exposed to neutron irradiation, which decreases ductility and fracture resistance.

To meet a design life of 60 years, the elevated temperature Code Cases N-47, N-201, and perhaps N-48, N-49, N-50, and N-51, will have to be extrapolated from the present 34-year lifetime.

17.6.3 Material Engineering Research Needs for Advanced Reactors—ACRS, USNRC/RES, and ORNL

Several presentations were made by Dr. Joseph Muscara of NRC in 2002 at coordination meetings with ACRS, USNRC Office of Nuclear Regulatory Research (USNRC/RES), and ORNL to review material engineering needs for advanced (high-temperature) reactor design [17–19]. The major issues concern the applicability of structural design codes–Section III, Subsection NH, and Code Cases N-201 and N-499—to high-temperature applications. These Codes are based primarily on studies and data gathered in the 1970s and 1980s for design of LMFBRs with maximum temperatures in the range of 1100°F (593°C) to 1500°F (816°C). There is a need to extend these Codes, particularly in the areas of creep, creep fatigue, and environmental effects, to cover higher temperatures and include databases developed in recent years.

Safety issues identified for high-temperature (unspecified) structural design of metallic components include the following:

- Lack of appropriate databases for calculating fatigue, creep, creep fatigue, and SCC lifetimes, including environmental effects
- Effects of impurities including oxygen on degradation
- Aging behavior of alloys
- Sensitization of austenitic alloys and weldments
- Degradation by carburization, decarburization, and oxidation
- Treatment of connecting pipe as a vessel for code application

NRC research under way in 2002 included the following:

- Review and evaluation of current national and international engineering design codes for components in HTGRs, including Codes and methodology developed in Germany, Japan, China, the United Kingdom, and France
- Review of existing literature and studies on HTGR materials and environmental effects on various degradation mechanisms
- Development of NUREG/CR-6824 [21], Material Behavior in HTGR Environments

17.6.4 Review and Assessment of Codes and Procedures for HTGR Components, NUREG/CR-6816, June 2003 [20]

The objective of this work was to review and evaluate currently available national and international Codes and procedures to be used in the design of HTGRs, including, but not limited to, the pebble bed modular reactor (PBMR) and the gas turbine-modular helium reactor (GT-MHR) designs. The evaluation is based on the materials that have been used or recommended for HTGRs, taking into account the HTGR operating environments. The ASME B&PV Code sections review included Section III, Subsections NB and NH, Code Cases N-499-1 and N-201-4, and a Draft Code Case for Alloy 617 for very high-temperature design.

The major findings of the evaluation were as follows:

- Most of the materials needed for HTGR are not included in the Code Cases. New code cases will be needed.
- The maximum temperature permitted by the Code and Code Cases for materials acceptable for HTGR components is lower (760°C/1400°F) than the maximum temperature (≥850°C/1562°F) that these components may experience during operation. The Code therefore needs to be expanded to include materials and limits for higher temperatures.
- The Codes and Code Cases do not provide specific guidelines for environmental effects, especially the effect of impure helium on the high-temperature behavior (e.g., fatigue, creep, and creep fatigue) of the materials considered. High-temperature fatigue life may be influenced more by environment than by creep damage for some materials.

Subsection NB is considered to be applicable to those HTGR components (e.g., pressure vessel) that will operate at relatively low temperatures.

Subsection NH provides design rules for construction of out-of-core nuclear structures fabricated from only five materials. This is potentially the biggest obstacle to its use in the design of HTGR components. The scope of Subsection NH needs to be expanded to include materials with higher allowable temperatures and other materials of interest. The candidate materials for core support structure and vessel internals include Alloy 617, 9Cr-1Mo-V steel, and Hastelloy X.

There are other concerns with the use of Subsection NH for design of HTGR components. Its rules are written for materials that follow a classical creep curve consisting of primary, secondary, and tertiary creep. However, many of the materials being considered (e.g., Alloy 617) do not show any evidence of primary or secondary creep. New rules are needed for such materials. Subsection NH does not require inelastic stress analysis to be conducted with rate-dependent, high-temperature unified constitutive equations (no distinction between creep and plastic strain), which are necessary when components operate at temperatures above 1200°F (649°C). At the higher temperatures, the tensile stress-strain relations depend on strain rate and the classical distinction between plasticity and creep becomes untenable. Thus, strain rate effects need to be included in Code design analyses for very high temperatures. Subsection NH states that the combined effects of exposure to elevated temperature, contacting fluid, and nuclear radiation on material properties shall be considered. However, the Code does not provide specific guidelines for considering environmental effects. The conclusion is that more mechanistically based predictive methods are needed to handle the various material-specific damage mechanisms in different environments.

The scope of Code Case N-499-1 should be expanded to include 9 Cr-1 Mo-V steel, which is specified for an uninsulated reactor vessel with an operating temperature of about 500°C (932°F). The effects of helium environment, including impurities, on the elevated temperature fatigue design curve, isochronous stress-strain curves, stress rupture curves, and the creep fatigue damage envelope need to be evaluated to further assess the applicability of this Code Case to low-alloy steel pressure vessel materials.

Code Case N-201-4 provides design rules for construction of core support structures fabricated from the same five materials covered in Subsection NH. The maximum temperature permitted by this case for the materials acceptable for use in HTGR is 760°C (1400°F). Since the GT-MHR core support structures may experience temperatures of 850°C (1562°F) or higher, the scope of the Code Case needs to be expanded to include materials with higher allowable temperatures. The candidate materials for core support structures and vessel internals are Alloy 617 and 9Cr-1Mo-V steel. As with Subsection NH, the deleterious effects of primary coolant and nuclear radiation need to be considered.

The Draft Code Case for Alloy 617 was patterned after relevant portions of Subsection NH and limited to Alloy 617, a temperature of 1800°F (982°C), and a maximum service life at temperatures above 800°F (427°C) of 100,000 h. Most of the design rules addressed by the Draft Code Case are similar to those provided by NH. Some design rules are different because the Code Case considers higher temperature and a different material. At the very high temperatures of interest, Alloy 617 exhibits unique material behavior that includes (1) lack of clear distinction between time-independent and time-dependent behavior, (2) high dependence of flow stress on strain rate, and (3) softening with time, temperature, and strain. One result is that the Case specifies that inelastic analysis for temperatures above 1200°F (649°C) must be based on unified constitutive equations that do not distinguish between time-independent plasticity and time-dependent creep.

The Draft Code Case for Alloy 617 is a work in progress and its completion requires further development of the Code Case, material database and structural design methodology. In the Code area, Alloy 617 must be added to the low-temperature rules of Section III; and weldment stress rupture factors, thermal expansion coefficients, and isochronous stress-strain curves for the temperature range 427°C (800°F)–649°C (1200°F) must be added to the Code Case. In the material area, weldment fatigue data and a more complete creep fatigue database are needed. Also, the synergistic effects of aging, environment, loading, and temperature need to be better understood and the effects of aging on toughness must be characterized. Relative to structural design methodology, the unified constitutive model needs to be further developed, simplified ratcheting evaluation procedures are needed at temperatures above 649°C (1200°F), and very high-temperature structural model tests are needed to validate the design methodology. Probably the greatest need is to develop a more suitable damage theory to replace the use of the linear damage fractions as the basis for the creep fatigue rules.

17.6.5 Material Behavior in HTGR Environments, NUREG/CR-6824, July 2003 [21]

The objective of this work was to review and evaluate available information on performance and long-term behavior of materials in environments that are typical of high-temperature helium-cooled reactors. The availability and adequacy of design codes, rules, and procedures for component structural design are discussed in the companion report, NUREG/CR-6816 [20], described previously. However, the results presented here are pertinent because they provide the current state of knowledge on candidate structural materials that must be treated in the Code for nuclear structural design.

The primary helium coolant in the gas turbine-based HTGRs is expected to be at temperatures in the range of 850–900°C (1562–1652°F), and the selected materials should have adequate performance over the long service life at temperatures in the range of 900–950°C (1652–1742°F). Among the materials, 2¼ Cr-1 Mo and modified 9 Cr-1 Mo ferritic steels are considered for application in reactor pressure vessels. Fe-Cr-Ni alloys such as Alloy 800H and austenitic stainless steels are considered for

recuperators and reactor internals. Alloy 617, Hastelloy X, and Hastelloy XR are considered for components that will be exposed to helium coolant at temperatures up to 900°C (1652°F). The key technical issues addressed were:

- Baseline mechanical property data
- Effects of helium coolant chemistry on material degradation
- Corrosion effects on mechanical properties of candidate materials
- Fission product release and its effect on materials
- Corrosion–erosion due to particulate-laden gas flow.

The major findings of this task concern environmental effects on material properties. Some pertinent conclusions are as follows:

- The primary materials for high-temperature application in HTGRs that have been studied in detail are Alloys 800H and 617 and Hastelloy X. Among them, Alloy 800H is Code certified for temperatures up to 760°C (1400°F) for use in nuclear systems. A substantial database has been developed for both Alloys 800H and 617 and a limited database exists for Hastelloy X.
- Even though helium by itself is inert toward the materials, it is often contaminated by small amounts of gaseous impurities. The gas chemistry and the thermodynamic activity for carbon and oxygen in the gas phase are difficult to ascertain because of the nonequilibrium nature of the gas mixture. Also, most studies on gas chemistry simulations were performed close to atmospheric pressure, whereas the system pressure in the reactor is on the order of 7 MPa.
- Structural alloys can be significantly corroded by the gaseous impurities in helium at elevated temperatures. Corrosion of heat-resistant materials such as austenitic stainless steels and Alloys 800H and 617 may involve oxidation, carburization, and decarburization. Furthermore, the corrosion process is "dynamic" in that it is dictated by the exposure time, gas chemistry variations, integrity of the corrosion product scales, and pressure of particulates in the gas phase.

17.6.6 Design Features and Technology Uncertainties for the Next Generation Nuclear Plant, INEEL/Ext-04-01816, June 30, 2004 [22]

The U.S. DOE authorized the INEEL to have the ITRG conduct a review of technology alternatives for meeting the functional objectives of the NGNP.

The results of the review do not necessarily represent the concerns of NRC. However, the ITRG is a broadly experienced group and has offered conclusions, observations, and recommendations that are relevant to structural design code development.

The high-level functional objectives of NGNP include demonstrating an economically viable nuclear system, licensable in the United States, with commercially attractive production capabilities including high-efficiency power conversion, effective utilization of process heat (e.g., for production of hydrogen), and intrinsic safety. The NGNP is to be designed, constructed, licensed, and operated by no later than 2020, with a target date of 2017 for initial operations. Meeting these objectives will require technology stretch, but if the stretch is too great, the NGNP may become solely an exercise in research and development and would fail to accomplish the broader demonstration mission.

The ITGR reviewed several nuclear system concepts for a VHTR for the NGNP including the helium-cooled prismatic reactor, the helium-cooled pebble bed reactor, and the molten salt-cooled prismatic reactor. Results and recommendations of the review that are pertinent to structural design code development are summarized here:

- Few choices exist for metals for use at VHTR design conditions, and lifetime requirements may restrict the maximum operating temperature. The development of new materials (e.g., oxide dispersion-strengthened metals or refractory metals, or ceramics and carbon-based materials) would not be compatible with construction time objectives.
- For high-temperature applications, there are several undeveloped components, including the IHX, the hot gas isolation valves, the reactor pressure vessel, selected reactor internals, the reactor inlet/outlet pipes, the helium circulator, the insulation systems, and instrumentation for high-temperature application.
- Definition of design basis conditions for a helium-cooled reactor system.
- Based on material development considerations, it is recommended that maximum metal temperature be limited to 900°C (1652°F). This corresponds to a maximum core average outlet temperature of 900–950°C (1652–1742°F). Even at this metal temperature, some reactor core subassemblies might require replacement during the 60-year design plant life. A reactor outlet temperature of 1000°C (1832°F) would require material development and testing well beyond the metals currently used in high-temperature design.
- It is recommended that the temperature of the irreplaceable primary reactor coolant pressure boundary be limited such that time-dependent (creep) deformation is insignificant. Creep deformation and configuration change would cause excessive uncertainty and risk over a 60 year design life.

17.6.7 NGNP Technical Issues Safety Research Needs, June 2006 [23]

This USNRC presentation provided an overall summary of research and application needs for licensing of the NGNP project. It includes safety R&D arenas, licensing framework, probability risk assessment, nuclear analysis, thermal-fluid analysis, metallic components, nuclear graphite, fuel performance, qualification, fabrication, and testing.

Technical issues identified for metallic components that need resolution include the following:

- Fatigue, creep, and creep–fatigue interaction
- Coolant impurities and crevice concentration impacts
- Metal carburization, decarburization, and oxidation
- Sensitization of austenitic steels
- Alloy aging behavior at elevated temperatures
- Adequacy of in-service inspection plans and methods
- ASME Code Case and database applicability/adequacy
- PRA failure probabilities for vessels, pipes, and components.

17.6.8 Framework for Development of a Risk-Informed, Performance-Based Alternative to 10 CFR Part 50, NUREG-1860, July 2006 [24]

The purpose of this report is to document the technical basis to support the development of a risk-informed and performance-based process for the licensing of future nuclear power plants (NPPs). As

such it documents an approach, scope, and criteria that could be used by the NRC staff to develop a set of regulations that would serve as an alternative to 10 CFR 50 for licensing future plants.

This report provides very broad guidance for safety review. It does not provide specific guidance for codes and standards because it is expected that most codes and standards will be associated with design-specific features. However, the evaluation approach described in this report relies heavily on probabilistic risk assessment (PRA), which could have implications to high-temperature structural design codes. For example, the barrier integrity strategy provides isolation features that protect the primary radionuclide inventory from release. One feature is barrier structural integrity. PRAs are used to demonstrate that the frequency of radionuclide release is low enough, with adequate consideration of uncertainty. Therefore, uncertainties associated with barrier degradation, for example, corrosion, erosion, aging, chemical interactions, and other material issues need to be modeled. This does not necessarily imply that the structural design code must be based on PRA, but it appears that the code assessment results should be in a form that will allow PRA of barrier structural failure.

17.7 HOW STRUCTURAL INTEGRITY ISSUES ARE ADDRESSED BY CURRENT ASME CODE? INCLUDING CODE CASES AND SECTION III, SUBSECTION NH, "CLASS 1 COMPONENTS IN ELEVATED TEMPERATURE SERVICE"

Subsection NH of Section III evolved from prior Code Cases originally intended for CRBR. The CRBR was designed to operate at temperatures in the range of 1000°F (538°C)–1100°F (593°C) with low-pressure, relatively thin-walled sodium-containing components–reactor vessel, tanks, piping, heat exchangers, steam generators, pumps, and valves. At these temperatures and loading conditions, the structural materials exhibited limited creep. As a result, it was possible to make extensive use of simplified analysis and bounding methods such as the O'Donnell-Porowski bounds for creep ratcheting. The major thrust of the confirmatory programs was to insure that the effects of creep were bounded. Although a great deal of detailed inelastic analysis was performed, basically they were used to confirm the validity of simplified analysis methods for conditions dominated by cyclic thermal stresses.

While Subsection NH has evolved substantially since CRBR, the design and operating conditions of VHTR and Gen IV systems are quite different. There are a number of different design concepts being considered and temperatures of interest are in the range of 1600°F (870°C)–1700°F (925°C). Although there will be an effort to put the more highly stressed structural elements in cooler regions, the primary loads for many of the components will be higher than those encountered in CRBR. At these very high temperatures, there will be a significant change in material behavior as well as structural response. Environmental effects will be more significant. Creep and the effects of creep on component integrity are expected to be limited and will have to be analyzed in detail. Creep rupture damage, creep fatigue, and potential creep crack growth are of particular concern. Material models will probably have to include tertiary creep as well as multiaxial states of stress. Although Subsection NH has the basic structure to handle elevated temperature structural design, it will have to be extended and validated to handle the additional materials, higher temperatures, longer operating times and creep damage mechanisms anticipated for these reactors.

17.7.1 Material Creep Behavior, Creep Fatigue, and Environmental Effects

Section III, Subsection NH, and the Code Cases for elevated temperature design require further development to make them applicable for structural design and evaluation of HTGR and Gen IV systems. The temperature limits of code applicability need to be extended from 760°C (1400°F) to a maximum temperature of 950°C (1742°F). The design lifetime limit of 34 years needs to be extended to 60 years. Subsection NH currently provides design limits for five materials up to 760°C (1400°F). Additional materials such as Alloy 617, 9 Cr-1 Mo-V steel, and Hastelloys X and XR need to be added for temperatures up to 950°C (1742°F). Mitigating solutions are needed for environmental effects, including the degradation effects of impure helium, and the constitutive models for predicting inelastic and creep behavior of materials need to be developed. This must include the tertiary creep behavior exhibited very early by Alloy 617, and cyclic creep behavior at operating temperatures.

NRC foresees the need for increased focus on VHTR Licensing structural integrity issues not currently covered by the ASME Code and Code Cases, including

- Material behavior characterization for cyclic loads at very high temperatures
- Adequacy of structural analysis methods for cyclic loads at very high temperatures.
- Fatigue, creep, and creep-fatigue interaction
- Coolant impurities and crevice concentration impacts
- Metal carburization, decarburization, and oxidation
- Sensitization of austenitic steels
- Alloy aging behavior at elevated temperatures

17.7.2 The Structural Integrity of Welds

The structural integrity of welds in elevated temperature service is a major regulatory concern requiring increased attention at elevated temperatures. Details of the regulatory concerns are described in Section 17.5.2.1. Subsection NH has rules for design of welded joints that are separated into Categories A–D. The permissible types of welded joints and their dimensional requirements are also described.

NRC has expressed concern for the limited ductility of weldments at elevated temperatures and strain concentrations (both metallurgical and geometric) in the HAZs. Paragraph NH-3353 provides analysis requirements for the design and location of all pressure-retaining and other primary structural welds subjected to metal temperatures where creep effects are significant. Special examination requirements are included for welded joints. Permissible weld materials are limited. Creep stress rupture reduction factors for weldments are given as a function of temperature and time.

Subsection NH contains special limits on inelastic strains accumulated in the weld regions. These weld strain limits are one-half the strain values permitted for the parent material. The weldment strain limits are as follows:

1. Strains averaged through the thickness = 0.5%
2. Strains at the surface due to an equivalent linear distribution of strain through the thickness = 1%
3. Maximum local strains at any point = 2.5%

Subsection NH also reduces the allowable number of design cycles for weldments to one-half of the parent metal. It reduces the allowable time for creep rupture damage by multiplying the stress by the weld strength reduction factor when determining the time to rupture.

Subsection NH also imposes additional examination requirements on Categories A–D vessel weld joints.

The adequacy of these and other weldment structural design requirements in Subsection NH has been questioned by the NRC even for the temperatures currently covered, which are lower than VHTR and Gen IV high-temperature systems. Accordingly, Section 17.8, which covers the material models, design criteria, and analysis methods needed in the ASME Code to cover regulatory issues for very high-temperature service, includes further discussion of these weldment issues.

17.7.3 Development and Verification of Simplified Design Analysis Methods

The NRC sees the use of simplified methods of performing creep ratcheting, creep fatigue, and creep rupture damage analyses, such as the O'Donnell-Porowski bounds, as a way of verifying the "black box" of cyclic creep finite element analyses. The latter have not seen extensive safety-related applications. Simplified methods are now used extensively in Subsection NH. However, their derivation and verifications are based on simplifications and approximations such as thermal through-wall stresses being essentially linear, bending stresses being essentially secondary, weldments having essentially homogeneous properties, no metallurgical notches, and so on.

17.7.4 Verification Testing

Because VHTR design analysis methods do not have a long history of successful application and require complex thermal cyclic finite element creep analysis, the NRC would like to see confirming tests verifying the material models and structural features analyses. Cyclic material models including strain hardening and time hardening require verification. Is primary creep repeated under cyclic load conditions and is it recoverable? The cyclic behavior of representative key structural features is also an issue.

The Code does not explicitly require verification testing, but as an American National Standard Safety Code, the Code Committees have an obligation to meet the verification criteria thereof and to satisfy NRC licensing requirements to prevent the need for supplementary NRC requirements.

17.8 MATERIAL MODELS DESIGN CRITERIA AND ANALYSIS METHODS NEEDED IN THE ASME CODE FOR VERY HIGH-TEMPERATURE SERVICE

17.8.1 Material Creep Behavior, Creep Fatigue, and Environmental Effects

Refer to Sections 17.6.1–17.6.5 for descriptions of current Code coverage of regulatory needs for very high-temperature service. These needs are heavily material-oriented and involve the Subcommittee on Materials (SC-II), the Subcommittee on Nuclear Power (SC-III), Subcommittee on Pressure Vessels (SC-VIII), and Subcommittee on Design (SC-D), as well as the Subgroup on Elevated Temperature Design. In addition to these generic materials coverage Code needs, there are more specific needs related to weldments, the development and verification of simplified design methods, and test verification of material models and representative structural features. These needs are discussed in the following paragraphs.

17.8.2 The Structural Integrity of Welds

Because of the importance of potential elevated temperature cracking of weldments, NRC wants the designer to account for potential creep strain concentrations due to metallurgical notch effects. Subsection NH does not include methods for analyzing the effects of varying properties between the base metal, weld metal, and HAZ, or even how to determine these properties after welding and postweld heat treating. Moreover, NRC expressed concern with potential early crack initiation at the inside wall surface in the HAZ, how crack propagation can be quantified, and the stability of the remaining uncracked wall section. Methods of evaluating such weldment integrity issues and the corresponding safety margins are needed in the ASME Code to satisfy regulatory concerns. These methods will require material models, cyclic creep analysis methods, crack growth analyses, and remaining ligament-enhanced creep stability analysis methods. Such methods essentially parallel Section XI flaw evaluation methods, which are only applicable below the creep regime. The NRC has also requested confirmation of the creep rupture, creep fatigue, and interaction evaluation procedures at weldments, accounting for load sequence effects. These confirmations were required by ACRS before they would issue a plant operating license for CRBR, a matter that became mute when Congress terminated this demonstration project.

These issues involve the Subcommittee on Nuclear Power (SC-III), the Subcommittee on Materials (SC-II), the Subcommittee on Welding (SC-IX), the Subcommittee on Pressure Vessels (SC-VIII), and the Subcommittee on Nondestructive Examination (SC-V), as well as the Subgroup on Elevated Temperature Design.

17.8.3 Development and Verification of Simplified Design Analysis Methods

Existing simplified design analysis methods have proven to be valuable in providing assurance of structural integrity in the moderate creep regime and have been used in France, Germany, Japan, and the United States for this purpose. These methods can be further developed to include higher temperatures, where creep effects control the design margins and where structural discontinuity notches, and defects need to be evaluated. Cyclic finite element creep analysis results are difficult to trust without having comparative results of simplified design analysis methods. These needs involve the Subcommittee on Nuclear Power (SC-III), the Subcommittee on Pressure Vessels (SC-VIII), and the Subcommittee on Design (SC-D), and are focused in the Subgroup on Elevated Temperature Design. The TF Elastic-Plastic Finite Element Analyses could be expanded to include creep, the SG Design Analysis could verify and develop these rules, and/or the SG Elevated Temperature Design could reinstate their TF on creep analyses.

17.8.4 Verification Testing

Verification testing was carried out on representative structural features of CRBR as part of the licensing effort. VHTR temperatures are much higher than the CRBR temperatures, as previously discussed. Consequently, additional verification testing is desired

by ACRS and NRC to validate the elevated temperature designs of VHTRs. Such tests include validation of the material models needed to perform cyclic creep analyses, validation of the finite element software capabilities to handle cyclic creep at structural discontinuities, elastic follow-up, creep rupture at notches, weldment behavior, and possibly flaw tolerance evaluation methods.

The development and delineation of such test needs come under the purview of the Subgroup on Elevated Temperature Design. However, material testings are generally in the domain of the Subcommittee on Materials (SC-II). The testing of NPP components is under Subcommittee III and design adequacy comes under the Subcommittee on Design (SC-D).

17.9 RECENT MATERIAL DATA COMPILATIONS

Refs. [26] and [27] contain recent compilations of high temperature nuclear materials data. Ref. [28] evaluates the degradation of core international materials due to newtron irradiation. Ref. [29] evaluates the impact of material and design criteria on the assessment of negligible creep.

17.10 PERSPECTIVE ON NEXT GENERATION NUCLEAR PLANTS

Ref. [28] contains a European perspective on High Temperature Reactors for Industry, Nuclear Cogeneration and Generation IV Reactors. Refs. [31] and [32] contain early DOE next generation nuclear plant licensing and demonstration for the generation of electricity and/or hydrogen with a high-temperature nuclear energy source.

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CHAPTER

18

LICENSE RENEWAL AND AGING MANAGEMENT

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18.1 INTRODUCTION

The U.S. Nuclear Regulatory Commission (NRC) license renewal process establishes the technical and administrative requirements for renewal of operating power plant licenses. Reactor operating licenses were originally issued for 40 years and are allowed to be renewed for up to an additional 20 years. The review process for license renewal applications (LRAs) provides continued assurance that the level of safety provided by an applicant's current licensing basis is maintained for the period of extended operation. The license renewal review focuses on passive, long-lived structures and components (SCs) of the plant that are subject to the effects of aging. The applicant must demonstrate that programs are in place to manage those aging effects. The review also verifies that analyses that are based on the current operating term have been evaluated and shown to be valid for the period of extended operation. As of March 2013, the NRC has renewed the licenses for 73 reactors, applications to renew the licenses of 15 additional reactors are under review. If the applications currently under review are approved, approximately 80% of the licensed operating reactors will have extended their life span by up to 20 years. As license renewal is voluntary, the decision to seek license renewal and the timing of the application is made by the licensee. However, the NRC expects that, over time, essentially most of the remaining U.S. operating reactors will request license renewal.

To meet this growing interest, the NRC has established a vigorous process for reviewing applications in a consistent and timely manner. Likewise, the Nuclear Energy Institute (NEI) has developed guidance for the industry on how to prepare an application for renewal. This chapter describes several license renewal guidance documents that have been developed to describe interrelated aspects of preparing and reviewing LRAs, including the following: the *Standard Review Plan for review of License Renewal Applications for nuclear power plants* [22], the *Generic Aging Lessons Learned (GALL) Report* [29], the *Technical Bases for Revision to the License Renewal Guidance Documents* [27], the *Analysis of Public Comments on the Revised License Renewal Guidance Documents* [28], and the regulatory guide for license renewal [24], which endorses NEI's industry guideline for implementing the requirements of 10 CFR Part 54, the license renewal rule (NEI 95-10) [5]. The objective of this chapter is to provide background information on the development of these documents and to briefly explain the intended use of the guidance documents, singularly and in combination, to facilitate the renewal process from application development to NRC staff review, including its audits and inspections of onsite supporting technical documentation. This chapter also provides a brief description of the NRC's environmental review process for license renewal.

18.2 HISTORICAL BACKGROUND

Based on the Atomic Energy Act as amended [7], the NRC issues licenses for commercial power reactors to operate for up to 40 years and allows these licenses to be renewed. A 40-year license term was selected on the basis of economic and antitrust considerations, not technical limitations. However, once the license term was selected, individual plant designs may have been engineered on the basis of an expected 40-year service life.

There are currently 104 licensed, operating commercial nuclear power plant reactors in the United States. The first 40-year operating licenses expired for four reactors in the year 2009, and they have already entered into the period of extended operation; 36 of the remaining operating reactors have licenses that will expire by the year 2015. License renewal is voluntary and the decision whether to seek license renewal rests entirely with nuclear power plant owners. This decision is typically based on the plant's economic situation and whether it can continue to meet NRC's requirements.

The NRC has established a license renewal process that can be completed in a reasonable period of time with clear requirements to ensure safe nuclear plant operation for up to an additional 20 years of plant life. Currently, nuclear power provides approximately 20% of the electricity generated in the United States and is the second largest source of electrical generation.

In the 1980s, the NRC established a comprehensive program for nuclear plant aging research. Based on the results of that research, a technical review group concluded that, although many aging phenomena were identified, they do not pose technical issues that would preclude life extension for nuclear power plants.

[1]Kenneth C. Chang and P.T. Kuo were the authors of this chapter for the second and third editions of the "Comapanion Guide to the ASME Boiler & Pressure Vessel Code". Kaihawa R. Hsu was the author for the third edition. – Editor

In 1991, the NRC first published safety requirements for license renewal as Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54 (the license renewal rule). To establish a scope of review, the rule defined age-related degradation unique to license renewal. The NRC participated in an industry-sponsored demonstration program to apply the rule to a pilot plant and develop experience to establish implementation guidance. However, during the demonstration program, the NRC found that many aging effects are dealt with adequately during the initial license period and that no aging unique to the period of extended operation was identified. Also, the NRC found that the review did not allow sufficient credit for existing programs, particularly the maintenance rule (10 CFR 50.65) [9].

As a result, the NRC amended the license renewal rule in 1995 [8]; the amended Part 54 established a regulatory process that is more efficient, more stable, and more predictable than the previous license renewal rule. In particular, Part 54 was clarified to focus on managing the adverse effects of aging on passive, long-lived structures and components instead of age-related degradation unique to license renewal. The rule changes were intended to ensure that important systems, structures, and components continue to perform their intended function during the 20-year period of extended operation. In parallel, the staff initiated a first-ever attempt to consolidate aging information from various sources; in 1996, the result of this effort in the "Generic Aging Lessons Learned Report" as NUREG-6490 in 1996 [6].

To provide credit for existing plant programs and to increase the effectiveness and efficiency of the license renewal review process, the Commission completed and published a new "Generic Aging Lessons Learned" (GALL) Report [23] in July 2001. The new GALL Report [23], published as NUREG-1801, built on NUREG-6490 and updated the database to include all aging-related events reported in the licensee event reports (LERs) up to 1998. It also expanded the scope to include evaluation of existing plant programs to determine whether any of the existing plant programs can be acceptable as adequate aging management programs for the identified aging effects. NUREG-1801, Revision 1 [29] that was published in September 2005 further updated the database to include NRC-endorsed past precedents, approved interim staff guidance (ISGs), and aging related events reported in the LERs up to 2004. Finally, Revision 2 of NUREG-1801 [32] that updated the database to include additional operating experience and public input, was published in December 2010.

The NRC's responsibilities under the U.S. National Environmental Policy Act of 1969 [10] require a review of the impact of license renewal on the environment. In parallel with aging review efforts, the NRC pursued a separate rule making to revise its environmental regulation, 10 CFR Part 51 [11], to focus the scope of review of environmental issues.

18.3 LICENSE RENEWAL REVIEW PROCESS

The license renewal process proceeds along two tracks: one for review of safety issues (10 CFR Part 54) and another for environmental issues (10 CFR Part 51). An applicant must provide the NRC with an evaluation that addresses the technical aspects of plant aging and describes the ways those effects will be managed. It must also prepare an evaluation of the potential impact on the environment if the plant operates for another 20 years. The NRC staff reviews the application and verifies the safety evaluations through inspections.

18.3.1 Safety Reviews

18.3.1.1 Principles and Process. The license renewal rule rests on the determination that current operating plants continue to maintain an adequate level of safety, and, over the lives of the plants, this level has been enhanced through maintenance of the current licensing basis, with appropriate adjustments to address new information from industry operating experience. Also, regulatory activities have provided ongoing assurance that the current licensing basis will continue to provide an acceptable level of safety. Based on this determination, the NRC established two fundamental principles for license renewal.

(a) The regulatory process is adequate to ensure that the licensing basis of all currently operating plants provides and maintains an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security. A possible exception may be the detrimental effects of aging on the functionality of certain systems, structures, and components, and possibly a few other issues that arise only during the period of extended operation.
(b) Each plant's licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

The NRC's regulatory process ensures the safety of operating plants through a variety of methods. These methods include the issuance of NRC bulletins, generic letters, information notices, orders, and new or revised regulations that require action by licensees. These activities are supported by numerous special NRC inspections that are performed in addition to the continuous oversight and routine inspection activities performed by the NRC onsite inspectors. Because of this comprehensive regulatory process, compilation of the current licensing basis or reverification of the current licensing basis is not considered necessary for license renewal.

The license renewal rule defines the technical and administrative process for evaluating the effects of aging on system, structure, and component performance, and for developing an LRA. There are two major safety assessments that an applicant must perform and submit in an LRA.

(a) an integrated plant assessment
(b) an assessment of time-limited aging analyses (TLAA)

These assessments are in addition to the requirement to update the plant's final safety analysis report (FSAR) to include a summary description of the programs and activities for managing the effects of aging, the evaluation of TLAA, and any revisions to the plant's operating technical specifications that may be required.

18.3.1.2 Integrated Plant Assessment. The applicant's integrated plant assessment must demonstrate that the structures and components within the nuclear power plant requiring aging management review (AMR) have been identified, and that the effects of aging on the functionality of such structures and components will be managed for the current licensing basis and to ensure that an acceptable level of safety will be maintained for the period of extended operation. The first step in the process is to identify all plant systems, structures, and components that are within the scope of the license renewal rule. The scope of the rule is defined

as those systems, structures, and components that meet the following criteria:

(a) safety-related and relied upon to ensure the following functions:
  (1) maintain the integrity of the reactor coolant pressure boundary
  (2) ensure the capability to shut down the reactor and maintain it in a safe shutdown condition
  (3) prevent or mitigate off-site radioactive exposures comparable to limits specified in the regulations

(b) Non-safety-related and whose failure could prevent satisfactory accomplishment of safety-related functions

(c) Relied upon to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48) [17], environmental qualification (10 CFR 50.49) [18], pressurized thermal shock (10 CFR 50.61) [19], anticipated transients without scram (10 CFR 50.62) [20], and station blackout (10 CFR 50.63) [21]

Once the systems, structures, and components that are within the scope of the license renewal rule are identified, the applicant must identify those structures and components that are subject to an AMR. Structures and components subject to an AMR are those that are passive and long-lived. Passive structures and components perform their intended function without moving parts or without a change in configuration or properties. Long-lived structures and components are those that are not subject to replacement based on a qualified life or a specified time period. Passive and long-lived structures and components include the reactor vessel, reactor coolant system piping, steam generators, pressurizer, pump casings, valve bodies, containment building, electrical cables, and electrical cabinets.

The NRC determined that structures and components with only active functions could be generically excluded from a license renewal review, because functional degradation resulting from the detrimental effects of aging in active components is more readily detected and corrected by routine surveillance, performance indicators, and maintenance. Surveillance and maintenance programs for active components are required throughout the period of extended operation. Active components include equipment such as motors, diesel generators, control rod drives, cooling fans, switchgear, breakers, batteries, relays, and switches.

The LRA must contain a list of all structures and components subject to an AMR and a description of the methodology used to identify them. The application must also identify the materials of construction, the environment in which the structure or component must function, and all potential aging effects. The applicant is then required to demonstrate that aging management programs (AMPs) exist such that the effects of aging are managed so that the intended functions of those structures and components will be maintained for the period of extended operation.

For some passive structures and components within the scope of the renewal evaluation, no additional action may be required where an applicant can demonstrate that the existing programs provide adequate aging management throughout the period of extended operation. However, if additional aging management activities are warranted for a structure or component within the scope of the rule, applicants will have the flexibility to determine appropriate actions. These activities could include, for example, adding new monitoring programs or increasing inspections.

18.3.1.3 Time Limited Aging Analysis (TLAA). Another requirement for license renewal is the identification and update of TLAA. During the design phase for a plant, certain assumptions about the length of time the plant would be operated are made and incorporated into design calculations of certain plant systems, structures, and components. Under a renewed license, these calculations must be shown to be valid for the period of extended operation.

TLAA are defined as those licensee calculations and analyses that meet all six of the following criteria:

(a) Involve systems, structures, and components within the scope of the license renewal rule.
(b) Consider the effects of aging.
(c) Involve time-limited assumptions defined by the current operating term (40 years).
(d) Are determined to be relevant by the licensee in making a safety determination.
(e) Involve conclusions or provide the basis for conclusions related to the capability of a system, structure, or component to perform its intended functions.
(f) Are contained or incorporated by reference in the plant's current licensing basis.

The LRA must contain a list of all TLAAs that were identified. To comply with 10 CFR 54.21(c)(1), the LRA must also contain a demonstration that each analysis: (i) the analysis remains valid for the period of extended operation, (ii) the analysis has been projected to the end of the period of extended operation, or (iii) the effects of aging on the intended functions will be adequately managed for the period of extended operation.

Typical TLAAs that must be evaluated include reactor vessel neutron embrittlement, metal fatigue, environmental qualification of electrical equipment, concrete containment tendon prestress, and containment liner plate, penetration sleeve fatigue and others.

18.3.2 Environmental Reviews

Environmental protection regulations were revised in December 1996 to facilitate the environmental review for LRAs. Certain issues are evaluated generically for all plants rather than separately in each plant's LRA. The Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants [14] assesses the scope and impact of environmental effects that would be associated with license renewal at any nuclear power plant site. A plant-specific supplement to the generic environmental impact statement is required for each licensee who applies for license renewal.

The NRC performs plant-specific reviews of the environmental impacts of license renewal in accordance with the National Environmental Policy Act [10] and the requirements of 10 CFR Part 51 [11]. A public meeting is held near the nuclear power plant seeking renewal to scope out or identify environmental issues specific to the plant for the license renewal action. The result is an NRC recommendation on whether or not the environmental impacts are so great that they should preclude license renewal. This recommendation is presented in a plant-specific draft supplement to the GEIS and is published for comment and discussed at a separate public meeting. After consideration of comments on the draft, the NRC prepares and publishes a final plant-specific supplement to the GEIS.

The NRC issued a supplement to the Environmental Standard Review Plan [15], which provides guidance on how to review the environmental portions of renewal applications. The NRC also issued a supplement to the Environmental Regulatory Guide [16], identifying the format and content of environmental reports that must accompany LRAs.

18.4 LRA

LRAs are prepared to provide the administrative, technical, and environmental information required by 10 CFR Part 54 [8] and 10 CFR Part 51 [11] to support the renewal of the operating license for nuclear power plants.

The format and content of the LRA follows the recommendation of the Regulatory Guide [24], which endorses the NEI guidance document [5]. The following sections and appendices are the essential portions of the LRA:

(a) Section 2.0 of the LRA, "Scoping and Screening Methodology for Identifying the Structures and Components Subject to Aging Management Review Implementation Results," provides the scoping and screening results for those components, structural members, and commodity groups that are subject to AMR. Tables are normally provided in the LRA to identify those plant systems and structures that are and are not in the scope of license renewal.

(b) Section 3.0 of the LRA, "Aging Management Review Results," describes the results of the aging management reviews (AMRs) for the components and structures requiring them and includes a comparison of these results with the evaluation in the GALL Report [32].

(c) Section 4.0 of the LRA, "Time-Limited Aging Analyses," includes a list of TLAAs, as defined by 10 CFR 54.3. Also, it includes the identification of the component or subject, and an explanation of the time-dependent aspects of the calculation or analysis.

(d) Appendix A of the LRA, "Final Safety Analysis Report Supplement," contains a summary description of the programs for managing the effects of aging for the period of extended operation. A summary description of the evaluation of TLAAs for the period of extended operation is also included. The license renewal commitments are identified in a license renewal commitment table.

(e) Appendix B of the LRA, "Aging Management Programs and Activities," describes the aging management programs (AMPs) used for managing the aging effects on structures and components within the scope of license renewal and demonstrates that the aging effects are managed such that the structures and components continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. Where the AMPs are consistent with corresponding programs in the GALL Report [29], the appropriate GALL Report program is referenced.

18.4.1 Scoping and Screening Methodology

The applicant, in the integrated plant assessment (IPA), describes and justifies methods used to identify those passive, long-lived structures and components subject to an AMR. The identification of the systems, structures, and components (SSCs) within the scope of license renewal is called "scoping." For those SSCs within the scope of license renewal, the identification of passive, long-lived structures and components that are subject to an AMR is called "screening." To verify that the applicant has properly implemented scoping and screening methodology, the NRC staff reviews the implementation results.

18.4.1.1 Scoping. To determine the safety-related SSCs that are within the scope of the rule under 10 CFR 54.4 (a)(1), the applicant must identify those SSCs that are relied upon to remain functional during and following DBEs, consistent with the CLB to ensure the required functions defined in para. 18.3.1.2. Most licensees have developed lists or a database that identify SSCs relied upon for compliance with other regulations in a manner consistent with the CLB. Under the rule of 10 CFR 54.4 (a)(2), all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4 (a)(1) are within the scope of license renewal. By rule 10 CFR 54.4 (a)(3), all SSCs relied upon in safety analysis to perform a function that demonstrates compliance with the regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout are also within the scope.

The applicant need not consider technical specifications and applicable limiting conditions of operation when scoping for license renewal. Rather, those SSCs governed by an applicant's technical specifications that are relied upon to remain functional during a DBE, as identified within the applicant's updated FSAR, applicable NRC regulations, license conditions, NRC orders, and exemptions, need to be included within the scope of license renewal.

For licensee responses to NRC bulletins, generic letters, or enforcement actions; those documented in staff SEs or LERs; and those that make up the remainder of an applicant's CLB, many of the associated SSCs need not be considered under license renewal. However, any generic communication, safety evaluation, or licensee commitment that specifically identifies or describes a function associated with an SSC necessary to fulfill the requirement of a particular regulation, order, license condition, and/or exemption may need to be considered when scoping for license renewal. An applicant may take an approach in scoping and screening that combines similar components from various systems.

18.4.1.2 Screening. Once the SSCs within the scope of license renewal have been identified, the next step is to determine which structures and components are subject to an AMR.

18.4.1.2.1 Passive Structures and Components (SCs). The applicant's methodology shall ensure that passive structures and components are identified as those that perform their intended functions without moving parts or a change in configuration or properties. The description of passive may also be interpreted to include structures and components that do not display a change in state. The reviewer verifies that the applicant's screening methodology includes consideration of the intended functions of structures and components consistent with the plant CLB. The license renewal rule focuses on passive structures and components because they generally do not have performance and condition characteristics that are as readily observable.

18.4.1.2.2 Long-Lived SCs. The applicant's methodology shall ensure that long-lived structures and components are identified as those that are not subject to periodic replacement based on a qualified life or specified time period. Passive structures and components that are not replaced on the basis of a qualified life or specified time period require an AMR. Replacement programs may be based on vendor recommendations, plant experience, or any means that establishes a specific replacement frequency under a controlled program. Structures and components that are replaced on the basis of performance or condition are not generically excluded from an AMR. Rather, performance or condition monitoring may be evaluated later in the integrated plant assessment as programs to ensure functionality during the period of extended operation.

18.4.1.3 Review Process

18.4.1.3.1 Scoping. The scoping methodology used by the applicant should be consistent with the process described in Section 3.0, "Identify the SSCs Within the Scope of License Renewal and Their Intended Functions," of the NEI guideline document [5], endorsed by the license renewal regulatory guide [24], or the justification provided by the applicant for any exceptions.

18.4.1.3.2 Screening. The screening methodology used by the applicant should be consistent with the process described in Section 4.1, "Identification of Structures and Components Subject to an Aging Management Review and Intended Functions," of the NEI guidance document [5].

18.4.1.3.3 Review Procedures. Preparation for the review of the scoping and screening methodology should include the following:

(a) Review of the NRC's safety evaluation report (SER) for the initial operating license for the purpose of familiarization with the principal design criteria for the facility and its CLB.
(b) Review of Chapters 1 through 12 of the updated FSAR and the facility's technical specifications for the purposes of familiarization with the facility design and the nomenclature.
(c) Review of Chapter 15 (or equivalent) of the updated FSAR to identify the anticipated operational occurrences and postulated accidents that are explicitly evaluated in the accident analyses for the facility.
(d) Review of the set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the updated FSAR.
(e) Review of the facility's probabilistic risk analysis (PRA) summary report that was prepared by the licensee in response to Generic Letter (GL) 88-20 "Individual Plant Examination (IPE) for Severe Accident Vulnerabilities – 10 CFR 50.54(f)," November 23, 1988 [13].
(f) Review of the results of facility's individual plant examination of external events (IPEEE) study conducted as a follow-up to the IPE to identify any changes or modifications made to the facility.
(g) Review of the applicant's docketed correspondence related to the following:
    (1) fire protection
    (2) environmental qualification of electric equipment
    (3) fracture toughness requirements for protection against pressurized thermal shocks
    (4) requirements for reduction of risk from anticipated transients without scram
    (5) loss of all alternating current power (applicable to PWR plants only)

18.4.2 AMR Process and AMPs

The methodology used by the applicant should be consistent with the process described in the latest revision of the NEI guidance document [5], which is endorsed by the NRC in its regulatory guide [24]. Justifications shall be provided by the applicant and accepted by the reviewers for any exceptions.

AMRs reported by the applicant in the LRA are structured in three component groups: aging management evaluations that are consistent with the GALL Report, for which no further evaluation is required; aging management evaluations that are consistent with the GALL Report, for which further evaluation is recommended; and AMR results that are not consistent with the GALL Report.

The NRC staff reviews the applicant's evaluation for each component group to determine whether conclusions are accurate and justified. For aging management evaluations that are consistent with the GALL Report and for which further evaluation is recommended, the staff verifies whether or not it adequately addressed the issues for which the GALL Report recommended further evaluation. The following demonstrate typical aging management evaluations of auxiliary systems for which further evaluation is recommended:

(a) loss of material due to general, pitting, and crevice corrosion
(b) hardening and cracking or loss of strength due to elastomer degradation or loss of material due to wear
(c) cumulative fatigue damage
(d) crack initiation and growth due to cracking or stress corrosion cracking
(e) loss of material due to general, microbiologically influenced pitting and crevice corrosion
(f) loss of material due to general, galvanic, pitting, and crevice corrosion
(g) loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and biofouling
(h) quality assurance for aging management of non-safety related components
(i) crack initiation and growth due to stress corrosion cracking and cyclic loading
(j) reduction of neutron-absorbing capacity and loss of material due to general corrosion
(k) loss of material due to general, pitting, crevice, and microbiologically influenced corrosion

18.4.2.1 AMRs. The NRC staff verifies that the AMRs reported by the applicant to be consistent with the GALL Report are consistent with the GALL Report, and verifies that the plant-specific AMRs reported to be justified on the basis of an NRC-approved precedent are technically acceptable and applicable. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommended further evaluation, the staff reviews the further evaluation summarized in the LRA to determine whether or not it adequately addressed these issues. The AMRs reviewed by the staff are either consistent with the GALL Report, justified by the applicant on the basis of an NRC-approved precedent, or justified by the applicant on a plant-specific basis.

The applicant is required to provide a summary of AMRs for the applicable systems, which include structures and components, associated materials, environment, aging effects requiring management, and an AMP for each line item in LRA tables. Notes in the table describe how the information in the LRA aligns with the information in the GALL Report. Those AMRs that are defined in the GALL Report are assigned standard notes with letters A through J (described in Table 18.1) consistent with the GALL Report classification. Those notes defined by the applicant are assigned numbers and are defined in the LRA. For any discrepancies or issues discovered by the staff during the audit and review process that require a response on the docket are documented in an audit and review report. A request for additional information (RAI) is to be prepared by the staff describing the issue and the information needed to disposition the issue. The RAI will be included and dispositioned in the SER related to the plant LRA.

TABLE 18.1 CONSISTENT WITH GALL REPORT CLASSIFICATION

Note	Description
A	The AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report.
B	The AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff verifies that the identified exceptions to the GALL AMPs are acceptable.
C	The component for the AMR line item is different, but consistent with the GALL Report for material, environment, and aging effect. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report but, identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP. The staff verifies that the AMR line item of the different component was applicable to the component under review.
D	The component for the AMR line item is different, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff reviews these line items to verify consistency with the GALL Report. The staff verifies that the AMR line item of the different component was applicable to the component under review and that the identified exceptions to the GALL AMPs are acceptable.
E	The AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviews these line items to verify consistency with the GALL Report.
F	The material is not in the GALL Report for the identified component.
G	The environment is not in the GALL Report for the identified component and material.
H	The aging effect is not in the GALL Report for component, material, and environment combination.
I	The aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.
J	Neither the identified component nor the material and environment combination is evaluated in the GALL Report.

18.4.2.2 AMP. For those AMPs for which the applicant claims consistency with the GALL AMPs, the staff conducts an audit to verify that the applicant's AMPs are consistent with the AMPs in the GALL Report. For each AMP that has one or more deviations, the staff evaluates each deviation to determine the following:

(a) whether the deviation is acceptable
(b) whether the AMP, as modified, would adequately manage the aging effect(s) for which it is credited

For AMPs that are not evaluated in the GALL Report, the applicant must fully justify the adequacy of the plant-specific AMPs. The applicant evaluates the AMPs against the ten program elements defined in SRP-LR Appendix A (see Table 18.2).

18.4.2.3 AMP/AMR Audits. A significant portion of the review and audit of AMPs and AMRs are performed at the plant site with the intention to enhance the efficiency and effectiveness of the LRA review process. In addition to the review of consistency with the GALL Report, consistency with previously approved AMPs/AMRs is also reviewed onsite. For those AMPs that the applicant claims are consistent with the GALL Report, an audit team of NRC staff and contractors review and audit the applicant's work and conclusions onsite. The audits are performed in accordance with the procedure and methodology described in a plant-specific audit and review plan. The applicant's internal documents, including the basis document, engineering calculations, condition reports, corrective actions, and other supporting references, are reviewed onsite. The applicant's staff involved in the preparation of the basis document and the LRA are interviewed by the audit team members. The face-to-face discussions between the applicant and NRC staff enable the staff to resolve most of the questions which, in turn, minimizes the number of requests for additional information and expedites the review process.

The audit results are documented in an audit report that is referenced in a plant-specific safety evaluation report SER.

18.4.3 TLAA

The requirement for the identification and update of TLAAs is discussed in Section 2.1.3 of the SRP-LR. Typical TLAAs that must be evaluated include reactor vessel neutron embrittlement, metal fatigue of mechanical components, environmental qualification of electrical equipment, concrete containment tendon prestress, containment liner plate and other components with an explicit design life. As an example, the following section provides a discussion on the evaluation of metal fatigue related to mechanical components.

18.4.3.1 Metal Fatigue. Fatigue protection for SSCs of nuclear power plants is provided either through explicit rules defined in the ASME BPVC Section III [1] or through implicit rules defined in the USAS B31.1 Code [25]. Fatigue damage, measured in terms of cumulative usage factor (CUF), is calculated using the design fatigue curves defined in the ASME Code. However, more recent research studies and tests indicate that the effects of the light water reactor (LWR) environment could significantly reduce the fatigue resistance of materials used for the

TABLE 18.2 ELEMENTS OF AN AGING MANAGEMENT PROGRAM

Element	Description
1. Scope of program	The scope of the program should include the specific structures and components subject to an aging management review.
2. Preventive actions	Preventive actions should mitigate or prevent the applicable aging effects.
3. Parameters monitored or inspected	Parameters monitored or inspected should be linked to the effects of aging on the particular structure and component intended functions.
4. Detection of aging effects	Detection of aging effects should occur before there is a loss of any structure and component intended function.
5. Monitoring and trending	Monitoring and trending should provide for prediction of the extent of the effects of aging and timely corrective or mitigative actions. The monitoring, inspection, testing frequency, and sample size should be appropriate for timely detection of aging effects.
6. Acceptance criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the particular structure and component intended functions are maintained under all Current Licensing Basis design conditions during the period of extended operation.
7. Corrective actions	Corrective actions, including root cause determination and prevention of recurrence, should be timely.
8. Confirmation process	The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative controls	Administrative controls should provide a formal review and approval process.
10. Operating experience	Operating experience involving the Aging Management Program, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support a determination that the effects of aging will be adequately managed so that the structure and component intended functions will be maintained during the period of extended operation.

reactor coolant pressure boundary components of operating nuclear power plants. NUREG/CR-6260 [26] provides an environmental fatigue evaluation of select components for representative plants using the interim fatigue curves presented in NUREG/CR-5999 [4]. The GALL Report recommends the assessment of the reactor coolant environmental impact on a sample of Class 1 critical components that includes, as a minimum, those presented in NUREG/CR-6260. The assessment applies the correction factors (F_{en}) to obtain the environmentally adjusted fatigue usage. Acceptable means for calculating F_{en} are contained in NUREG/CR-6583 [2], NUREG/CR-5704 [3] and NUREG-6909 [30].

The F_{en} method includes using the results of existing Code fatigue analysis. For plants where explicit fatigue analyses were performed, the application of the F_{en} is straightforward. If the resulting CUF is greater than 1.0, there are other means to address metal fatigue, for example, ASME Code, Section XI, Appendix L provides an alternative with flaw tolerance evaluation and in-service inspection to address CUF greater than 1.0 for operating plants. However, when pressure boundary piping was designed to the implicit rules of the ASME B31.1 Code, a process needs to be established to assess or calculate fatigue usage factors at critical locations. The following steps should be taken into consideration:

(a) *Critical Locations.* The GALL Report contains an AMP to monitor and track the number of critical temperature and pressure transients for the effects of the coolant environment on the fatigue life for a sample of critical components that includes, as a minimum, those components presented in NUREG/CR-6260. Also, a review should be performed to identify additional locations for which transient monitoring may be necessary to ensure that the fatigue design limit is not exceeded during the period of extended operation.

(b) *Operating Transients*. CLB fatigue analysis was performed using design transients and the associated cycles. TLAA fatigue analysis for license renewal may use the actual operating transients to perform its CUF evaluation. The operating transient experience has to be review to ensure that all transients, including those unanticipated transients during design stage, has to be addressed.

Some applicant's TLAA used current operating transient CUF result to project CUF for past operation. This approach has to provide adequate justification, since operation procedures may have been modified. For example, PWR surge line stratification transients may have been changed due to modification of operation procedures.

(c) *Fatigue Monitoring*. Each plant may have to implement a fatigue monitoring program (FMP) for all significant plant transients. The GALL Report recommended FMP as an acceptable aging management program to address metal fatigue of the reactor coolant system components according to 10 CFR 54.21(c) (1) (iii). Cycle-based FMP and stress-based FMP are most commonly presented by LRA applicants. The cycle based FMP tracks and monitors transient cycles to ensure that the assumed cycles of design

transients in the fatigue analysis are not exceeded. If a specified alarm limit is reached, a corrective action program must be initiated. The stress-based FMP has the ability to compute a real time stress history for a given components from actual temperature, pressure transient data. Fatigue usage is then evaluated from the stress history. The stress-based method to calculate CUF involves developing transfer function/ Green's function to convert plant data to stress versus time for a given component.

(d) *Environmentally Assisted Fatigue (EAF) Evaluation*. The GALL Report addresses the effects of the reactor coolant environment on component fatigue life by applying a fatigue life correction factor F_{en}, which is the ratio of life in water at the service temperature to that in air at room temperature. The usage factor for a specific load pair is multiplied by the correction factor F_{en}. Formulas for calculating F_{en} are contained in NUREG/CR-6583 [2], NUREG/CR-5704 [3] and NUREG-6909 [30].

The following three options are identified for calculating F_{en}:

(1) single-factor multiplication to the CUF
(2) simplified method (using average strain rate to calculate F_{en} for each load pair)
(3) detailed method (using average strain rate to calculate F_{en} for each time interval)

Discussions on using an FMP to address the environmental effects on high-CUF components have been presented in many LRAs. A reevaluation of the fatigue usage factors at critical locations will be performed prior to the period of extended operation to determine the bounding locations that will be included in the FMP.

The aging management approach developed for the locations with CUF exceeding design limit of 1.0 could include one or more of the following options:

(1) further refinement of the fatigue analysis to lower the CUF(s) below 1.0
(2) repair of the affected locations
(3) replacement of the affected locations
(4) management of the effects of fatigue through an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of affected locations at inspection intervals to be determined by a method accepted by the NRC)

If option (4) is selected, the inspection details, including scope, qualification, method, and frequency, must be provided to the NRC for review and approval prior to the commencement of the period of extended operation. Several recently submitted LRAs applied the combination of FMP, online CUF calculations, and the environmental correction factor F_{en} to CUF. All high-fatigue locations are to be qualified to the Code limit of 1.0 for 60-year life considering the environmental effect. Some programs included plant-specific locations beyond those defined in NUREG/CR-6260 [26]. When option (1) alone does the job, the more costly and time-consuming options (2) through (4) are not required. For piping components design to ANSI B31.1 standard and ASME Class 2 and 3 components, metal fatigue can be addressed by (i) confirming the full range transient cycles within the limit of design cycles; (ii) increasing allowable stress value based on the actual cycles instead of the standard 7000 cycles and code associated allowable stress value; and (iii) establishing an aging management program (e.g., repair and/or replacement).

18.4.4 FSAR Supplement

The application for a renewed operating license is required by 10 CFR 54.21(d) to include an FSAR supplement that provides a summary description of the programs and activities for managing the effects of aging for the period of extended operation. A summary description of the evaluation of TLAAs for the period of extended operation must also be included, as well as a matrix of the license renewal commitments.

18.4.5 Issues of Interest

License renewal permits the applicant to operate a facility up to 20 years beyond the initial 40-year license term. Although the license renewal process and staff's review relies on the principle that the CLB is adequate to ensure safe operation, additional aging management issues could be identified based on operating experience that warrant consideration for license renewal. During the review of LRAs, issues may be identified affecting current as well as operation for the period of extended operation. These issues may be complicated in nature and may take the industry and the NRC significant efforts and time to develop appropriate solutions. For license renewal, the applicant only needs to show that the plant can operate safely in accordance with the CLB until the regulatory process resolve the issues. Once an issue is resolved generically, the NRC will require whatever actions are appropriate for all affected operating reactors, whether they are operating under the initial 40 years operating licenses or renewed licenses. A partial list of AMPs involving issues of interest that are currently being evaluated or have been recently resolved are provided below:

(a) environmental impact on fatigue
(b) alloy 600/PWSCC issues
(c) medium voltage underground cable testing
(d) steam Generator tube integrity
(e) small bore piping ISI
(f) fuse holder AMP
(g) reactor internal loose-parts-monitoring program

18.5 INTERIM STAFF GUIDANCE (ISG) PROCESS

The objective of the ISG process is to capture lessons learned from license renewal reviews and communicate them to stakeholders. The process includes interaction with stakeholders during the development of the ISG, including publishing of a *Federal Register* notice for comment. If the ISG is approved, then an applicant for a renewed license needs to address the issue. Also, the ISG will be incorporated into the next revision of the license renewal guidance (LRG) documents.

18.6 GUIDANCE DOCUMENTS

18.6.1 Standard Review Plan for License Renewal (SRP-LR)

The NRC uses standard review plans to process licensing actions. Standard review plans specify the quality requirements for performing licensing review activities and provide the framework

to ensure that staff reviews are uniformly conducted. Standard review plans provide guidance to NRC staff for performing application reviews. This standardized guidance ensures that the staff reviews are consistently applied to all applicants for renewal. It defines how the review of an application should be and presents a well-defined approach for evaluating AMPs and similar activities. The SRP-LR also serves as a source of information to the nuclear power industry and members of the public who are interested in the regulatory review process governing license renewal. It is not a requirement for the applicant to follow the SRP-LR format or suggestions, but the guidance facilitates staff reviews. The SRP-LR incorporates the GALL Report by reference and focuses the NRC review on areas where existing programs need to be augmented or further evaluated for license renewal as recommended in the GALL Report.

The SRP-LR is divided into the following four major chapters:

(a) administrative information
(b) scoping and screening methodology
(c) AMR results
(d) TLAAs

The administrative information chapter provides criteria for determining the sufficiency of an application for docketing. The scoping and screening chapter focuses the staff's review on the applicant's identification of passive and long-lived structures and components. It also directs the staff to determine if the applicant properly implemented a methodology to identify structures and components subject to an AMR. The AMR chapter directs the review staff to perform a consistent and thorough evaluation of aging effects and AMPs provided in the application. The TLAA chapter directs the staff to verify that all applicable TLAAs have been included in an application and have been adequately evaluated for the period of extended operation.

An appendix to the SRP-LR contains branch technical positions, which document the staff's resolution of specific regulatory issues. The SRP-LR can be applied to a wide variety of plant designs and site conditions. It consists of multiple sections, each of which contains complete procedures for performing staff reviews. For any specific application, the staff may focus its review on particular aspects of an SRP-LR section as appropriate to ensure an adequate level of staff understanding to support a licensing decision.

Each SRP-LR section is organized into six subsections. Subsection 1 governs the areas of review; it describes the SSCs, analyses, data, or other information in the application that should be reviewed. Subsection 2 identifies the acceptance criteria (applicable NRC requirements) and defines the technical basis (e.g., by referencing NRC regulatory guides, codes and standards, and branch technical positions) for determining if an applicant's proposal is acceptable. Subsection 3 contains step-by-step review procedures for verifying that applicable acceptance criteria have been met. Subsection 4 governs evaluation findings and presents alternative staff conclusions that may apply to a particular review area. Subsection 5 addresses implementation of the SRP-LR by specifying the conditions under which the SRP-LR can be applied as guidance for the review of LRAs. Subsection 6 contains references.

18.6.2 GALL Report

The GALL Report evaluates existing programs generically to document the conditions under which existing programs are considered adequate to manage identified aging effects without change and the conditions under which existing programs should be augmented for this purpose.

During the review of the first renewal application, the NRC and industry recognized that many of the existing programs at the plants could adequately manage aging effects for license renewal without change. Therefore, the NRC staff undertook a generic review and a technical evaluation of existing plant programs to determine which ones would adequately manage aging effects without change and which ones would need to be augmented. These existing AMPs were evaluated against a set of ten element criteria as defined in Branch Technical Position RLSB-1 in the SRP-LR. Only those programs that passed the 10-element test were accepted as adequate AMPs.

The GALL Report evaluates existing programs generically to document the following:

(a) the conditions under which existing programs are considered adequate to manage identified aging effects without change.
(b) the conditions under which existing programs should be augmented for this purpose.

The GALL Report is referenced in the SRP-LR as the technical basis for identifying those programs that warrant particular attention during the NRC's review of an LRA. The principal purposes of the GALL Report are to ensure the quality and uniformity of reviews and to present a well-defined base from which to evaluate renewal applicant programs and activities for the period of extended operation. The GALL Report is also intended to make information about regulatory matters widely available to enhance communication with interested members of the public and the nuclear power industry.

The GALL Report is treated as an approved topical report. Because the AMPs are already reviewed generically, the NRC reviewers need not repeat their review of a matter described as acceptable in the GALL Report, but would ensure that the material presented in the GALL Report is applicable to the specific plant involved. The reviewer would also ensure that the applicant-identified AMPs are consistent with the AMPs evaluated in the GALL Report, if they rely on the report for license renewal.

18.6.3 Regulatory Guide

The NRC also issued the license renewal regulatory guide [24], which provides applicants with the format and content for an LRA. The regulatory guide endorses the NEI guidance document [5]. The SRP-LR sections are numbered consistently using the regulatory guide standard format.

18.6.4 License Renewal Guidance Documents Updates

Since the publication of the guidance documents in July 2001, the NRC staff has completed a significant number of LRA reviews. During the course of its evaluation, both the NRC staff and applicants have gained valuable lessons in preparing and reviewing LRAs. The lessons learned have been in both technical and procedural areas. To document these lessons learned and to incorporate additional staff positions established on current issues of interest, an update of these guidance documents was initiated. In addition, the revised final guidance documents were published in 2005; two companion documents were published at the same time. The first document, Analysis of Public Comments on the Revised License Renewal Guidance Documents (NUREG-1832) [28], addresses all comments received during the public comment period for the revised guidance documents. The second document, Technical Bases for Revision to the License Renewal Guidance Documents (NUREG-1833) [27], provides staff positions and technical justifications that provide the bases

for the changes to the guidance documents. A similar companion document to Revision 2 of NUREG-1800 and NUREG-1801 was published as NUREG-1950, "Deposition of Public comments and Technical Bases for Changes in the License Renewal Documents, NUREG-1800 and NUREG-1801" [33] in April 2011.

18.7 INTERNATIONAL ACTIVITIES

With the success of U.S. license renewal programs, the interest on the program has increased among the international nuclear utilities. The International Atomic Energy Association (IAEA) has taken the lead to organize the international efforts to generate a guidance documents for its member states. Working groups were set up to collect idea, iGALL and recommendations on safety aspects of long-term operation of water-moderated reactors. The NRC staff has been supporting IAEA at all levels and sharing the U.S. experience by placing license renewal–related documents on the NRC's Web site www.nrc.gov.

18.8 DISCLAIMER AND ACKNOWLEDGEMENT

It is noted that the opinions expressed in this paper are those of the Author and do not represent the position of USNRC.

I would like to acknowledge Mr. Robert Hsu's contribution to this article. He provided many valuable comments on the draft of this article. In particular, he provided the example of how an TLAA for metal fatigue for the original 40-year design life could be justified for a 60-year operation.

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CHAPTER

19

BWR REACTOR INTERNALS AND OTHER BWR ISSUES

Hardayal S. Mehta

19.1 INTRODUCTION

The objective of this Chapter is to provide some details of many and sometimes unique ways in which the provisions of Section III and Section XI have been used in addressing the service-induced degradations in the BWR vessels, internals, and pressure boundary piping. Among the items covered are reactor internals, weld overlays, and reactor vessel. The most common form of service-induced cracking in the stainless steel and Ni-Cr-Fe components in the BWR pressure boundary is typically due to intergranular stress corrosion cracking (IGSCC).

19.2 BWR INTERNALS

The BWR reactor internals fall into two categories. The first category includes components constituting the core support structure that are important to safe shutdown of the reactor. The components in this category include the shroud, shroud support structure, core plate, jet pumps, and such. Most of the BWR internals were designed using the guidance of Class 1 component design by analysis rules of Subsection NB in Section III. Only in some of the newer BWRs was Subsection NG formally used. The second category includes internal components (e.g., steam dryer) that are not safety related (i.e., not important to safe shutdown of the reactor). Only some recently observed cracking in steam dryers under increased steam flows due to extended power uprate has drawn some attention to the need for inspection and detailed stress evaluation of this component to assure its structural integrity [1]. The discussion in this section is mostly focused on the first category of components; the steam dryer issues are covered at the end of this section. Figure 19.1 shows a schematic of the BWR internal components.

Most of the BWR RPV internals are fabricated from either stainless steel or Ni-Cr-Fe to avoid the presence of corrosion products in the reactor water. In view of the earlier IGSCC experience with Type 304 and 316 stainless steels in external piping, the material for later-constructed BWR internals was replaced by lower carbon (L grade, carbon $<0.035\%$) stainless steels [2,3]. For some of the replacement external piping, low carbon stainless steel with added nitrogen (LN grade) for structural strength (i.e., higher S_m value) was used. An additional degradation mechanism for the reactor internals is the irradiation. The irradiation can cause the initiation of cracking (irradiation-assisted stress-corrosion cracking or IASCC), accelerated crack growth rate, and a reduction in fracture toughness. Typically, the components affected by irradiation are the shroud and the top guide.

19.2.1 Inspection, Evaluation, and Repair Methods

In the Section XI space, the reactor internals fall under category B-N-2 core support structures. However, Section XI does not have evaluation standards or repair/replacement guidelines available for this category for the following reason [4]: "A Subgroup of SC XI was established to develop a complete program, including evaluation standards and repair/replacement techniques. After several years of work to establish generic requirements and, later, to separate PWR and BWR requirements, the Subcommittee failed to reach a consensus on its approach, and because industry interest and support had diminished, the effort was terminated. The power plants and the NRC now resolve problems on an individual basis."

In the wake of the observed cracking in the shroud of an overseas reactor followed by several in the United States, an urgent need was identified to develop inspection, evaluation, and, if necessary, repair techniques. The BWR Vessels and Internals Project (BWRVIP) was formed in 1994 with the following objectives [5–7]: to lead the BWR industry towards generic resolution of reactor pressure vessel and internals materials condition issues; to identify or develop generic cost-effective material management strategies from which each operating plant will select the most appropriate alternative; to serve as the focal point for the regulatory interface with the industry on BWR vessel and internals issues; and to share information and promote communication and cooperation among participating utilities. The first BWR internal component addressed was the shroud. Since then, over 100 reports have been published by the BWRVIP on the various internals and RPV issues. Key reports have been approved by the NRC for use by utilities on a generic basis. This obviates the need for an individual submittal and its review/approval by the NRC for a specific technical evaluation. Most of the BWRVIP reports are proprietary. However, technical details from the published technical papers are provided in this Section to illustrate the use of flaw evaluation procedures of IWB-3600 in flaw disposition.

19.2.2 Shroud

One of the first BWR internal components to show cracking was the shroud, and the observed cracking was in the heat-affected

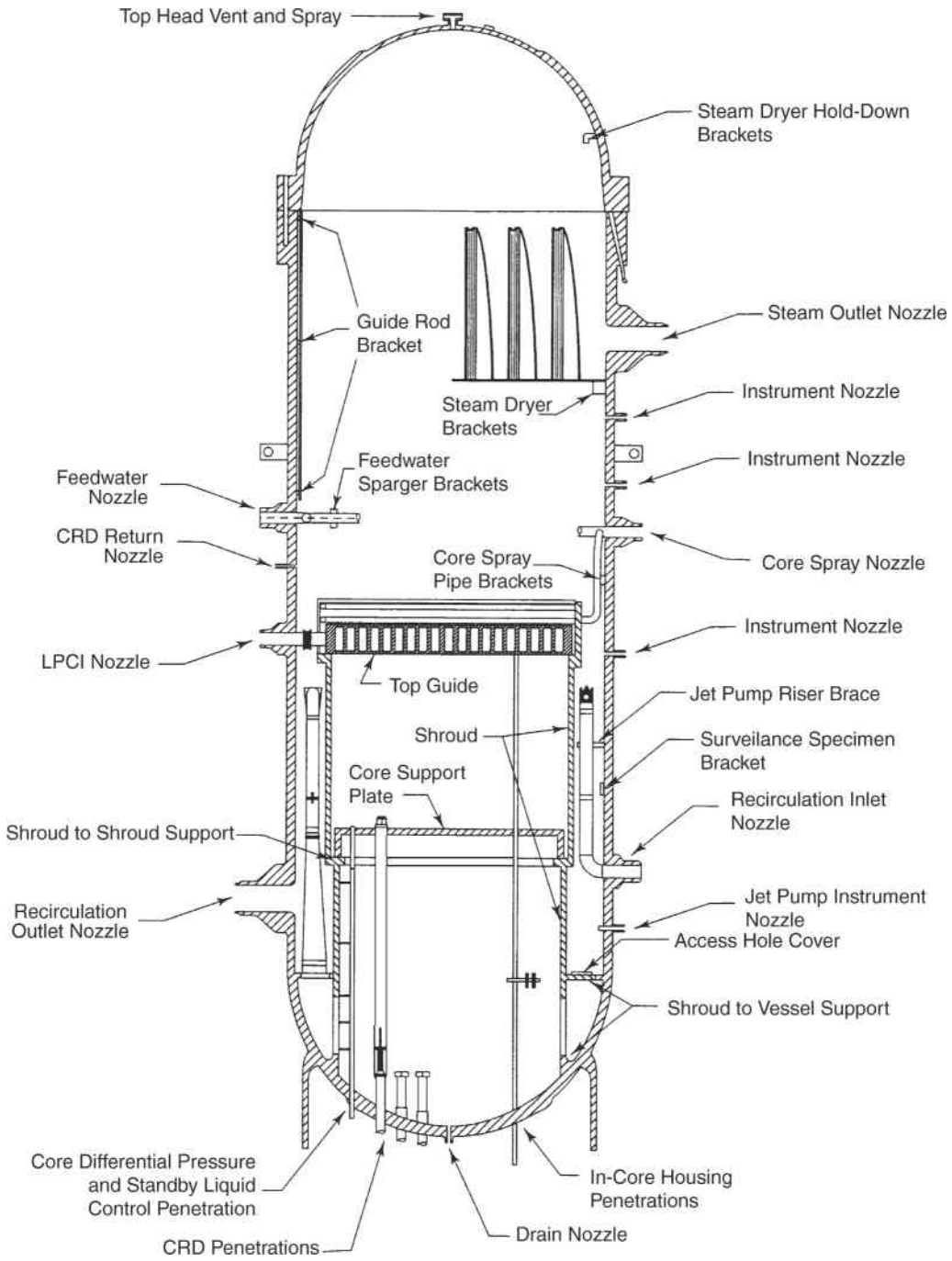


FIG. 19.1 OVERVIEW OF BWR PRESSURE VESSEL AND INTERNAL COMPONENTS

zones (HAZs) of the circumferential welds. The BWR shroud is a cylindrical structure surrounding the core. The shroud material is Type 304 or 304L grade stainless steel. It is typically 200 in. in diameter and 1.5–2 in. thick. It is constructed by welding together several cylindrical sections (see Fig. 19.2).

The limit load methodology for cylindrical geometries outlined in Appendix C of Section XI has been used as a flaw evaluation guideline for the shroud [8]. However, several additional considerations were required to complete an analytical evaluation of flaws per IWB-3600. These considerations include crack growth rate under BWR water environment, inspection uncertainty, and the fracture toughness considering irradiation effects.

19.2.2.1 SCC Growth Rate Relationships. The crack growth rate relationship for stainless steels included in the current Section XI is for fatigue mechanism in air environment only. For a crack exposed to BWR water environment, the crack growth rate due to stress corrosion cracking (SCC) essentially overwhelms that due to fatigue. The Section XI Committee is currently in the process of developing SCC growth rate relationships for austenitic materials.

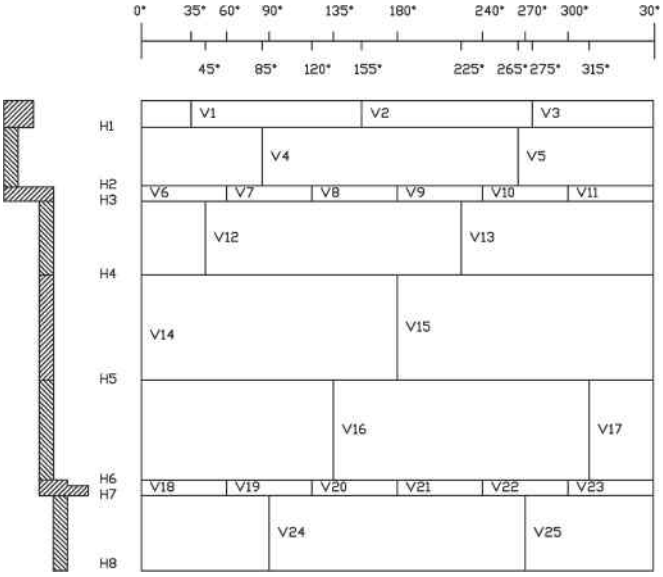


FIG. 19.2 BWR CORE SHROUD WELD DESIGNATIONS

In the crack length direction, the evaluations use a bounding crack growth rate of 5×10^{-5} in./hr approved by the USNRC [9,10].

The detailed guidance for the crack growth rates (CGRs) used in the evaluation of BWR stainless steel internals is provided in BWRVIP-14 [11], as modified by the stipulations given in the NRC's final safety evaluation (SE) [12] on this report. The SE stated, in part, ". . . by using an appropriately reduced value for the CGR from the 5×10^{-5} in./hr value found in NUREG-0313, Rev. 2, it would be possible for licensees to get credit for improved water chemistry and other measures to mitigate cracking, e.g., hydrogen water chemistries (HWC) and/or noble metal additions. The revised CGR of 2.2×10^{-5} in./hr corresponds to water chemistries with a conductivity of ≤ 0.15 μS/cm and an electrochemical potential (ECP) of +200 mV. The BWRVIP-14 correlation indicates that this bounding CGR could be reduced for HWC with ECP ≤ -230 mV. The staff finds acceptable a reduction in the CGR from 2.2×10^{-5} in./hr to 1.1×10^{-5} in./hr for plants with HWC. The crack growth rates stated are only applicable to components with uences $< 5 \times 10^{20}$ n/cm^2 (E $>$ 1 MeV), since the CGR database is presently based only on unirradiated materials."

In many of the inspected shrouds, the fluence at the midcore weld such as the H4 weld in Fig. 19.2 is greater than 5×10^{20} n/cm^2. For such cases, the approach used is to take no structural credit for the material that is expected to exceed the preceding value during the evaluation period [13]. The BWRVIP proposed SCC growth rate relationships [14] have been reviewed and accepted by the NRC.

19.2.2.2 Inspection Uncertainty. The shroud inspections are typically conducted by either the visual testing (VT) or ultrasonic testing (UT) means. Since the VT cannot provide the crack depth, the VT-detected flaws are assumed as through-wall for the purposes of the shroud structural evaluation. The indication length and/or depth measurement uncertainties are a function of NDE delivery system that may vary by the vendor. The BWRVIP conducted an extensive program to document these uncertainties as a function of internal component, NDE method, vendor, and other variables [15]. For example, in one typical case [13], each nominally reported indication length and depth in the shroud was increased by 0.472 in. and 0.108 in., respectively, for the purpose of the structural evaluation.

19.2.2.3 Irradiated Stainless Steel Fracture Toughness. Data showing trends in yield strength, reduction in area, and uniform elongation as a function of fluence at irradiation and test temperature of 550°F have been published previously [16,17]. A review of this data indicated that the yield strength increases occur at a significant rate beyond $3-5 \times 10^{20}$ n/cm^2. Based on this and other ductility data, the limit load flaw evaluation for the shroud is also supplemented by a LEFM/EPFM analysis where the fluence exceeds 3×10^{20} n/cm^2. Based on the irradiated fracture toughness tests reported [18−20], a K_{Ic} value of 150 ksi $\sqrt{\text{in.}}$ has been used in the shroud flaw evaluations [15]. Additional irradiated stainless steel fracture toughness data in the fluence range of BWR shrouds have also recently become available [21]. The BWRVIP has developed fracture toughness relationships for irradiation levels covering fluences in excess of 1×10^{21} n/cm^2 [22] that have been reviewed and approved by the NRC.

19.2.2.4 Evaluation with Multiple Indications. When multiple indications are involved, which is generally the case, a conservative approach is to stack all of the indications (after adding crack growth, inspection uncertainty, and the application of proximity criteria) into one continuous flaw and compare it with the allowable flaw length calculated using the limit load equation of Appendix C. However, this approach is too conservative and, therefore, an alternative approach has generally been followed.

Figure 19.3 shows a schematic representative plan view of an asymmetrically distributed uncracked ligament. It is assumed that there are 1, 2,...i,...n ligament lengths and that the i length is of thickness t_i and extends from an azimuth of θ_{i1} to θ_{i2}. The ligament length li of the i ligament is related to azimuth angles θ_{i1} and θ_{i2} by the following relationship:

$$l_i = (D/2)(\theta_{i1} - \theta_{i2}) \tag{19.1}$$

where

D = the diameter of the shroud

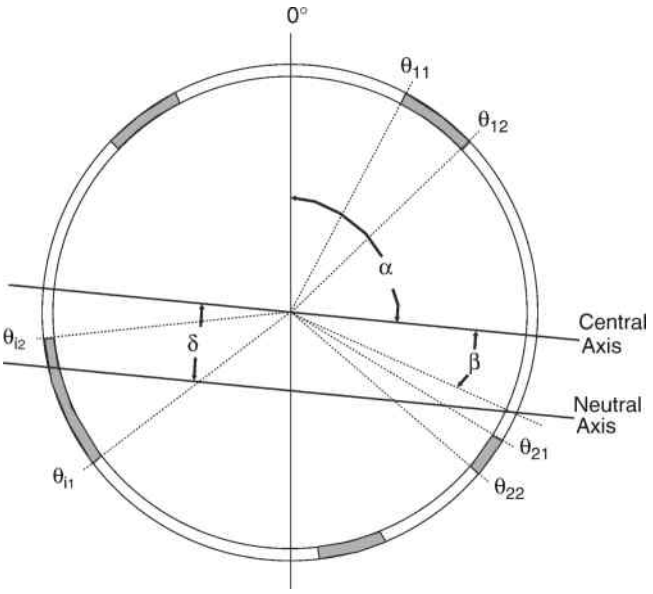


FIG. 19.3 A DISTRIBUTED LIGAMENT LENGTH EXAMPLE

The calculation of moment M that this ligament configuration can resist is somewhat complicated, because it is not a priori clear as to which azimuthal orientation of the neutral/central axis would produce the least value of bending moment, M. Therefore, the value of M is calculated for various orientations of the central axis from 0° to 360°. This calculation is performed in the following two steps:

(a) In this step, a central axis orientation, α is first selected. The location of the neutral axis, which is parallel to the central axis, at a distance δ from the central axis is determined using the following (see Fig. 19.3):

$$\int_{-(\pi - \alpha + \beta)}^{\alpha + \beta} Rt(\theta)\, d\theta - \int_{\alpha + \beta}^{-(\pi - \alpha + \beta)} Rt_n\, d\theta = (\sigma_m/\sigma_f)(2\pi R t_n) \quad (19.2)$$

where

α = assumed azimuth angle of the central axis
β = angle of the neutral axis with respect to central axis, or $\sin^{-1}(\delta/R)$
δ = distance between the central axis and the neutral axis
R = mean radius of the shroud
$t(\theta)$ = t_i (thickness of the i ligament), if angle θ is such that $\theta_{i1} < \theta < \theta_{i2}$, or 0 otherwise
t_n = nominal thickness of shroud
σ_m = membrane stress
σ_f = material flow stress = $3S_m$

Thus, this step helps define the location of the neutral axis when the central axis is assumed to be at an azimuth angle of α.

(b) Once the location of the neutral axis relative to the central axis is determined, the moment $M\alpha$ is then obtained by integrating the bending moment contributions from individual ligament lengths. The mathematical expression used is the following:

$$M_\alpha = \int_{-(\pi - \alpha + \beta)}^{\alpha + \beta} \sigma_f R^2 t(\theta) \sin(\alpha - \theta)\, d\theta - \int_{\alpha + \beta}^{-(\pi - \alpha + \beta)} \sigma_f R^2 t_n \sin(\alpha - \theta)\, d\theta \quad (19.3)$$

The orientation α that produces the least value of M is called $\alpha\, min$ and defines the axis capable of resisting the limiting moment. Whether the specified set of uncraked ligament lengths provides the required structural margin is verified by the following:

$$M_{\alpha\, min}/Z + P_m \geq SF(P_m + P_b) \quad (19.4)$$

where

Z = section modulus of the shroud based on uncracked cross-section
P_m = applied membrane stress
P_b = applied bending stress
SF = safety factor

The current approach uses a safety factor of 2.78 for normal/upset (Level A/B) conditions and 1.39 for emergency/faulted (Level C/D) conditions.

19.2.2.5 Repair/Replacement. BWR utilities have taken a variety of approaches to addressing shroud cracking, ranging from a proactive implementation of a preemptive repair to an inspection based approach in which a repair is installed only when warranted by periodic inspection results. The approach selected by a utility is based on many factors, including a plant-specific assessment of the potential for significant cracking. The design, fabrication, and installation of a shroud repair implemented at a BWR plant has been described [23]. An example of the shroud replacement (along with other internals such as jet pumps) has been given [24]. The replacement shroud material was chosen as Type 316L stainless steel to ensure higher IGSCC resistance.

19.2.3 Jet Pumps

The jet pump recirculation system provides forced circulation flow through the BWR core. During the normal operation of the plant, the jet pump structure is subjected to flow-induced vibration (FIV) and exposed to a high-temperature (approximately 530°F) reactor water environment. The FIV loading could produce fatigue crack growth in a flaw if the applied stress intensity factor range exceeds the fatigue threshold (cyclic stress intensity factor range, ΔK_{th}) below which cracks do not propagate (i.e., virtually no crack growth) under cyclic stress. The magnitude of the FIV stresses is proportional to the square of the flow rate in the riser. The power produced by the reactor is typically proportional to the core flow rate. Thus, the predicted fatigue crack growth at a flaw would depend on the operating scenario (i.e., core flow) assumed.

An example of the flaw evaluation at one of the locations in a jet pump where inservice inspection (ISI) detected an indication has been provided [25]. The flaw was approximately 13 in. long, oriented circumferentially, and located in a 10-in. diameter schedule 40 section. Figure 19.4 shows the BWR jet pump geometry. For the analysis purposes, the flaw was assumed to be through-wall. Since it is not a pressure boundary, a through-wall flaw in a reactor internal is acceptable for continued operation as long as the safety margins of either the original Code of construction or ASME BPVC Section XI are satisfied. Allowable circumferential flaw length was determined as approximately 18 in. using the limit load equations (with *a/t* assumed to be 1.0) in Appendix C of Section XI. The SCC growth rate was assumed to be 5×10^{-5} in./hr.

The flaw length at inspection was such that crack growth due to fatigue during next cycle of operation could not be ruled out. A key input in the fatigue crack growth evaluation was the relationship between the applied stress intensity range (ΔK) and the crack growth rate per cycle (da/dN). The fatigue crack propagation behavior above ΔK_{th} can be represented by the following equation:

$$da/dN = C(\Delta K)^n \quad (19.5)$$

where

da = increment in crack length, a
N = number of cycles
ΔK = mode I stress intensity factor range (C and n are constants)

The ΔK is equal to the maximum value of K (K_{max}) minus the minimum value of K (K_{min}). When a mean stress or load is present, the value of K_{min} is different from the negative of K_{max}. An indication of the relative magnitudes of the mean and the fluctuating stresses is the R ratio or R, defined as K_{min}/K_{max}. The cyclic frequency of the FIV stresses is on the order of 32 Hertz. This cyclic frequency is high enough that the reactor water environmental

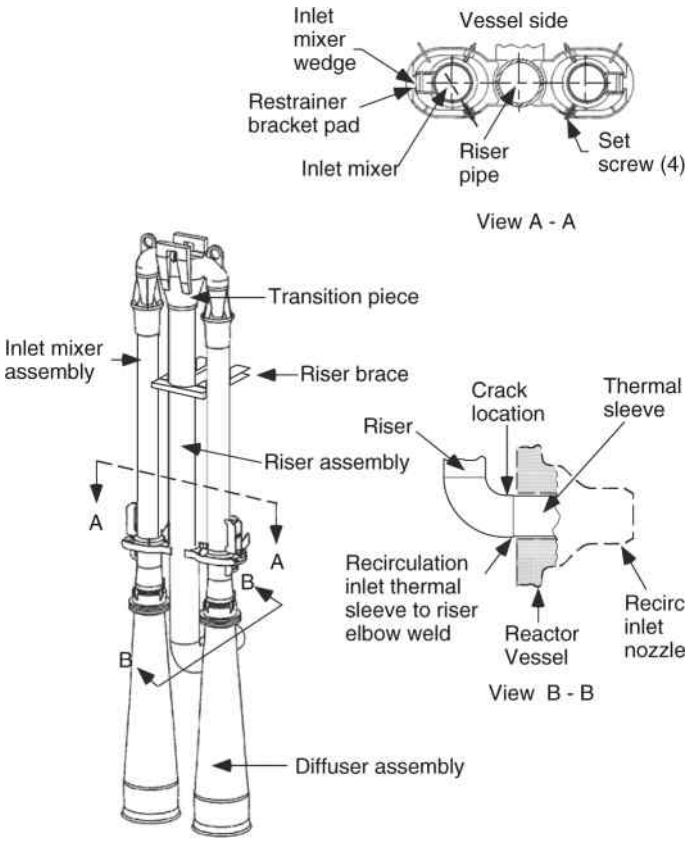


FIG. 19.4 TYPICAL GEOMETRY OF A BWR JET PUMP

effects are expected to be negligible. Therefore, the fatigue crack growth rate relationship developed in air environment was used in the evaluation. ASME Section XI, Fig. C-3210-1 of Appendix C shows air fatigue crack growth rate curves for austenitic stainless steels. The exponent n of the curve is given as 3.3. The dotted-line curves in this figure are at 550°F. The R ratio for the subject flaw configurations was determined to be of the order of 0.5. Interpolation between R values of 0.0 and 0.79 was used to obtain the curve for $R = 0.5$.

A review of the GE test data [26] and those available in the open literature indicated that 5 ksi $\sqrt{\text{in.}}$ is a reasonably conservative value for K_{th} at $R = 0.5$. Thus, the fatigue crack growth rate relationship used in this evaluation was mathematically represented as the following:

$$da/dN = 2.705 \times 10^{-10} (\Delta K)^{3.3} \quad \text{for} \quad \Delta K \geq 5 \text{ ksi}\sqrt{\text{in.}} \quad (19.6)$$
$$= 0.0 \quad \text{for} \quad \Delta K < 5 \text{ ksi}\sqrt{\text{in.}}$$

During startup testing, the riser brace is instrumented with strain gages and, thus, the strain/stress ranges at that location are available. The key task is to infer the stress-time history at the cracked location given the stress-time history at the riser brace. The steps involved in calculating the vibration stress ranges at the cracked section from the test data are summarized as follows:

(a) Review the startup vibration data for the applicable lead plant to determine the primary structural modes of interest for the jet pump. A 128-sec trace of the startup test data was available for this purpose.

(b) Using a finite element model of the jet pump, determine the natural frequencies, mode shapes, and modal stresses of all structural modes of interest. Compare the results to the startup test results to ensure applicability of strain measurements.

(c) From the modal stresses, determine the mode shape factor for each mode of interest to relate the strain at the riser brace to the stress at the crack location.

(d) Decompose the riser brace strain-time history into individual modal strain-time histories for each mode of interest. The jet pump riser brace-time history is from the startup test data for the lead plant, whose jet pump was identical in design to that for the plant with cracked thermal sleeve.

(e) Multiply these individual modal strain-time histories by their corresponding mode shape factors to arrive at the crack location modal stress–time histories.

(f) Algebraically sum (recombine) the modal stress–time histories at the crack location to arrive at the resultant stress–time history. Care was taken in the decomposition (d) and recombination processes to ensure that the phase relationships among the modal components were maintained. Figure 19.5 shows the plot of a small segment of the stress-time history.

(g) Using the resultant stress-time history at the crack location, rank the stress amplitudes from maximum to minimum.

(h) Combine the largest positive and negative amplitudes to determine the maximum stress ranges.

(i) Group the stress ranges in increments of 50 psi and count the number of cycles in each group. Assign the median stress value to that group. For example, the cycles grouped in the 700–750 psi range were assigned a stress range of 725 psi.

(j) Scale the cycle numbers from the 128-sec test data sample to equivalent numbers for 100 hr of operation. The 100-hr interval was chosen to correspond to the time increment used in the crack growth calculation to update the crack length. Table 19.1 shows the resulting cycle numbers for each stress range determined.

(k) The ΔK values from the FIV stress cycles were determined using the mathematical expressions provided by Zahoor [27].

When the calculated value of ΔK for an FIV stress cycle exceeds the assumed threshold value of 5 ksi $\sqrt{\text{in.}}$, crack growth due to fatigue is predicted. Because the subject crack is also expected to experience crack growth due to SCC, the crack growth due to both mechanisms was linearly added. A small time interval of 100 hr was chosen to calculate the SCC and fatigue crack growth. The calculated value of crack growth from these two mechanisms was then added together and the crack length a at the beginning of the interval was updated to $a + 2\Delta a$. The factor of 2 accounts for crack growth at each end of the postulated

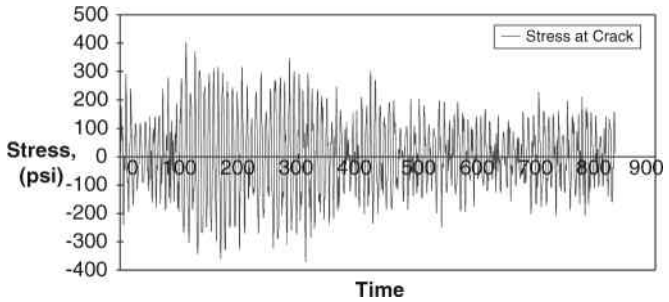


FIG. 19.5 SAMPLE OF STRESS TIME HISTORY AT CRACKED LOCATION

TABLE 19.1 JET PUMP FIV STRESS RANGE VERSUS CYCLE DATA (100 HR OF OPERATION)

Stress Range (psi)	Cycles
775	19,688
725	30,938
675	50,625
625	106,875
575	194,063
525	360,000
475	556,875
425	843,750

through-wall indication. This time-integration process was continued for operation intervals of interest.

Figure 19.6 shows the results of crack growth calculations for two core flow scenarios. The FIV stresses are proportional to the square of the core flow and, thus, the fatigue crack growth is sensitive to the assumed core flow. Typically, the power produced by the plant is directly proportional to core flow. At 80% core flow, the crack is predicted to grow to allowable crack length in 2,000 hours (~3 months) of operation. On the other hand, at 80% core flow level, the crack is predicted to grow to allowable value in excess of 8,000 hours or approximately 1 year of operation. The difference between the two scenarios is essentially the crack growth rate difference due to fatigue. Similar curves were generated for other core flow levels for use by the plant operator; this allowed for flexibility in operating at different core flow (power) levels while ensuring that predicted total crack length is less than the allowable value.

Following approximately 4 months of operation at 80% core flow, the plant was shut down for the installation of repair hardware at the cracked weld. UT ultrasonic examination of the crack prior to the installation of the repair showed virtually no crack growth since the last examination. This confirmed the conservative nature of the fracture mechanics and crack growth evaluations to justify continued operation in the as-is condition for a limited period. The repair consisted of installing a tongue-and-groove type of clamp to replace the cracked weld.

19.2.4 Other BWR Internals and Steam Dryers

Other internal components covered by the BWRVIP reports are core shroud support, top guide, core plate, core spray piping/spargers, standby liquid control system, CRD guide/stub tube/housing instrument penetrations, and vessel ID brackets. The flaw evaluation guidelines for most of these components are essentially based on the limit load methods described in Appendix C of ASME BPVC Section XI.

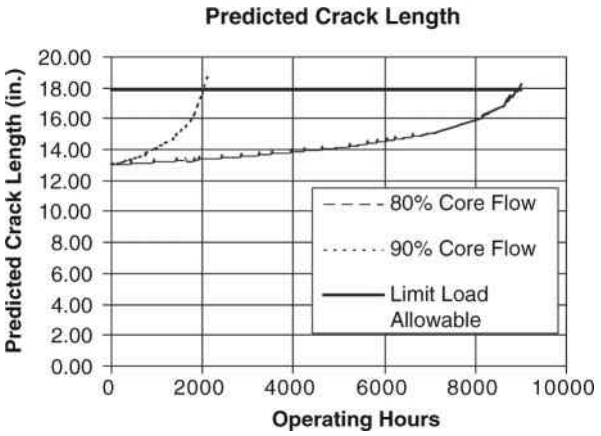


FIG. 19.6 PREDICTED CRACK LENGTHS FOR VARIOUS CORE FLOW LEVELS

Recently observed fatigue failure in the steam dryer of a BWR plant has focused attention on this component [1]. Although performing a nonsafety-related function, the steam dryer in a BWR plant must maintain its structural integrity to avoid loose dryer parts from entering the reactor vessel or steam lines and adversely affecting plant operation. Figure 19.7 shows the details of a BWR steam flow path and the steam dryer assembly. The steam dryer assembly is mounted in the reactor vessel above the steam separator assembly and forms the top and the sides of the wet steam plenum. Vertical guides on the inside of the vessel provide alignment for the dryer assembly during installation. The dryer assembly is supported by pads extending inward from the vessel wall. Steam from the separators flows upward and outward through the drying vanes. These vanes are attached to a top and bottom supporting member forming a rigid, integral unit. Moisture is removed and carried by a system of troughs and drains to the pool surrounding the separators and then into the recirculation down-comer annulus between the core shroud and RPV wall.

Figure 19.8 shows the failure locations in a steam dryer [28]. Extensive metallurgical and analytical evaluations (e.g., detailed finite element analyses, flow-induced vibration analyses, computational fluid dynamics analyses, 1:16 scale model testing, and acoustic circuit analyses) concluded that the root cause of this steam dryer failure was high cycle fatigue driven by flow-induced vibrations associated with the higher steam flows during extended power uprate (EPU) conditions (~18% above the original rated power). It is noted that no significant fatigue failures were observed in this dryer during the rated thermal power operation for more than 20 years. Most of the plant start-up FIV data are at the original rated power level or less, and the sensors, such as strain gages, on the dryer were not necessarily located where the fatigue failures were observed during EPU operation. The repairs at the failure locations were designed to provide a significant relative improvement (e.g., a factor of improvement in excess of 3) in the cyclic fatigue stress compared to that in the previous configuration. This technical approach was necessary in view of significant uncertainty in the fatigue loading during uprated condition operation. A recommended action was, among others, a VT-1 inspection of susceptible locations as determined by a dryer stress analysis [28]. Subsequently, the BWRVIP has developed an inspection and evaluation guidelines document [29] for the BWR steam dryers. The current stress analyses are conducted using the ASME BPVC Section III, Class 1 rules as guidance. Some of the activities currently in progress include extensive subscale model testing and acoustic circuit analysis. Also, some of the replacement steam dryers are being instrumented with strain gages and accelerometers to validate the analytically calculated vibratory stress magnitudes.

19.3 BWR PRESSURE VESSEL

19.3.1 Application of Probabilistic Fracture Mechanics for Inspection Exemption

The ISI of pressure-retaining RPV shell welds (Category B-A welds in Table IWB-2500-1) is an important element of ASME BPVC Section XI inspection requirements. Examination of the BWR vessel beltline region in early design BWRs posed problems

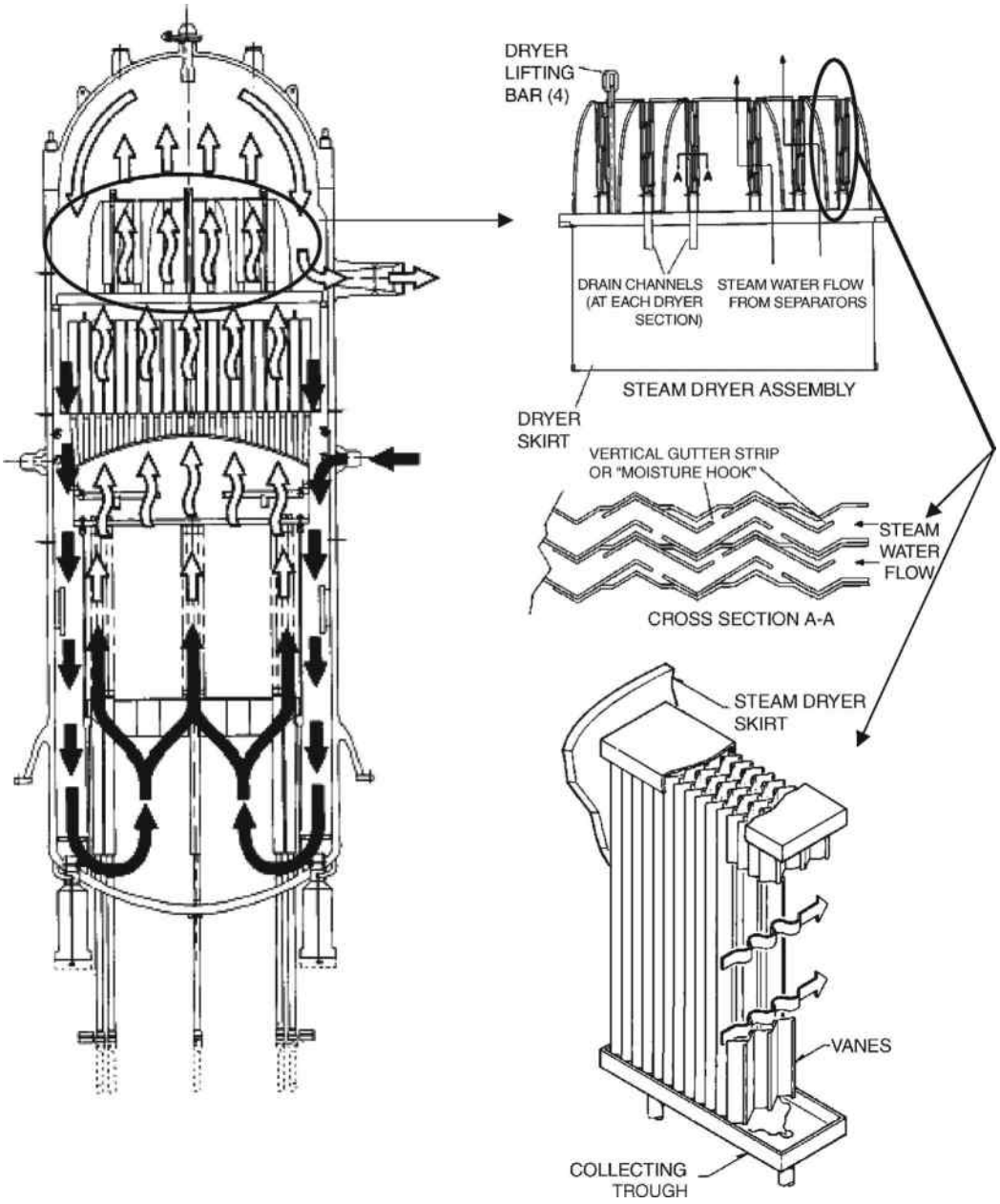


FIG. 19.7 BWR STEAM DRYER ASSEMBLY (WHITE ARROWS INDICATE STEAM FLOW PATH)

because of the limited access on the outside surface between the vessel and the biological shield. Also, interference from jet pumps and the complication of inspecting through the clad made inspection from the inside surface difficult. For the older plants with access problems, the NRC had granted exemption from the inspection requirement. In the early 1990s, the NRC changed its position and required inside diameter (ID) examinations of the older BWRs. This has led to the development of new inspection systems to meet the challenge of ID inspections [30]. Over the past several years, BWRVIP has developed [31] and successfully completed a program to assess the reliability of BWR vessels, specifically focusing on the effect of not inspecting the RPV circumferential welds [32]. The technical approach is based on probabilistic fracture mechanics (PFM) [33].

"In January 1991, the NRC published in the *Federal Register* a proposed Rule to amend Section 50.55a to Title 10 of the *Code of Federal Regulations* [10 CFR 50.55a], 'Code and Standards' [33]. One purpose of this amendment was to incorporate by reference a later edition and addendum to ASME BPVC Section XI, Division 1, and Addenda through 1988. Also, the rule proposed to create Section 50.55a(g)(6)(ii)(A) to 10 CFR 50.55a, "Augmented Examination of Reactor Vessel," which required that all licensees perform volumetric examinations of "essentially 100%" of the RPVs pressure-retaining shell welds during all inspection intervals in accordance with ASME BPVC Section XI on an "expedited" schedule, and revoked all previously granted reliefs for RPV weld examinations. Expedited in this context effectively meant during the inspection interval when the rule was approved or the first period of the next inspection interval. The final rule was published in the *Federal Register* on August 6, 1992.

By letter dated September 28, 1995, as supplemented, the BWRVIP submitted EPRI proprietary report BWRVIP-05 [31].

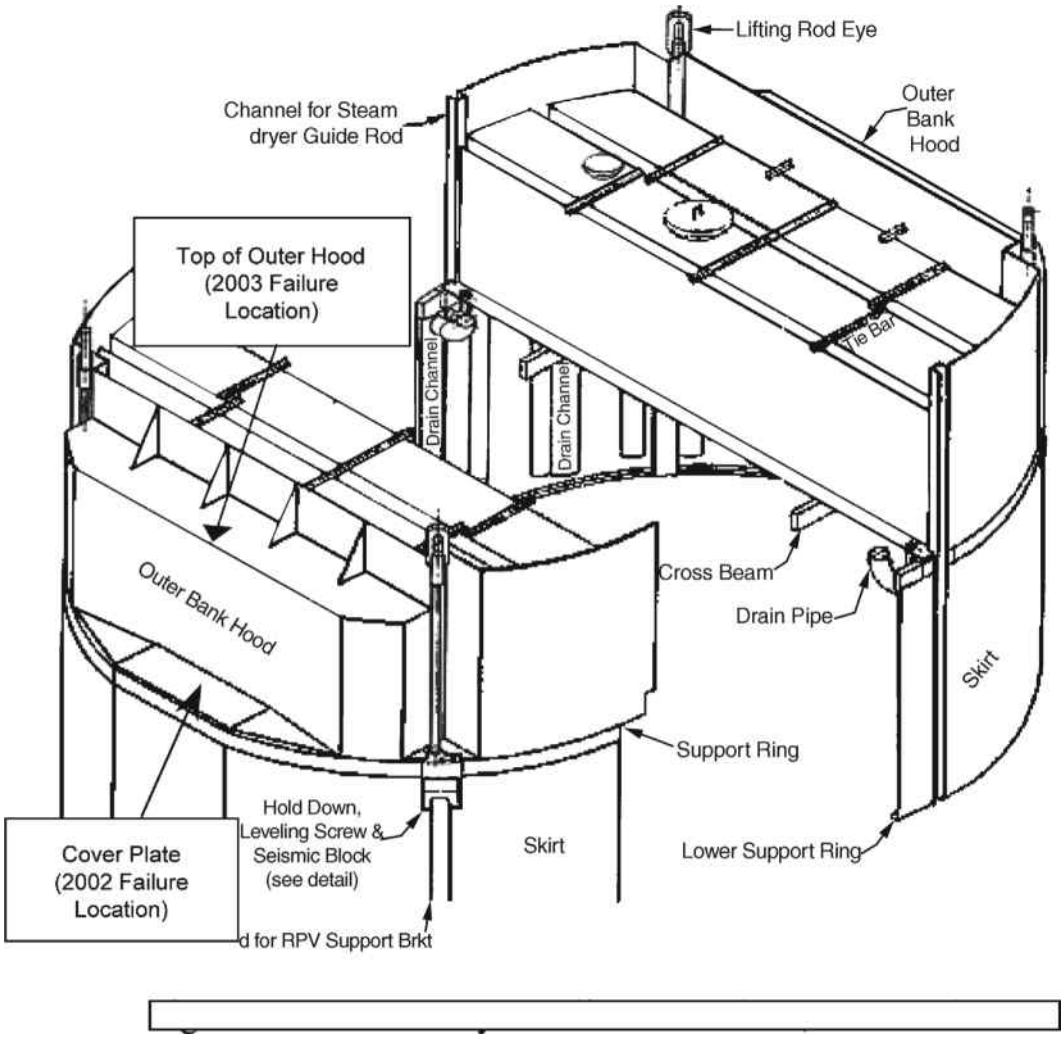


FIG. 19.8 STEAM DRYER DAMAGE

The BWRVIP-05 report evaluated the current inspection requirements for the RPV shell welds in BWRs, formulated recommendations for alternative inspection requirements, and provided a technical basis for these recommended requirements. As modified, it proposed to perform ISI on "essentially 100% of the RPV axial shell weld, and eliminate the inspection of all but approximately 2–3% of the circumferential welds at the intersection of the axial and circumferential welds."

The NRC's technical bases for granting this exemption are summarized. "Regulatory Guide 1.174 provides guidelines as to how defense-in-depth and safety margins are maintained, and states that a risk assessment should be used to address the principle that proposed increases in risk, and their cumulative effect, are small and do not cause the NRC Safety Goals to be exceeded. The estimated failure frequency of the BWR RPV circumferential welds is well below the acceptable core damage frequency (CDF) and large early release frequency (LERF) criteria discussed in RG 1.174. Although the frequency of RPV weld failure cannot be directly compared to the frequencies of core damage or large early release, the staff believes the estimated frequency of RPV circumferential weld failure bounds the corresponding CDF and LERF that may result from a vessel weld failure. On the above bases, the NRC staff concluded that the BWRVIP-05 proposal, as modified, to eliminate BWR vessel circumferential weld examinations, was acceptable."

The alternate PFM analysis of the NRC also considered a low-temperature overpressure (LTOP) transient at a non-U.S. BWR [34]. During this transient, the RPV was subjected to high pressure (7.9 MPa or 1,150 psig) at a low temperature (26–31°C or 79°–88°F). An Appendix E–based deterministic fracture mechanics analysis and corrective actions that justified plant startup following the transient are documented [34].

The PFM analysis can also be used to justify inspecting less than 100% of the vertical welds due to the local inaccessibility of the RPV and equipment issues. During a refueling outage, a U.S. BWR found that only 89.9% of the total length of the beltline vertical welds and 91.8% of the total vessel vertical weld length could be inspected. In the case of one particular vertical weld, the entire length was not accessible. Part of this weld was in the beltline region. A PFM evaluation [35] concluded that the resultant increase in the vessel failure probability was very small, even after factoring in the contribution of a postulated LTOP event. Thus, a less than 100% inspection of the welds was technically justified.

19.3.2 Feedwater Nozzle

Cracking was observed in BWR feedwater nozzles and control rod drive (CRD) return line nozzles during the 1970s. Since then, the CRD return lines in most BWRs have been rerouted and the

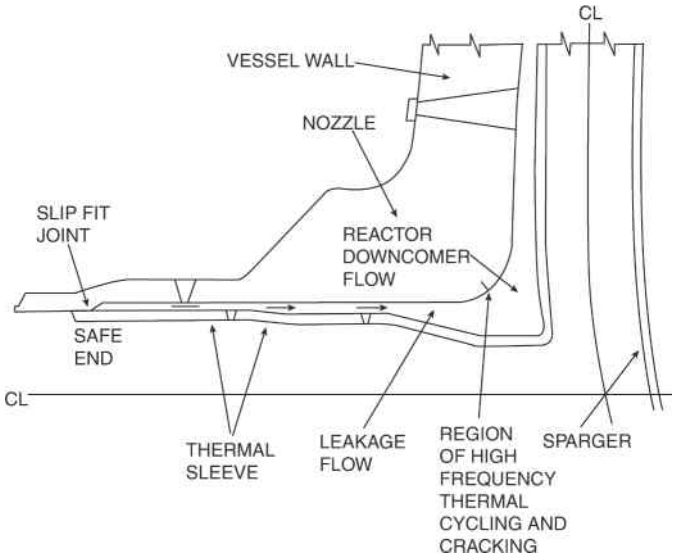


FIG. 19.9 CROSS-SECTION OF FEEDWATER NOZZLE WITH CRACKING LOCATION

nozzles capped. In the case of the feedwater nozzle, an extensive study of the problem attributed the cracking to relatively cooler feedwater leaking past loosely fitted sparger thermal sleeves installed inside the nozzle. The bypass leakage from around the loose thermal sleeves caused fluctuations in nozzle metal temperatures, which resulted in metal fatigue and crack initiation (see Fig. 19.9). These cracks were then driven deeper by the larger temperature and pressure cycles associated with startups, shutdowns, and certain operational transients. The NRC issued its findings and resolutions of the cracking problem in NUREG-0619 [36] in which it recommended that licensees take the following six actions to reduce the potential for initiating and growing cracks in the inner nozzle areas:

(a) remove the cladding from the inner radii
(b) replace loose-fitting or interference-fitting sparger thermal sleeves
(c) evaluate flow controllers for acceptability
(d) modify operating procedures to reduce thermal fluctuations
(e) reroute reactor water clean-up system to both feedwater loops
(f) conform to the inspection interval specified in Table 19.2 of NUREG-0619

Most of the BWRs adopted a triple thermal sleeve design as replacement for the original loose-fitting design. This design was developed as a part of an extensive experimental and analytical program [37] conducted to address feedwater nozzle cracking. Figure 19.10 shows this design and the temperature variations with and without bypass.

In 1981, the NRC issued Generic Letter 81-11 amending the recommendations in NUREG-0619. The generic letter allowed plant-specific fracture mechanics analysis in lieu of hardware modifications. To be acceptable to the NRC, such analysis had to analytically demonstrate that stresses from conservative controller temperature and flow profiles, when added to those resulting from the other crack growth phenomena such as startup/shutdown cycles, did not result in the growth of an assumed crack to greater than the allowable value of 1 in. during the 40-year life of the plant. The BWR feedwater nozzles have large flaw tolerance. The leak-before-break analyses concluded that even a through-wall flaw is structurally acceptable at the cracking location [37]. Thus, the critical flaw depth at this location is the through-wall dimension, typically 10 in. in most BWRs. If the approach of ASME BPVC IWB-3611 (for normal/upset conditions) is taken in setting the allowable flaw depth to be one-tenth of the critical flaw depth, one obtains the value of 1 in. as the allowable flaw depth.

The initial flaw depth is assumed to be 0.25 in.; this is considered to be a reasonable depth detectable with a high degree of confidence. The fatigue crack growth rate relationship used is that provided in Appendix A of ASME BPVC Section XI for water environment. This fracture mechanics analysis is essentially similar to a flaw tolerance evaluation per Appendix L of ASME BPVC Section XI. Figure 19.11 shows the results of fracture mechanics calculations for some of the BWRs. The results show a fairly large interval (in excess of 25 years) before the projected crack depth reaches 1 in.

Improvements in UT capability and the acceptable crack growth results seen in a majority of the fracture mechanics analyses provided justification to revise the inspection frequency and allow an alternate method. In fact, it was the intent of the NRC to eliminate penetrant testing (PT) requirements when improved UT techniques were available. The revised inspection schedules (see Table 19.2) were developed [38] and were approved by the NRC [39] for use by the BWR owners. The inspection zones referred to in Table 19.2 are shown in Fig. 19.12. The inspection intervals based on Table 19.2 provide considerable relief in inspection efforts without sacrificing safety.

Several BWR plants have implemented thermal sleeve bypass leakage detection systems since the time NUREG-0619 was published. Such systems were still under development at that time, but preliminary testing and implementation of the systems suggested them to be feasible and practical. The intent of these systems was to detect significant leakage through degraded thermal sleeve seals or cracks in thermal sleeve welds. This detection was accomplished by relating exterior surface metal temperatures (from newly installed thermocouples) to leakage flow. Leakage monitoring was expected to be a beneficial system to employ, because it might provide the most direct assessment of conditions known to lead to nozzle fatigue cracking.

Leakage monitoring systems have not been implemented as consistently as anticipated when NUREG-0619 was published. This has been primarily due to high installation and maintenance costs as well as field experience suggesting that the cracking problem had been eliminated. Also, erroneous leakage readings can be common with these systems due to sensor movement, which has led to unnecessary leakage concerns. Systems that have continued to operate properly have shown leakage to be insignificant; these results have further verified observations of no sparger cracking.

Based on these results, leakage monitoring does not possess the necessity and promise it once had. Nevertheless, for those installations that continue to operate properly, it does remain a viable method for further assessing the presence of fatigue cracking in nozzles. Therefore, for those plants that have such systems, leakage data obtained from these systems can be used to enhance the technical argument used to establish inspection frequency.

19.3.3 Inspections of Other Vessel Nozzles and Welds

19.3.3.1 Alternate Inspection Method for Nozzle Inner Radii. Other than the feedwater nozzles and the operational CRD

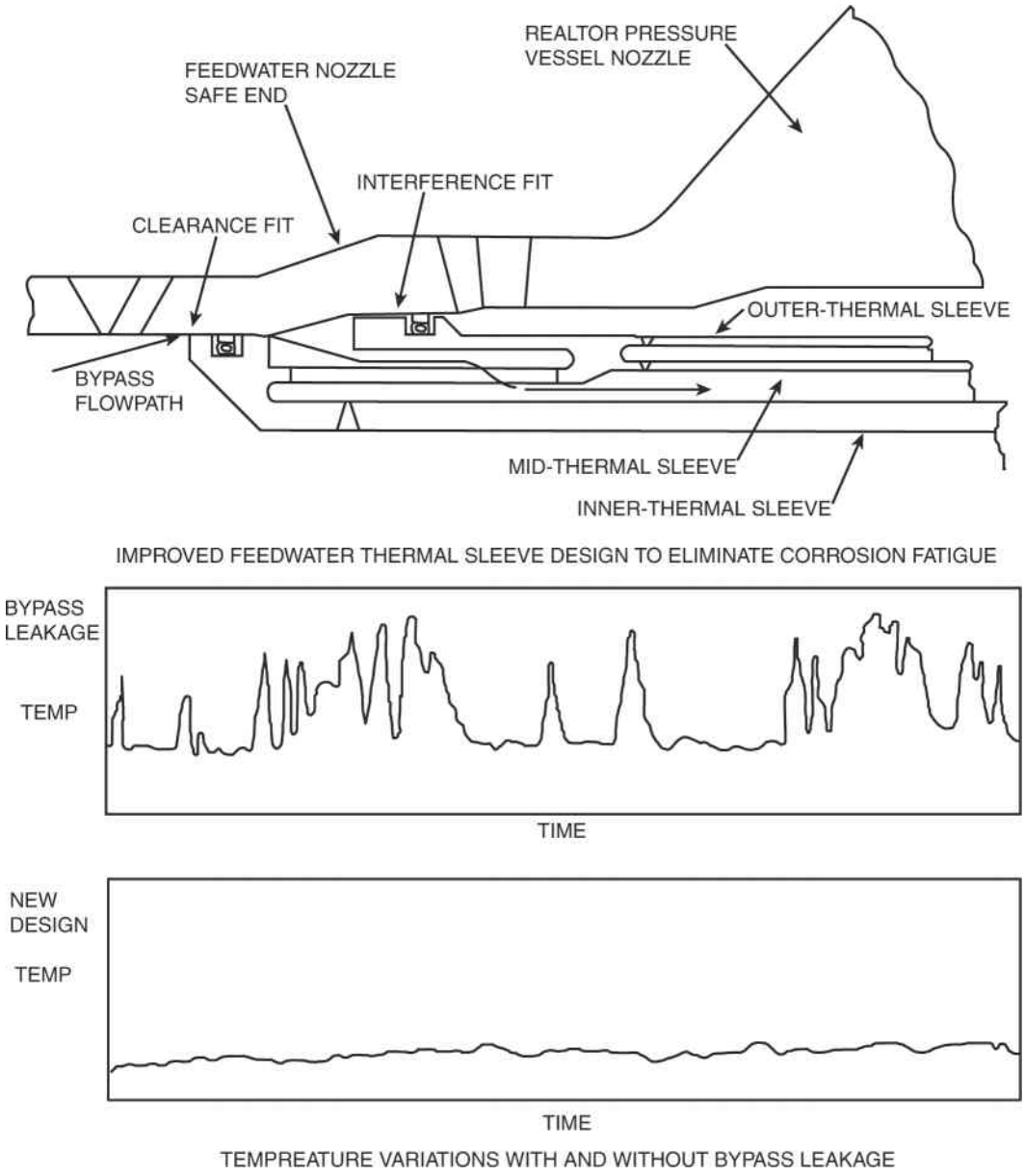


FIG. 19.10 IMPROVED THERMAL SLEEVE DESIGN AND TEMPERATURE VARIATIONS WITH AND WITHOUT BYPASS

return line nozzles in BWRs, the ISI inspections of inner radii of the other RPV nozzles, including PWR vessel nozzles, have not found any indications. This led to the adoption of Code Case N-648-1 [40]. This Code Case allows a VT-1 examination of the inner radii surface [surface M-N in Figs. IWB-2500-7(a) through(d)] in lieu of the volumetric examination required by Table IWB-2500-1, Examination Category B-D, Item B3.20 or B3.100, for ISI of reactor vessel nozzles other than BWR feedwater nozzles and operational CRD return line nozzles. If crack-like surface flaws exceeding the acceptance criteria of Table IWB-3510-3 are found, acceptability for continued service can be shown by meeting the requirements of ASME BPVC IWB-3142.2, IWB-3142.3, or IWB-3142.4.

Briefly, the technical bases [19] for this Code Case are as follows: volumetric inspections have been required for the nozzle inner radius regions of reactor vessels since the inception of Section XI of the ASME Code in 1970. In over 30 years of

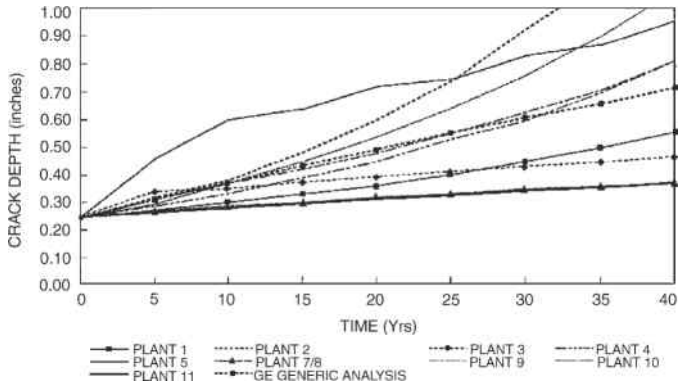


FIG. 19.11 FRACTURE MECHANICS RESULTS FOR SEVERAL BWRs

TABLE 19.2 FEEDWATER NOZZLE/SPARGER INSPECTION RECOMMENDATIONS[1]

Thermal Sleeve/Sparger Design Configuration	UT Inspection Interval Factor[2] for Zones 1 and 2			Visual Inspection of Sparger[4]
	Method 1[3]	Method 2[3]	Methods 3 or 4[3]	
Interference fit, clad nozzle	0.05	0.10	0.20	2
Welded, clad nozzle	0.10	0.17	0.33	2
Single thermal sleeve, single piston ring, unclad nozzle	0.10	0.17	0.33	4
Oyster Creek and Nine Mile Point 1 (unclad nozzle, significantly modified spargers installed)	0.10	0.17	0.33	4
Welded, unclad nozzle	0.10	0.17	0.33	4
Triple sleeve, double piston ring, unclad nozzle	0.10	0.17	0.33	4
Other Configurations	see note (5)	see note (5)	see note (5)	see note (5)

Notes: (1) The inspection interval is to begin at the time when a qualified inspection plan that meets the requirement of this report is established and implemented. The need for routine PT exams is eliminated.

(2) For each configuration, the maximum inspection interval is defined by a fraction of the time until a 0.25 inch or greater depth crack reaches the appropriate allowable value, as obtained from a plant-specific fracture mechanics analysis following the recommendations of Section 5.6 of this report. For example (when Method 3 is used):

Sparger Design = Triple Thermal Sleeve
Fracture Mechanics Result = 0.25″ crack grows to allowable depth in 30 years
Required UT Inspection Interval = Allowable time × Factor
= 30 × 0.33 = 10 years

For Zones 1 and 2, in no case shall the maximum allowable time between inspections exceed 10 years. For Zone 3, the inspection intervals can be twice the value recommended for Zones 1 and 2. The inspection frequency is not required to be more often then every second cycle regardless of interval factor.

(3) The UT methods are defined as follows:

Method 1 = Manual
Method 2 = Automated, Threshold Recording
Method 3 = Automated, Full RF Recording (No Threshold)
Method 4 = Phased Array (No Threshold)

(4) Visual inspection of flow holes and welds in sparger arms and sparger tees. These requirements are the same as those specified in NUREG-0619.

(5) Other configurations not specifically identified here should be evaluated on a case-by-case basis.

inspections, no indications have been found in any pressurized water reactor (PWR) nozzles. Indications have been found in two nozzle types in boiling water reactor (BWR) nozzle, both the other nozzle types have the same flawless history as the PWRs. In 1999, a project was begun to eliminate this inspection from the requirements of ASME BPVC Section XI; the following three independent arguments were advanced:

(a) a good inspection history (the nozzles that had cracked in service were eliminated)
(b) a very large flaw tolerance
(c) a risk argument that was based on the finding that elimination of the inspection resulted in negligible change in core damage frequency

These arguments were accepted by the ASME Code, as well as the NRC, and Code Case N-648-1 was approved by ASME in December of 2000 [19].

The NRC, in a conditional acceptance of this Code Case, stated the following [42]: "In place of a UT examination, licensees may perform a visual examination with enhanced magnification that has a resolution sensitivity to detect a 1-mil width wire or crack, utilizing the allowable flaw length criteria of Table IWB-3512-1 with limiting assumptions on the flaw aspect ratio. The provisions of Table IWB-2500-1, Examination Category B-D, continue to apply except that, in place of examination volumes, the surfaces to be examined are the external surfaces shown in the figures applicable to this table." Thus, the NRC requires a more sensitive visual examination technique than that specified in the Code Case.

19.3.3.2 Alternate Inspection Frequency. Currently, BWR RPV nozzle inner radius and nozzle-to-shell welds are inspected per ASME BPVC Section XI requirements (Table IWB-3500-1, Examination Category B-D), which requires 100% inspection for each 10-year interval. These examinations are costly and result in significant radiation exposure to examiners. Since 1990, the performance of NDE has improved substantially such that there is a high reliability of detecting flaws that can challenge the structural

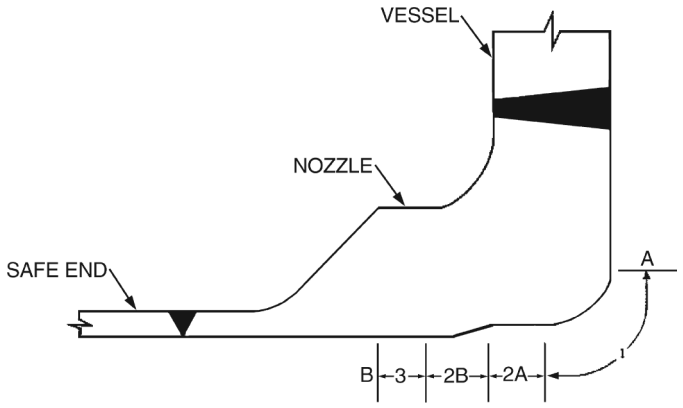


FIG. 19.12 BWR FEEDWATER NOZZLE INSPECTION ZONES (CLAD-REMOVED NOZZLE)

integrity of BWR nozzles and their associated welds. Code Case 702 [43], approved at the December 2003 meeting of the Section XI Main Committee, allows a reduction of the nozzle-to-shell welds and nozzle blend radii from 100% to 25% of the nozzles every 10 years, 25% inspection each 10-year interval.

BWRVIP-108 [44], which provided the technical basis for this Code Case, described the technical approach as follows: "The project team evaluated the available field inspection data and performance demonstration data for BWR nozzles. They selected representative nozzles for the evaluation, including core spray, main steam, and recirculation inlet and outlet nozzles. PFM and deterministic fracture mechanics (DFM) calculations were performed to assess the reliability of the nozzles after implementing the revised inspection approach. The PFM code, VIPER, developed by the BWRVIP with a successful first use in BWRVIP-05, employs Monte Carlo methods to assess the reliability of a BWR RPV having flaw distributions, material properties, fluence distributions, and several other parameters, which are assumed to be randomly distributed. A DFM evaluation was also performed to demonstrate that expected flaws, based on field experience, would not jeopardize the structural integrity of the vessel. A flaw is selected that bounds any expected flaws based on field inspection results. Using appropriate material properties, a deterministic LEFM evaluation is performed to demonstrate that failure is not expected."

19.3.4 Stub Tube Cracking

The CRD and In-Core Housing penetrations in a BWR are on the bottom head of the vessel. The earlier BWR CRD penetrations used a stub tube to which the CRD housing is welded. The typical CRD housing is 6 in. in diameter and is made of either Type 304 stainless steel or Alloy 600. The use of the stub tube allows the stainless steel housing to be welded to the stub tube after post-weld heat treatment (PWHT) of the vessel. Figure 19.13 shows the typical CRD stub tube penetration in a BWR/2 bottom head. This is referred to as a set-in stub tube design since the stub tube is in a socket in the bottom head prior to welding. In some BWRs, the stub tube was made of Type 304 stainless steel and was welded to the bottom head before PWHT. The subsequent PWHT caused furnace sensitization of the stub tube making it susceptible to IGSCC with the exposure to a high-temperature, water environment. The cracking could occur in the HAZs of the welds and anywhere along the length of the sensitized stub tube.

Cracking and, in some case, leakage has been observed in BWR plants with furnace-sensitized stub tubes. The observed leakage has been well within the system leakage limits and has been a small fraction of the system makeup capability. Unlike the PWRs where the coolant uses borated water, there is no boron in the BWR water and leakage from the stub tube cracking does not lead to boron corrosion concerns. Stub tube cracking by itself does not pose a direct safety issue. Limiting the leakage has been the focus of the corrective action prior to plant startup. Roll expansion of the housing against the vessel penetration has been used to address the leakage concern. The plastic deformation of the housing against the vessel results in an effective leakage barrier.

The stub tube roll expansion repair has been used successfully in several BWRs and has been reviewed by the NRC staff. For the domestic BWR plants, the NRC typically approved the repair process as an alternative to the requirements of ASME BPVC Section XI, para. IWA-5250(a)(3) pursuant to 10 CFR 50.55a(a)(3)(I) on a case-by-case basis. Recently, the NRC allowed continued plant operation for the second cycle following discovery of CRD stub tube leakage in a BWR/2 plant [45]. Summary of the NRC's safety evaluation follows.

> The NRC staff concluded that, based on industry experience, roll expansion of the CRD housing to the RPV is an appropriate alternative repair for use at the BWR/2 plant. The roll expansion process will eliminate, or reduce to an acceptable

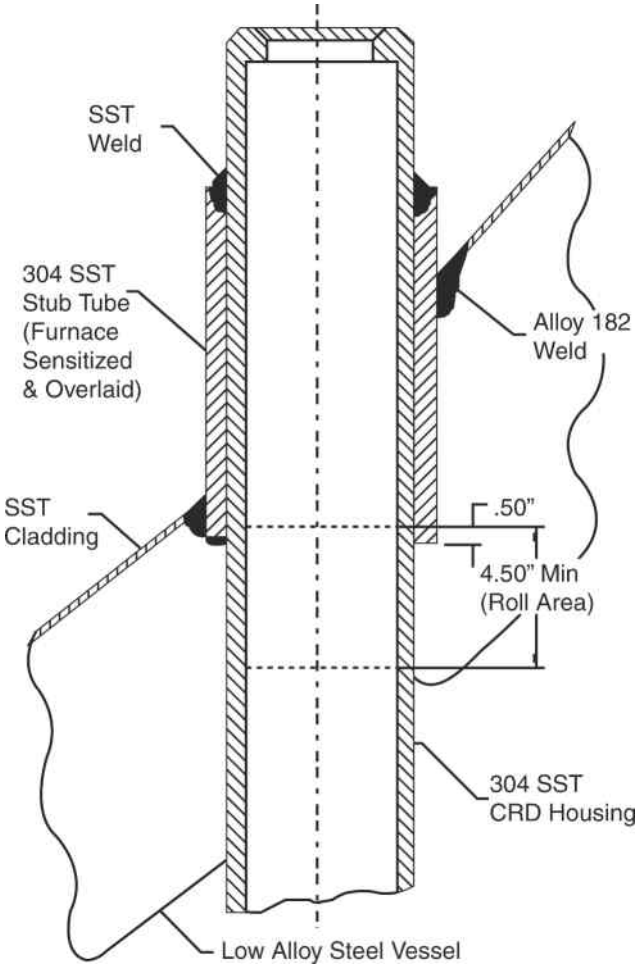


FIG. 19.13 A TYPICAL BWR SET-IN CRD STUB TUBE DESIGN

level, leakage from CRD housings. The housings will be plastically expanded within the RPV lower head bore to create a radial contact pressure between the housing and the vessel bore. Proper contact pressure is achieved by controlling the radial expansion of the housing and by utilizing additional passes to increase the contact length. The process will have no harmful effects on the CRD housing, stub tubes, or the reactor vessel. Potential failures, which could occur as a result of this repair, have been evaluated. The roll repair will meet the qualification criteria, without exception, and the nominal 3–5% minimum thinning to achieve continuous contact. Additionally, the alternative provides for the pre-repair and post-repair inspections to ensure the adequacy of this proposed repair. Thus, the proposed alternative will provide assurance of structural integrity for the approval period requested.

Imposition of the Code repair would require that the plant remain in a shutdown condition for an extended period in order to disassemble and remove fuel from the reactor to determine the exact leak location and to perform an in-vessel repair involving additional personnel exposure. Because use of the alternative repair (roll expansion) until the next refueling outage will provide adequate assurance of structural integrity, compliance with the specified requirements of the Code (a weld repair) would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

The NRC staff has evaluated the licensee's proposed alternative for the plant. The staff finds that the proposed roll expansion repair, as described above, is acceptable until the next refueling outage. The NRC staff does not approve the roll-expansion process as a permanent repair in lieu of meeting the ASME Code repair criteria. The NRC staff recommends that if the licensee intends to use this alternative as a permanent repair, it should pursue this alternative repair of the CRD housings with the Code Committee to accept this as a permanent repair through a Code Case on an expedited basis. Should this prove to be not successful, the NRC staff recommends that the licensee follow up with a schedule for a permanent Code repair. The implementation of the alternative is subject to inspection by the NRC.

Based on the NRC's recommendation, the plant owner helped develop Code Case N-730 [46], the technical basis of which is documented in [47]. Reference 47 builds on the BWRVIP roll repair document [48] that was part of a full-scale effort to develop and qualify the roll repair process and equipment. A Code Case (tentatively assigned the number N-769) is currently under development for the roll repair of BWR bottom head in-core housing penetrations.

Other types of stub tube repair concepts include the following:

(a) a mechanical seal forming a pressure boundary around the weld
(b) a welded sleeve forming a pressure boundary and weld load path (see Fig. 19.14 for a typical example for a set-on stub tube [49])
(c) a replacement of the stub tube and housing

The replacement option involves welding close to the P3 vessel material where preheat or PWHT may not be feasible. Code Case N-606-1 [50] was specifically developed to permit the use of ambient temperature machine GTAW temper bead technique for BWR CRD housing/stub tube repairs.

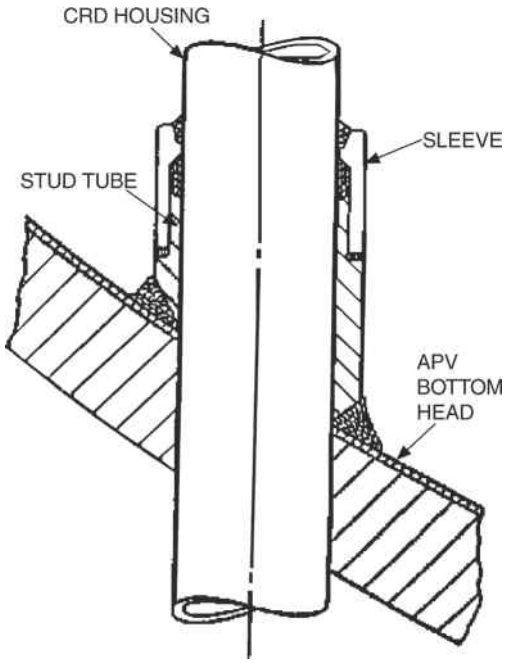


FIG. 19.14 STUB TUBE NARROW GROOVE WELDED PARTIAL DESIGN

19.3.5 Vessel Attachment Weld Cracking

There are numerous internal attachments to the BWR RPV that are welded using the alloy 182 that is known to be susceptible to SCC. Also, some attachments such as the jet pump riser brace are fatigue sensitive. One of the aspects that needs to be considered when field cracking is detected at an attachment weld is the potential for crack growth into the vessel material during future operation.

19.3.5.1 Vessel-to-Shroud Support Weld Cracking. In late 1999, stress corrosion cracks were discovered in alloy 182 welds in the shroud support structure of Tsuruga-1, a BWR-2 located in Japan (see Fig. 19.15). This weld material was used in the construction of the conical support structure as well as to attach the support structure to the RPV. These cracks were detected visually and confirmed with penetrant inspection as well as by metallography during core shroud replacement activities. The number of crack indications was more extensive than had been seen previously in BWRs and the cracks were located on the underside of the core support structure; thus, they could not be detected during routine visual inservice inspection from the top.

Following this finding, BWR owners were advised to review their inservice inspection programs and consider performing an examination of the RPV-to–shroud support plate weld [51]. Somewhat similar cracking on the underside of the H9 weld was detected at a U.S. BWR-2 plant though UT inspection conducted from outside the vessel. A fracture mechanics evaluation [52] was performed to address the following two issues:

(a) What is the structural margin during future operation at the shroud support in the presence of observed cracking?
(b) What is the number of years of plant operation until an assumed flaw at the clad base metal interface would be projected to grow into the base metal to allowable flaw depth calculated by the rules of ASME BPVC IWB-3600?

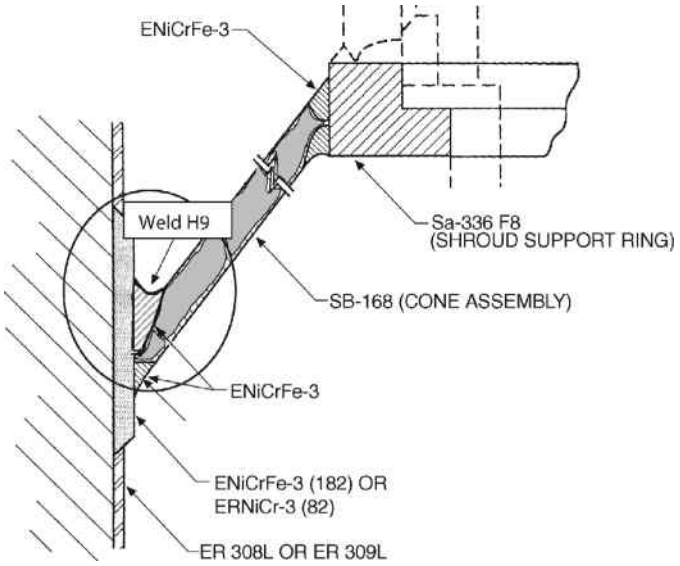


FIG. 19.15 BWR-2 SHROUD SUPPORT GEOMETRY

The evaluations conducted to address both of these issues considered projected crack growth from at least 80,000 hr (approximately 10 years) of future operation.

The detailed examinations during shroud replacement activities at the Japanese BWR-2 confirmed that none of the cracks entered the vessel low-alloy steel base metal adjacent to the weld metal. This clearly indicated that the cracking was confined to alloy 182 even though the plant had operated for over 25 years. Therefore, the fracture mechanics approach to quantify the allowable operating time conservatively considered a long axial flaw (aspect ratio of 0.1) placed at the depth of the clad low-alloy steel interface.

The stresses considered in the evaluation were those due to internal pressure, thermal expansion, cladding, and weld residual. The values of total applied stress intensity factor K as a function of crack depth a are shown in Fig. 19.16. The fatigue crack growth using the Appendix A curves was found to be insignificant. However, the potential crack growth due to stress corrosion cracking was taken into account using the following K versus da/dt relationship [53]:

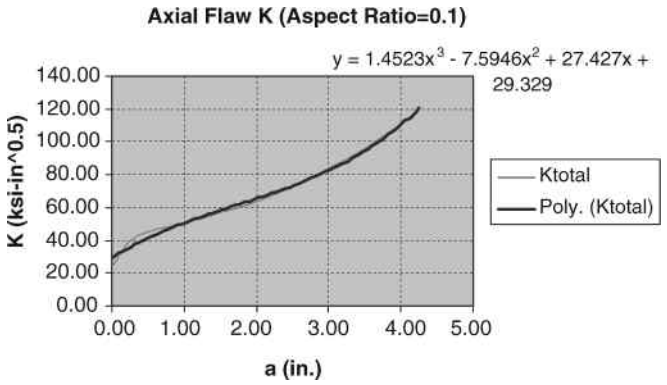


FIG. 19.16 CALCULATED VALUES OF TOTAL *K* AND THE POLYNOMIAL FIT

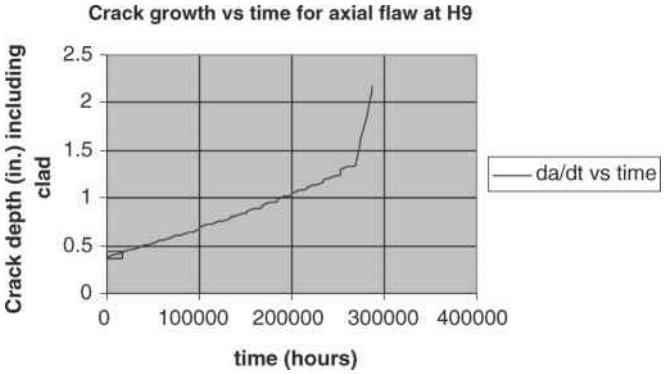


FIG. 19.17 PREDICTED CRACK GROWTH AS A FUNCTION OF OPERATING HOURS

$$da/dt = 2.8 \times 10^{-6} \quad \text{in./hr for } K < 50 \text{ ksi}\sqrt{\text{in.}} \tag{19.7}$$

$$6.82 \times 10^{-12}\,(K)^4 \quad \text{in./hr for transient condition, or } K < \text{ksi}\sqrt{\text{in.}} \tag{19.8}$$

For the purpose of the crack growth calculation, it was assumed that there would be approximately 800 hr of transient condition operation during a 2-year (approximately 16,000 hr) cycle of operation. The results of crack growth prediction are shown in Fig. 19.17. The allowable crack depth was determined to be 2 in. based on normal/upset conditions. Figure 19.17 indicates that this value of crack depth is reached in excess of 200,000 hours of operation. This flaw evaluation provided technical justification for continued operation of the RPV with the observed H9 weld cracks for at least 5 additional operating cycles, equivalent to 10 years of operation.

19.3.5.2 Steam-Dryer-Support-Bracket Cracking. Steam dryer support brackets are four stubby projections from the ID of the vessel that support the steam dryer. They are 3 × 5 × 11-in. tall forgings, full penetration welded to alloy 182 pads about 10 ft below the closure flange. Figure 19.18 shows the geometry of the cracked bracket [54]. A metallurgical analysis indicated that the bracket failed by a fatigue mechanism. During normal operation, the only design loads transferred between the steam dryer and the support brackets are vertical. The loads are transferred to the bracket through a seismic block, which provides horizontal restraint during earthquake loading. Examination of the failed bracket on the upper surface showed that the dryer support ring was in direct contact with the edge of the bracket farthest from the reactor wall due to an improperly positioned seismic block. This was different from the other three identical brackets that showed contact with the seismic block attached to the support ring. The point of application of the load on the failed bracket was 80% farther away from the crack initiation edge than was the load application point on the uncracked bracket 180° away from it. This meant 56% higher cyclic bending stresses at the failed bracket. Therefore, the corrective action for the cracked bracket was to replace it exactly as in the original design (same bracket material, configuration, and weld material) and to ensure that the seismic block was in contact with the bracket rather than the dryer support ring. A review of the ASME BPVC Section III fatigue design curve for Ni-Cr-Fe materials (ASME BPVC Section III, Fig. 19.2) indicated that a 56% improvement in stress would translate into a fatigue life improvement by a factor of at least 25. This meant that

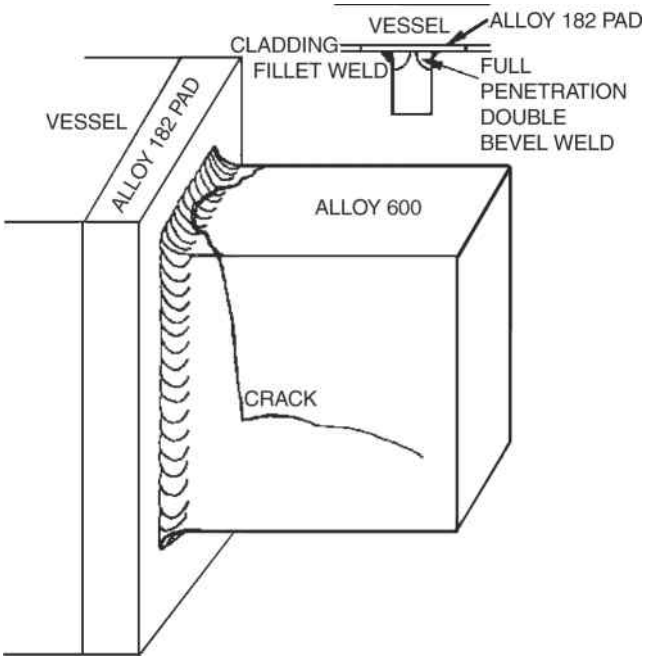


FIG. 19.18 STEAM DRYER SUPPORT BRACKET CRACK

the repair extended the life of the bracket significantly past the vessel design life. A VT examination after 1 year of service revealed that this bracket was free of cracks.

19.3.6 Low Upper Shelf Energy Evaluation

19.3.6.1 Background. Appendix G of 10 CFR50 [52] states that the RPV must maintain upper-shelf energy (USE) throughout its life of no less than 50 ft-lb, unless it is demonstrated, in a manner approved by the director of the office of Nuclear Reactor Regulation, that lower values of USE will provide margins of safety against fracture equivalent to those required by Appendix G of ASME BPVC Section XI. Regulatory Guide 1.99, Revision 2 [56] provides a method to estimate the decrease in USE as a function of fluence and copper content. It was recognized in the early 1980s that some RPVs have materials for which the USE may fall below 50 ft-lb due to irradiation embrittlement. In 1982, the NRC published proposed procedures for the analyses required by 10 CFR50 for operating RPVs as NUREG-0744 [57]. At the time of publication of this document, the NRC officially requested that the ASME Code recommend criteria, analysis methods, and suitable specifications for material properties to be used for the assessment of reactor vessels that do not meet the Charpy USE requirements. As a result of this request, the Section XI Working Group (WG) on Flaw Evaluation developed, through an approximately 10-year effort, acceptance criteria and acceptable analysis methods to address this issue. The WG also developed simplified evaluation procedures applicable for use in evaluations of Service Level A and B conditions. WRC Bulletin 413 [58] documents the results of the WG's effort; Part 1 of the Bulletin contains the basis for the recommendations sent from the WG to the NRC, dated January 11, 1991. These recommendations included the acceptance criteria that were subsequently implemented as Code Case N-512 [59] and later as Nonmandatory Appendix K in ASME BPVC Section XI. Part 2 of the Bulletin contains the basis for the simplified evaluation procedures for Service Level A and B conditions. The NRC published Regulatory Guide 1.161 [60] to provide additional guidance to include analysis procedures for Service Levels C and D, guidance on selecting the transients for evaluation, and details on temperature-dependent material properties. The low USE analysis also has been called equivalent margin analysis.

For the evaluation of Level A and B service conditions, a $^1/_4\,t$ surface flaw with an aspect ratio of 6:1 oriented axially or circumferentially (whichever direction is relevant) is postulated. The two criteria to be satisfied are the following.

(a) The applied J-integral, evaluated at a pressure that is 1.15 times the accumulation pressure as defined in the plant-specific Overpressure Protection Report, with a factor of safety of 1.0 on thermal loading for the plant-specified heat-up/cool-down conditions, shall be shown to be less than $J_{0.1}$, the J-integral characteristic of the material resistance to ductile tearing at a flaw growth of 0.1 in.
(b) The flaw shall be shown to be stable, with the possibility of ductile flaw growth at a pressure that is 1.25 times the accumulation pressure defined in (*a*), with a safety factor of 1.0 on thermal loading.

The J-R curve shall be a conservative representation for the vessel material under evaluation. The criteria for the evaluation of Level C service conditions are essentially the same, except that the postulated flaw is $\frac{1}{10}\,t$ deep and the safety factor on the pressure loading is 1.0. Additional relaxation in the criteria for Level D service conditions is that a best estimate J-R curve can be used.

19.3.6.2 Generic BWR Evaluation. In September 1992, the NRC, in discussing the preliminary review of the responses to Generic Letter 92-01, strongly recommended that equivalent margin analyses be done by the Owners Group. The BWR Owners Group developed a generic analysis in the form of a topical report [61]. The objective was to provide a safety net analysis for plants that could not quantitatively demonstrate, using NRC-approved methods, that USE would remain above 50 ft-lb and might, therefore, be subject to regulatory action. A second objective, which developed within the BWR Owners Group in the process of performing the analysis, was to provide a topical report, which could be referenced by utilities as part of their licensing basis, to address compliance with the 50 ft-lb requirement on USE in 10 CFR50 Appendix G.

Both the axial and circumferential flaws in plate material, with the corresponding longitudinal and transverse USE data, were considered in the analysis. For welds, only the more limiting axial flaw case was evaluated. The analysis addressed BWR/2 plates separately from BWR/3–6 plates, due to differences in geometries, material properties, and availability of USE data. The welds were addressed together for BWR/2–6 vessels but were grouped by weld type, specifically shielded metal arc, electroslag, and submerged arc welding.

Figure 19.19 shows the Level C condition transient used in the analysis, and Figure 19.20 shows the results for $J_{0.1}$ assessment also for Level C conditions. Topical report was reviewed and approved by the NRC [62]. Table 19.3 (Table 1 [62]) provides a summary of the results. Equivalent margin was demonstrated for 35 ft-lb USE values, except in the longitudinal plate direction where the results were 50 ft-lb for BWR/2 plates and 59 ft-lb for BWR/3 – 6 plates. The analysis results for Levels C

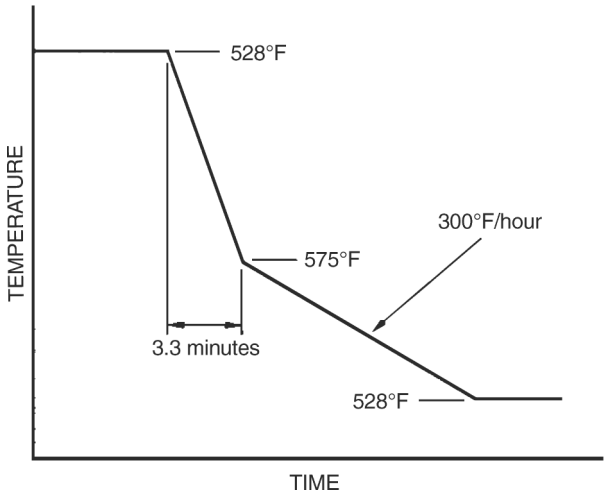


FIG. 19.19 TEMPERATURE-TIME VARIATIONS DURING AUTOMATIC BLOWDOWN TRANSIENT (LEVEL C CONDITION)

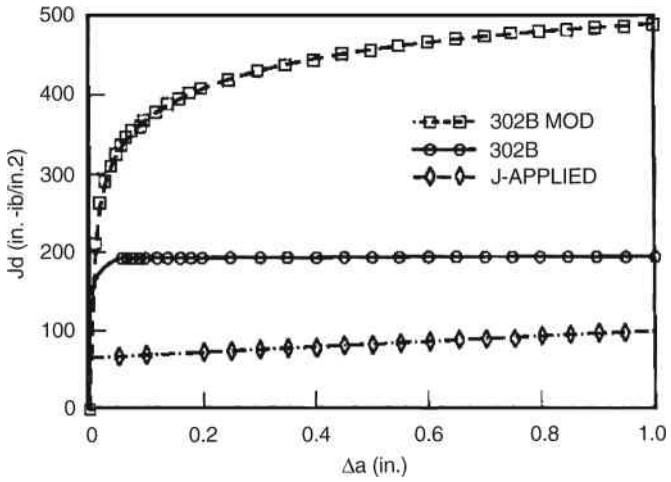


FIG. 19.20 $J_{0.1}$ ASSESSMENT FOR LEVEL C CONDITIONS

and D conditions were less limiting than Levels A and B conditions. The material property projections used 32 effective full-power years (EFPY), which is taken to be the equivalent to 40 years of operation. Table 19.3 also shows the NRC-predicted end-of-life USE values.

Specific BWR plants can compare their USE surveillance results to the predictions of Regulatory Guide 1.99 to verify that the comparisons of 32 EFPY USE with the equivalent margin analysis are bounding for their vessel beltline, using a worksheet [61]. Once the bounding nature of the BWR Owners Group analysis has been established, the plant can reference the analysis [61] to demonstrate compliance with the USE requirements of 10 CFR50 Appendix G for 32 EFPY of operation.

19.4 REACTOR PRESSURE BOUNDARY PIPING

The BWR reactor pressure boundary piping material is typically either carbon steel (SA-106, Grade B, SA-333, Grade 6, and SA-516 Grade 70) or stainless steel (Type 304 or 316, regular carbon, L grade, or LN grade). The safe end material could also be Ni-Cr-Fe material (SB-166). The experience with the BWR carbon steel piping has been excellent and there is no field degradation incidents attributed to it. On the other hand, the BWR stainless steel piping (made of Type 304/316) has experienced cracking during service [63–65]. As discussed later, the development of Appendix C of ASME BPVC Section XI in the early 1980s and several Code Cases were intended to provide guidance in the evaluation and repair of this type of stainless steel pipe cracking.

19.4.1 Cause of Cracking

Cracking in weld-sensitized Type 304 stainless steel piping has been mainly due to IGSCC. The IGSCC mechanism requires a combination of sensitized material condition, high-sustained stress, and susceptible environment. Weld sensitization results in carbide precipitation in the HAZ leaving a region of IGSCC susceptible material. Applied stress coupled with weld residual stresses provide conditions that could cause cracking. Finally, the

TABLE 19.3 BWR RPV EQUIVALENT MARGIN REVIEW SUMMARY [62]
Summary on results from equivalent margin analysis for eight types of beltline material

MATERIAL TYPE	CU %	FLUENCE $\times 10^{18}$ (n/cm^2)	INI. USE (ft-lb)	PREDICTED USE DROP %	PREDICTED EOL USE BWROG (ft-lb)	PREDICTED EOL USE NRC (FT-LB)	CODE CASE N-512 EOL USE (ft-lb)	NUREG/ CR-6023 EOL USE (FT-LB)
BWR/2 (L)*	.27	2.4	76	26	56	—	50 [45]**	55
BWR/2 (T)	.27	2.4	49	26	36.5	—	35 [25]	36
BWR/3-6 (L)***	.17	3.8	91	21	72	78	59 [59]	55
BWR/3-6 (T)	.17	3.8	59	21	47	51	35 [25]	36
SMAW	.35	2.4	87	34	57	56	35 [33]	33
ELECTROSLAG	.35	2.4	69	34	46	36	35 [33]	33
NON-LINDE 80	.35	2.4	71	34	47	46	35 [33]	33
LINDE 80	.31	1.0	—	—	—	—		33

* Containing SA302B plates only.
** Values inside brackets are estimated by the staff directly from Figures 5-2a, b, 5-3a, b, and 5-4 of the topical report, which represent the lowest limits that the USE values of beltline materials may reach. These values are only used to assess margins; they do not represent the minimum permissible USE values acceptable to the staff.
*** Containing SA302B Modified and 533B plates.

high-temperature oxygenated water provides the environmental conditions needed for IGSCC. The IGSCC is explained by the presence of the three necessary conditions for cracking.

19.4.2 Remedial/Mitigation/Repair Measures

In October 1979, in response to the increased number of incidents of IGSCC of austenitic stainless steel piping in BWRs and the appearance of cracking in large-diameter (24–28 in.) recirculation system piping, a group of BWR utilities organized an Owners Group to provide the R&D resources necessary to solve the pipe-cracking problem. EPRI was given the responsibility of integrating these resources into ongoing research and development efforts funded by EPRI, the BWR Owners, and GE so as to establish a single, unified industry program addressing pipe cracking in BWRs. Most overseas BWR Owners also participated in the resulting program, known as the BWR Owners Group IGSCC Research Program, which began in 1979 and was completed in 1988 [66–68].

The initial set of IGSCC remedies was referred to as near term. These remedies could be applied to susceptible Type 304 stainless steel components in the short term to field repairs and replacements and to plants under construction that were committed to the use of Type 304 stainless steel piping. The near-term remedies included solution heat treatment (SHT), corrosion-resistant cladding (CRC), and heat-sink welding (HSW). Following welding, SHT redissolves grain-boundary carbides and restores the grain-boundary chromium concentration. CRC consists of cladding the susceptible part of the pipe inside the surface adjacent to the girth weld with SCC-resistant duplex weld metal. HSW is designed to generate compressive residual stresses at the ID of the HAZ through the use of carefully controlled welding parameters in conjunction with water cooling of the inside of the pipe during welding.

To mitigate IGSCC in operating piping, induction heating stress improvement (IHSI) and last-pass heat sink welding (LPHSW) were also qualified in the early 1980s. IHSI modifies the as-welded residual stresses by inducing small amounts of plastic deformation in the HAZ. This is accomplished by generating a through-wall temperature gradient (by induction heating the outside of the pipe and water cooling the inside) that is sufficient to cause a small amount of yielding. The LPHSW is essentially similar to HSW except that it only involves remelting the weld crown while providing a heat sink and, therefore, can be applied to existing welds. Mechanical stress improvement (MSIP) has also been used to favorably modify the weld residual stresses in HAZ [69]. In MSIP, a similar result as IHSI is obtained by hydraulically squeezing the pipe adjacent to the HAZ to induce a small amount of plasticity.

IGSCC-resistant piping materials (Type 316 nuclear grade and Type 304 nuclear grade stainless steel) were also developed as the materials remedy for replacement piping. All stress- and sensitization-related remedies are limited to the specific component to which they are applied. In contrast, environment-related remedies have the potential of protecting the whole coolant system. Laboratory and field studies demonstrated that electrochemical corrosion potential (ECP) of stainless steel in the recirculation systems of operating BWRs can be reduced to low values by injecting hydrogen into the feedwater (hence the name hydrogen water chemistry) and that IGSCC is suppressed when the ECP is below −230 mV SHE.

Stress improvement remedies and hydrogen water chemistry were effective in retarding the further growth of shallow cracks; however, sometimes deep cracks were observed, particularly in the alloy 182 butter at the low-alloy steel nozzles. The dissimilar metal weldment joining the BWR nozzles to safe ends is one of the more complex configurations in the entire recirculation system. Field installation techniques typically specify that a special shop weld deposit (butter) be placed on the end of the nozzle prior to final shop PWHT to facilitate field welding without PWHT. Many BWR vessels used Inconel 182 manual shielded metal arc electrodes to weld deposit the butter. Later laboratory studies determined that alloy 182 was susceptible to IGSCC, especially under severe conditions such as crevices and/or cold work. Repair/replacement activities at two BWRs, where axially oriented IGSCC from the butter progressed into the low-alloy steel nozzle, have been described [70]. Many BWR plant owners proactively undertook repair/replacement/mitigation activities to address potential IGSCC of alloy 182 butters [71].

Weld overlay type of repair is also a very attractive remedy and has been used extensively in the field. It is applicable both at the pipe-to-pipe welds and at pipe-to-nozzle or safe-end welds.

19.4.3 Weld Overlay Repairs

Weld overlays were first applied in 1982 as a repair for IGSCC in stainless steel piping [72]. As shown in Fig. 19.21, the repair technique is based on the application of weld metal to the outside pipe surface over and to either side of the flawed location, extending circumferentially 360°. The weld overlay repair performs the following functions:

(a) It provides structural reinforcement of the flawed location, such that adequate load-carrying capability is provided, either in the overlay by itself or in some combination of the overlay and the original pipe wall thickness.
(b) It provides a barrier of IGSCC-resistant material to prevent IGSCC propagation into the overlay weld metal.
(c) It introduces a compressive residual stress distribution in at least the inner portion of the pipe wall, which will inhibit IGSCC initiation and propagation in the original pipe joint.
(d) It prevents local leakage from small axial flaws.

Although these repairs were accepted by the NRC, the early regulatory position was that such repairs were only interim measures. The utilities were allowed to operate for two fuel cycles with weld overlay repairs to enable them to develop and adequately plan for replacement activities. In NUREG-0313, Revision 2 [9], the NRC

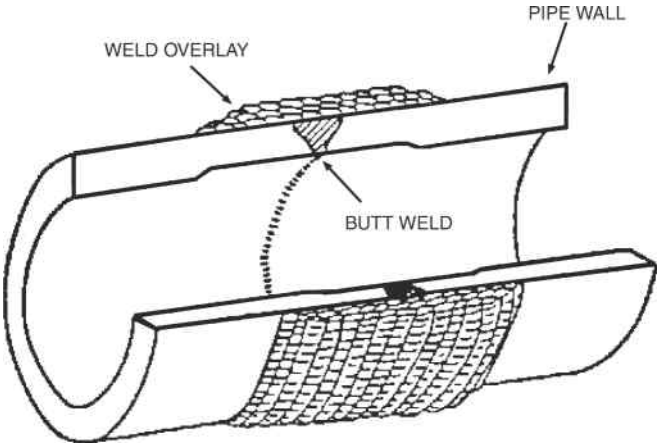


FIG. 19.21 WELD OVERLAY REPAIR

indicated that, "If it is desired to operate for more than two fuel cycles with overlay reinforcement repair, the overlayed weldments should be inspected to ensure that the overlays will continue to provide the necessary safety margin." The BWR Owners Group and EPRI in the meanwhile conducted several inspections, weld residual stress measurement, and fracture toughness studies on weld overlays [73–75] to justify their long-term operation. In 1992, the ASME BPVC Code published Code Case 504 [76] specifically addressing the weld-overlay-type repair of cracked austenitic stainless steel piping.

19.4.3.1 Code Case 504. The Code Case specifies various requirements for implementing weld overlay repairs, such as weld metal composition, surface preparation, design, pressure testing, and examination. Some of these requirements are discussed.

The requirement (e) specifies that the first layer of weld metal with delta ferrite content of at least 7.5 FN shall constitute the first layer of the weld reinforcement design thickness. Generally, ferrite readings are taken at the weld center and edge of the weld crown in the overlay layer at each of the quadrants. The values are averaged for comparison with the minimum required value. Lower values, but no less than 5 FN, may be acceptable based on evaluation.

The design considered in (f)(1) is what is called as the full structural or standard weld overlay. The flaw is assumed to be 100% through the original pipe wall thickness for the entire circumference of the pipe. The advantage of this design is that any uncertainty in the sizing of the original crack(s) is unimportant for this case. The thickness of the full structural weld overlay can be based on either the Tables given in ASME BPVC IWB-3640 or the source equations in Appendix C of ASME BPVC Section XI. The source equations in Appendix C [77,78] typically provide smaller thickness. The reason is that the membrane stress (P_m) used in the source equations is the calculated value and is typically smaller than the assumed P_m of 0.5 S_m in the tables. The source equations applicable to full structural weld overlay are the following:

$$\beta = \pi\,(1 - a/t - P_m/\sigma_f)/(2 - a/t) \tag{19.9}$$

$$P_{bc} = (2\sigma_f/\pi)(2 - a/t)\sin(\beta) \tag{19.10}$$

$$P_{bc} + P_m = \mathrm{SF}\,(P_m + P_b) \tag{19.11}$$

where

σ_f = material flow stress = $3S_m$
S_m = material design stress intensity
P_m = primary membrane stress
P_b = primary bending stress
P_{bc} = failure bending stress
a = crack depth (equal to pipe thickness)
t = total thickness (pipe wall + weld overlay thickness)
SF = safety factor
= 2.77 for normal/upset conditions
= 1.39 for emergency/faulted conditions

The weld overlays are typically applied using gas tungsten arc welding (GTAW), a nonflux welding process. Therefore, only the primary stresses are used in the above equations. The primary loading is typically the internal pressure, weight, and seismic inertia. The membrane and bending stresses are calculated on the basis of overall thickness including the weld overlay thickness. Therefore, an iterative solution of Eqs. (19.9) through (19.11) is necessary to calculate the required weld overlay thickness. The ASME BPVC IWB-3640 rules require the a/t value to be ≤ 0.75. In many cases, this criterion would require an increase in the calculated thickness. Although not explicitly stated in the rules of ASME BPVC IWB-3640, the weld overlay design thickness is also typically evaluated against the primary stress limits of the Code of Construction. For Class 1 components such as piping, ASME BPVC IWB-3610(d)(2) states that a component containing the flaw is acceptable for continued service during the evaluated time period if the primary stress limits of ASME BPVC NB-3000, assuming a local area reduction of the pressure-retaining membrane that is equal to the area of the detected flaw.

The Code Case also provides guidance for overlay thickness determination when fewer than five axial flaws and/or short circumferential flaws (less than 10% of circumference) are present at a weld. The specified overlay length is at least 0.75 (Rt) beyond each end of the observed flaws, where R and t are the outer radius and nominal wall thickness of the pipe prior to depositing the weld overlay. The circumferential cracks are generally assumed to be located axially at the end of the HAZ. If the cracked weld has on one side a larger thickness component such as a valve, the overlay can be terminated in the length direction where the valve section thickness is equal to the pipe thickness plus overlay thickness.

The results of experiments conducted to assess the adequacy of the thickness design equations for the weld overlay repairs (WORs) are documented [79]. The maximum stress from each of the four WOR pipe experiments conducted was significantly higher than that predicted by the ASME BPVC IWB-3640 analysis for a full structural overlay. The calculated safety factors were 30% higher than those used in the Code. The margins were slightly lower when actual flaw dimensions were used.

Application of weld overlays typically is performed with water backing on the inside of the weld to be repaired, which produces a through-wall gradient. The temperature difference, coupled with the normally occurring shrinkage of the overlay weld metal, has been shown to produce a highly favorable residual stress distribution in the pipe wall [80]. A favorable stress distribution is the one when combined with the applied stress distribution produces a nonpositive calculated value of stress intensity factor at a crack depth equal to the pipe thickness. This ensures nonpropagation of the IGSCC cracking during future operation. In some cases, the structural configuration may be such that water backing is not feasible; then, typically an application-specific finite element residual stress analysis is conducted to demonstrate that a favorable residual stress distribution is produced following the weld overlay.

Weld overlay application results in both radial and axial shrinkage at the repaired weld. Axial shrinkage magnitude is a function of the pipe diameter, weld overlay length, and the number of weld layers applied. Field measurements suggest that the bulk of the shrinkage occurs as a result of application of the first two layers. Generally, a finite element model of the piping system is required to calculate the shrinkage stresses at the various locations in the system. These shrinkage stresses are steady state secondary stresses of the cold-spring type and are not explicitly factored into the equations of ASME BPVC Section III, NB-3650; NB-3672.8 limits the cold springing stress to $2S_m$. However, the shrinkage stresses due to weld overlay are typically limited to a smaller value equal to the yield strength at temperature. In the evaluation of other flawed locations in the piping system, the calculated axial shrinkage stress shall be included as an expansion stress (P_e).

The axial shrinkage may result in changed air gaps of pipe whip restraints, the normal set points of variable spring hangers, and so on. Therefore, the Code Case requires the evaluation of system restraints, supports, and snubbers to determine whether design tolerances are exceeded. The non-mandatory Appendix O [81] of ASME Section XI also provides additional design, examination and inspection guidance for austenitic stainless steel weld overlay repairs.

19.4.3.2 Dissimilar Metal Weld Overlays. With the development of the weld overlay repair as an acceptable long-term repair measure to primary system austenitic stainless steel pressure boundary piping, industry attention had expanded to those pressure boundary joints that do not fall within this family of acceptable joints for weld overlay repair. In a BWR recirculation system, the inlet and outlet nozzle joints, where the low-alloy steel nozzle is welded to an austenitic safe-end material, represent a special weld overlay repair case not covered by Code Case 504. IGSCC had been observed in the Inconel 182 butter to the low-alloy steel nozzles. As a result, an Inconel 82 weld overlay repair technique was developed for application to a low-alloy steel nozzle to stainless steel or Inconel 600 safe end [82]. The alloy 82 weld overlay repair could also be used at a weld joint between an austenitic stainless steel pipe and alloy 600 safe end.

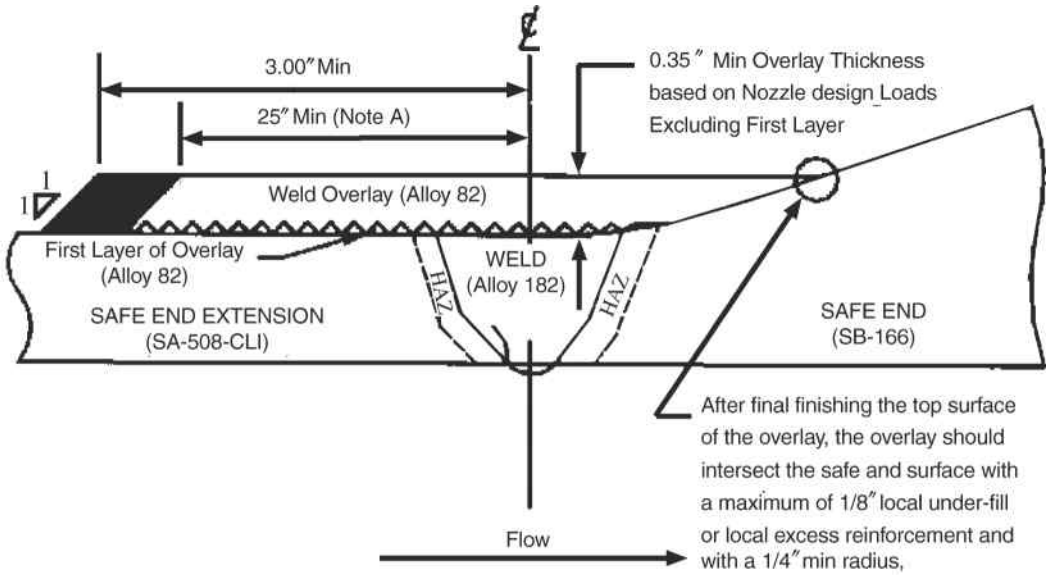
The repair approach consisted of a full structural weld overlay, using automatic GTAW technique deposited in accordance with a temper-bead-welding approach similar to that presented in Code Case N-432 [83]. The temper bead technique generally requires the application of elevated preheat, specific bead/layer formation, heat input controls, and a postweld heat treatment (PWHT). The preheat and PWHT requirements are specified primarily to preclude the introduction of hydrogen into the final weld. Hydrogen, the source of delayed cracking in the base material HAZ, is of primary concern when welding ferritic materials. Preheat is intended to eliminate moisture and contaminants that could be introduced into the molten metal during welding. PWHT allows the hydrogen potentially trapped in the HAZ and weld metal to diffuse out.

A later Code Case, N-638 [84], allowed an ambient temperature temper bead welding without the use of preheat or PWHT for implementation. This technique is applicable to both the similar (e.g., austenitic pipe to pipe) and dissimilar (e.g., safe end to nozzle) metal weld overlay repairs.

Figure 19.22 shows an example of the dissimilar metal weld overlay. Code Case 504 currently does not cover dissimilar weld overlays; therefore, this Code Case was used only as a guide in the design of this weld overlay. The provision regarding ferrite number does not apply to alloy 82 weld overlays. The weld overlay thickness was determined using the source equations in ASME BPVC Appendix C using S_m value for alloy 600 materials. Note that the length of the weld overlay in Fig. 19.22 is slightly larger (by the shaded length) to facilitate its inspection. Except for the flat surface requirement for UT inspection, the minimum thickness requirement is optional in the shaded area. At the safe end side, the weld overlay was terminated where the pipe plus overlay thickness exceeds the safe-end thickness. Alloy 82 weld metal has been used in some early dissimilar metal weld overlay repairs; nevertheless, more recently, Alloy 52 has been used in most applications.

The ASME Code has now developed the Code Case N-740 [85] to cover the application of dissimilar metal weld overlay repairs.

19.4.3.3 Impact of Revised ASME BPVC Section XI, Appendix C (2002 Addenda). Prior to the 2002 Addenda of ASME BPVC Section XI, the safety factors for the evaluation of



Notes:

A. 2.5″ min. width required for structural reinforcement; minimum overlay thickness is required for this section.

B. Minimum overlay thickness is optional outside the minimum width; however, a flat surface for UT inspection is required.

FIG. 19.22 CORE SPRAY SAFE END TO SAFE-END EXTENSION WELD OVERLAY

flawed austenitic piping, specified in Appendix C and referenced in ASME BPVC IWB-3640, were 2.77 for normal and upset conditions and 1.39 for emergency and faulted conditions [see Eq. (19.11)]. These safety factors were revised when a revised Appendix C was included in the 2002 Addenda [86]. Example calculations to assess the impact of the revised safety factors on existing evaluations of weld overlay repairs were performed [87,88]. The pipe material was Type 304 austenitic stainless steel, and the service temperature was assumed as 550°F. A summary of the calculations of the required weld overlay thickness values for three welds is given in Table 19.4. Required weld overlay thickness values from acceptance criteria on ($\sigma_m + \sigma_b$) in the 2001 Edition of Section XI were governed by Service Level B (upset condition). Required weld overlay thickness values from acceptance criterion on ($\sigma_m + \sigma_b$) in the 2002 Addenda to Section XI were governed either by Service Level B or C (emergency) condition, while required weld overlay thickness values from the separate acceptance criterion on 6_m in the 2002 Addenda were governed by Service Level B. The required weld overlay thickness values from the governing criterion for each weld are highlighted in bold italic in Table 19.4, and these are governed by the ASME BPVC Section III, NB-3200, primary stress intensity limits. Based on these results, it was concluded that there is no significant impact of the revised safety factors in the 2002 Addenda to Section XI on the required thickness of the weld overlay repairs.

The revised safety factors in Section XI, Appendix C, of the 2002 Addenda are also applicable Ni-Cr-Fe materials (Alloy 600 base metal and Alloy 82 or 52 welding materials).

19.5 CRACK INITIATION, GROWTH RELATIONSHIPS, AND PLANT MONITORING

Protection against fatigue crack initiation through an explicit calculation of cumulative fatigue usage factor, is one of the design criteria for ASME Code Sections III and VIII (Division 2) pressure-retaining components. Protection against SCC type of crack initiation is not currently covered in the Code. However, several mitigation measures have been used by the BWR plant owners as indicated by the discussion in earlier paragraphs (e.g., para. 4.2 for BWR NSSS piping). When a component is inspected and found to have cracking, the appropriate crack growth rate relationship is an essential element in the flaw evaluation to justify continued operation. The cyclic loading aspects are covered in Chapter 39. Some of the unique aspects of fatigue evaluations for BWRs and the SCC growth rate relationships are discussed. A comprehensive review of the fatigue and SCC crack growth rate relationships in BWR water environment in provided in Reference 89.

19.5.1 Fatigue Initiation

The scope and intent of the ASME BPVC Section III fatigue design procedure was articulated in a presentation by Dr. William Cooper to the PVRC Workshop on the Environmental Effects on Fatigue Performance in January 1992 [90]. Some of the points of this presentation are summarized.

(a) The Design-by-Analysis procedure included several related considerations; however, the purpose for adding fatigue as one of the failure modes was to ensure that the reduction of the nominal safety factor from four to three did not result in a decrease in reliability if the vessel was expected to be subjected to cyclic operating conditions. The fatigue design procedures were intended to provide confidence that the component could be placed in service safely, not necessarily to provide a valid measure of actual component service life.

(b) The cyclic loading conditions defined in the Owner's Design Specification were not intended to represent a commitment on how the vessel was to be operated, only that the design transient definitions should provide useful information. For example, if an Owner were able to show the Design Specification included a cyclic event more severe than an event actually experienced, this would verify that the vessel was not subjected to an unevaluated condition.

19.5.1.1 Actual Versus Design Cyclic Duty. As pointed out in the preceding, the number and severity of cyclic events may differ from those specified in the design specification. Figure 19.23 shows a comparison of the actual number of transient events compared to the design basis for a typical BWR plant [91]. It is seen that the actual number of transients (such as startup and shutdown or SCRAM events) experienced at some operating reactors may be higher than that expected in the design basis. However, the severity

TABLE 19.4 COMPARISON OF REQUIRED THICKNESS OF WELD OVERLAY REPAIR

WELD	PIPE D, in. (mm)	PIPE NOMINAL t, in. (mm)	PIPE NOMINAL σ_m FOR ASME LEVELS B AND C, ksi (MPa)	PIPE NOMINAL σ_m ksi (Mpa)		REQUIRED WELD OVERLAY THICKNESS (in. (mm)) BASED ON:					
				ASME LEVEL B	ASME LEVEL C	2001 EDITION SECT. XI CRITERIA	2002 ADDENDA SECT. XI CRITERIA FOR $\sigma_m + \sigma_b$	2002 ADDENDA SECT. XI CRITERIA FOR σ_m	SECT. XI $0.75t$ CRITERION	SECT. III LIMIT ON P_m	SECT. III LIMIT ON $P_m + P_b$
DSRHR-3-II	20.0 (508)	1.25 (32)	5.5 (38)	5.2 (36)	10.2 (70)	0.43 (11)	0.48 (12)	0.40 (10)	0.42 (11)	0.41 (10)	***0.52 (13)***
24A-R-13	20.0 (508)	1.15 (29)	7.75 (53)	5.39 (37)	9.75 (67)	0.49 (12)	0.52 (13)	0.52 (13)	0.38 (10)	0.53 (14)	***0.59 (15)***
12BR-A-4	12.75 (324)	0.75 (19)	6.67 (46)	3.13 (22)	4.83 (33)	0.25 (6)	0.25 (6)	0.29 (7)	0.25 (6)	***0.30 (8)***	***0.29 (7)***

Notes:
(1) Required weld overlay thickness from the governing criterion is in bold italics.

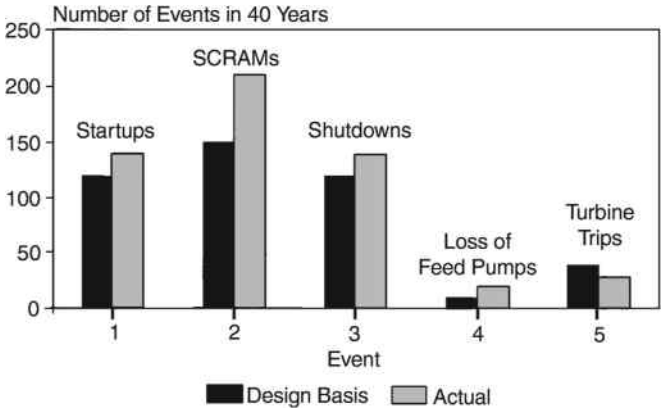


FIG. 19.23 DESIGN VERSUS ACTUAL NUMBER OF TRANSIENT EVENTS FOR A TYPICAL BWR PLANT

of the actual transient events (i.e., temperature and pressure fluctuations) is typically significantly lower than that assumed in the design basis. Figure 19.24 shows a comparison of the assumed design basis event and the actual transient based on measured temperatures; the number of actual transients may be higher but they are often less severe than the design basis, and the overall fatigue usage may be lower. In this respect, online, continuous monitoring of system transients and keeping track of the resulting fatigue usage in critical plant components offer important benefits in meeting plant licensing basis. The technical basis and the results of online fatigue usage monitoring at some BWR plants has been described [92,93]. In most cases, the calculated fatigue usage by the fatigue monitor was an order of magnitude lower than that calculated by design basis transient.

ASME BPVC Section XI, IWB-3740 and Nonmandatory Appendix L permit the fatigue usage factor reevaluation for a component in service. If the recalculated fatigue usage is greater than 1.0, flaw tolerance evaluation procedures can be used to demonstrate acceptance of a component for service.

19.5.1.2 Environmental Fatigue Effects. The current Section III fatigue design curves were based primarily on strain-controlled fatigue tests of small polished specimen at room temperature in air. Higuchi and Iida [94] demonstrated that the fatigue life of carbon

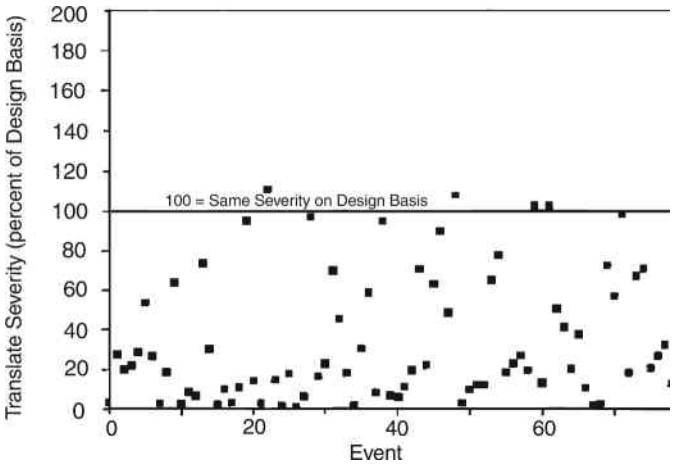


FIG. 19.24 SEVERITY OF TRANSIENT ACTUAL TEMPERATURE CHANGE VERSUS PERCENTAGE OF DESIGN BASIS

steel laboratory specimen could be considerably shorter than that predicted by the Code S-N curves when exposed to high-temperature reactor water. Since then extensive laboratory testing has been conducted both in Japan [95,96] and the United States, principally at Argonne National Laboratory [97,98]. One of the earliest proposed methodologies to incorporate environmental effects in the Code fatigue analyses was the so-called EPRI/GE methodology [99]. This methodology was adopted by the PVRC with some modifications [100] and was forwarded to the BNCS for potential implementation into the ASME Code [101]. The NRC also wrote a letter to the BNCS requesting ASME action to address issues related to the effects of the reactor water environment on the reduction of fatigue life of light-water reactor (LWR) components [102]. In Japan, the Thermal and Nuclear Power Engineering Society (TENPES) Committee for Environmental Fatigue Evaluation Guidelines also has issued a document [103] providing procedures for the evaluation of environmental fatigue effects. Section III has formed a special Task Group to address the issue; the Task Group plans to consider input [100,103] to develop a recommended procedure in the form of a Code Case.

Examples of application of EPRI/GE methodology at critical locations in the RPV and main piping in a BWR have been provided [104,105], as identified elsewhere [106]. The results of environmental fatigue evaluations for one BWR and two PWRs for 60-year operation have been reported [107], and they showed the CUF to be less than 1.0.

Based on the probabilistic analyses and associated sensitivity studies, the NRC concluded that no generic regulatory action was required for the 40-year operating life. However, for the 60-year operation (i.e., an additional 20-year license renewal operation), the Generic Aging Lessons Learned (GALL) Report [108] provides the regulatory guidance to address issues related to metal fatigue of reactor coolant pressure boundary components for license renewal. "The aging management program (AMP) addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components, as a minimum, those components selected in NUREG/CR-6260. The sample of critical components can be evaluated by applying environmental correction factors to the existing ASME Code fatigue analyses. Formulas for calculating the environmental life correction factors are contained in NUREG/CR-6583 for carbon and low-alloy steels and in NUREG/CR-5704 for austenitic stainless steels." The GALL report also lists ten desirable characteristics of an AMP on metal fatigue.

The NRC issued Draft Regulatory Guide DG-1144 [109], later issued as Regulatory Guide 1.207 in March 2007, which includes guidelines for evaluating fatigue analyses incorporating the life reduction of metal components due to the effects of the light water reactor environment for new reactors. The technical basis for the guidelines is contained in NUREG/CR-6909 [110]. The results of the application of DG-1144 guidelines to a BWR feedwater piping system are reported in Reference 111.

The ASME Code has released several Code Cases related to environmental fatigue initiation. Code Cases N-761 [112] and N-792 [113] are such examples. The strain rate is a key input into the determination of environmental correction factor, F_{en}, for a load state pair. A draft Code Case on how to calculate the strain rate for a load state pair is currently under active discussion in the Working Group on Environmental Fatigue Evaluation Methods of Section III. NUREG/CR-6909 and Regulatory Guide 1.207 are currently undergoing revisions by the NRC and the revised versions are expected to be released in 2014 following the public comment period.

19.5.2 Crack Growth Rate Relationships for Fatigue

Fatigue crack growth rates for air environment for austenitic stainless steels is included in ASME BPVC Section XI, Appendix C, and for ferritic materials in Appendix A. Crack growth relationships in the BWR water environment are discussed.

19.5.2.1 Austenitic Stainless Steels. Some of the early fatigue crack growth data in the BWR environment are documented [114,115]. In 1986, a Section XI task group reviewed the available data for both PWR and BWR environment [78]. It recommended that the fatigue crack growth rate for BWR environment be higher than the air rate by a factor of 10. Argonne researchers have proposed the following relationship of the form [116]:

$$da/dN_{env} = (da/dN)_{air} + A(da/dN)_{air}^{0.5} \qquad (19.12)$$

where $(da/dN)_{air}$ is that given by the equations in ASME BPVC Section XI, Appendix C. Recently, Argonne researchers have proposed that the first term on the right-hand side of Eq. (19.12) be multiplied by a factor of two [117]. Japanese researchers also have proposed the following relationship [118]:

$$da/dN_{env} = (8.17 \times 10^{-12})(T_r{}^{0.5})(\Delta K)^{3.0}/(1-R)^{2.12} \qquad (19.13)$$
$$= (R > 0,\ 1 \le \Delta K \le 50\ \text{MPa}\sqrt{m})$$

where, da/dN is in m/cycle, T_r is the rise time in seconds, and ΔK is in MPa $\sqrt{m}$. T_r should be assumed to be 1 sec when rise time is less than 1 sec; T_r should be assumed to be 1,000 seconds if rise time is unknown. This relationship has been incorporated in the draft Japan Maintenance Standard [119].

An EPRI-funded effort [120] is currently underway to review the available literature to develop austenitic stainless steel fatigue crack growth relationships in a water environment for inclusion in ASME BPVC Section XI, Appendix C. It may be noted that the fatigue crack growth is typically insignificant compared to SCC growth rate in the evaluation of cracked stainless steel components subjected to a BWR water environment.

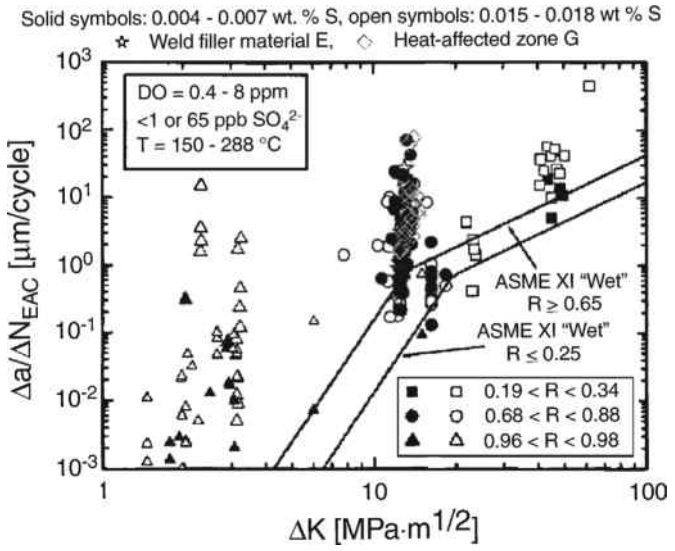


FIG. 19.25 EFFECT OF LOADING CONDITIONS ON $\Delta a/\Delta N_{EAC}$ AND COMPARISON WITH ASME SECTION XI CURVES

19.5.2.2 Ferritic Steels. ASME BPVC Section XI, Appendix A, contains the environmental fatigue crack growth rates. These relationships are presently used in BWR applications such as the fracture mechanics evaluation of postulated nozzle corner crack. Based on more recent data on the LWR environment, a new rise-time-based model has been proposed [121]. Based on this work and the work by James [122] on conditions that lead to the initiation and cessation of environmentally assisted crack growth, Code Case N-643 [123] has been developed for PWR applications.

Some recent data [124] indicate that, under certain conditions (such as very high R-ratio and long rise time), environmentally assisted fatigue crack growth under a BWR environment could be significantly higher than that predicted by the current ASME BPVC Section XI, Appendix A curves (see Fig. 19.25). A review of available relevant BWR data is in progress under a joint EPRI/GE-sponsored program; the outcome of this program is expected to be a proposed Code Case, similar to Code Case N-643, applicable to BWR environments.

19.5.3 Crack Growth Rate Relationships for SCC

Key drivers in the crack growth rate due to SCC are the sustained stresses that include not only the externally applied stresses but also residual stresses from sources such as welding. Therefore, the crack growth rate relationships are of the following form:

$$da/dt = C(K)^n \qquad (19.14)$$

where C and n are constants dependent on material and environmental conditions. ASME BPVC Section XI does not provide any guidance in this area. Efforts are currently underway in the Working Group on Flaw Evaluation to review the available information and develop SCC growth rate relationship for incorporation

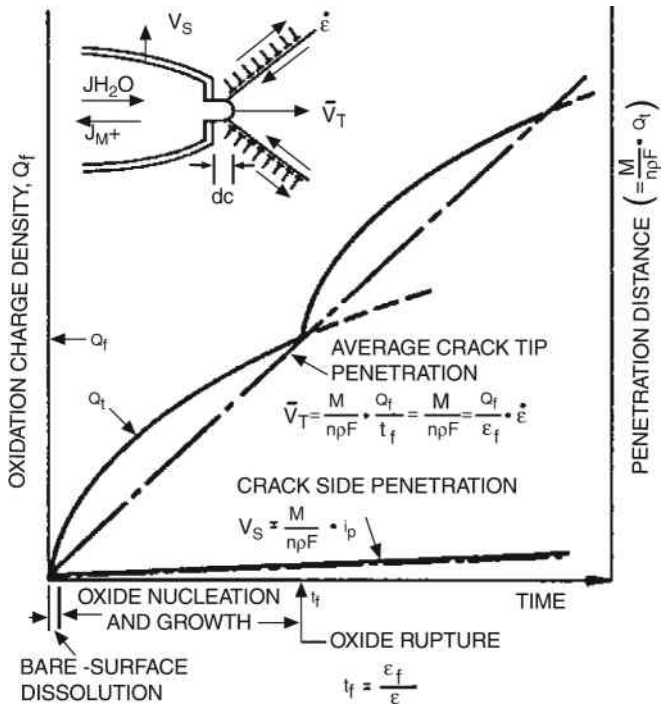


FIG. 19.26 SCHEMATIC OXIDATION CHARGE DENSITY/TIME RELATIONSHIP FOR A STRAINED CRACK TIP AND UNSTRAINED CRACK SIDES

into ASME BPVC Section XI. The BWR Owners have generally used the NRC-approved bounding crack growth rates for flaw evaluation purposes (e.g., see discussion in para. 19.2.2.1 regarding shroud). For piping, NUREG-0313, Revision 2 [9] provides crack growth rate relationship in the Eq. (19.14) format. Some of the other available BWR SCC growth rate correlations are reviewed.

19.5.3.1 Austenitic and Nickel-Based Materials. A crack growth rate prediction model based on slip dissolution/film rupture mechanism [125] has correlated well with the measured crack growth rates in widely varying BWR environmental conditions (e.g., NWC and HWC). In this model (Fig. 19.26), crack advance is related to the oxidation reactions that occur at the crack tip as the protective film is ruptured by increasing strain in the underlying matrix. This rupture event occurs with a periodicity, t_f, which is determined by the fracture strain of the oxide and the strain rate at the crack tip. The extent of the crack advance is related by Faraday's Law to the oxidation charge density associated with dissolution and oxide growth (passivation) on the bare metal surface, as represented in Fig. 19.26. These relations vary with time in a complex manner for different environment and material chemistries; however, the resultant growth rate, V_T, relationship shown in Fig. 19.26 can be restated in a general form as follows:

$$V_T = f(n)(\varepsilon_{ct})^n \tag{19.15}$$

where ε_{ct}', the crack tip strain rate, embodies the mechanical contributions and n is a parameter that represents the effects of the environment (ECP, water conductivity) and material chemistries (EPR, a measure of sensitization of stainless steel) on environmentally assisted crack growth. For NWC conditions (conductivity = 0.1 μS/cm, ECP = 200 mV), and EPR = 15.0 (weld-sensitized condition), n = 0.61 and the crack growth rate relationship is the following:

$$da/dt = 2.93 \times 10^{-07} K^{2.455} \tag{19.16}$$

For HWC conditions (conductivity = 0.1 μS/cm, ECP = −230 mV), and EPR = 15.0 (weld-sensitized condition), n = 0.97 and the crack growth rate relationship is the following:

$$da/dt = 2.53 \times 10^{-11} K^{3.884} \tag{19.17}$$

where

da/dt = crack growth rate in mm/hr
K = sustained stress intensity factor, MPa $\sqrt{m}$

The BWRVIP has also developed an SCC growth rate relationship for use by the participating members [126] and represented by the following:

$$Ln(da/dt) = C_1[ln(K)] - C_2(Cond)^m + C_3(ECP) + C_4/T_{ABS} - C_5 \tag{19.18}$$

where

da/dt = crack growth rate
K = sustained stress intensity factor
$Cond$ = water conductivity
T_{ABS} = temperature, °K
C_1, C_2, C_3, C_4, C_5, and m are constants

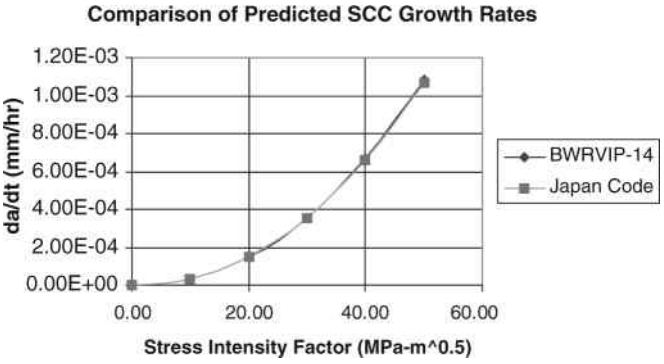


FIG. 19.27 COMPARISON OF BWRVIP-14 AND JAPAN MAINTENANCE CODE PREDICTIONS

For BWR NWC conditions, the appropriate values are as follows $Cond$ = 0.1 μS/cm, ECP = 200 mV (SHE), and T_{ABS} = temperature, °K, = 561°K (= 550°F). Using a specified factor of 10.3 to obtain 95th percentile curve, the relationship is the following:

$$da/dt = 2.135 \times 10^{-07} K^{2.181} \tag{19.19}$$

The units of da/dt and K are the same as those in Eq. (19.17). The draft Japan Maintenance Standard [119] provides the following crack growth rate relationship for BWR NWC conditions [units the same as in Eq. (19.19)]:

$$da/dt = 2.27 \times 10^{-07} K^{2.161} \tag{19.20}$$

Figure 19.27, [127] shows a comparison of the predictions of Eqs. (19.19) and (19.20). It is seen that the crack growth predictions based on the BWRVIP and draft Japan Maintenance Standard are very close. However, the factors of reduction in crack growth rate in going from NWC to HWC are different. The BWRVIP correlation predicts a reduction factor of 4.7 and the draft Maintenance Standard allows a factor of 7.9. The NRC has, however, allowed only a credit of factor of 2 in BWR flaw evaluations [128].

For the nickel-based alloys (such as alloy 600, weld metals alloys 182 and 82), several relationships have been proposed. The relationships based on the film/rupture model have been given [129], including the BWRVIP-59 relationships [127]. Lastly, the crack growth relationships proposed by the Argonne researchers have also been described [117].

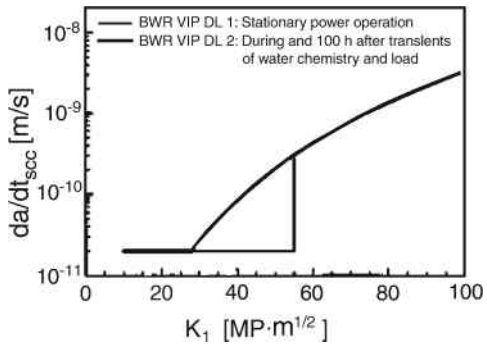


FIG. 19.28 BWRVIP-60 SCC DISPOSITION LINES

19.5.3.2 Ferritic Steels. ASME BPVC Section XI does not contain SCC growth rate relationship for the ferritic materials in BWR environment. Reference 130 provides an assessment of SCC crack growth rate algorithms for low alloy steels under BWR conditions. Figure 19.28 shows the BWRVIP-proposed relationship [124]. The basic crack growth rate is 2×10^{-11} mm/sec. The DL2 line is given by the following:

$$da/dt = 3.29 \times 10^{-14} (K)^4 \qquad (19.21)$$

where K is in MPa$\sqrt{\text{m}}$ and the crack growth rate is in mm/sec. The vertical line in Fig. 19.28 is at 55 MPa$\sqrt{\text{m}}$.

Field experience [131,52] has shown that even when SCC initiated in the cladding, the cracks did not progress into the low-alloy steel base metal or beyond HAZ. However, the proposed BWRVIP relationship was used in flaw evaluation [52].

The data that formed the basis of the BWRVIP SCC relationship and the fatigue crack growth rate data, such as that shown in Fig. 19.25, will be reviewed as a part of a joint EPRI/GE project discussed in para. 19.5.2.2.

19.5.4 Crack Growth Rate Monitoring

Online monitoring of crack growth rates on a fracture mechanics specimen under actual reactor environment may provide extra confidence in the crack growth rate used in the flaw evaluation. One such monitoring system is called crack arrest/advance verification system (CAVS); an example of the successful application of CAVS for monitoring crack indications in the recirculation inlet safe end at an operating BWR has been presented [132]. Use of CAVS confirmed the benefit of water chemistry improvements implemented at this plant and, subsequently, led to the elimination of a special midcycle UT examination required by the NRC.

During a routine scheduled ISI, UT indications were discovered in certain recirculation inlet safe ends at an operating BWR plant. The indications were located in the region of the thermal sleeve to safe-end weld. Since immediate replacement of the safe end would have caused an unanticipated extended outage and very high costs, a fracture mechanics crack growth analysis was performed to demonstrate that continued operation for the next fuel cycle could be justified while maintaining acceptable structural margins required by ASME BPVC Section XI. The analysis considered the indication in the limiting safe end and assumed conservative residual stresses for crack growth analysis. Also, the plant owner agreed to complete the maintenance of plant chemical equipment and to implement improved water quality procedure, along with the installation of CAVS, to monitor the expected improvements in crack growth during the following operating cycle. Although the NRC accepted the technical arguments concerning structural integrity, they also requested a midcycle UT to provide further assurance that sufficient structural margins were being maintained.

The CAVS installed at the plant consisted of a crack growth monitor and a water quality module. The crack growth monitor used reversing DC potential technology for accurate measurement of the growth of pre-existing cracks in fracture mechanics specimens. The water chemistry module monitored the bulk water chemistry (dissolved oxygen, pH, conductivity, and ECP) of the water being supplied to CAVS; 1 in. thick compact tension specimens with heat treatment similar to that of the safe end were tested in an autoclave connected to the reactor recirculation line. Because CAVS used the actual plant recirculation water, the crack growth specimens were subjected to the same water chemistry exposure as recirculation safe ends and piping.

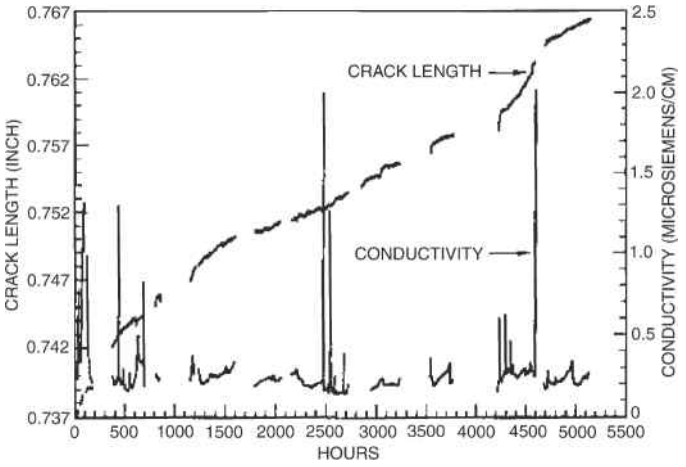


FIG. 19.29 CRACK LENGTH VERSUS TOTAL TIME-ON-TEST FOR TYPE 304 STAINLESS STEEL

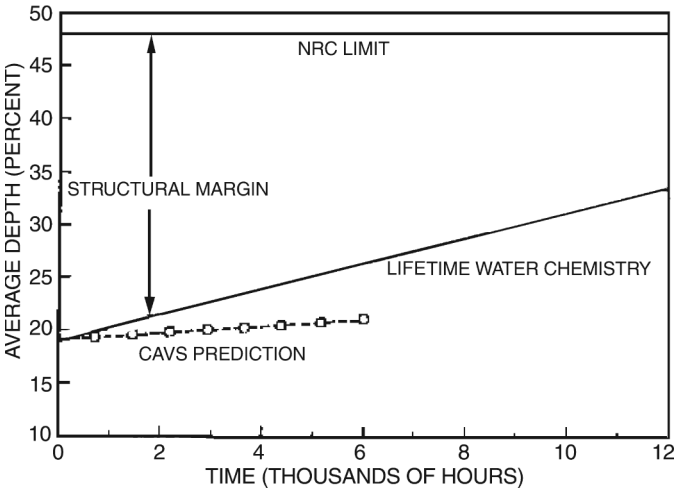


FIG. 19.30 PREDICTED CRACK GROWTH IN SAFE END

Figure 19.29 shows typical results from CAVS for a 304 stainless steel specimen. It is seen that the monitoring system is extremely sensitive and that the observed crack growth rates correlate with conductivity [i.e., the crack growth rate is higher when the conductivity is high over a period of time (such as during startup) and is lower when the average conductivity is lower]. Using the CAVS specimen data, plant-specific growth rates were established and used to predict crack growth in the safe end (Fig. 19.30). It is seen that the CAVS growth prediction was well below the bounding crack growth evaluation based on plant water chemistry history. In turn, the final crack depth at the end of the fuel cycle was well below the allowable depth based on providing the nominal ASME Code margin of 3 on stress and an additional factor of 1.5 on crack depth imposed by the NRC. These results confirmed that sufficient structural margins were maintained and that a special midcycle examination was unnecessary. The NRC concurred, and the midcycle inspection requirement was eliminated.

19.6 SUMMARY

A review of the applications of many and sometimes unique ways in which the provisions of ASME BPVC Sections III and XI have been used in addressing the service-induced degradation in the BWR vessels, internals, and pressure boundary piping. The vessel internals addressed included steam dryer, shroud, and jet pumps. The vessel components considered were feedwater nozzle, stub tube welds, and attachment and shroud support welds. A review of pressure boundary piping flaw evaluation methods also included consideration of weld overlay repairs. The service-related degradation mechanisms considered were environmental fatigue crack initiation and growth and stress corrosion cracking.

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CHAPTER

20

PWR Reactor Vessel Integrity and Internals Aging Management

Hardayal Mehta, William L. Server and Timothy J. Griesbach[1]

20.1 INTRODUCTION

The integrity of the reactor pressure vessel is critical to plant safety. A failure of the vessel is beyond the design basis. Therefore, the design requirements for vessels have significant margins to prevent brittle or ductile failure under all anticipated operating conditions. The early vessels in the United States were designed to meet the requirements of ASME BPVC Section VIII. The design requirements for these vessels were supplemented by special requirements based on earlier U.S. Navy design experiences. In general, the allowable stress limits were lower than vessels designed to later ASME BPVC Section III requirements. The early design codes did not include the rigorous fracture toughness requirements found in today's codes. Section VIII relied on a "fracture-safe" design approach, which sought to ensure that pressure vessels were operated in a temperature regime (upper-shelf region) where small flaws or cracks would not affect the load-carrying capacity of the structure.

As Section III of the ASME Code was developed, many of the early special requirements were incorporated and used to update the earlier requirements of Section VIII. Section III included requirements for more detailed design stress analyses than did Section VIII. Thus, the explicit design safety factor could be reduced without reducing the actual margin against vessel failure. Section III also included a fracture mechanics approach to establish operating pressure-temperature heat up and cooldown curves and to ensure adequate margins of safety against brittle or ductile failure incorporating the nil-ductility reference temperature index, RT_{NDT}, that was correlated to the material reference toughness.

Radiation embrittlement is a known degradation mechanism in ferritic steels, and the beltline region of reactor pressure vessels is particularly susceptible to irradiation damage. To predict the level of embrittlement in a reactor pressure vessel, trend curve prediction methods are used for projecting the shift in RT_{NDT} as a function of material chemistry and fluence at the vessel wall. Because the ASME Code does not include trend curves for prediction of embrittlement, the NRC issued Regulatory Guide 1.99. Revision 2 of this Regulatory Guide is being used by all plants for predicting RT_{NDT} shift in determining heatup and cooldown limits and hydrostatic test limits.

In 1988, the ASME Code approved the Section XI Nonmandatory Appendix G, Fracture Toughness Criteria for Protection Against Failure [1]. This appendix replaced the Section III, Appendix G [2] for heatup and cooldown limits in operating plants when it became mandatory according to 10 CFR Part 50, Appendix G, Fracture Toughness Requirements [3]. Since the inclusion of Appendix G in ASME BPVC Section XI, the appendix has been updated several times to use more up-to-date technology for determining stress intensity factors, safety margins, and material reference fracture toughness. While incorporating these technical changes, the philosophy of protecting the vessel against brittle fracture has remained the same.

As plants age, the effect of radiation damage on vessel materials has caused a narrowing of operating heatup and cooldown limits for PWRs and an increase of the hydrostatic test temperatures for BWRs, which may cause hardships for plant operation. The requirements for low-temperature overpressure protection (LTOP) systems for PWRs also reduce the operating window for plants. Improvements in the Code methods for determining the heatup and cooldown limit curves have provided some relief from the narrowing window of operation. However, the possible future changes to embrittlement trend curves based on new embrittlement data may negate the benefits obtained from the improvements in Section XI, Appendix G.

For example, the NRC is planning to issue draft Revision 3 of Regulatory Guide 1.99 in 2009. Preliminary versions of the revised embrittlement trend curve model show higher predicted RT_{NDT} shifts than Regulatory Guide 1.99, Rev. 2 for the limiting materials in many BWR vessels. The corresponding increase in Adjusted Reference Temperature (ART) causes a change in the P-T limit curves for heatup/cooldown and hydrotest conditions. In some cases, plants may have to perform the system hydrotest at temperatures exceeding 212°F (i.e., boiling at atmospheric pressure) in order to maintain the ASME Code safety margins for prevention of vessel brittle fracture. This issue will need to be revisited by the ASME Code Section XI Working Group on Operating Plant Criteria.

Another aspect of ensuring reactor vessel integrity is characterizing the actual toughness of the reactor vessel materials. Because sampling of the vessel is not a realistic option, using surveillance sample coupons to measure a toughness may be the best available source for irradiated vessel material data. However, small

[1] The original chapter was authored by Timothy J. Griesbach in the second and third editions of the publication "Companion Guide to the ASME Boiler & Pressure Vessel Code". For the current publication this chapter is revised for the current edition by Hardayal Mehta and William L. Server. – Editor

specimens do not provide a representative constraint for large specimens or structures, so the data must be characterized according to a Master Toughness curve. The alternative Master Curve approach, recently approved by ASTM and the ASME BPVC, provides a measured T_o value that relates the measured fracture toughness data directly to the Master Curve reference toughness. The ASTM test method was specifically developed to provide a reliable measure of fracture toughness transition temperature, T_o, that is independent of specimen size. This will have direct benefits for determining plant heatup and cooldown limits.

Related discussions of pressure vessel integrity margins in the French and Japanese Codes are given in Chapters 49 and 50, respectively of "Companion Guide to the ASME Boiler & Pressure Vessel Code: Criteria and Commentary on Select Aspects of the Boiler & Pressure Vessel and Piping Codes, Third Edition, Volume 3", Editor K. R. Rao, ASME Press, NY 2009.

The last part of this chapter covers the examination, evaluation aspects of the observed cracking at the vessel nozzle penetrations and nozzle dissimilar metal welds.

20.2 CODES AND REGULATIONS FOR THE PREVENTION OF BRITTLE FRACTURE

20.2.1 10 CFR 50, Appendix G

The rules and regulations governing the licensing of nuclear facilities are contained in Title 10, Part 50 of the U.S. Code of Federal Regulations. In particular, Appendix G, Fracture Toughness Requirements for Nuclear Power Reactors [3], and Appendix H, Reactor Vessel Surveillance Program Requirements [4], define applicable rules and reference the Codes and Standards that determine the methods of compliance and margins to be maintained for prevention of vessel fracture. The requirements of Appendices G and H became effective on August 16, 1973, when the fracture mechanics concepts for prevention of brittle fracture were fully adopted.

The basis for these regulations first came from the recommendations of the PVRC Task Group on Toughness Requirements that was formed in 1971. The charter of the PVRC Task Group was as follows:

To recommend, on the basis of current knowledge, criteria for ferritic material toughness requirements for pressure-retaining components of the reactor pressure boundary, which will permit the establishment of safe procedures for operating nuclear reactor components below 700°F.

20.2.2 Section III, Appendix G and WRC 175

The Task Group completed a draft report and delivered it to the PVRC, ASME, and AEC on August 13, 1971. The delivery to the AEC was, in part, a response to their proposal for new toughness requirements, which had been published in July 1971 in the *Federal Register*. The ASME Code approved, with some modifications, the new requirements proposed by the PVRC Task Group in January 1972, which were then issued, first as Code Case 1514, and subsequently as revisions to ASME BPVC Section III, NB-2330 and a new Appendix G in the Summer 1972 Addenda of the Code. The PVRC Task Group draft report was modified to be consistent with the ASME Code modifications and the final draft was published as WRC 175 [5] in August 1972.

The key to this new approach was the establishment of the fracture mechanics term of crack tip "stress intensity factor" (K_I), which can be compared to the measured material toughness ($K_{critical}$) as a function of reference temperature, RT_{NDT}, to determine crack stability. The initial RT_{NDT} values for all reactor vessel beltline materials had to be measured or estimated from test data. Critical values of K are determined from precracked specimen tests loaded to failure, and the Charpy test specimens were standardized as the method of establishing an initial RT_{NDT} and changes in RT_{NDT} due to irradiation. While not a true measure of toughness, the Charpy test specimen results for energy to break the specimen are correlated to a dynamic or static reference toughness curve. In particular, the temperature to achieve either 30 ft-lb or 50 ft-lb of energy are the results determined from a series of Charpy test specimens that are then correlated to the vessel material reference toughness. When adequate Code margins were included, this approach permitted the safe design and operation of pressure vessels for all anticipated normal and abnormal events.

This was the first time that a fracture mechanics – based approach was used in the ASME Code, and it represented a significant change in the design procedure for nuclear pressure vessels, which is still being used today. It also provided a method for establishing acceptable plant operating criteria for the prevention of brittle fracture of the vessel. The Section III, Appendix G approach established margins against failure in three areas:

(a) A reference toughness curve was adopted from a conservative lower bound of available fracture toughness data, designated as K_{IR}, which is a function of temperature, for reactor vessel steels.
(b) A very large (quarter-thickness) postulated reference flaw was to be used in the analysis.
(c) A safety factor of 2 was applied to the calculated stress intensity factor for pressure loading.

Each of these assumptions and procedures of the traditional Appendix G method are discussed here in more detail.

20.2.2.1 K_{IR} Index and Temperature Indexing. The basis for the K_{IR} curve was the available unirradiated dynamic and crack arrest fracture toughness data from three heats of SA-533-B1 and SA-508-2 steels. The K_{IR} curve was established as an empirical lower bound to the data that were normalized on a (T-RT_{NDT}) scale. RT_{NDT} is intended to be a heat-normalizing parameter, and the procedure for obtaining the initial RT_{NDT} is contained in ASME BPVC, Section III, NB-2300 [6]. With the establishment of the K_{IR} curve for the lower-bound material toughness, the RT_{NDT} for all vessel materials was required to be measured in vessels that were designed or fabricated to Code requirements after 1972. The same requirements were not in place for those vessels prior to 1972, so the initial RT_{NDT} for those vessels had to be inferred from limited data or bounded conservatively from generic data sets. The RT_{NDT} reference temperature index, adjusted to include the effects of radiation damage, has become the single most important parameter in determining the allowable (P-T) limits for plant operation and for evaluation of reactor vessel integrity form severe events such as pressurized thermal shock (PTS) transients.

20.2.2.2 Postulated Flaw Size and Location. For locations away from discontinuities (e.g., the vessel beltline region), the maximum postulated reference flaw is a semi-elliptical surface crack oriented in the axial direction. This postulated flaw has a depth of one-fourth of the section thickness and a length of 1.5 times the thickness. For sections less than 4-in. thick, a 1-in. deep flaw is postulated. Smaller flaw sizes may be used on an individual case basis if a smaller size of maximum postulated flaw can be

ensured. However, no plants to date have been able to take credit for smaller than a $\frac{1}{4}$-t flaw.

The relatively large quarter-thickness reference flaw size was selected because a database did not exist at that time to assess NDE reliability, and it was thought that the chosen reference flaw was the largest flaw that could be missed by the inspection methods in use at that time. Another determining factor was the on-site preservice hydrotest failure of a fossil vessel. In this instance, failure resulted from a 3.5-in. deep by 13-in. long flaw that was produced after weld repair. Although no NDE was performed on this vessel after the repair, the failure was used as evidence that large flaws could exist in vessels. Finally, the reference flaw was considered to be an end-of-life flaw size that supposedly would include any (unspecified) environment-induced subcritical crack growth.

20.2.2.3 Factor of Safety. For normal and upset events (Levels A and B), Appendix G to Section III of the Code adopted safety factors within the range included in WRC 175, a safety factor of 2.0 on the stress intensity factor due to pressure (K_{IM}) and a factor of 1.0 on the thermal stress intensity factor (K_{IT}). A safety factor of 2.0 for pressure is consistent with the Code margins for other allowable loadings. The PVRC Task Group recommended the lower factor of 1.0 on K_{IT} in WRC 175 "due to its secondary and self-relieving nature."

ASME BPVC Section III, Appendix III became mandatory by reference in Appendix G of 10 CFR Part 50; the BPVC appendix defines the pressure-temperature requirements for vessel heatup and cooldown when the core is critical. Supplemental requirements were added to 10 CFR Part 50 for the flange region and for critical and noncritical core operation. For example, when the core is not critical and when pressure exceeds 20% of the presservice hydrostatic test pressure, the temperature of the closure flange regions that are highly stressed by the bolt preload must exceed the reference temperature of the material in those regions by at least 120°F for normal operation and by 90°F for hydrostatic pressure tests and leak tests. When the core is critical (other than for the purpose of low-level physics tests), the temperature of the reactor vessel must not be lower than 40°F above the mini-mum permissible temperature established for noncritical operation, nor lower than the minimum permissible temperature for the inservice system hydrostatic pressure test.

An exception was made for boiling-water reactor (BWR) vessels when the water level is within the normal range for power operation and the pressure is less than 20% of the service system hydrostatic test pressure. In this case, the minimum permissible temperature is 60°F above the adjusted reference temperature of the reactor vessel material in the region that is controlling. If there is fuel in the reactor during hydrostatic pressure test or leak test, the preceding requirements apply, depending on whether the core is critical during the test.

In July 1973, the NRC established specific material surveillance requirements by adding Appendix H, Reactor Vessel Material Surveillance Program Requirements, to 10 CFR Part 50. Appendix H requires a material surveillance program to monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region. Appendix H applies to all light-water reactors (LWRs) and the fracture toughness degradation is directly related to the exposure of the beltline materials to neutron irradiation and thermal environments. Charpy impact specimens are exposed to the neutron flux in surveillance capsules and withdrawn periodically from the reactor vessel. The impact specimens are tested and the Charpy shift data used in accordance with trend curve prediction methods and 10 CFR Part 50, Appendix G. For reactor vessels that can conclusively show the peak neutron fluence (E $>$ 1 Mev) at the end of the vessel design life is below 1×10^{17} n/cm^2, Appendix H specifies that no material surveillance program is required. For vessels projected to be above this fluence, surveillance programs must be in place in accordance with Appendix H.

20.2.3 ASME BPVC Section XI, Appendix G

In the mid-1980s it became obvious that the original Section III, Appendix G method needed to be revised. ASME BPVC Section XI, Appendix G was first introduced into the Code in 1987 as a duplication of ASME BPVC Section III, Appendix G with the addition of toughness shift due to irradiation embrittlement for plant operating pressure-temperature limit curves. The adoption of Appendix G into Section XI provided a vehicle to review the Appendix and update it to current technology. The ASME Section XI Working Group on Operating Plant Criteria has responsibility for this section of the Code; there is no equivalent group in Section III that meets to review the Section III, Appendix G. While Section XI, Appendix G is considered to be a nonmandatory appendix, it became mandatory by reference in 10 CFR50, Appendix G, officially replacing ASME BPVC Section III, Appendix G for operating plants.

The Section XI, Appendix G method is used as the basis for calculating pressure-temperature operating limits and temperature limits for cold hydrostatic testing and leak testing. However, in the implementation of the Appendix G method, there are numerous additional technical and administrative requirements that, in essence, add to the margins for protection against brittle fracture of the vessel. One such requirement for pressurized water reactors (PWRs) is to have a LTOP system. These LTOP system requirements came about as part of the resolution of a generic safety issue (USI-A26) in the 1970s. The recommendations were documented in NUREG-0224, *Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors*, and the results were a revision to NRC's Standard Review Plan Section 5.2.2 [7] and the establishment of Branch Technical Position RSB 5-2 [8].

Following these regulatory actions, PWRs have implemented procedures and modified equipment to protect the Appendix G heatup and cooldown limit curves. This was accomplished by installing or enabling relief valves with fixed or variable setpoints that would function during low-temperature operation to mitigate the severity of inadvertent pressure excursions. The fact that these valves are set below the limits of the calculated Appendix G curve means that additional margin was added for protection against brittle fracture in the implementation of the LTOP systems. The implementation of the LTOP systems causes restrictions in the operating window for heatup and cooldown. The LTOP setpoint limits may come close to the minimum required pressure to achieve pump seal or the net positive suction head (NPSH) limit for prevention of pump cavitation. These restrictions become even more severe for plants with a significant amount of vessel embrittlement.

20.2.3.1 Revisions to ASME BPVC Section XI, Appendix G. The stress intensity factors of Appendix G are based on an assumed semi-elliptical surface flaw oriented in the axial direction, i.e., normal to the direction of maximum principal stress. The original methods used for computing K_I for pressure and thermal loading are described in Welding Research Council Bulletin 175 [6]. The methods included classical stress function methods, boundary collocation methods, and the (then emerging) finite element method. For the K_I due to pressure, the particular expression

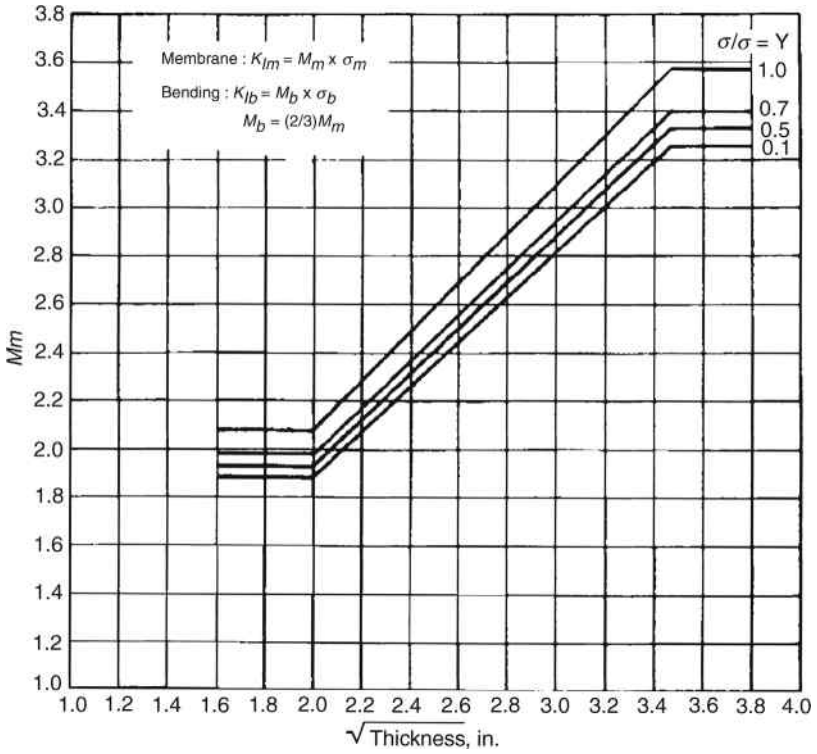


FIG. 20.1 M_m FACTOR FOR MEMBRANE STRESS INTENSITY FACTOR FROM ASME SECTION XI, APPENDIX G

chosen was based on the collective work of many experts at that time, and the general expression is given as follows:

$$K_{Im} = M_m \sigma_m \tag{20.1}$$

where σ_m is the membrane pressure stress and the M_m factor was based was based on a semi-elliptical surface crack solution in a plate under uniform tension. The M_m factor combined flaw shape correction factors and included corrections for plastic zone size for the $\frac{1}{4}$-thickness reference flaw. A plot of the M_m factor as a function of wall thickness and stress ratio is given in Fig. 20.1.

For the K_I due to thermal loading, a simplified stress function was used that related the thermal stress intensity factor to the thermal gradient as follows:

$$K_{It} = M_t \Delta T_w \tag{20.2}$$

where ΔT_w is the temperature difference through the wall due to heatup or cooldown. The M_t factor was based on a plate solution for an infinitely long flaw assuming a typical (parabolic) temperature distribution across the vessel wall. A plot of the M_t factor vs. wall thickness is given in Fig. 20.2. This method was judged to be conservative for the full range of heatup or cooldown rates in the range of 0 to 100°F/hr.

The postulated reference flaw adopted in WRC 175, and later in Appendix G of ASME BPVC Section III, has a semi-elliptical surface geometry with a $\frac{1}{4}$ thickness depth and a surface length equal to six times the depth. The basis for this reference flaw is discussed in the EPRI *White Paper on Reactor Vessel Integrity Requirements for Levels A and B Conditions* [9].

Prior to 1993, the general approach for flaw evaluation (given in ASME BPVC Section XI, Appendix A) was a simplified method for calculating stress intensity factor whereby stresses at the flaw location are resolved into membrane and bending stresses using a linearization technique. The equivalent linear representation of stress distribution is shown in Fig. 20.3. This figure demonstrates the differences between the actual stress distribution and the equivalent linear stress distribution through the vessel wall. This same approximation applies to the simplified method of stress intensity factors used in ASME BPVC Section XI, Appendix G.

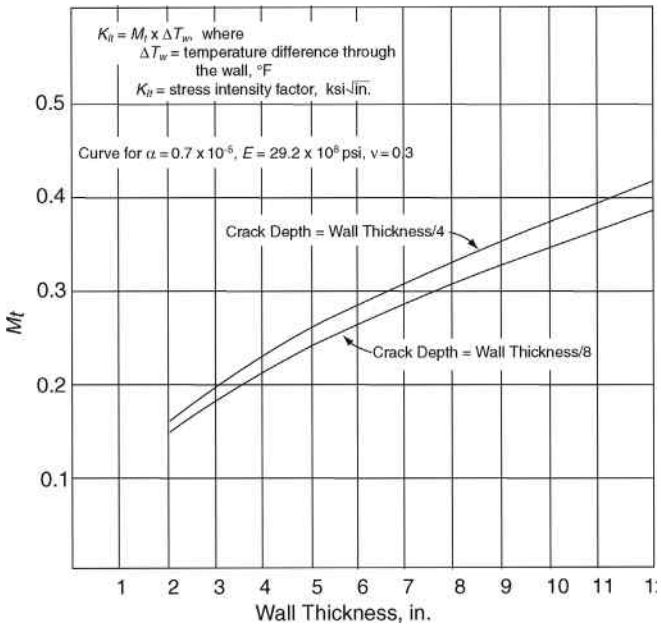


FIG. 20.2 M_t FACTOR vs. THICKNESS FOR BENDING STRESS INTENSITY FACTOR FROM ASME SECTION XI, APPENDIX G

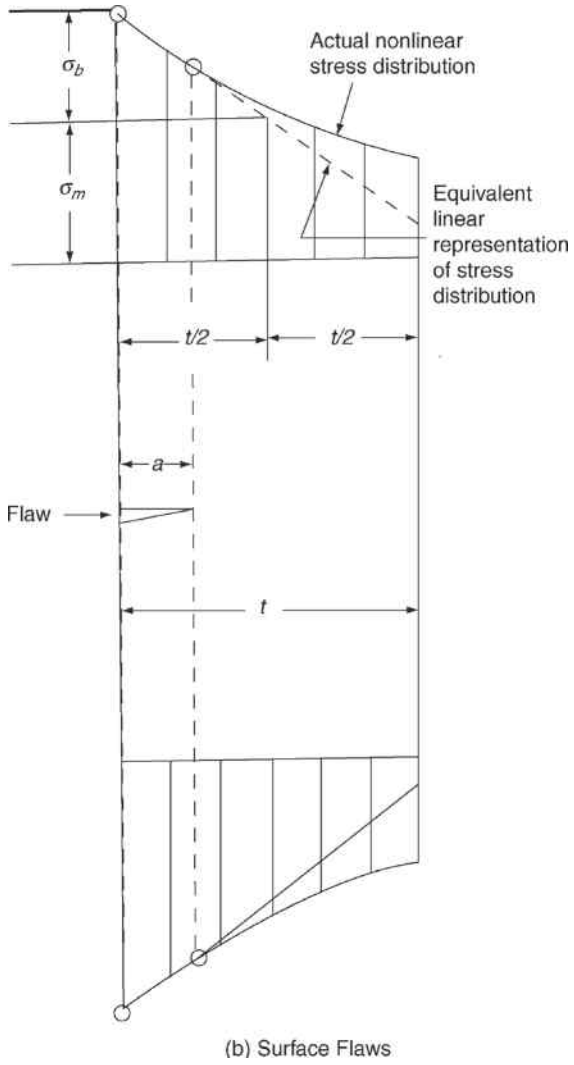


FIG. 20.3 LINEARIZED REPRESENTATION OF STRESSES FOR SURFACE FLAWS

20.2.3.2 Revised Stress Intensity Factors. In 1993, the ASME Section XI Working Group on Flaw Evaluation approved changes to the Appendix A flaw evaluation method including revisions for determination of the applied stress intensity factor, K_I, in Article A-3000 [10]. This Article provides a method for calculating K_I using a representative third-order polynomial stress distribution at the flaw location of the following form:

$$\sigma = C_o + C_1(x/a) + C_2(x/a)^2 + C_3(x/a)^3 \qquad (20.3)$$

where,

x = distance through the wall from the flawed surface
a = maximum flaw depth
C_o, C_1, C_2, C_3 = curve-fitted constants.

The stress intensity factor, K_I, is calculated using an equation of the following form:

$$K_I = [C_0G_0 + C_1G_1a + C_2G_2a^2 + C_3G_3a^3]\sqrt{\pi a/Q} \qquad (20.4)$$

where G_0, G_1, G_2, and G_3 are stress intensity factor influence coefficients and Q is a flaw shape parameter.

This methodology of stress intensity factor influence coefficients was proposed by Raju and Newman for internal and external surface cracks in cylindrical vessels [6], and three-dimensional finite element analyses were used to determine the specific G coefficients as a function of crack depth for semi-elliptical cracks. Ultimately, the Appendix A coefficients were determined from several sources, and the tabulated coefficients in Table A-3320-1 were chosen for applicability to surface flaws of various depths, flaw aspect ratios, and crack tip positions [11].

This same approach was applied for the $\frac{1}{4}$-thickness reference flaw of Appendix G (with a 6:1 aspect ratio), which is a special case of the general solutions provided in Appendix A. The revision to Appendix G in 1996 incorporated the most recent elastic solutions for K_I due to pressure and radial thermal gradients during heatup and cooldown of reactor vessels. The new solutions were based on finite element analyses for inside surface flaws performed by ORNL [11] and other research published by EPRI for outside surface flaws [12]. These solutions provided results that were essentially the same as those obtained by Raju and Newman [13].

These solutions are determined to be a more accurate method for implementation in Appendix G that provides consistent computational methods for both pressure and thermal stress intensity factors. In addition, the revisions to Appendix G provide a method to calculate the thermal stress intensity factor, K_{IT}, for any thermal gradient through the vessel wall and at any time during the transient. Consistent with the original version of Appendix G, no contribution for crack face pressure is included in the K_I due to membrane tension (i.e., pressure) loading terms. Also, the revised solutions do not include plastic zone size correction, because plastic zone size is negligible during normal heatup and cooldown conditions.

20.2.3.3 Pressure Stress Intensity Factors. The variation in hoop stress due to internal pressure in a hollow cylinder can be expressed as follows:

$$\sigma_{\theta\,\theta}(r) = \frac{R_i^2 p}{R_o^2 - R_i^2}\left(1 + \frac{R_o^2}{r^2}\right) \qquad (20.5)$$

where

p = internal pressure
r = radial distance through the vessel wall
R_i = vessel inner radius
R_o = vessel outer radius

While the through-wall stress varies, the revised pressure stress intensity factor determination in ASME BPVC Section XI, Appendix G was simplified by using a stress formula (pR_i/t) and a constant (M_m) such that the membrane stress intensity factor, K_{Im}, is given by the following:

$$K_{Im} = M_m \times (pR_i/t), \qquad (20.6)$$

where M_m for a postulated inside surface axial reference flaw is given by the following:

$M_m = 1.85$ for $\sqrt{t} < 2$
$M_m = 0.926\sqrt{t}$ for $2 \le \sqrt{t} \le 3.464$
$M_m = 3.21$ for $\sqrt{t} > 3.464$.

Similarly, M_m for a postulated outside surface axial reference flaw is given by the following:

$$M_m = 1.77 \text{ for } \sqrt{t} < 2$$
$$M_m = 0.893\sqrt{t} \text{ for } 2 \le \sqrt{t} \le 3.464$$
$$M_m = 3.09 \text{ for } \sqrt{t} > 3.464$$

where

p = internal pressure (psi)
R_i = vessel inner radius (in.)
t = vessel wall thickness (in.)

These M_m factors were calculated for the $\frac{1}{4}$-thickness, semi-elliptical (6:1 aspect ratio) surface flaws in cylindrical vessels, and are determined to be exact solutions for a vessel mean radius-to-thickness ratio of 10.

20.2.3.4 Thermal Stress Intensity Factors. A general solution for stress thermal stress intensity factor was provided in the revision to ASME BPVC Section XI, Appendix G for any thermal stress distribution at any specified time during heatup or cooldown for assumed $\frac{1}{4}$-thickness surface flaws [7]. The new Appendix G method used the same polynomial form of the radial thermal gradient at the reference flaw location as given by Eq. (20.3). Then, the K_{It} value can be determined for an axial inside surface flaw during cooldown from the equation following:

$$K_{It} = [1.0359C_0 + 0.6322C_1 + 0.4753C_2 + 0.3855C_3]\sqrt{\pi a} \quad (20.7)$$

Similarly, the K_{It} value can be determined for an axial outside surface flaw during heatup from the following equation:

$$K_{It} = [1.043C_0 + 0.630C_1 + 0.481C_2 + 0.401C_3]\sqrt{\pi a} \quad (20.8)$$

where C_0, C_1, C_2, and C_3 are the curve-fitted constants determined from the thermal stress distribution at a particular time in the heatup or cooldown transient.

Note that these equations differ slightly from the form of Eq. (20.5); the term ($\sqrt{Q}$) representing the flaw shape parameter is included in the influence factor terms since Q is a constant based on the $\frac{1}{4}$ thickness reference flaw. The flaw shape factor for an elliptical crack is approximated by the following equation:

$$Q = 1 + 1.464\,(a/c)^{1.65} \quad (20.9)$$

where a is the depth and c is the half-crack length. For the reference flaw geometry ($a/2c = 1/6$), the shape factor is the following:

$$Q = 1 + 1.464\,(1/3)^{1.65} = 1.239 \quad (20.10)$$

The 3-D influence coefficients for the inside surface flaw were generated from finite element stress analyses conducted at Oak Ridge National Laboratory (ORNL). Detailed finite element analyses were performed for a range of crack depths and aspect ratios, and the results were used to determine the exact coefficients used in Eq. (20.7) [12]. The ORNL analyses were compared to the Raju and Newman solutions and other published results that showed good agreement in all cases. The 3-D influence coefficients for the outside surface flaw were determined from closed-form solutions by Zahoor given in the EPRI *Ductile Fracture Handbook* [13].

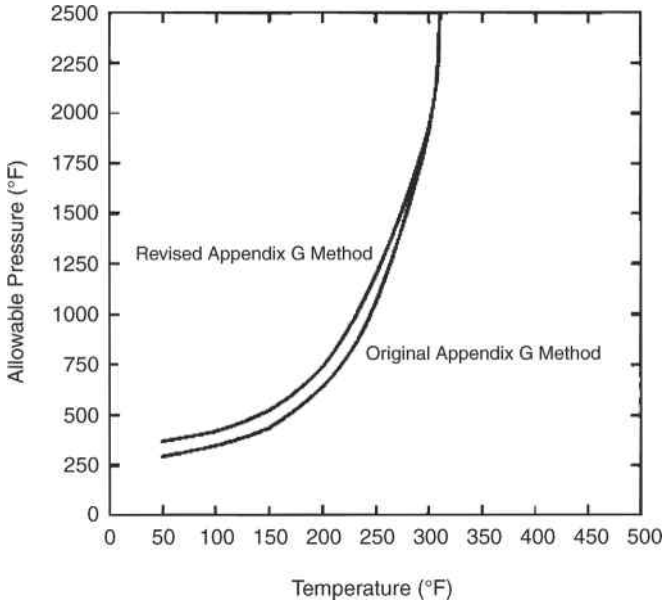


FIG. 20.4 EXAMPLES OF 50°F/hr. COOLDOWN CURVES USING THE ORIGINAL AND REVISED APPENDIX G STRESS INTENSITY FACTOR METHODS

These new solutions are elastic solutions that do not include a plastic zone size correction. The new stress intensity factor solutions better characterize the conditions for irradiated vessels in the low-temperature region where the thermal stresses and allowable pressure are low. For these conditions, the plastic zone size is negligible, and the elastic solutions are the technically correct solutions. This new method will provide some relief in the allowable operating pressure curve, as shown in Fig. 20.4 for a sample 50°F/hr cooldown limit curve. The benefit is approximately a 70 psi increase in allowable pressure at the low-temperature portion of the curve. Although the relief may be relatively small in terms of absolute pressure, the benefits to plant operators are substantial because even a small increase in allowable pressure can be a significant increase in the operating window at the low temperatures.

20.2.3.5 Circumferential Reference Flaw. The traditional Appendix G reference flaw is assumed to be axially oriented. This came about from the words in Article G-2120 as follows:

"The postulated defect used in this recommended procedure is a sharp, surface defect normal to the direction of maximum stress. For section thicknesses of 4 in. to 12 in., it has a depth of one-fourth of the section thickness and a length of $1\frac{1}{2}$ times the section thickness."

The basis for this reference flaw is documented in WRC 175. The axial orientation was assumed because it is normal to the maximum (membrane) stress in the vessel. The flaw is assumed to be in the vessel beltline weld or plate material with the highest RT_{NDT}. Even if there are no longitudinal welds in the vessel, it has traditionally been the interpretation of WRC 175 and Appendix G that a longitudinal flaw must be assumed. While this is clearly conservative, it is unrealistic for vessels with only circumferentially oriented welds.

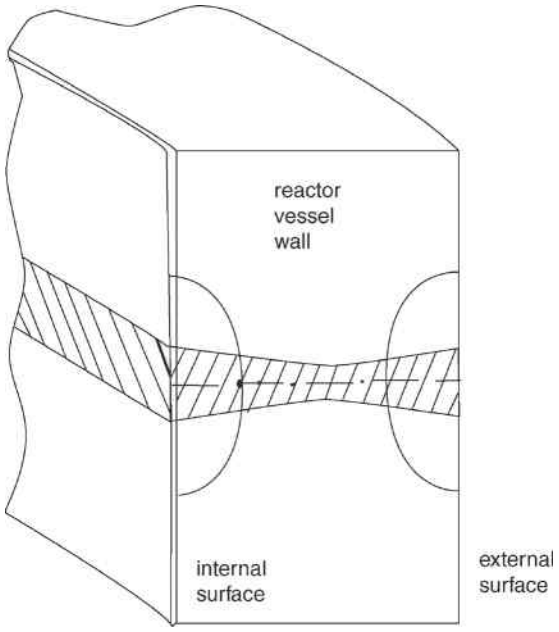


FIG. 20.5 ASSUMED AXIAL FLAWS IN CIRCUMFERENTIAL WELDS

Historically, vessels made from ring forgings have had to assume long axial flaws at the vessel I.D. and O.D. extending outside the weld region as well as the toughness properties of the weld occuring at the deepest point of the crack front as shown in Fig. 20.5. Although physically unrealistic, this assumption was generally agreed to be conservative because

(a) the flaw is projected to occur well outside the girth weld region.
(b) the weld thickness is small compared to the total reference flaw length.
(c) no credit is given for the toughness of the adjacent heat-affected zone or base metal.
(d) worst-case girth weld properties are used with the assumed axial flaw orientation.
(e) there is no evidence of transverse-oriented defects occurring in welds.

In 1996, the Section XI Working Group on Operating Plant Criteria approved a Code Case [15] and a Code Change to Appendix G to permit the assumed orientation of circumferential reference flaws for vessels with circumferential welds. As shown in Fig. 20.6, these assumed circumferentially oriented reference flaws would remain within the plane of the girth weld.

This is a more physically realistic assumption for a reference flaw for vessels fabricated from ring forgings, and it results in improved pressure-temperature operating limits. The applied stress intensity factor for pressure loading on a circumferential flaw is half as large as that for an axial flaw because the vessel membrane stresses normal to the circumferential reference flaw are half as large. This results is an increase in the allowable pressure vs. temperature for heatup and cooldown.

The allowable pressure is determined from the following equation:

$$2K_{Im} + K_{It} < K_{IR} \tag{20.11}$$

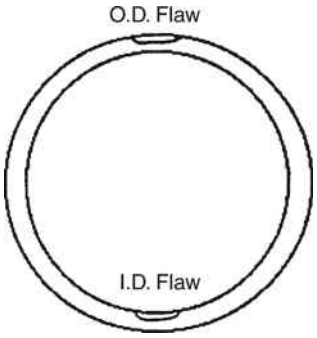


FIG. 20.6 CIRCUMFERENTIAL FLAWS IN GIRTH WELDS

where

K_{Im} = the applied pressure stress intensity factor
K_{It} = the applied thermal stress intensity factor
K_{IR} = the material reference toughness of the limiting vessel beltline material

The corresponding changes for calculation of applied pressure and thermal stress intensities have been incorporated into ASME BPVC Section XI, Appendix G and are now standard practice for determining allowable pressure-temperature limits. When using the circumferential reference flaw for girth welds, the other regions of the vessel must still assume an axial reference flaw and similar pressure-temperature limits calculated for these regions. The final set of operating heatup and cooldown limit curves is then a composite of the lowest allowable pressure as a function of temperature for all conditions.

20.2.4 LTOP Setpoints

Reactors must operate within the specified pressure-temperature limits to maintain adequate safety margins against brittle fracture. However, LTOP transients sometimes cause reactors to operate beyond those limits. In the implementation of the requirements for prevention against brittle fracture reactor vessels, one such requirement for PWRs is to have LTOP. This came about in the 1970s when the NRC conducted a review of 30 reported overpressure transients that exceeded the Appendix G pressure-temperature (P-T) limits. Because of the frequency and severity of LTOP occurrences, the LTOP issue became an Unresolved Safety Issue in 1978. This was resolved in 1979 by the NRC recommending that all PWRs must implement procedures and install LTOP systems to mitigate such events.

Prior to 1992, the ASME Code did not provide guidelines for the margins and setpoints for the LTOP systems. The regulatory guidelines at that time required plants with LTOP systems to have LTOP P-T limits that precluded exceeding the P-T limits for normal heatup and cooldown at temperatures less than RT_{NDT} + 90°F, where RT_{NDT} is the adjusted reference temperature, including margin, at the vessel $\frac{1}{4}$-thickness location. This was accomplished by plants installing or enabling pressure relief valves to limit the pressure at low-temperature operation. The fact that the pressure settings for the LTOP valves were set below the limits of the Appendix G curve meant that the margin against brittle fracture of the vessel had been added by the LTOP systems.

These requirements for LTOP protection create further restrictions in plant operability, as shown in Fig. 20.7.

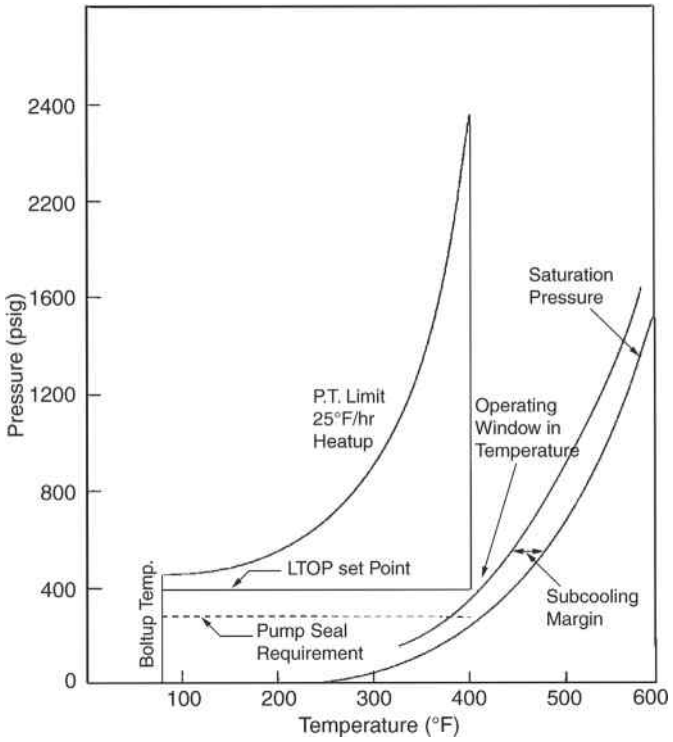


FIG. 20.7 FIXED LTOP SETPOINT AFFECTS OPERATING WINDOW

The LTOP setpoint limits may come close to the minimum required pressure to achieve pump seal or the NPSH for prevention of pump cavitation. Part of the restriction in implementation of these systems has to do with additional administrative margins that are added to account for pressure overshoot during an LTOP event and to account for instrument error uncertainty. The net effect of these administrative margins is to make the plant operating window narrower. These restrictions become even more severe for plants with a significant amount of vessel embrittlement.

In 1992, the Section XI Working Group on Operating Plant Criteria approved a Code Case and a Code change to incorporate the method for determining LTOP setpoints into ASME BPVC Section XI, Appendix G. There are two setpoints involved: the enable temperature below which LTOP systems must be active and the LTOP pressure setpoint limiting the maximum pressure during a low temperature overpressurization event. The change addressed both of these setpoints by incorporating the following words into Appendix G:

"LTOP systems shall be effective at coolant temperatures less than 200°F or at coolant temperatures corresponding to a reactor metal temperature less than RT_{NDT} + 50°F, whichever is greater. LTOP systems shall limit the maximum pressure in the vessel to 110% of the pressure determined to satisfy Appendix G of Section XI, Article G-2215."

The criteria for the pressure setpoint of 110% of the Appendix G curve pressure at the lowest temperature applies only if the curve is based on the K_{IR} reference toughness, as given in eq. (20.11). Subsequent changes to Appendix G allowed the use of the K_{IC} reference toughness curve instead of K_{IR}. When the K_{IC} curve is used in place of K_{IR}, the resulting heatup and cooldown plant limit curves provide a larger window of operation; however, the corresponding LTOP pressure setpoint criterion is only 100% of the pressure to satisfy the Appendix G limits.

An alternative method for determining the LTOP enable temperature setpoint was approved in Code Case N-641. This Code Case allows an enable temperature of RT_{NDT} + 40°F for assumed axial surface flaws in axial welds and plates, and RT_{NDT} −85°F for assumed flaws in circumferential welds. Use of this Code Case increases the plant operating window when determining the LTOP enable temperature setpoints.

20.3 REFERENCE TOUGHNESS CURVES

20.3.1 Initial RT_{NDT} and Shift Due to Irradiation

The toughness levels of reactor vessel plates, ring forgings, and welds must be established to perform a vessel integrity analysis or to establish pressure-temperature operating limits. The fracture toughness of ferritic steels is very temperature dependent, as noted by distinct changes in fracture behavior from brittle to ductile, with characteristic changes in fracture toughness from low to high values as temperature increases. This transition behavior is most apparent when the specimen contains a sharp notch or a crack. The Charpy V-notch (ASTM E 370-88a) and the drop weight tests (ASTM E 208-87a) are the most commonly used specimens for this purpose. The temperature at which the material changes from ductile to brittle behavior, as measured in the drop weight test, is often referred to as the nil-ductility transition temperature, or NDTT. The initial RT_{NDT} for vessel materials must be established in accordance with ASME BPVC Section III, NB2331 requirements. The reference nil-ductility transition temperature, RT_{NDT}, is the higher of either the NDTT or the temperature, obtained from Charpy tests, at which the material exhibits at least 50 ft-lb of impact energy and 35 mils lateral expansion, minus 60°F.

Reactor vessel surveillance programs, using actual vessel steel samples loaded in surveillance capsules and placed in or near the core region, monitor neutron embrittlement of reactor vessel materials. Embrittlement is measured by an upward shift in the RT_{NDT} temperature of the materials. This shift is equated to the change in temperature of the Charpy 30 ft-lb energy level between unirradiated and irradiated material, as shown in Fig. 20.8.

Prediction of embrittlement in reactor vessel welds, plates, and forgings is determined according to the methods in Regulatory Guide 1.99, Rev. 2 [13], which provides trend curves as a function

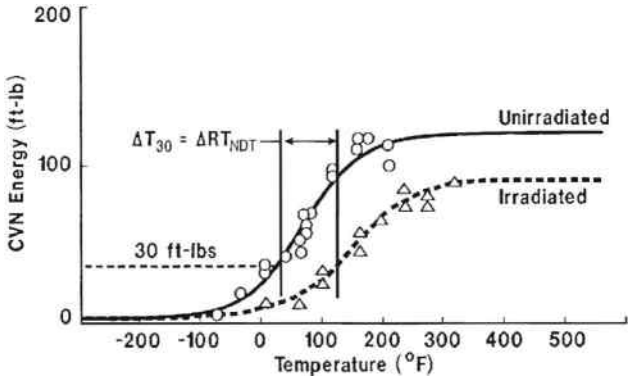


FIG. 20.8 CHARPY V-NOTCH SURVEILLANCE DATA SHOWING RT_{NDT} SHIFT DUE TO IRRADIATION

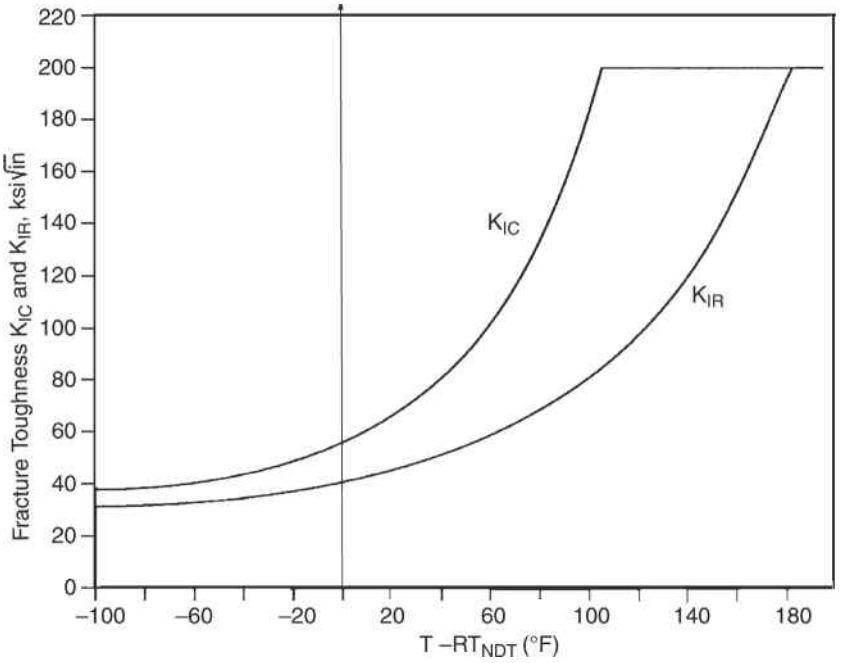


FIG. 20.9 ASME CODE K_{IC} AND K_{IR} TOUGHNESS CURVES

of copper and nickel content and fluence or determines projections of embrittlement (for the same heat of material) from the fitted results to actual Charpy surveillance data.

20.3.2 K_{IC} Versus K_{IR} Reference Toughness

There are two lower bound fracture toughness curves available in ASME BPVC Section Xl, as shown in Fig. 20.9. K_{IA} (also known as K_{IR}) is lower bound on all static, dynamic, and arrest fracture toughnesses and K_{IC} is lower bound on static fracture toughness only.

Code Case N-640 [17], which was approved in 1999, changed the fracture toughness curve used for development of P-T limit curves from K_{IR} to K_{IC}. The other margins involved with the process remained unchanged. The justification for this change is as follows. The methodology defined in Appendix G of ASME BPVC Section XI incorporates four specific safety margins as follows:

(a) large postulated flaw, $\frac{1}{4}$ thickness ($\frac{1}{4}$ T)
(b) safety factor = 2 on pressure stress
(c) lower bound fracture toughness (K_{IA})
(d) upper bound adjusted reference temperature (RT_{NDT})

Although the four safety margins were originally included in the methodology used to develop P-T limit curves and hydrotest temperatures, some sources of stress were not considered in the original methodology. These include weld residual stresses and stresses due to clad-base metal differential thermal expansion. Furthermore, the original methodology assumed that the maximum value of the computed stress intensity factor occurred at the deepest point of the flaw. Therefore, these elements required consideration to assess their effects on safety margins and justify the use of K_{IC}.

There are several reasons for the limiting toughness in the Appendix G P-T limits being changed from K_{IA} to K_{IC}. Each of these is described in the following paragraphs.

20.3.2.1 Use of K_{IC} Is More Technically Correct. The heatup and cooldown processes for nuclear plants are very slow, with the fastest rate allowed typically being 100°F/h. For this rate of temperature change, the rate of change of pressure and temperature is often constant, so the resulting stresses are essentially constant. Therefore, both the heatup and cooldown processes, as well as pressure test conditions that have little or no thermal stress, are essentially static processes. In fact, with regard to fracture toughness, all operating transients (levels A, B, C, and D) correspond to static loading conditions.

The only time when dynamic loading can occur and where the dynamic/arrest fracture toughness, K_{IA}, should be used for the reactor pressure vessel (RPV) is when a crack is propagating. This situation may be postulated during a PTS transient event, but is not a credible scenario during the heatup or cooldown processes. Therefore, use of the static lower bound fracture toughness, K_{IC}, is more technically correct for development of P-T limit curves.

20.3.2.2 Use of Historically Large Margin Is No Longer Necessary. In 1974, when the Appendix G methodology was first approved for use and implemented into the ASME Code, the use of K_{IA} (K_{IR} in the terminology of the time) to provide an additional margin was thought to be necessary to cover uncertainties and several postulated (but unquantified) effects. Almost 25 years later, significantly more information was known about these uncertainties and effects.

20.3.2.3 Flaw Size. With regard to flaw indications in RPVs, there have been no indications found at the inside surface of any operating reactor in the core region that exceed the acceptance standards of ASME BPVC Section XI in the entire 28-year history of Section XI. This is a particularly impressive conclusion considering that core region inspections have been required to concentrate on the inner surface and near inner surface region since the

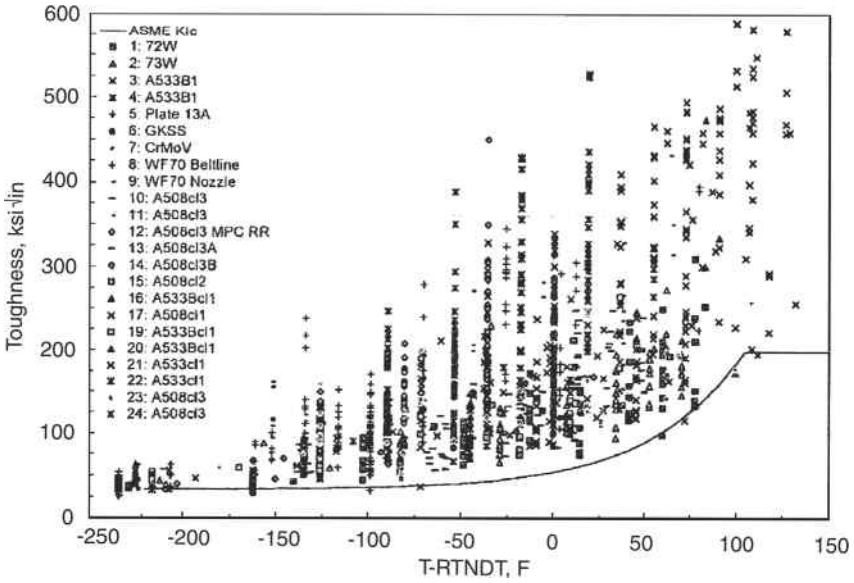


FIG. 20.10 STATIC FRACTURE TOUGHNESS DATA (K_{JC}) NOW AVAILABLE, COMPARED TO K_{IC}

implementation of U.S. NRC Regulatory Guide 1.150 in 1983. Flaws have been found, but all have been qualified as buried or embedded.

There are many reasons why no surface flaws exist, and these are related to the fabrication and inspection practices for vessels. For the base metal and full penetration welds, a full volumetric examination and surface exam are required before cladding is applied, and these exams are repeated after cladding deposition.

Further confirmation of the lack of any surface indications has recently been obtained by the destructive examination of portions of several commercial RPVs, such as the Midland vessel and the PVRUF vessel.

20.3.2.4 Fracture Toughness. Since the original formulation of the K_{IA} and K_{IC} fracture toughness curves in 1972, the fracture toughness database has increased by more than an order of magnitude, and both K_{IA} and K_{IC} remain lower bound curves. This is shown in Fig. 20.10 for K_{IC} [1], compared to Fig. 20.11, which is the original database [2]. Also, the temperature range over which the data have been obtained has been extended to both higher and lower temperatures than the original database. It can be seen from Fig. 10 that there are a few data points falling just below the K_{IC} curve. Consideration of these points, as well as the many (over 1,500) points above the curve, leads to the conclusion that the K_{IC} curve is a lower bound for a large percentage of the data. An example set, of carefully screened data in the extreme range of lower temperatures, is shown in Fig. 20.12 [3]. Data in Figs. 20.11 and 20.12 satisfy K_{IC} validity limits in ASTM E 399 standard for cleavage fracture toughness, whereas K_{JC} data in Fig. 20.10 include significant ductile tearing in higher toughness data points.

20.3.2.5 Local Brittle Zones. Another argument for the use of K_{IA} in the original version of Appendix G was based on the concern that there could be a small, local brittle zone in the weld or heat-affected zone of the base material that could pop-in and produce a dynamically moving cleavage crack. Therefore, the

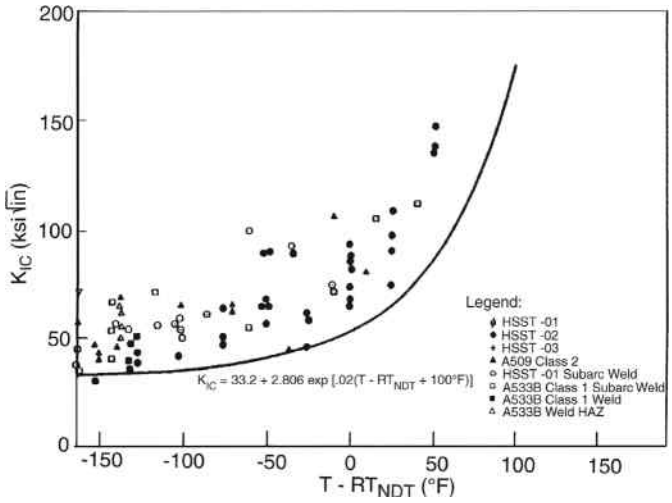


FIG. 20.11 ORIGINAL K_{IC} REFERENCE TOUGHNESS CURVE, WITH SUPPORTING DATA

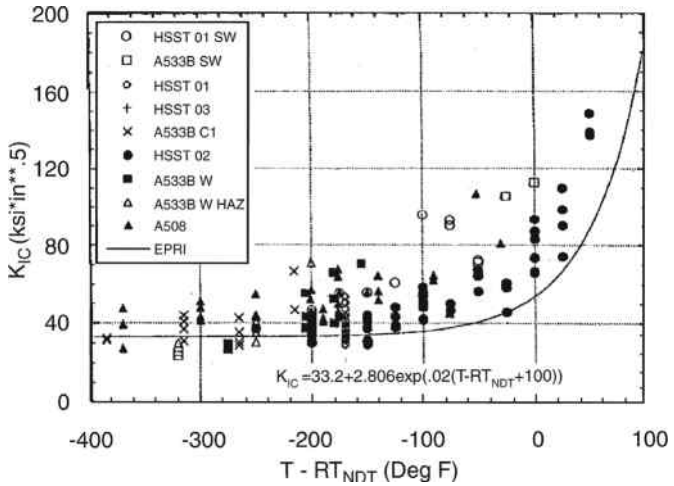


FIG. 20.12 K_{IC} REFERENCE TOUGHNESS CURVE WITH SCREENED DATA IN THE LOWER TEMPERATURE RANGE

toughness property used to assess the moving crack should be related to dynamic or crack arrest conditions, especially for a ferritic RPV steel showing distinct temperature and loading-rate (strain-rate) dependence. The dynamic crack should arrest at a $\frac{1}{4}$ thickness depth ($\frac{1}{4}$T), and any reinitiation should consider the effects of a minimum toughness associated with dynamic loading. This argument provided a rationale for assuming a $\frac{1}{4}$T postulated flaw size and a lower bound fracture toughness curve considering dynamic and crack arrest loading. The K_{IR} curve in Appendix G of Section III and the equivalent K_{IA} curve in Appendices A and G of Section XI provide this lower bound curve for high-rate loading (above any realistic rates in RPVs during any accident condition) and crack arrest conditions. This argument, of course, relied on the existence of a local brittle zone.

After over 30 years of research on RPV steels fabricated under tight controls, microcleavage pop-in has not been found to be significant. This means that researchers have not produced catastrophic failure of a vessel, component, or even a fracture toughness test specimen in the transition temperature regime. Testing of some specimens at Oak Ridge National Laboratory (ORNL) [4] has shown some evidence of early pop-ins for some simulated production weld metals. However, the level of fracture toughness for these possible early initiations is within the data scatter for other ASTM-defined fracture toughness values (K_{IC} and/or K_{JC}). Therefore, there is excess conservatism associated with this postulated condition and the use of the lower bound K_{IA} curve to assess fracture initiation. This conservatism leads to the unnecessary margin that could reduce overall plant safety.

20.3.2.6 Overall Plant Safety Is Improved. The primary reason for developing Code Case N-640 was to reduce the excess conservatism in the current Appendix G approach that could in fact reduce overall plant safety. Considering the impact of the change on other systems (such as pumps) and also on personnel exposure, a strong argument was made that the change increases plant safety and reduces personnel exposure for both PWRs and BWRs.

20.3.3 Master Curve Reference Toughness

During the late 1990s, industry research focused on the direct use of measures fracture toughness properties in the assessment of RPV integrity. These efforts were initiated to develop procedures for determining a material transition temperature, designated as T_o, based on measured fracture toughness testing using the Master Curve approach [21]. The ASME Code endorsed this new technology by adopting two Code Cases in 1998, Code Cases N-629 and N-631. In these Code Cases, the fracture toughness curves are not changed from the reference fracture toughness curves, K_{IC} and K_{IA}, but the indexing parameter RT_{NDT} is determined from the reference temperature T_o from the Master Curve method of ASTM E 1921 [22]. In contrast to RT_{NDT}, T_o is determined by performing fracture toughness tests on the material of interest. This procedure was made possible by the development of J-integral fracture toughness test techniques generally used on 1-in. (2.54 cm) (or less) thick specimens. By testing multiple specimens at a single temperature, it is possible to use Weibull statistics to determine the median fracture toughness.

The development of the Master Curve is based on the observation that fracture toughness transition curves for all ferritic steels have a characteristic shape. Therefore, one Master Curve is used for all ferritic steels and the curve is shifted along the temperature axis to match a measured mean fracture toughness. The temperature at which the mean fracture toughness curve equals 100 Mpa $\sqrt{\text{m}}$ (91 ksi $\sqrt{\text{in.}}$) is defined as the fracture toughness reference temperature, T_o. Because it is a statistical methodology, the Master Curve approach might also be used to construct a bounding curve for the data, with a corresponding degree of confidence. Typically a bounding curve with a 95% degree of confidence is used as a lower bound on the fracture toughness; a lower tolerance bound noted as 5% is most commonly used. This implies that 95% of all fracture toughness measurements should fall above the confidence/tolerance bound.

The statistical basis of the ASTM E 1921 procedure allows a consistent level of conservatism to be set by selecting an appropriate level of confidence. The ASTM procedure incorporates advances in fracture mechanics technology that were not available when the ASME reference curve was adopted. The ASME K_{IC} reference toughness curve and the 5% bounding curve from the ASTM test method are both lower limits to the fracture toughness data. However, the manner in which these lower limits to the fracture toughness data leads to some significant differences. The K_{IC} curve is a lower limit to all data on a series of pressure vessel steels, while the Master Curve bound is a statistically derived bound based on measurements for a specific material. The shape and location of the K_{IC} reference curve is actually set by a relatively small sampling of materials. By comparison, the distribution of measurements with respect to the ASTM bounding curve is predictable and described by the Weibull parameters.

The procedure used to determine T_o is based on measurements of fracture toughness, and a lower bound toughness curve can be constructed with a specified level of confidence. Wallin performed a statistical analysis of the empirical relationship between RT_{NDT} and fracture toughness by treating the horizontal shift temperature between the data and the K_{IC} curve as a statistical variable [23]. Figure 20.13 shows how the new variable $TK_{IC}-$T, is defined for the plate and forging data used for the K_{IC} curve.

The average shift between the measured data and the K_{IC} curve is 40.4°C (72.7°F); the standard deviation of this population is 20.2°C (36.4°F). Therefore, the K_{IC} curve appears to represent a 2-σ lower bound of the original K_{IC} data. Wallin then performed a similar analysis by size-adjusting the same fracture toughness data to 1T equivalent values and comparing the results to the 5% lower confidence bound to the corresponding Master Curve, as shown in Fig. 20.14.

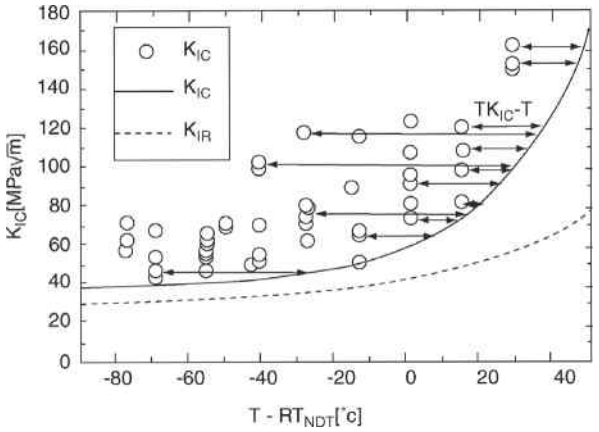


FIG. 20.13 ORIGINAL ASME K_{IC} DATA AND NEW VARIABLE T_{KIC} -T

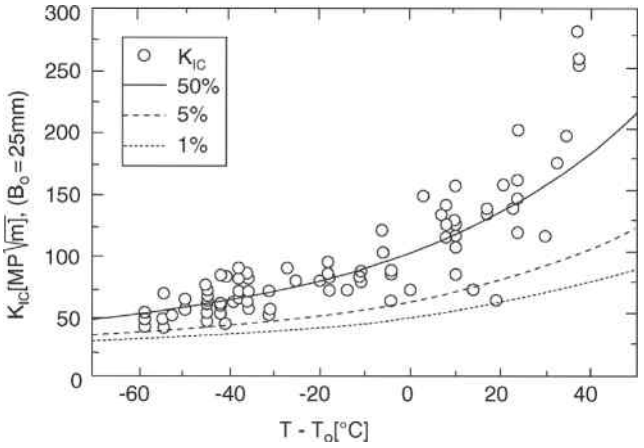


FIG. 20.14 ORIGINAL K_{IC} TOUGHNESS DATA VERSUS $T - T_O$

There is a fundamental relationship between the K_{IC} curve and the Master Curve: both curves bound the static crack initiation toughness results. Thus, it should be possible to use the parameter T_o to define a value of reference temperature, RT_{To}, such that the K_{IC} curve appropriately bounds the fracture toughness data. The K_{IC} curve is an empirical lower bound curve, whereas the Master Curve method fits the median of the measured fracture toughness data.

The key parameters required to determine the Master Curve-based lower bound structural curve are T_o and the appropriate statistical lower tolerance bound level. The bounding curve for the Master Curve technique is defined for a specific specimen size. In determining T_o, it is common practice to adjust all fracture toughness data to the 1-in. (2.54 cm) thickness (1T) equivalent value, even though the actual test specimens might be larger or smaller.

The method for applying the Master Curve as given in Code Cases N-629 and N-631 is to determine T_o and then add an appropriate temperature shift to the K_{IC} curve using the following equation:

$$RT_{TO} = T_o + 35°\text{F} \tag{20.12}$$

where the value of $R0T_{To}$ replaces the initial RT_{NDT}. Figure 20.15 shows how this applies to three large data sets evaluated in the PVRC Task Group activities. These toughness data were first normalized to 1T size and the corresponding alternate K_{IC} curve indexed using $T_o + 35°$F is shown relative to data.

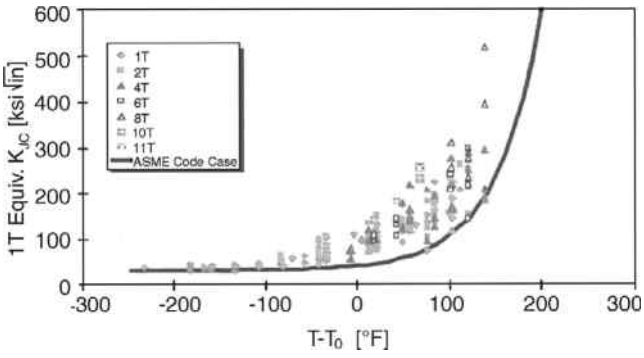


FIG. 20.15 FRACTURE TOUGHNESS DATA NORMALIZED TO 1*T* AND COMPARED TO CODE CASE N-629 CURVE

20.3.4 Alternative Shift Prediction Method: E900 Trend Curves

The embrittlement correlation described in ASTM E 900-87, Standard Guide for Predicting Neutron Radiation Damage to Reactor Vessel Materials [24], was derived from Regulatory Guide 1.99, Rev. 2 [16], and was based on 216 Charpy V-notch surveillance data points that were available in the mid-1980s [25,26]. Since that time, the database of Charpy surveillance test data has increased by a factor of about five. A reevaluation of these data produced draft radiation embrittlement trend equations, which were submitted for ASTM Subcommittee E 10.02 consideration [27,28]. These draft trend equations were developed using mechanistic modeling of the embrittlement process and statistical analyses.

Following this, EPRI sponsored work to independently evaluate the mechanistic and statistical bases for these draft trend equations and, in particular, provide further statistical basis [29], which contains several additional correlation parameters. The EPRI correlation agreed with the general form of the draft NRC correlation parameters; the primary difference between the EPRI study and the NRC studies was in the interpretation of the statistical results. This EPRI correlation was subsequently accepted for use in ASTM E 900-02, Guide for Predicting Radiation-Induced Transition Temperature Shift in Reactor Vessel Materials [30]. The revised transition temperature shift correlation has the following form:

$$\begin{aligned}\text{Shift} = {} & \text{A} \exp[20{,}730/(T_c + 460)\,(\phi t)^{0.5076} \\ & + \text{B}[1 + 2.106\,\text{Ni}^{1.173}]\,\text{F(Cu)}\,\text{G}\,(\phi t)\end{aligned} \tag{20.13}$$

where

$A = 6.70 \times 10^{-18}$
T_c = the cold leg (irradiation) temperature (°F)
(ϕt) = the fluence (n/cm^2 for E > 1MeV)

$$\text{B} = \left\{ \begin{array}{l} 234, \text{ weld} \\ 128, \text{ forging} \\ 208, \text{ plates in CE vessels} \\ 156, \text{ other plates} \end{array} \right\}$$

Ni is the measured nickel content in wt%

$$\text{F(Cu)} = \left\{ \begin{array}{l} 0, \text{Cu} \le 0.072 \text{ wt\%} \\ (\text{Cu} - 0.072)^{0.577}, \text{Cu} > 0.072 \text{ wt\%} \end{array} \right\}$$

and subject to the following:

$$\text{Cu}_{\max} = \left\{ \begin{array}{l} 0.25, \text{ for welds with Linde 80 or Linde 0091 flux} \\ 0.305, \text{ for other welds} \end{array} \right\}$$

and $G(\phi t)$ is a fluence function term as follows:

$$G(\phi t) = \frac{1}{2} + \frac{1}{2} \tanh\left[\frac{\log(\phi t) - 18.24}{1.052}\right]$$

This correlation showed improvement over previous trend curve prediction methods, and the overall fit to the latest database has a standard error of 22.0°F. In using the ASTM E 900-02

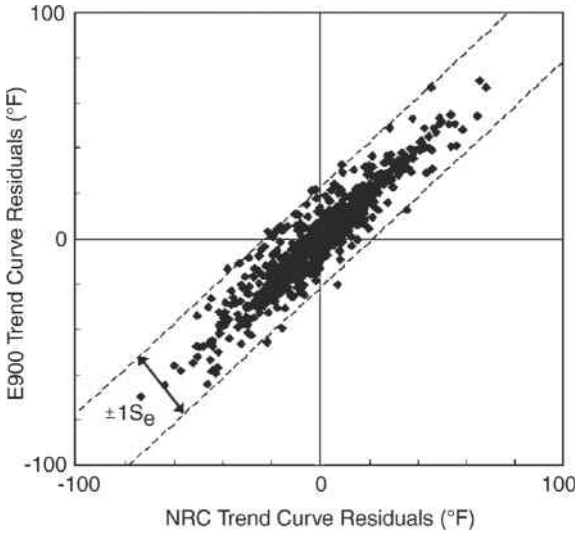


FIG. 20.16 COMPARISON OF RESIDUALS FROM ASTM E900-02 AND RECENT NRC EMBRITTLEMENT TREND CURVE EQUATIONS

correlation, a proper understanding of uncertainties is required. The past regulatory practice in using Regulatory Guide 1.99, Rev. 2, applies a two-standard deviation approach, where 2σ = 34°F for base metal and 2_s = 56°F for welds.

This newly adopted ASTM E 900-02 trend equation is a simplified version of the general form originally developed by the NRC [27]. There is a general consensus that this form of the trend equation provides an improvement over the current Regulatory Guide 1.99, Rev. 2 equations [16]. However, there remains some controversy over the significance and importance of some of the terms in a later version of the draft NRC equation [28], which has not been openly published. A comparison of the two differing trend curve forms shows much similarity. Evidence supporting the similarity of the approaches is given in Fig. 20.16, which shows a comparison of the residual (actual/predicted) results for the two methods.

A form of these new trend curves may be included in a future revision to Regulatory Guide 1.99, but until the NRC decides to make the change, Rev. 2 of the Regulatory Guide is to be used for developing P-T limits and for performing vessel integrity analyses.

20.4 MARGIN STUDIES FOR OPERATING P-T LIMITS

Several studies to evaluate margin in the P-T operating limit curves have been performed to support the activities of the ASME Section XI Working Group on Operating Criteria. Analyses were performed using both deterministic and probabilistic methods to assess the true margins in the Appendix G heatup and cooldown limit curves. These analyses are discussed in the White Paper on Reactor Vessel Integrity Requirements for Levels A and B Conditions [9]. The Appendix G approach uses a deterministic fracture mechanics method with defined assumptions (e.g., $\frac{1}{4}t$ reference flaw) and safety factors, such as the factor of 2 on pressure stress to establish allowable pressure as a function of temperature that ensures no brittle fracture of the vessel. The built-in assumptions and safety factors are intended to bound the uncertainties in the analysis without knowing the exact condition of the vessel. They also allowed the simplification of the Appendix G method, because they were generally regarded to have adequate conservatism.

At the time the method was developed, there were no good inspection techniques that could detect and characterize actual flaws or indications in a reactor vessel, so a large reference flaw was assumed. Today, we have the technology to use focused NDE techniques to detect the presence or absence of vessel flaws and to measure the toughness of the vessel irradiated vessel materials, which enables a best estimate determination of the vessel integrity limits. Using the state-of-the-art technologies, much can be learned about the margins or degree of conservatism in the Appendix G method. In fact, these analyses formed part of the technical basis for changing from the K_{Ia} toughness to the K_{IC} reference toughness curve for P-T limits.

A probabilistic fracture mechanics analysis that quantifies the conditional probability of failure for a PWR vessel as a function of temperature and pressure was performed by Gamble [31]. This probabilistic analysis used LEFM to predict conditions for which brittle failure would occur in the embrittled vessel beltline region. Four stress components were considered: pressure stress, stress due to a difference in thermal expansion between the clad and base metal, residual stress associated with the pressure boundary welds, and thermal stress due to the heatup or cooldown of the vessel. Probability distributions were used for many of the unknown variables including flaw depth, copper and nickel contents, initial RT_{NDT}, neutron fluence, shift in RT_{NDT}, initiation toughness (K_{IC}), and arrest toughness (K_{Ia}). The analyses assumed a cooldown rate of 100°F/hr from 500°F to 410°F and a rate of 20°F/hr from 415°F to 100°F. An adjusted RT_{NDT} of 320°F was selected because it approximates the highest end-of-life value currently predicted for U.S. reactors. The results of the evaluation are shown in Fig. 20.17. The Appendix G P-T limits for a 20°F/hr cooldown based on the K_{Ia} curve is also shown.

A deterministic crack initiation limit was also calculated to compare with these results for conditional failure probability of the vessel. The deterministic analysis used similar vessel model

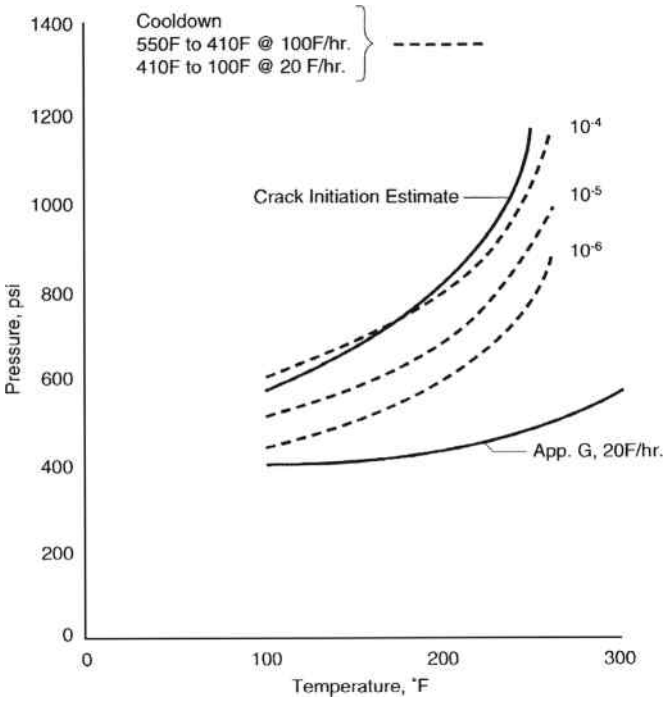


FIG. 20.17 ESTIMATES OF CRACK INITIATION COMPARED TO P-T LIMITS FOR NORMAL COOLDOWN TRANSIENT

assumptions (including cladding), with an assumed semi elliptical surface flaw at the I.D. of the vessel with a depth through the clad and 10% into the base metal thickness (1.17 in.). A comparative evaluation of these curves estimated the conditional failure probability associated with the deterministic crack initiation limit as approximately 10^{-4} at the low temperatures. The comparison of conditional failure probability with the Appendix G cooldown limit (based on K_{Ia} toughness) shows that the probability of vessel failure during a normal vessel cooldown is less than 10^{-6}. While attempts were made to ensure compatibility between the analyses (i.e., the same cooldown rate and vessel RT_{NDT}), identical fracture mechanics algorithms and identical assumptions were not entirely possible. Consequently, the above evaluation only provides a rough estimate of conditional failure probability associated with a crack initiation limit. Nevertheless, it provides another benchmark for comparison of the margin embedded in the Appendix G method.

As part of the ongoing pressurized thermal shock (PTS) reevaluation effort by the NRC, the updated FAVOR code [32] has been used to analyze the risk of vessel failure during PTS events. The results of the NRC PTS reevaluation study state that the risk of vessel failure due to PTS is *very low*, and the same method could be applied to evaluate vessel integrity during normal heatup and cooldown events [32a].

20.5 AREAS FOR FUTURE IMPROVEMENTS TO SECTION XI, APPENDIX G

Several areas for improvement to the Section XI, Appendix G method have been identified [9]; two of the key areas are discussed here.

20.5.1 Reduce the Reference Flaw Size

The postulated flaw size used in determining the allowable P-T curves has a great effect on the margin associated with the Appendix G limits. The $\frac{1}{4}$t flaw was intentionally chosen to be a conservative bound to any existing flaws in the vessel. At the time it was selected, a database did not exist to assess NDE reliability, and it was thought that a $\frac{1}{4}$t flaw was the largest flaw that could be missed by then current ASME inspection methods. UT inspection methods were not yet available, and reliable volumetric examination techniques were not expected to be used inservice. An additional factor to note is the relationship between the allowable surface indications in ASME BPVC Section XI (Table IWB-3510) and the Appendix G reference flaw. This relationship was established to maintain a factor of 10 on the allowable flaw size in the flaw acceptance standards, as noted in Fig. 20.18.

Appendix G (Article G-2120) states that, in choosing a reference flaw size, "smaller defect sizes may be used on an individual case basis if a smaller size of maximum postulated defect can be ensured." Unfortunately, there is no guidance on how to justify a smaller reference flaw in the ASME Code. With the improvements in NDE technology, and with the current requirements of Appendix VIII of Section XI for demonstration of near-surface flaw detection capabilities, it may be appropriate to evaluate the new inspection reliability in light of the credit that may be derived for adjusting the Appendix G reference flaw size if certain acceptance standards can be met.

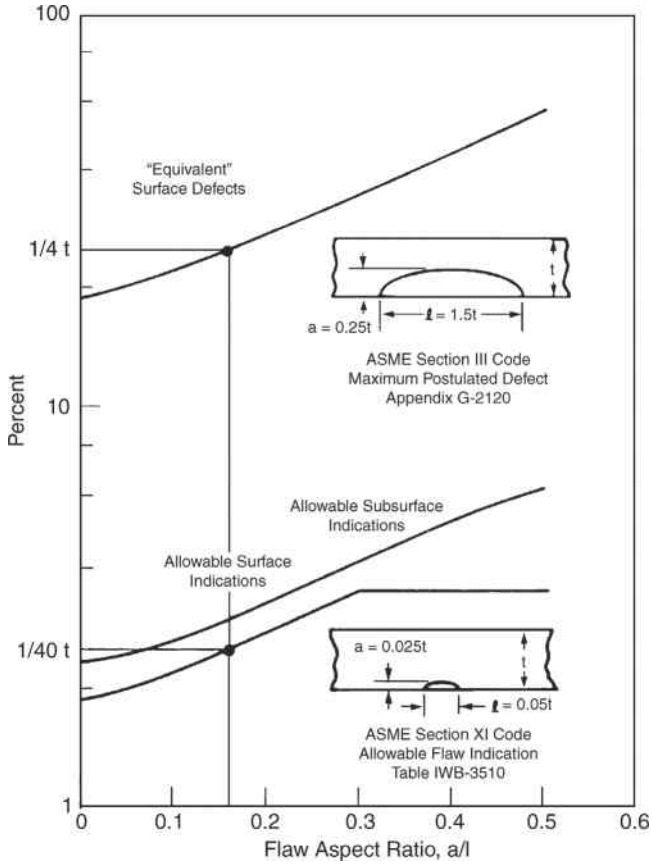


FIG. 20.18 RELATIONSHIP BETWEEN MAXIMUM POSTULATED DEFECT (ASME BPVC SECTION III) AND ALLOWABLE SURFACE INDICATIONS (ASME BPVC SECTION XI)

20.5.2 Probabilistic P-T Limit Curves

Probabilistic fracture mechanics analyses have been used as an alternative means for assessing margins in the Appendix G method. The probabilistic analyses have several advantages. Firstly, the results can be directly compared to safety levels established for the nuclear industry, such as what vessel conditions are needed to ensure a probability of less than 1×10^{-6} that a large release will occur. Secondly, the event frequencies, as well as failure probabilities, can be included in the evaluation to better define margins associated with normal operation and postulated events. Finally, because distributed variables are used, sensitivity studies can be performed to more accurately assess the effect of uncertainties on the overall failure margin. The probabilistic methods provide a useful tool for evaluating vessel integrity margins and developing an alternative means to assess the acceptable level of protection against vessel failure.

It is recognized that, because of the interaction between the variables in the Code method (e.g., toughness, reference flaw size, and safety factors), there are trade-offs to consider in the selection of the individual values or assumptions used to establish the P-T limit curves. This is where the probabilistic analyses can be used most effectively to assess the level of protection against nonductile failure of the vessel. Because the inputs for the variables are given as distributions rather than single values, the uncertainties can be built into the method. In fact, curves of allowable PT can be constructed without having to assume conservative values for each of the variables for a specific reactor vessel.

An alternative risk-informed methodology has been developed for ASME Section XI, Appendix G. This alternative methodology provides easy to use procedures to define risk-informed P-T limits for Service Level A and B events, including leak testing and reactor start-up and shut-down. Risk-informed P-T limits provide more operational flexibility, particularly for reactor pressure vessels with relatively high irradiation levels and radiation sensitive materials. The development of this methodology used selected plants spanning the population of pressurized water reactors (PWRs) and boiling water reactors (BWRs). The evaluation included determining appropriate material properties, reviewing operating history and system operational constraints, and performing probabilistic fracture mechanics analyses. The analysis results were used to define risk-informed P-T relationships that provide an acceptable level of risk, consistent with safety goals defined by the NRC. This alternative methodology will provide greater operational flexibility, especially for Service Level A and B events that may adversely affect efficient and safe plant operation, such as LTOP for PWRs and system leak testing for BWRs. Overall, application of this methodology can result in increased plant efficiency and increased plant and personnel safety.

This alternative risk-informed approach is now included in Section XI, Appendix G, G-2216, Risk-Informed Allowable Pressure, and G-2500, Risk-Informed Hydrostatic Leak Testing.

The increase in hydrotest temperature in BWRs (i.e., performing effective leak detection and minimizing costs and personnel risks while maintaining fracture margin) are needed to avoid the additional burden caused by increases in fluence and expected changes in Regulatory Guide 1.99, Revision 3 which will result in more projected embrittlement than currently calculated using Regulatory Guide 1.99, Revision 2. The risk-informed approach for developing P-T limit curves, including the alternative method for calculating the hydrostatic pressure test curve limits reduces the impact from the potential increase in the projected embrittlement.

20.6 AGING MANAGEMENT OF PWR VESSEL INTERNALS[2]

Management of materials aging effects, such as loss of material, reduction in fracture toughness, or cracking, depends on the demonstrated capability to detect, evaluate, and potentially correct conditions that could affect function of the internals during the license renewal term. License renewal applicants in their submittals to the NRC have identified the general elements of AMP for PWR reactor internals, including the use of inservice inspection and monitoring with the possibility of enhancement or augmentation if a relevant condition is discovered. As plants near the license renewal term, plant-specific AMP are implemented, focusing on those regions most susceptible to aging degradation. A framework for the implementation of an AMP is proposed in this paper. This proposed framework is based on currently available research results and the state of knowledge, and uses inspections and flaw tolerance evaluations to manage the degradation issues. The important elements of this framework are as follows:

(a) the screening of components for susceptibility to the aging mechanisms
(b) performing functionality analyses of the components with representative material toughness properties under PWR conditions
(c) evaluating flaw tolerance of lead components or regions of greatest susceptibility to cracking, loss of toughness, or swelling
(d) using focused inspections to demonstrate no loss of integrity in the lead components or regions of the vessel internals

The EPRI Material Reliability Program (MRP) Reactor Internals Issue Task Group (RI-ITG) is actively working to develop the data and methods to quantify understanding regarding aging and potential degradation of reactor vessel internals and to develop materials/components performance criteria, providing tools for utilities to implement for extended plant operation. Under this MRP, the technical basis for the framework will be documented. Then, based on that technical basis, PWR internals Inspection and Evaluation Guidelines will be developed for plants to manage reactor internals aging and associated potential degradation.

20.6.1 Overview

The reactor internals assembly in a PWR is part of the reactor coolant system (RCS) and is located inside the reactor vessel. The reactor internals are long-lived, passive structural components that support the RCS functions of core cooling, provide guidance and protection (for insertion) of the rod control cluster assemblies, and ensure integrity of the fuel and the surrounding vessel pressure boundary. There are some differences in the internals designs among the three different NSSS vendor types of plants. However, many similarities exist in the overall means of structural support and guidance and in the flow of coolant through the reactor vessel and internals.

Several aging mechanisms have been identified that may affect the reactor internals components, such as irradiation embrittlement, thermal embrittlement, stress corrosion cracking (SCC), irradiation-assisted stress corrosion cracking (IASCC), irradiation-enhanced stress relaxation (i.e., loss of preload), and irradiation-induced void swelling. Demonstration that these potential aging effects do not lead to the loss of component function is an important part of a plant LRA. Several industry programs and Owners Group programs are being conducted to examine these effects in more detail, gather data for improved understanding of the aging mechanisms, recommend aging management strategies for plants considering license renewal, and ensure component function of the PWR vessel internals.

As more PWR plants are submitting LRAs, several utilities have committed to performing inspections for detecting and managing cracking and loss of toughness of susceptible reactor internals components. The NRC has either approved these applications or has required additional utility commitments to perform inspections for managing the aging effects in reactor internals. Void swelling appears to be an issue that may require additional data to demonstrate that it is not a concern through the end of the license renewal period for PWR plants.

20.6.2 Aging Management Review

An LRA has to consider the effects of aging on SSCs within the scope of license renewal. The subcomponents of the reactor

[2] The authors acknowledge the contributions of coauthors for this section: Robert E. Nickell (Consultant), H.T. Tang (EPRI), and Jeff D. Gilreath III (Duke Energy).

internals are subject to an AMR to identify any potential age-related degradation. When these analyses indicate that aging mechanisms exist that may affect the function of the internals during the license renewal term, an AMP has to be in place to effectively manage the potential aging effects.

The potential for significant age-related degradation of specific PWR vessel internals components depends on their design features, materials, operation and maintenance histories including fluence and temperature environments, and the extent to which they are susceptible to the age-related degradation mechanisms. If it can be shown that the internals components are either not susceptible, or are susceptible but to such a degree that the specific component safety function is not affected throughout the license renewal term, then the component/degradation mechanism is not significant. Similarly, future advances in technology and evaluation methodology may be able to show the adequacy of components to avert further measures. Otherwise, an AMP must be defined to address these potential conditions.

In 2001 the NRC issued the Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (NUREG-1800) [33], and the Generic Aging Lessons Learned (GALL) Report (NUREG-1801) [34], which provided the NRC staff's evaluation of existing plant AMPs and documented the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for extended plant operation.

According to these documents, a license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

20.6.3 Aging Management Program Attributes

AMPs are generally of four types: prevention, mitigation, condition monitoring, and performance monitoring. Prevention programs preclude the effects of aging. Mitigation programs attempt to slow the effects of aging. Condition monitoring programs inspect for the presence and extent of aging effects. Performance monitoring programs test the ability of a structure or component to perform its intended function(s). In defining an AMP, it is not necessary to demonstrate absolute assurance that structures and components will not fail, but rather that there is reasonable assurance that they will perform the intended functions through the period of extended operation. An acceptable AMP should consist of the 10 elements described in the GALL Report [34] and here.

20.6.3.1 Scope of Program. The specific program necessary for license renewal should be identified. The scope of the program should include the specific structures/components of which the program manages the aging.

20.6.3.2 Preventive Actions. The activities for prevention and mitigation programs should be described. These actions should mitigate or prevent aging degradation.

20.6.3.3 Parameters Monitored or Inspected. The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure/component intended function(s).

20.6.3.4 Detection of Aging Effects. Detection of aging effects should occur before there is a loss of the structure/component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure/component intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure timely detection of aging effects. Information should be provided that links the parameters to be monitored or inspected to the aging effects being managed.

Nuclear power plants are licensed based on redundancy, diversity, and defense-in-depth principles. A degraded or failed component might reduce the reliability of the system, challenge safety systems, and contribute to plant risk. Thus, the effects of aging on a structure or component should be managed to ensure its availability to perform its intended function(s) as designed when called upon.

This program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program). The method or technique and frequency may be linked to plant-specific or industry-wide operating experience. Justification should be provided, including codes and standards referenced, that the technique and frequency are adequate to detect the aging effects before a loss of structure/component intended function.

When sampling is used to inspect a group of structures/components, provide the basis for the inspection population and sample size. The inspection population should be based on such aspects of the structures/components as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects. The sample size should be based on such aspects of the structures/components as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The samples should be biased toward locations most susceptible to the specific aging effect of concern in the period of extended operation. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

20.6.3.5 Monitoring and Trending. Monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and, thus, affect timely corrective or mitigative actions. Plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency.

This program element describes "how" the data collected are evaluated and may also include trending for a forward look. This includes an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation to confirm that timing of the next scheduled inspection will occur before a loss of structure/component intended function. Although aging indicators may be quantitative or qualitative, aging indicators should be quantified, to the extent possible, to allow trending. The parameter or indicator trended should be described. The methodology for analyzing the inspection or test results against the acceptance criteria should be described. Trending is a comparison of the current monitoring results with previous monitoring results to make predictions for the future.

20.6.3.6 Acceptance Criteria. The acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended

function(s) are maintained under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria.

Acceptance criteria could be specific numerical values or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited.

It is not necessary to justify any acceptance criteria taken directly from the design basis information that is included in the FSAR because that is a part of the CLB. Also, it is not necessary to discuss CLB design loads if the acceptance criteria do not permit degradation because a structure and component without degradation should continue to function as originally designed. Acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads.

20.6.3.7 Corrective Actions. Actions to be taken when the acceptance criteria are not met should be described. Corrective actions, including root cause determination and prevention of recurrence, should be timely.

If corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure and component intended function(s) will be maintained consistent with the CLB.

20.6.3.8 Confirmation Process. The confirmation process should be described. It should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective. The effectiveness of prevention and mitigation programs should be verified periodically. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition-monitoring program (ultrasonic inspection) to verify that corrosion is indeed insignificant.

When corrective actions are necessary, there should be follow-up activities to confirm that the corrective actions were completed, the root cause determination was performed, and recurrence is prevented.

20.6.3.9 Administrative Controls. The administrative controls of the program should be described. They should provide a formal review and approval process.

Any AMPs to be relied on for license renewal should have regulatory and administrative controls. That is the basis for 10 CFR 54.21(d) to require that the FSAR supplement includes a summary description of the programs and activities for managing the effects of aging for license renewal. Thus, any informal programs relied on to manage aging for license renewal must be administratively controlled and included in the FSAR supplement.

20.6.3.10 Operating Experience. Operating experience with existing programs should be discussed. The operating experience of AMPs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP, because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

An applicant may have to commit to providing operating experience in the future for new programs to confirm their effectiveness.

20.6.4 Aging Concerns in PWR Vessel Internals

20.6.4.1 Irradiation Embrittlement. Irradiation embrittlement is a potential age-related degradation mechanism for PWR reactor vessel internals fabricated from austenitic stainless steel and nickel-base alloys, which experience neutron fluences in excess of 1×10^{20} n/cm^2 ($E > 1$ MeV). Irradiation embrittlement is a well-documented effect that is known to increase strength and reduce toughness properties. The internals components most susceptible to irradiation embrittlement are those located nearest to the reactor core. The main concern related to irradiation embrittlement is that cracked or fractured parts may be the result of a reduced toughness material toughness and a lower resistance to crack initiation.

20.6.4.2 Thermal Aging Embrittlement. Thermal aging embrittlement is a potential age-related degradation mechanism for cast austenitic stainless steel (CASS) PWR vessel internals components (predominantly for materials with high delta ferrite content). The synergistic effect of thermal aging and irradiation embrittlement is a particular concern for CASS materials.

20.6.4.3 Stress Corrosion Cracking. Stress corrosion cracking (SCC) is a potential age-related degradation mechanism for PWR reactor internals components that are fabricated from alloy 286 or Alloy X-750 materials. A limited number of A 286 core barrel bolt failures have been observed that may be attributable to SCC.

20.6.4.4 Irradiation-Assisted Stress Corrosion Cracking. Irradiation-assisted stress corrosion cracking is a potential age-related degradation mechanism for PWR internals components with combinations of high accumulated neutron fluence and operating stress above some prescribed thresholds.

20.6.4.5 Stress Relaxation. Irradiation-enhanced stress relaxation is a potential age-related degradation mechanism for PWR internals components that require adequate preload to perform their intended function. This is a concern only for those components with substantial preloads, such as torqued bolts, because adequate preload may be required to their functionality.

20.6.4.6 Void Swelling. Irradiation-induced void swelling has been identified as a potential age-related degradation mechanism under the combination of high fluence neutron exposure and high temperatures. Swelling generally proceeds at a very low rate during an incubation period before accelerating to a higher rate. Almost all of the currently available data are from non-PWRs (e.g., fast reactors).

20.6.5 Aging Management Strategies

The EPRI Materials Reliability Program (MRP) Reactor Internals Issue Task Group (RI-ITG) has been sponsoring research to obtain data for improved understanding of the degradation mechanisms and develop recommended strategies and guidelines for managing the effects of aging in PWR internals.

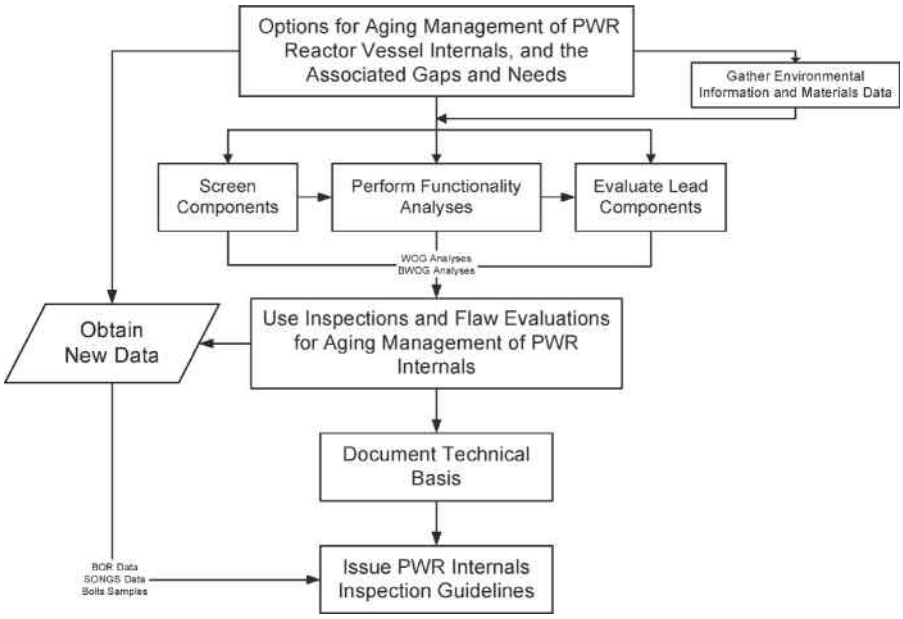


FIG. 20.19 FRAMEWORK FOR IMPLEMENTATION OF AGING MANAGEMENT USING INSPECTIONS AND FLAW EVALUATION

Inservice inspection and flaw tolerance evaluation are key elements of the overall process for managing aging effects for PWR internals components. A proposed framework for the implementation of an AMP incorporating these research results and using inspections and flaw tolerance evaluations to manage these issues is given in Fig. 20.19.

A key element in this framework is the reliance on focused inspections to detect the presence (or absence) of degradation in the lead components. Enhanced visual examinations, along with screening to identify lead components and flaw evaluation criteria, may be necessary for certain components in certain regions. The procedure will use screening and categorization of components to eliminate those regions that are not susceptible to aging degradation.

Visual examinations using VT-3 and enhanced VT-1 techniques are being considered along with flaw tolerance evaluations assuming postulated reference flaws. Also being evaluated are flaw tolerance, or fitness-for-service, demonstrations that rely on the relationship between frequency/coverage of inservice examinations; the reference flaw location, orientation and size; service loads expected to occur during the period of operation between inspections; and the critical flaw size that serves as a surrogate for component failure.

The NRC staff have stated that ASME Subsection IWB Examination Category B-N-3 is inadequate, in part, as a program for managing some of the effects of aging during the license renewal term. They questioned the capabilities of current VT-3 inspections to detect the effects of cracking. The ostensible reasons for this question are the relevant conditions cited in IWB-3520.2 (compared with those of IWB-3520.1 for VT-1 visual examination) together with the differences between maximum examination distance and character recognition height for VT-1 and VT-3 inspections, as given in Table IWA-2210-1. Both the maximum direct examination distance and the character recognition height are essentially twice as large for VT-3 as for VT-1.

For the accessible surfaces of removable PWR internals components subject to relatively high service or residual stresses, including relatively high preload stresses, enhanced VT-3 visual examination may not be capable of surface-breaking crack detection and sizing without excessive uncertainty. For such cases, VT-1 visual examination may be an acceptable alternative for PWR internals.

Another key aspect of the aging management strategy is performing functionality analyses of the components to assure no loss of component function throughout the period of extended plant operation. Standard fracture mechanics methods may be used along with bounding assumptions for crack growth due to IASCC and loss of toughness due to irradiation. Research data and predictive models can be useful in determining the performance of these components in the PWR environment. These models will be based on irradiated materials data obtained in hot cell tests.

20.6.6 Status

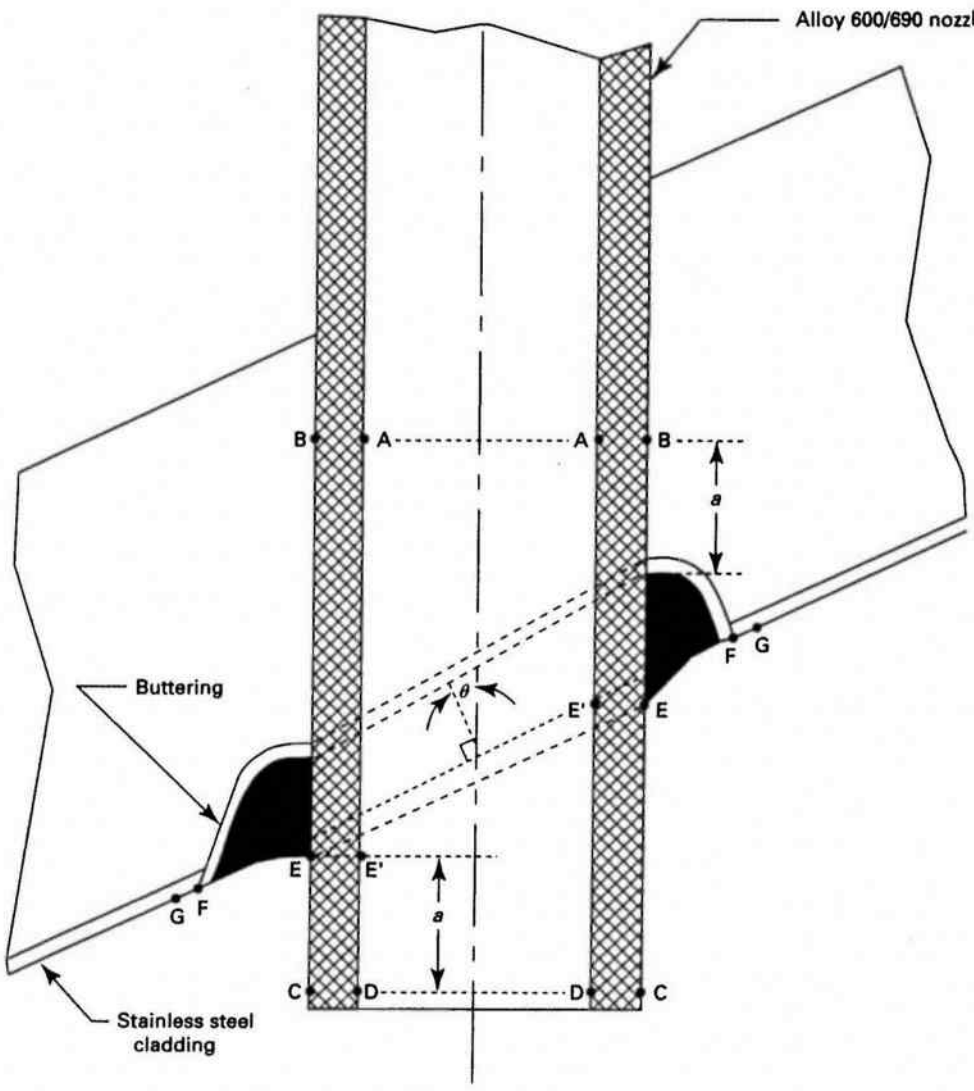
Radiation effect on materials behavior and reactor internals components performance is a complex phenomenon. The EPRI Materials Reliability Program (MRP) Reactor Internals Focus Group (RI-FG), guided by its utility advisors, is working with utilities, vendors, and owners groups sponsors to coordinate the industry research and development related to PWR vessel internals. The objectives are to better understand aging and the potential degradation mechanisms and to quantify the effects of aging in PWR internals. The research and development will provide data and tools for evaluating aging effects in the internals components and will form the technical basis to recommend strategies and approaches for managing these aging effects. In particular, the EPRI MRP is planning to issue IRE Guidelines for PWR internals in 2008. These Guidelines will include “mandatory” or “needed” actions under the NEI 03-08 materials initiative for managing the effects of aging degradation in PWR vessel internals [35].

20.7 CRACKING AT NOZZLE PENETRATIONS AND DISSIMILAR METAL WELDS

In the early 1990s, cracks were detected in Control Rod Drive Mechanism (CRDM) Alloy 600 tubes in Europe. Inconel Alloy 600 was found to be susceptible to stress corrosion cracking in PWR

primary side water environment with the residual stresses from the J-groove weld. This cracking mechanism is now referred to as PWSCC (Primary Water Stress Corrosion Cracking). The occurrence of PWSCC in the European PWRs was limited to the formation of axial cracks in the tubes. In early 2001, several circumferential cracks were found in CRDM tubes in US nuclear plants [36–39]. The circumferential cracks occurred above the J-grove weld in the Inconel Alloy 600 tube. Although the pressure induced axial stresses in the tube are low, some of the circumferential cracks were a significant fraction of the tube circumference, raising the possibility of the tube being ejected from the RPV head and thus pose a significant safety concern [36–39].

In the light of the observed cracking, ASME Section XI Code Case N-729 [40] was developed that provides the alternative examination requirements. Figure 20.20 from this Code Case shows the examination volume for nozzle base metal and examination area for weld and nozzle base metal. If the volumetric examination detects planar flaws (or, surface examination detects linear indications which are assumed to be planar), such flaws are acceptable for continued service without repair replacement activity if an analytical evaluation meets the requirements of Paragraph IWB-3660 of the 2004 or later Edition of ASME Section XI. A key input to the analytical evaluation is predicted future crack growth till the next inspection. The crack growth prediction is in turn dependent on a



a = 1.5 in. (38 mm) for Incidence Angle, θ, ≤ 30 deg and for all nozzles ≥ 4.5 in. (115 mm) OD or 1 in. (25 mm) for Incidence Angle, θ, > 30 deg; or to the end of the tube, whichever is less
A-B-C-D = extent of volumetric examination for the tube (base metal)
A-D = extent of surface examination for the tube inside surface
G-F = ¼ in. (6 mm) from the theoretical point "F" in accordance with the design drawings, including tolerances, unless the point "F" can be physically determined.
G-F-E-C = extent of surface examination for the J-groove weld (filler metal and buttering) and tube outside surface below the weld
G-F-E = extent of surface examination zone for the J-groove weld (filler metal and buttering)

FIG. 20.20 EXAMINATION VOLUME FOR NOZZLE BASE METAL AND EXAMINATION AREA FOR WELD AND NOZZLE BASE METAL

reliable weld residual stress characterization. It is a subject of continuing investigations [39,41–44].

Alloy 600 is also used in butt welds between the reactor vessel, steam generator and pressurizer nozzles of low alloy steel and stainless steel components such as piping. These welds are called Dissimilar Metal Welds. Reference [45] provides the flaw evaluation guidelines. Key input in the evaluation is the weld residual stress. The US Nuclear Regulatory Commission and Electric Power Research Institute cooperatively conducted an international round robin for weld residual stress analysis to improve stress analysis methods and to examine the uncertainties involved in the calculated stress values [46,47]. Additional results related to the calculated weld residual stresses for DM welds using finite element methods are provided in refs. [48–50]. A preemptive weld overlay or inlay is one of the measures to address future PWSCC concerns at DM welds [51,52]. The ASME B&PVC Task Group on Crack Growth Reference Curves is currently developing the weld residual stress guidance in the form of a Non-Mandatory Appendix to Section XI.

Another set of vessel nozzle penetrations that are potentially subjected to PWSCC are the bottom mounted nozzles (BMNs). These nozzles typically consist of the original Alloy 600 nozzle material attached to the reactor vessel bottom head by a partial penetration Alloy 182 weld. Reference [53] provides details of a nozzle repair development and implementation at a PWR plant. The calculated weld residual stresses at a BMN penetration are reported in Reference [54]. References [55] and [56] provide the details of safety assessments for a postulated BMN penetration failure.

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CHAPTER

21

PWR Reactor Vessel Alloy 600 Issues

Glenn A. White[1]

21.1 INTRODUCTION

Primary water stress corrosion cracking (PWSCC) of alloy 600 nickel-chromium-iron base metal and related alloys 82 and 182 weld metal has become a principal materials degradation concern for commercial pressurized water reactor (PWR) plants. Cracks and leaks have been discovered in alloys 600/82/182 materials at numerous PWR plant primary coolant system locations, including at several locations in the reactor vessels. The reactor vessel locations include top head control rod drive mechanism (CRDM) nozzles, top head thermocouple nozzles, bottom head instrument nozzles, and reactor vessel outlet nozzle butt welds. The consequences of this PWSCC have been significant worldwide with about 73 leaks through July 2013 (~57 CRDM nozzles, 13 reactor vessel closure head thermocouple nozzles, 2 reactor pressure vessel bottom-mounted instrument nozzles, and 1 piping butt weld), many cracked nozzles and welds, expensive inspections, more than 100 heads replaced, several plants with several-month outage extensions to repair leaks, and a plant shutdown for more than 2 years due to extensive corrosion of the vessel head resulting from leakage from a PWSCC crack in a CRDM nozzle. This chapter addresses alloys 600/82/182 material locations in reactor vessels, operating experience, causes of PWSCC, inspection methods and findings, safety considerations, degradation predictions, repair methods, remedial measures, and strategic planning to address PWSCC at the lowest possible net present value cost.

Several example cases of PWSCC, and resulting boric acid corrosion, are described in the following paragraphs of this chapter and, in some cases, the remedial or repair measures are described. It is important to note that the repairs and remedial measures described may not apply to all situations. Accordingly, it is important to review each new incident on a case-by-case basis to ensure that the appropriate corrective measures are applied, including the need for inspections of other similar locations that may also be affected.

[1]This chapter was initially published in the third volume of the second edition of the "Companion Guide to the ASME Boiler & Pressure Vessel Code" and authored by Jeff Gorman, Steve Hunt and Pete Riccardella. The chapter was updated in the third edition by Pete Riccardella and Glenn A. White. Glenn A. White revised the chapter for the current book that has been renumbered as Chapter 21 for the current publication. – Editor

In response to the discovery of the large cavity in the reactor vessel head at one unit caused by leakage from a PWSCC crack, the U.S. nuclear power industry developed and implemented an initiative to more proactively manage materials issues. This initiative is documented in NEI 03-08, which was issued in March 2003. The current issue is Revision 2, which was published in January 2010 [91]. The NEI 03-08 process commits utilities to meeting requirements in industry documents published by various materials Issue Programs such as the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP), the BWR Vessel and Internals Project, and the PWR Owners Group. In particular, the EPRI MRP is concerned with managing materials degradation of critical PWR systems and components.

The EPRI Materials Degradation Matrix (MDM) [92] is a key part of the industry's Materials Degradation and Issue Management Initiative. The MDM provides a comprehensive review of degradation mechanisms applicable to light water reactor plant nuclear steam supply system components, and assesses the extent to which these degradation mechanisms are understood. The MDM also evaluates the state of industry knowledge worldwide associated with mitigation of applicable degradation mechanisms. The initial version of the MDM was developed in 2004 to aid proactive identification of materials degradation issues and associated R&D needs; a third revision of the MDM was released in 2013.

21.2 ALLOY 600 APPLICATIONS

Figure 21.1 shows locations where alloy 600 base metal and alloy 82 or 182 weld metal are used in PWR plant reactor vessels. It should be noted that not all PWR reactor vessels have alloys 600/82/182 materials at each of the locations shown in Fig. 21.1.

21.2.1 Alloy 600 Base Metal

Alloy 600 is a nickel-based alloy (72% Ni minimum, 14–17% Cr, 6–10% Fe) with high general corrosion resistance that has been widely used in light water reactor (LWR) power plants, i.e., in PWRs and boiling water reactors (BWRs). In PWR plants, alloy 600 has been used for steam generator tubes, CRDM nozzles, pressurizer heater sleeves, instrument nozzles, and similar applications. The alloy was originally developed by the International Nickel Corporation (INCO) and is also known as

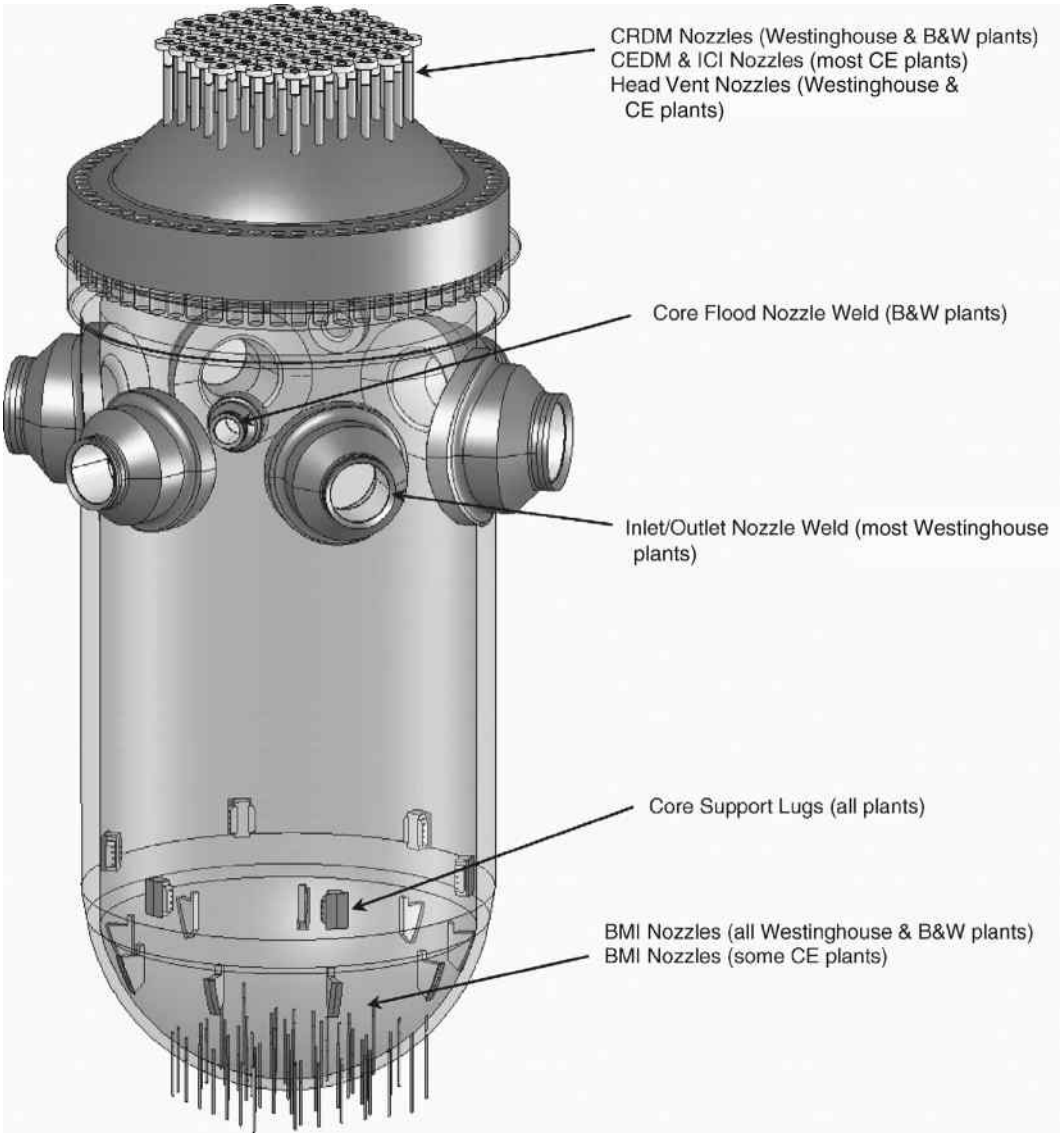


FIG. 21.1 LOCATIONS WITH ALLOYS 600/82/182 MATERIALS IN TYPICAL PWR VESSEL

Inconel 600, which is a trademark now held by the Special Metals Corporation [1]. The reasons that alloy 600 was selected for use in LWRs in the 1950s and 1960s include the following [2–7]:

(a) It has good mechanical properties, similar to those of austenitic stainless steels.
(b) It can be formed into tubes, pipes, bars, forgings, and castings suitable for use in power plant equipment.
(c) It is weldable to itself and can also be welded to carbon, low-alloy, and austenitic stainless steels.
(d) It is a single-phase alloy that does not require postweld heat treatment. Also, when subjected to postweld heat treatments that are required for low-alloy steel parts to which it is welded, the resulting sensitization (decreased chromium levels at grain boundaries associated with deposition of chromium carbides at the boundaries) does not result in the high susceptibility to chloride attack exhibited by austenitic stainless steels that are exposed to such heat treatments.
(e) It has good general corrosion resistance in high temperature water environments, resulting in low levels of corrosion products entering the coolant and resulting in low rates of wall thinning.
(f) It is highly resistant to chloride stress corrosion cracking (SCC), and has better resistance to caustic SCC than austenitic stainless steels.
(g) Its thermal expansion properties lie between those of carbon/low-alloy steels and austenitic stainless steels, making it a good transition metal between these materials.

It was alloy 600's high resistance to SCC, especially chloride-induced SCC, that led to its selection for steam generator tubing in PWRs in the 1950s and 1960s. Several early PWRs had experienced SCC of austenitic stainless steel steam generator tubing, variously attributed to chlorides and caustics, and this had led to a desire to use a tubing alloy with increased resistance to these environments. Similarly, some early cases of SCC of stainless

steel nozzle materials in BWRs during initial plant construction and startup, which was attributed to exposure to chlorides and fluorides, led to the wide-scale adoption of alloy 600 and its related weld materials for use in BWR vessel nozzles and similar applications [8].

The first report of SCC of alloy 600 in high-temperature pure or primary water environments was that of Coriou and colleagues in 1959 [9] at a test temperature of 350°C (662°F). This type of cracking came to be known as pure water or primary water SCC (PWSCC) or, more recently, as low potential SCC (LPSCC). In response to Coriou's 1959 report of PWSCC, research was conducted to assess alloy 600's susceptibility to SCC in high-temperature pure and primary water. Most of the results of this research in the 1960s indicated that alloy 600 was not susceptible unless specific contaminants were present [10–12]. The conditions leading to susceptibility included the presence of crevices and the presence of oxygen. Most of the test results of the 1960s did not indicate susceptibility in noncontaminated PWR primary coolant environments. However, by the early 1970s, it had been confirmed by several organizations in addition to Coriou that PWSCC of highly stressed alloy 600 could occur in noncontaminated high-temperature pure and primary water environments after long periods of time [13–15]. Starting with Siemens in the late 1960s, some designers began to move away from use of alloy 600 to other alloys, such as alloy 800 for steam generator tubes and austenitic stainless steels for structural applications [15]. By the mid-1980s, alloy 690, an alternate nickel-based alloy with about twice as much chromium as alloy 600 (~30% vs. ~15%), had been developed and began to be used in lieu of alloy 600 for steam generator tubing [16]. By the early 1990s, alloy 690 began to be used for structural applications such as CRDM nozzles and steam generator divider plates.

21.2.2 Alloys 82 and 182 Weld Metal

Weld alloys 82 and 182 have been commonly used to weld alloy 600 to itself and to other materials. These alloys are also used for nickel-based alloy weld deposit (buttering) on weld preparations and for cladding on areas such as the insides of reactor vessel nozzles and steam generator tubesheets. Alloy 82 is bare electrode material and is used for gas tungsten arc welding (GTAW), also known as tungsten inert gas (TIG) welding. Alloy 182 is a coated electrode material and is used in shielded metal arc welding (SMAW). The compositions of the two alloys are somewhat different, leading to different susceptibilities to PWSCC. Alloy 182 has lower chromium (13–17%) than alloy 82 (18–22%) and has higher susceptibility to PWSCC, apparently as a result of the lower chromium content. Most welds, even if initiated or completed with alloy 82 material, have some alloy 182 material.

In recent years, alloys 52 and 152, which have about 30% chromium and are thus highly resistant to PWSCC, have been used in lieu of alloys 82 and 182, respectively, for repairs and for new parts such as replacement reactor vessel heads.

21.2.3 RPV Top-Head Penetrations

As mentioned above, many of the original reactor vessel top heads have been replaced with heads using nozzles fabricated from alloy 690. This subsection discusses the design of the original heads using alloy 600 nozzles.

CRDMs in Westinghouse- and Babcock & Wilcox–designed PWR plants and control element drive mechanisms (CEDMs) in Combustion Engineering–designed PWR plants are mounted on the top surface of the removable reactor vessel head. Figure 21.2 shows a typical CRDM nozzle in a Babcock & Wilcox-designed

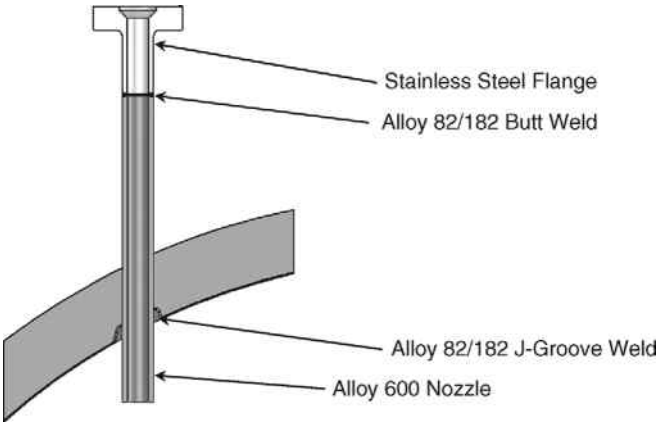


FIG. 21.2 TYPICAL CONTROL ROD DRIVE MECHANISM (CRDM) NOZZLE

plant. Early vintage Westinghouse PWR plants have as few as 37 CRDM nozzles and later vintage Combustion Engineering plants have as many as 97 CEDM nozzles. These nozzles are machined from alloy 600 base metal with finished outside diameters ranging from 3.5 to 4.3 in. and with wall thicknesses ranging from about 0.4 to 0.8 in. In some cases, a stainless steel flange is welded to the alloy 600 nozzle with an alloy 82/182 butt weld. The nozzles are installed in the reactor vessel head with a small clearance or interference fit (0.004 in. maximum interference on the diameter) and are then welded to the vessel head by an alloy 82/182 J-groove weld. The surface of the J-groove weld preparation is coated with a thin butter layer of alloy 182 weld metal before stress relieving the vessel head so that the nozzles can be installed and the final J-groove weld can be made after vessel stress relief. This avoids possible distortion that could occur if the CRDM nozzles were welded into the vessel head before vessel stress relief.

Most vessels have a single 1.0–1.3 in. outside diameter alloy 600 head vent nozzle welded to a point near the top of the head by a J-groove weld. Two of the early Babcock & Wilcox–designed vessels had eight 1.0-in. outside diameter alloy 600 thermocouple nozzles welded to the periphery of the head by J-groove welds.

Most of the Combustion Engineering vessels have alloy 600 incore instrument (ICI) nozzles welded to the periphery of the top head by J-groove welds. These ICI nozzles are similar to CEDM nozzles except that they range from 4.5 to 6.6 in. outside diameter. Several Westinghouse plants have 3.5 to 5.4 in. outside diameter alloy 600 auxiliary head adapters and de-gas line nozzles attached to the top head by J-groove welds. Several Westinghouse plants have 5.3 to 6.5 in. outside diameter internals support housings and auxiliary head adapters attached to the vessel top head surface by alloy 82/182 butt welds.

In summary, the original PWR reactor vessel top heads had between 38 and 102 alloy 600 nozzles attached by alloy 82/182 J-groove welds.

21.2.4 BMI Penetrations

All of the Westinghouse and Babcock & Wilcox–designed reactor vessels in the United States and three of the Combustion Engineering–designed reactor vessels in the United States have alloy 600 instrument nozzles mounted to the vessel bottom heads. These are often referred to as bottom-mounted instrument (BMI) nozzles or bottom mounted nozzles (BMNs). These nozzles range from 1.5 to 3.0 in. outside diameter. As shown in Fig. 21.3, a

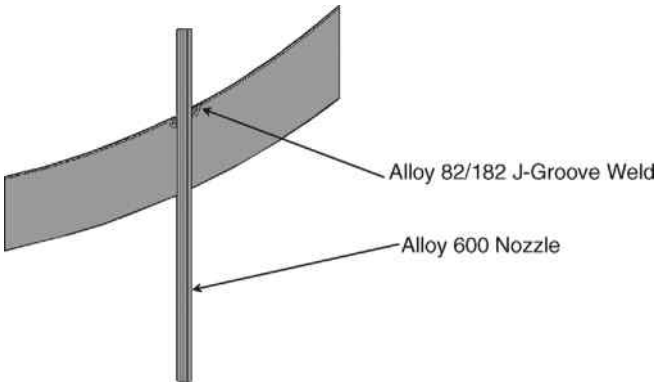


FIG. 21.3 TYPICAL BOTTOM-MOUNTED INSTRUMENT (BMI) NOZZLE

typical BMI nozzle is welded to the bottom head by a J-groove weld. In most cases of Westinghouse and Combustion Engineering plants, the J-groove welds were made after stress relieving the vessel. In the case of the Babcock & Wilcox–designed plants, the J-groove welds were made prior to vessel stress relief. Early test experience at a Babcock & Wilcox-designed plant showed a flow vibration concern with the portions of the BMI nozzles inside the bottom head plenum. Accordingly, all of the Babcock & Wilcock plant BMI nozzles were modified after initial installation to increase the diameter of the portion of the nozzle extending into the lower plenum. The new extension was alloy 600 and the modification weld was made using alloy 82/182 weld metal, with no subsequent stress relief heat treatment.



FIG. 21.4 TYPICAL REACTOR VESSEL INLET/OUTLET NOZZLE [105]

21.2.5 Butt Welds

Many Westinghouse reactor vessels have alloy 82/182 butt welds between the low-alloy steel reactor vessel inlet and outlet nozzles and the stainless steel reactor coolant pipe, as shown in Fig. 21.4. In most cases, these welds include alloy 182 cladding on the inside of the nozzle and an alloy 182 butter layer applied to the end of the low-alloy steel nozzle prior to vessel stress relief. Similarly, reactor vessels in Westinghouse-designed PWRs with two loops have safety injection nozzles connected to stainless steel piping using alloy 82/182 butt welds.

Babcock & Wilcox–designed plants, and all but one Combustion–Engineering–designed plant, do not have alloy 82/182 butt welds at reactor vessel inlet and outlet nozzles since the reactor coolant piping is carbon steel as opposed to stainless steel.

Reactor vessel core flood line nozzles in Babcock & Wilcox–designed plants have alloy 182 cladding and alloy 82/182 butt welds between the low-alloy steel nozzle and stainless steel core flood pipe.

21.2.6 Core Support Attachments

Most PWR vessels have alloy 600 lugs attached to the inside surface of the vessel, as shown in Fig. 21.5, to guide the reactor internals laterally or to support the reactor internals in the event of structural failure of the internals. These lugs are attached to cladding on the inside of the vessel by full penetration alloy 82/182 welds. In most cases, the vessel cladding in the area of the lugs is also alloy 182 weld metal.

21.2.7 Miscellaneous Alloy 600 Parts

Most reactor vessel lower closure flanges have alloy 600 leakage monitor tubes welded to the flange surface by alloys 82/182 weld metal. These are not discussed further since the leakage monitor tubes are not normally filled with water and, therefore, are not normally subjected to conditions that contribute to PWSCC.

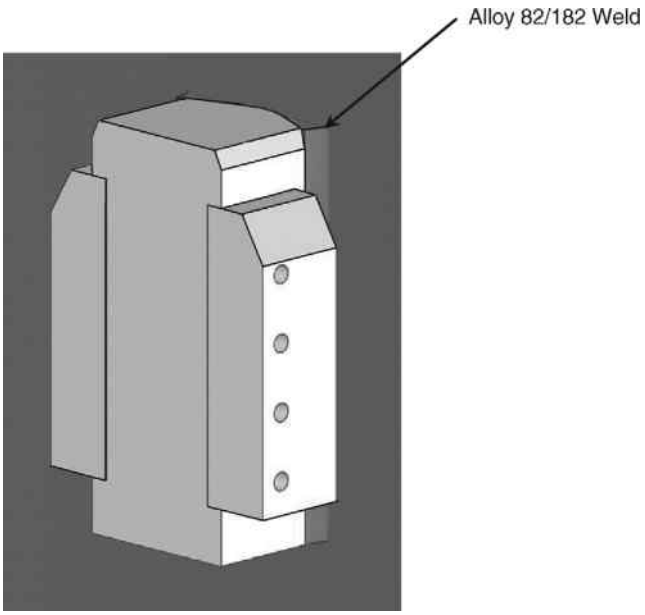


FIG. 21.5 TYPICAL CORE SUPPORT LUG

21.3 PWSCC

21.3.1 Description of PWSCC

PWSCC is the initiation and propagation of intergranular cracks through the material in a seemingly brittle manner, with little or no plastic deformation of the bulk material and without the need for cyclic loading. It generally occurs at stress levels close to the yield strength of the bulk material, but does not involve significant material yielding.

PWSCC occurs when three controlling factors, material susceptibility, tensile stress, and the environment, are sufficiently severe. Increasing the severity of any one or two of the three factors can result in PWSCC occurring, even if the severity of the remaining factor or factors is not especially high. The three factors are discussed separately in the following sections.

Mechanistic theories for PWSCC have been proposed, and advanced laboratory research and modeling approaches are being actively pursued [76]. However, a firm understanding of the underlying mechanism of PWSCC has not been developed. Accordingly, the influence of material susceptibility, stresses, and environment are generally treated on an empirical basis, without much support from theoretical models.

21.3.2 Causes of PWSCC: Material Susceptibility

Based on laboratory test data and plant experience, the following main factors influence the susceptibility of alloy 600 base metal and its weld alloys to PWSCC:

(a) *Microstructure*. Resistance to PWSCC tends to increase as the fraction of the grain boundaries that are decorated by chromium carbides increases. Various models have been proposed to explain this effect such as one where the carbides act as dislocation sources and enhance plastic deformation at crack tips, thereby blunting the cracks and impeding their growth [17]. The absence of carbides in the matrix of grains also correlates with higher resistance to PWSCC, as does larger grain size [18].

(b) *Yield Strength*. Susceptibility to PWSCC appears to increase as the yield strength increases. However, this is considered in part to be a result of higher yield strength material supporting higher residual stress levels and is, therefore, at least in part a stress rather than a material effect. As discussed in para. 21.3.3, tests indicate that the time to PWSCC initiation varies inversely with the fourth to seventh power of the total (applied plus residual) tensile stress [19–21].

(c) *Chromium Concentration*. Tests of wrought materials and weld materials in the nickel–chromium–iron alloy group of materials consistently indicate that susceptibility to PWSCC decreases as the chromium content increases [22,23]. Materials with 30% chromium or more are highly resistant to PWSCC. The improved resistance of alloy 82 vs. alloy 182 weld metal is attributed to the higher chromium concentration of alloy 82 (18–22%) vs. that of alloy 182 (13–17%). Alloy 690 base metal and alloys 52 and 152 weld metal, with about 30% chromium, have generally been found to be highly resistant to PWSCC in numerous tests.

(d) *Concentrations of Other Species and Weld Flaws*. No clear trends in PWSCC susceptibility have been observed as a function of the concentration of other species in the alloy such as carbon, boron, sulfur, phosphorous, or niobium. However, to the extent that these species, in combination with the thermomechanical processing to which the part is subjected, affect the carbide microstructure, they can have an indirect influence on susceptibility to PWSCC. Also, it is plausible that hot cracks caused by some of the species (e.g., sulfur and phosphorus) could act as PWSCC initiators or otherwise increase PWSCC susceptibility. However, some laboratory studies investigating this question have shown no significant effect of hot or ductility-dip cracks on the PWSCC process [62]. On the other hand, relatively large and sharp defects, such as some lack of fusion areas, could potentially promote PWSCC as a stress concentrator and source of increased stress intensity factor. Some plant experience [38,78,79] has demonstrated the potential for lack of fusion weld defects or weld inclusions to promote the occurrence of PWSCC.

21.3.3 Causes of PWSCC: Tensile Stresses

Industry design requirements, such as ASME BPVC Section III, specify the allowable stresses for reactor vessel components and attachments. The requirements typically apply to operating condition loadings such as internal pressure, differential thermal expansion, dead weight, and seismic conditions. However, the industry design standards do not typically address residual stresses that can be induced in the parts during fabrication. These residual stresses are often much higher than the operating condition stresses and are ignored by the standards since they are secondary (self-relieving) in nature. It is the combination of operating condition stresses and residual stresses that lead to PWSCC.

For the case of penetrations attached to the vessel heads by partial penetration J-groove welds, high residual stresses are caused by two main factors. Firstly, the surfaces of nozzles are typically machined prior to installation in the vessel. This machining cold works a thin layer (up to about 0.005 in. thick) on the surface, thereby significantly increasing the material yield and tensile strength near the surface. Secondly, weld shrinkage, which occurs when welding the nozzle into the high restraint vessel shell, pulls the nozzle wall outward, thereby creating yield strength level residual hoop stresses in the nozzle base metal and higher strength cold-worked surface layers. These high residual hoop stresses contribute to the initiation of axial PWSCC cracks in the cold-worked surface layer and to the subsequent growth of the axial cracks in the lower strength nozzle base material. The apparent lower frequency of cracking in weld metal relative to base metal may result from the fact that welds tend not to be cold worked and then subjected to high strains after the cold work.

Residual stresses in the nozzles and welds can lead to crack initiation from the inside surface of the nozzle opposite from the weld, from the outside surface of the nozzle near the J-groove weld, or from the surface of the J-groove weld.

Most PWSCC cracks have been axially oriented. This is consistent with results of finite element stress analyses, which predict that the hoop stresses exceed the axial stresses at most locations. However, axial stresses can also be high and circumferential cracks have occurred in some cases.

For the case of thick-wall butt welds, the weld shrinkage that occurs as progressive passes are applied from the outside surface produces tensile hoop stresses throughout the weld, axial tensile stresses on the outside weld surface (and often also the inside weld surface), and a region of axial compressive stress near midwall thickness. For welding performed from the outside (e.g., single-V design), the successive weld layers tend to reduce the magnitude of the hoop stress at the inside surface. The hoop stresses can contribute to axial PWSCC cracks in the weld and the axial stresses can contribute to circumferential cracks. Finite element analyses show

that the hoop stresses on the wetted inside surface of a butt weld are typically higher than the axial stresses at high stress locations, such that cracks are predicted to be primarily axial in orientation. However, if welds are repaired on the inside surface, or subjected to deep repairs from the outside surface, the residual hoop and axial stresses on the wetted inside surface can both approach the yield strength of the weld metal and can cause circumferential as well as axial cracks.

21.3.4 Causes of PWSCC: Environment

Several environmental parameters affect the rate of PWSCC initiation and growth. Temperature has a very strong effect. The effects of water chemistry variations are not very strong, assuming that the range of chemistry variables is limited to those that are practical for PWR primary coolant, i.e., with the coolant containing an alkali to raise pH above neutral and hydrogen to scavenge oxygen.

(a) *Temperature*. PWSCC is strongly temperature dependent. The activation energy for crack initiation is about 44 kcal/mole for thick section nozzle materials [24] and 50 kcal/mole for thinner cold-worked steam generator tubing material [25]. The activation energy for crack growth is about 31 kcal/mole [26]. Using these values, the relative factors for crack initiation and growth at typical pressurizer and cold leg temperatures of 653°F and 555°F relative to an assumed hot leg temperature of 600°F are given in Table 21.1.

(b) *Hydrogen Concentration*. Tests using crack growth rate specimens have shown that crack growth tends to be a maximum when the hydrogen concentration results in the electrochemical potential being at or close to the potential where the Ni/NiO phase transition occurs [27]. Higher or lower values of hydrogen decrease crack growth rates. This effect can be substantial, with peak crack growth rates in some cases being up to four times faster when the hydrogen concentration is at the value causing peak growth rate as compared to conditions with hydrogen values well away from the peak growth rate value, as shown in Fig. 21.6 [27]. Tests at various temperatures show that the hydrogen concentration for the Ni/NiO transition varies systematically with temperature, and that the hydrogen concentration causing the peak growth rate exhibits a similar trend, with the concentration causing the peak crack growth rate becoming lower as temperature decreases (e.g., 10 cc/kg at 320°C, 17 cc/kg at 330ºC, 24 cc/kg at 338°C, and 27.5 cc/kg at 360°C). Assessment of testing on the effect of hydrogen concentration on the initiation of PWSCC indicates that the time to initiation is reduced as hydrogen is increased up to the concentration correlating with the Ni/NiO equilibrium but that above the Ni/NiO equilibrium it has relatively little effect [69].

(c) *Lithium Concentration and pH.* Tests indicate that the effects of changes in pH on crack growth rate, once the pH is well above neutral, are minimal and cannot be distinguished from the effects of data scatter [28]. However, when considering the full pH range from acid to neutral to caustic, several tests indicate that crack growth rates decrease as pH is lowered to the neutral range and below, but is essentially constant for pH_T of about 6 to 8 [29,30].

While tests of crack growth rate indicate increases in pH and lithium concentration within the normal ranges used for PWRs have minimal effects on crack growth rate, some evaluations of crack initiation data indicate that increases in pH and lithium cause moderate decreases in the relative time to crack initiation, e.g., in the range of 10–15% for increases in cycle pH_T from 6.9 to 7.2 [28].

21.4 OPERATING EXPERIENCE

21.4.1 Precursor PWSCC at Other RCS Locations

PWSCC of alloy 600 material has been an increasing concern in PWR plants since cracks were discovered in the U-bend region of the original Obrigheim steam generators in 1971. The history of PWSCC occurrences around the full reactor coolant system up though 1993, i.e., not limited to the reactor vessel, is documented in an EPRI report [31]. Between 1971 and 1981, PWSCC cracks were detected at additional locations in steam generator tubes (e.g., at dents and at roll transitions), and in an increasing number of tubes. This experience showed that alloy 600 in the metallurgical condition used for steam generator tubes was quite susceptible to PWSCC, with susceptibility increasing as stress, cold work, and temperature increase. It was found that susceptibility was also strongly affected by the microstructure of the material, with susceptibility tending to decrease as the density of carbides on the grain boundaries increases.

The first case of PWSCC of alloy 600 in a non–steam generator tube application was reported in 1982. This incident involved PWSCC of an alloy 600 pressurizer heater sleeve [31]. Swelling of a failed electric heater element inside this sleeve was identified as a contributing cause. Subsequent to this occurrence, an increasing number of alloy 600 instrument nozzles and heater sleeves in pressurizers were detected with PWSCC. Also, increasing numbers of instrument nozzles in reactor coolant system hot legs and steam generator heads also were detected with PWSCC. Many of the susceptible nozzles and sleeves have been repaired or replaced on a corrective or preventive basis [31].

PWSCC in alloys 182 and 82 weld metals was first detected in 2000 in reactor vessel hot leg nozzle welds [32,77]. Also in 2000 was found the first detection of PWSCC in a reactor vessel head penetration weld, as discussed in para. 21.4.2.

TABLE 21.1 FACTORS ON CRACK INITIATION AND GROWTH TIME AT TYPICAL PWR TEMPERATURES

Location and Temperature	Crack Growth Q = 31 kcal/mole	Crack Initiation Thick Section Nozzles Q = 44 kcal/mole	Crack Initiation Thin Wall Tubing Q = 50 kcal/mole
Typical Cold Leg - 555°F	0.31	0.19	0.15
Typical Hot Leg - 600°F	1.00	1.00	1.00
Pressurizer - 653°F	3.54	6.00	7.66

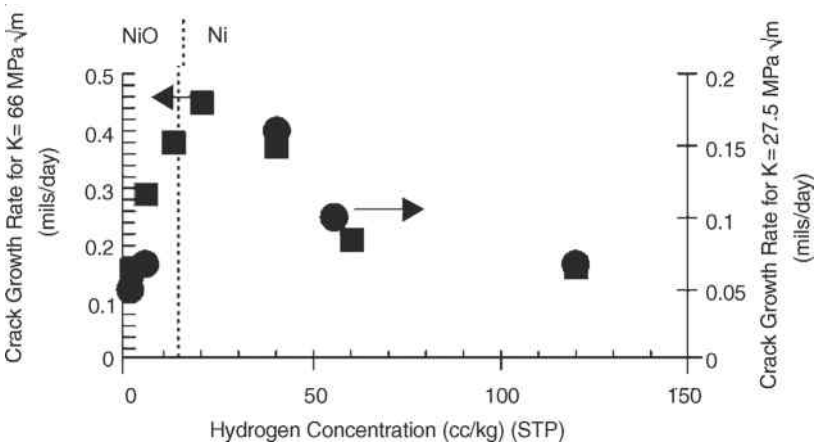


FIG. 21.6 ALLOY 600 CRACK GROWTH RATE AT 338°C PLOTTED VS. HYDROGEN CONCENTRATION [27]

21.4.2 RPV Top-Head Penetrations

The first reported occurrence of PWSCC in a PWR reactor vessel application involved a leak from a CRDM nozzle at Bugey 3 in France that was detected during a 10-year inservice inspection program hydrostatic test conducted in 1991 [33]. This initial occurrence, and the occurrences detected during the next few years, involved PWSCC of alloy 600 base material at locations with high residual stresses resulting from fabrication. The high residual stresses were mainly the result of weld-induced deformation being imposed on nozzles with cold-worked machined surfaces.

Subsequent to the initial detection of PWSCC in a CRDM nozzle in 1991, increasing numbers of plants detected similar types of PWSCC, typically resulting in small volumes of leakage and boric acid deposits on the head surface as shown in Fig. 21.7. In 2000, circumferential cracks were detected on the outside diameter of some CRDM nozzles. In 2002, significant wastage of the low-alloy steel Davis-Besse reactor vessel head occurred adjacent to an axial PWSCC crack in an alloy 600 CRDM nozzle. The wastage was attributed to corrosion by boric acid in the leaking primary coolant that concentrated on the vessel head. Figure 21.8 shows a photograph of the corroded surface at Davis-Besse. The Davis-Besse plant was shut down for approximately 2 years for installation of a new head and incorporation of changes to preclude similar corrosion in the future. The NRC issued several bulletins describing these events



FIG. 21.7 TYPICAL SMALL VOLUME OF LEAKAGE FROM CRDM NOZZLE



FIG. 21.8 LARGE VOLUME OF WASTAGE ON DAVIS-BESSE REACTOR VESSEL HEAD

and requiring utilities to document their inspection plans for this type of cracking [34–36].

The cracking discussed above was mainly related to PWSCC of alloy 600 base materials. Starting in November 2000, some plants found PWSCC primarily in the J-groove weld metal, e.g., in CRDM nozzle-to-vessel alloy 182 J-groove welds [37]. Since that time, several other cases of PWSCC of CRDM nozzle-to-head welds have been detected, and PWSCC in alloys 182 and 82 welds was detected at other non–reactor vessel locations around the reactor coolant system. However, the apparent frequency of PWSCC in welds remains lower than in alloy 600 base material. For example, after the detection of PWSCC in the weld metal of a CRDM nozzle at a PWR in the United States in November 2000, and the detection of PWSCC in the alloy 182 weld metal at reactor vessel outlet nozzles in the United States and Sweden in 2000, EDF inspected 754 welds in 11 replaced reactor vessel heads without detecting any cracks [24].

Between 2007 and 2012, PWSCC indications were reported in CRDM penetrations in five U.S. top heads operating at reactor cold-leg temperature. Between one and five nozzles were affected in each head, and all the indications were part through-wall. The earliest case was associated with the presence of a lack-of-fusion type defect located at the interface between the alloy 600 base metal and alloy 82/182 weld metal [78,79]. It is noted that this set of PWSCC experience is associated with a particular category of CRDM nozzle material that has shown a relatively high frequency of cracking at higher operating temperatures, demonstrating the importance of materials and fabrication-related factors to PWSCC susceptibility.

21.4.3 RPV Nozzle Butt Welds

In October 2000, a visual inspection showed a leak from an alloys 82/182 butt weld between a low-alloy steel reactor vessel hot-leg outlet nozzle and stainless steel hot-leg pipe at the V.C. Summer plant. Destructive failure analysis showed that the leak was from a through-wall axial crack in the alloys 82/182 butt weld, as shown in Fig. 21.9. The axial crack arrested when it reached the low-alloy steel nozzle on one side and stainless steel pipe on the other side, since these materials are generally considered to not be susceptible to PWSCC. The axial crack can propagate into the low-alloy steel and stainless steel by fatigue, but the fatigue crack growth rates will be low due to the small number of fatigue cycles. The destructive examination also showed a short-shallow circumferential crack intersecting the through-wall axial crack that grew through alloy 182 cladding and terminated when it reached the low-alloy steel nozzle base metal. Examination of fabrication records showed that the leaking butt weld had been extensively repaired during fabrication, including repairs made from the inside surface. Nondestructive examinations of the other two reactor vessel outlet nozzles at V.C. Summer showed some additional shallow axial and circumferential indications that were addressed by mechanical stress improvement during the subsequent refueling outage in 2002. Four indications were identified by eddy current testing in 2000, two of which were detectable via ultrasonic testing in 2002.

Shortly before the leak was discovered at V.C. Summer, part-depth axial cracks were discovered in alloys 82/182 reactor vessel outlet nozzle butt welds at Ringhals 3 and 4 [78,79]. Some of these cracks were removed and two were left in place to allow a determination of the crack growth rate. The crack growth rate is discussed in para. 21.7.2.

In addition to the PWSCC cracks in alloys 82 and 182 weld metal in reactor vessel CRDM nozzles and outlet nozzle butt welds, a leak was found from a pressurizer nozzle butt weld at Tsuruga 2 in Japan and a part-depth crack was detected in a hot-leg pressurizer surge line nozzle butt weld at TMI-1. Both of

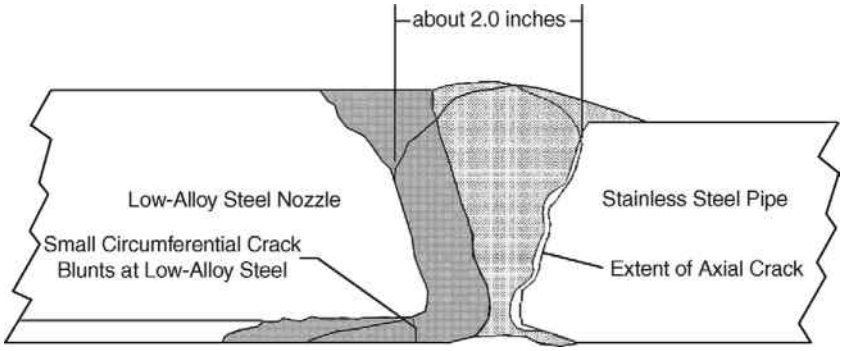


FIG. 21.9 THROUGH-WALL CRACK AND PART-DEPTH CIRCUMFERENTIAL CRACK IN V.C. SUMMER REACTOR VESSEL HOT-LEG OUTLET NOZZLE

these cases occurred in 2003. Cracks were also detected in alloys 82 and 182 cladding in steam generator heads that had been hammered and cold worked by a loose part [24].

In the 2005–2013 time period, the industry implemented a massive inspection program for PWSCC in primary coolant loop Alloy 82/182 butt welds (in accordance with Industry Guideline MRP-139 [58] and ASME Code Case N-770-1 [70] – see para. 21.5.6 below for complete discussion). Considering the temperature sensitivity of the PWSCC phenomenon discussed above, this program started with the highest temperature welds in the system: those at pressurizer nozzles. As of 2013, PWSCC indications have been reported in about 21 alloy 82/182 piping butt welds in U.S. PWRs, including several cases of circumferential indications (see Table 21.2). Beginning in 2007, several cases of PWSCC indications were reported in the alloy 82/132 inlet nozzle-to-safe-end weld region of steam generators in several Japanese PWRs [80]. (Alloy 132, which is close in composition to alloy 182, was used in Japanese PWRs instead of alloy 182.) As of 2013, many of the locations operating at pressurizer or hot-leg temperature in U.S. PWRs have been mitigated

TABLE 21.2 SURFACE CRACKING INDICATIONS IN REACTOR COOLANT LOOP ALLOY 82/182 BUTT WELDS IN US PWRS, THROUGH 2012 (LARGEST AXIAL AND CIRCUMFERENTIAL INDICATIONS LISTED IN EACH WELD)

Location	Plant	Nozzle Type	Inspection		Operating Temp. (°F)	Type of Indication	Indication Depth (a, in.)	ID Indication Length (l, in.)	a / thickness	l/a Aspect Ratio	l / circumference
			Operating Time (EFPY)	Date							
Pressurizer	A	Safety Relief	23.1	2006	653	Axial	0.10	0.60	8%	6.0	0%
	B	Safety Relief	19.2	2005	653	Axial	1.23	0.40	88%	0.3	0%
	C	Safety Relief	17.9	2006	653	Circ	0.30	2.51	23%	8.4	15%
	C	Safety Relief	17.9	2006	653	Circ	0.34	7.69	26%	22.6	47%
	F	Relief (Note 1)	10.0	1993	643	Circ	0.44	3.50	100%	8.0	32%
	D	Spray	13.9	2005	653	Axial	0.21	0.25	24%	1.2	0%
	E	Surge	21.9	2007	653	Axial	0.31	0.50	20%	1.6	0%
						Circ	0.51	3.00	33%	5.9	7%
	C	Surge	17.9	2006	653	Circ	0.45	4.03	31%	9.0	11%
Hot Leg	G	RPV Outlet	16.5	2009	621	Axial	0.61	0.96	21%	1.6	0%
	H	RPV Outlet	13.6	2000	621	Axial	2.50	2.50	100%	1.0	0%
						Circ	0.20	2.00	8%	10.0	2%
	H	RPV Outlet	14.7	2002	621	Axial	0.32	0.63	13%	2.0	0%
	H	RPV Outlet	14.7	2002	621	Circ	0.11	0.38	4%	3.4	0.4%
	K	RPV Outlet	20.2	2008	605	Circ	0.63	2.06	24%	3.2	2%
	I	SG Inlet	26.6	2012	620	Axial	4.10	2.00	88%	0.5	0%
	J	Decay Heat	19.2	2008	605	Axial	1.25	1.75	100%	1.4	0%
	L	Decay Heat	21.6	2008	601	Circ	0.90	10.00	69%	11.1	30%
	M	HL Surge	19.2	2003	601	Axial	0.59	Note 2	45%	Note 2	0%
	A	HL Surge	23.1	2006	597	Circ	0.40	2.40	25%	6.0	6%
	A	HL Drain	23.1	2006	597	Circ	0.10	0.45	19%	4.5	5%
	N	HL Drain	21.7	2005	597	Axial	0.39	Note 3	70%	Note 3	0%
Cold Leg	J	CL Drain	17.6	2006	555	Axial	0.06	≥ 0.25	7%	≥ 4.5	0%

Notes:
(1) PWSCC indication was located in heat affected zone of an Alloy 600 safe end.
(2) Indication reported to extend over the width of weld metal.
(3) Indication width not available

by weld overlay or by mechanical stress improvement. In addition, mitigation with peening surface stress improvement has been extensively applied in Japanese PWRs and BWRs [71,81], and has been announced for application to reactor vessel main loop nozzles in U.S. PWRs.

21.4.4 RPV Bottom-Head Penetrations

In 2003, bare metal visual inspections of the reactor vessel bottom head at South Texas 1 showed small leaks from two BMI nozzles, as shown in Fig. 21.10. These leaks were traced to PWSCC cracks in the nozzles that likely initiated at small regions of lack-of-fusion in the J-groove welds between the nozzles and vessel head [38]. The nozzles were repaired. Examinations of the other BMI nozzles at South Texas 1 showed no additional cracks. Essentially all other U.S. plants have performed bare metal visual inspections of RPV bottom-head nozzles without any evidence of leaks. About 23 U.S. plants have completed volumetric examinations of BMI nozzles, representing about a third of the total population of RPV bottom-head nozzles in the U.S., with no reported indications of cracking.

In France, two indications of PWSCC were reported in a single bottom-head nozzle at Gravelines 1 in 2011 [82]. The cracks were detected by UT inspection during the third in-service inspection. The indications did not extend through wall and no additional indications were detected in other nozzles at the plant. The affected nozzle was temporarily plugged to prevent the flaw from being exposed to primary coolant and the plant returned to service while a repair was planned. It was reported that the PWSCC indications were associated with previously detected fabrication defects in the alloy 600 nozzle tube base metal. Other than one other unconfirmed case [83,84], there have been no other reports of PWSCC in bottom-head nozzles in the U.S. or other countries as of July 2013.

Inspection experience has confirmed that BMI nozzles, which operate at the plant cold-leg temperature, are much less susceptible to PWSCC compared to locations operating at hot-leg or pressurizer temperatures. The cases of PWSCC reported in BMI nozzles seem to have been prompted by the presence of particular types of manufacturing defects.



FIG. 21.10 LEAK FROM SOUTH TEXAS 1 BMI NOZZLE

21.4.5 Conclusions Regarding Operating Experience

The key factors that act to increase the frequency of reports of PWSCC in PWRs are high operating temperature, high tensile residual stress, susceptible microstructures, and the presence of some types of manufacturing flaws. As components age, the locations affected by PWSCC are slowly spreading to those with lower temperatures and lower stresses. However, inspection programs are successfully identifying PWSCC flaws at relatively early stages and sizes, such that PWSCC is not significantly impacting safety.

21.5 INSPECTION METHODS AND REQUIREMENTS

As a result of the PWSCC cracks and leaks identified in important PWR reactor vessel alloys 600, 82, and 182 materials since 2000, significant efforts were made by the nuclear industry and the NRC to improve inspection capabilities and develop appropriate long-term inspection requirements. The following summarizes the status of inspection methods and requirements as of October 2013. It is recommended that users check with the NRC and industry programs to remain abreast of the latest changes in inspection methods and requirements.

21.5.1 Visual Inspections

Bare metal visual inspections have proven to be an effective way of detecting very small leaks, as shown by Figs. 21.7 and 21.10, and, therefore, should play an important role in any inspection program. A key prerequisite for these inspections is that the surface should be free of preexisting boric acid deposits from other sources, because the presence of preexisting boric acid deposits can mask the small volumes of deposits shown in Figs. 21.7 and 21.10. Visual inspections with insulation in place can provide a useful backup to bare metal visual inspections but will be incapable of detecting small volumes of leakage, as shown in Figs. 21.7 and 21.10.

In many cases, it has been necessary to modify insulation packages on the vessel top and bottom heads to facilitate performing bare metal visual inspections.

ASME Code Case N-722, Additional Examinations for PWR Pressure-Retaining Welds in Class 1 Components Fabricated with Alloys 600/82/182 Materials, Section XI, Division 1, was approved in 2005 to provide for direct visual inspections of potentially susceptible welds for boric acid leakage.

21.5.2 Nondestructive Examinations

Technology exists to nondestructively examine all of the alloys 600, 82, and 182 locations in the reactor vessel.

Partial-penetration welded nozzles (CRDM, CEDM, ICI) are typically examined using one of two methods. The nozzle base metal can be examined volumetrically from the inside surface by ultrasonics to confirm that the nozzle base material is free of detectable axial or circumferential cracks of detectable size. Alternatively, the wetted surfaces of the alloy 600 base metal and alloys 82 and 182 weld metal can be examined by eddy current probes to ensure that there are no surface cracks. If there are no surface cracks on wetted alloy 600/82/182 surfaces, then it can be inferred that there will also be no cracks within the nozzle base material. Ultrasonic and eddy current examination of the ID

surface of CRDM and CEDM nozzles is often performed using blade probes given the presence of a thermal sleeve inside many of these nozzles. Nozzles in the reactor vessel top head can be examined when the head is on the storage stand during refueling. Nozzles in the reactor vessel bottom head can be examined ultrasonically or by eddy current when the lower internals are removed from the vessel during a 10-year in-service inspection outage. In some cases, the inside surfaces of BMI instrument nozzles can be examined by tooling inserted through holes in the lower internals.

Reactor vessel inlet and outlet nozzle butt welds are inspected ultrasonically from the inside or outside surface. Eddy current methods are also being used in some cases for examining the inside surfaces of these welds for cracks, although eddy current inspection sensitivity is a function of the condition of the weld surface. For example, discontinuities in the weld profile can cause the eddy current probes to lift off of the surface being examined and, thereby, adversely affect the inspection sensitivity.

A key to obtaining good nondestructive examinations is to have the process and the operators qualified on mockups containing prototypical axial and circumferential flaws. The EPRI NDE Center in Charlotte, NC coordinates qualification efforts for inspection methods and inspectors in the United States.

21.5.3 ASME BPVC Reactor Vessel Inspection Requirements

ASME BPVC Section XI [51] specifies inservice inspection requirements for operating nuclear power plants in the United States. Portions of these requirements that apply to PWSCC-susceptible components in the RPV are summarized as follows:

(a) Table IWB-2500-1, Examination Category B-P, requires a VT-2 visual examination of the reactor vessel pressure-retaining boundary during the system leak test after every refueling outage. No leakage is permitted.

(b) Table IWB-2500-1, Examination Category B-O, requires that the welds in 10% of the peripheral control rod drive housings and the welds in 10% of the in-core instrumentation nozzle housings > NPS 2 be inspected by volumetric or surface methods each Section XI inspection interval (i.e., about every 10 calendar years).

(c) Table IWB-2500-1, Examination Category B-N-2, requires that attachment welds to the inside surface of the reactor vessel be examined visually each Section XI inspection interval. Welds in the beltline region must be inspected by VT-1 methods while welds outside the beltline region (which include BMI penetration attachment welds) must be inspected by VT-3 methods. PWSCC flaws typically are tight intergranular flaws, and as such typically are not expected to be detectable during a VT-3 visual examination. However, for unusually severe PWSCC there is the possibility of gross defects that are detectable via a visual examination.

(d) Table IWB-2500-1, Examination Category B-F, specifies examination requirements for dissimilar metal welds at reactor and other vessel nozzles. Nozzle-to-safe end socket welds must be examined by surface methods every Section XI inspection interval. Nozzle-to-safe end butt welds less than NPS 4 must be examined by surface methods every inspection interval. Nozzle-to-safe end butt welds NPS 4 and larger must be examined by volumetric and surface examination methods every inspection interval. Some deferrals of these inspections are permitted. For the case of alloy 82/182 dissimilar metal butt welds in PWR vessel nozzles, the alternative examination requirements of Code Case N-770-1 [70] have been mandated by the U.S. NRC in lieu of the Examination Category B-F requirements (see para. 21.5.6).

(e) Table IWB-2500-1, Examination Category B-J, specifies examination requirements for pressure retaining welds in primary system piping. The welds covered by this examination category include alloy 82/182 dissimilar metal piping welds not covered under Category B-F. The examination requirements depend on the weld type (circumferential weld, branch pipe connection weld, socket weld) and pipe size (NPS 4 or larger, less than NPS 4). Generally, all dissimilar metal welds not covered under Category B-F must be examined every Section XI inspection interval. For the case of alloy 82/182 dissimilar metal butt welds in PWR primary system piping, the alternative examination requirements of Code Case N-770-1 [70] have been mandated by the U.S. NRC in lieu of the Examination Category B-J requirements (see para. 21.5.6).

(f) As an alternative to the examination requirements of Table IWB-2500-1 for primary system piping (Examination Categories B-F and B-J) and subject to NRC approval, the examination requirements of Section XI, Nonmandatory Appendix R, "Risk-Informed Inspection Requirements for Piping," may be applied to primary system piping evaluated by a risk-informed process. For the case of alloy 82/182 dissimilar metal butt welds in PWR primary system piping and vessel nozzles, the alternative examination requirements of Code Case N-770-1 [70] have been mandated by the U.S. NRC (see para. 21.5.6).

In response to the cases of cracks and leaks caused by PWSCC of alloy 600/82/182 materials in PWR primary coolant systems, and also reflecting the severity of the boric acid corrosion that has been detected at a few of these cases, ASME has issued a set of code cases with augmented or alternative inspection requirements for alloy 600/82/182 pressure boundary components. As described below, Code Case N-729-1 [63] defines inspection requirements for top head nozzles, and Code Case N-770-1 [70] defines inspection requirements for alloy 82/182 butt welds in primary system piping and vessel nozzles. Code Case N-722-1 [64] defines requirements for external direct visual examinations (VEs) of other pressure boundary components fabricated with alloy 600/82/182 materials, including BMI penetrations, for evidence of pressure boundary leakage. These code cases have been made mandatory in the U.S. by U.S. NRC regulations (10 CFR 50.55a.) [86].

21.5.4 Augmented Inspection Requirements for RPV Top-Head Nozzles

Subsequent to the discovery of significant corrosion to the Davis-Besse reactor vessel head, the U.S. NRC issued NRC Order EA-03-009 [39] specifying new inspection requirements for RPV top-head nozzles in U.S. PWRs. This order mandated (1) periodic volumetric or surface examinations for PWSCC flaws and (2) periodic direct visual examinations for evidence of pressure boundary leakage.

ASME Code Case N-729-1 [63] superseded the NRC order and defines the current inspection requirements (as of October 2013) for alloy 600 top-head nozzles attached using partial-penetration (i.e., J-groove) welds, including CRDM and CEDM nozzles. Similar to the order, the code case specifies periodic volumetric/

surface examinations, as well as periodic direct visual examinations for evidence of pressure boundary leakage. In the surface examination approach, the absence of surface breaking indications on the nozzle and weld wetted surfaces is used to show that there are no axial or circumferential cracks in the nozzle base metal. It bases the frequency of inspection in part on calculated parameters called the Effective Degradation Years (EDY) and the Reinspection Years (RIY) of the head, each of which is a function of the time and temperature history of the head. As discussed in para. 21.3.4, PWSCC is strongly temperature dependent. Because RPV top heads operate at varying temperatures, there are relatively large head-to-head temperature differences between plants.

The code case provides detailed instructions regarding how to evaluate and follow up visual inspections that detect evidence of reactor coolant leakage or boric acid wastage, and also on how to follow up on flaws detected by volumetric or surface examinations. The requirements in Code Case N-729-1 were developed by ASME, with extensive technical input provided by the EPRI Materials Reliability Program [68]. This code case has been made mandatory in the U.S. by the U.S. NRC through regulation 10 CFR 50.55a(g)(6)(ii)(D), subject to conditions. The NRC conditions generally cover issues related to performance of ultrasonic inspections and required re-inspection intervals.

The volumetric inspection intervals (between examinations of all nozzles) per N-729-1 are based on the Reinspection Years (RIY) parameter, which is a measure of operating time normalized to a head temperature of 600°F using the consensus temperature dependence of the PWSCC crack growth rate. The required interval is every 8 calendar years or before RIY = 2.25, whichever is less. More frequent volumetric/surface examinations may be required if PWSCC has previously been detected in the subject head.

Code Case N-729-1 also contains inspection requirements for PWR top heads with nozzles and partial-penetration welds of PWSCC-resistant materials (i.e., alloy 690 nozzles with alloy 52/152 welds) to address new and replacement heads.

Updates to N-729-1 through N-729-4 (approved June 22, 2012) have been issued by ASME, but the version that is currently made mandatory by the NRC regulations is still N-729-1 as of October 2013. The most substantive change in the inspection requirements between N-729-1 and N-729-4 is the incorporation of NRC conditions in 10 CFR 50.55a(g)(6)(ii)(D) related to qualification by blind demonstration of ultrasonic examination personnel, procedures, and equipment.

21.5.5 Augmented Inspection Requirements for RPV BMI Nozzles

NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity" [40], summarized the leakage from BMI nozzles at South Texas 1 and required utilities to describe the results of BMI nozzle inspections that had been performed at their plants in the past and that were to be performed during the next and following refueling outages.

As noted in para. 21.5.1, ASME Code Case N-722-1 [64] defines augmented inspection requirements (as of October 2013) for PWR primary system pressure boundary components fabricated with alloy 600/82/182 materials. The components addressed by this code case include the RPV BMI penetrations located in most U.S. PWRs. Code Case N-722-1 specifies that all alloy 600 BMI penetrations are to be inspected every other refueling outage using direct bare metal visual inspection, or remote visual inspection with equivalent resolution of the component metal surface. In the U.S., N-722-1 has been made mandatory by the U.S. NRC through regulation 10 CFR 50.55a(g)(6)(ii)(E), subject to conditions that generally cover issues related to how to investigate detected flaws. The examination is performed for evidence of pressure boundary leakage and corrosion on the adjacent low-alloy steel material of the lower head, and the examination may be performed when the system is depressurized.

As of October 2013, there are no requirements for volumetric or surface examinations of BMI penetrations for the presence of PWSCC. Nevertheless, approximately one third of the BMI penetrations in U.S. PWRs have been volumetrically examined (often accompanied by eddy current surface examination) on a voluntary basis or as an alternative approved by the U.S. NRC on a case-specific basis to the direct visual examination requirement of N-722-1.

It is noted that the inspection frequency for BMI penetrations, which was originally specified in 2005 in the initial version of ASME Code Case N-722, was based on consideration of operating temperature and engineering judgment [104]. A detailed safety assessment published by EPRI in 2009 [85] constitutes a technical basis for the inspection requirements of N-722-1 as applicable specifically to BMI penetrations.

Code Case N-722-2 (approved September 8, 2011) has been issued by ASME, but the version that is currently made mandatory by the NRC regulations is still N-722-1 as of October 2013. The N-722-2 revision newly excludes alloy 82/182 butt welds in primary system piping. These locations are instead addressed by Code Case N-770-1 [70] as described below.

21.5.6 Augmented Inspection Requirements for Alloy 82/182 Dissimilar Metal Butt Welds in PWR Primary

ASME Code Case N-770-1 [70] provides alternative inspection requirements (as of October 2013) for visual, volumetric, and surface examinations of PWR piping and vessel nozzle butt welds in the primary system that are made of alloys 82 and/or 182, materials that are considered to be susceptible to PWSCC. This code case has been made mandatory in the U.S. by the U.S. NRC through regulation 10 CFR 50.55a(g)(6)(ii)(F), subject to conditions. The NRC conditions cover topics such as how to treat welds that have had PWSCC mitigation measures applied. Note that the inspection requirements including inspection frequencies for alloy 82/182 piping and nozzle butt welds were previously defined in Revision 1 of MRP-139 [58].

The volumetric re-inspection interval per N-770-1 for components not treated by a qualified mitigation method depends on the operating temperature of the component in consideration of the strong dependence of PWSCC susceptibility to temperature (see para. 21.3.4). The volumetric inspection frequency for unmitigated alloy 82/182 welds operating at reactor hot-leg temperature (Category A-2) is every 5 years. The volumetric inspection frequency for unmitigated alloy 82/182 welds operating at reactor cold-leg temperature (Category B) is every second inspection period (as defined in ASME Section XI), not to exceed 7 years.

Code Case N-770-1 includes specific categories to address inspection methods and frequencies for alloy 82/182 piping butt weld locations mitigated against PWSCC. It covers inspection requirements for welds mitigated by weld overlay, weld inlay, weld on-lay, and mechanical stress improvement. The repair and mitigation options are discussed further in para. 21.8 and 21.9. As

of October 2013, ASME is considering inspection requirements for welds mitigated by surface stress improvement via peening.

Updates to N-770-1 through N-770-3 (approved April 7, 2013) have been issued by ASME, but the version that is currently made mandatory by the NRC regulations is still N-770-1 as of October 2013. N-770-2 includes a modest change in the inspection requirements for components mitigated by a qualified stress improvement process. N-770-3 reduces the inspection frequency for large-diameter (i.e., NPS 14 or larger) unmitigated butt welds operating at reactor cold-leg temperature to once per Section XI inspection interval. Access to the inside surface of reactor vessel inlet nozzles requires removal of the vessel core barrel, which typically is scheduled only during 10-year reactor vessel in-service inspection outages. The technical basis for this change to inspection frequency is provided by EPRI report MRP-349 [80].

21.6 SAFETY CONSIDERATIONS

21.6.1 Small Leaks

Small leaks due to axial cracks such as shown in Figs. 21.7 and 21.10 do not pose significant safety risk. The leak rates are low enough that the leaking primary coolant water will quickly evaporate leaving behind a residue of dry boric acid. Most of the leaks detected to date have resulted in these relatively benign conditions. As shown in the figures, very small leaks are easily detected by visual inspections of the bare metal surfaces provided that the surfaces are free from boric acid deposits from other sources. One explanation for the extremely low leak rates is that short tight PWSCC cracks can become plugged with precipitates (e.g., boric acid deposits) from the evaporation of primary coolant, thereby preventing leakage under normal operating conditions. It is hypothesized that distortions, which occur during plant transients, allow small amounts of leakage through the crack before it becomes plugged again. Regardless, these small leaks do not pose a significant safety concern.

21.6.2 Rupture of Critical Size Flaws

Initially, leaking RPV top-head nozzles were thought to be exclusively the result of axial cracks in the nozzles, and it was thus believed that they did not represent a significant safety concern. However, as more examinations were performed, findings arose that called this hypothesis into question.

(a) Relatively long circumferential cracks were observed in two nozzles in the Oconee Unit 2 RPV head, and several other plants also discovered shorter circumferentially oriented cracks.
(b) Circumferential NDE indications were discovered in the North Anna Unit 2 head in nozzles that showed no apparent signs of boric acid deposits due to leakage.

Figure 21.11 presents a schematic of a top-head CRDM nozzle and J-groove weld and the nature of the cracking that has been observed. There is some uncertainty as to whether circumferential cracks arise as a result of axial cracks growing through the weld or nozzle and causing leakage into the annular region between the nozzle and head, ultimately leading to reinitiation of circumferential cracking on the outside surface of the tube, or if they are due to the axial cracks branching and reorienting themselves in a circumferential direction, as depicted on the right-hand side of Fig. 21.11. A destructive examination program has been performed on several of the North Anna Unit 2 nozzles, indicating

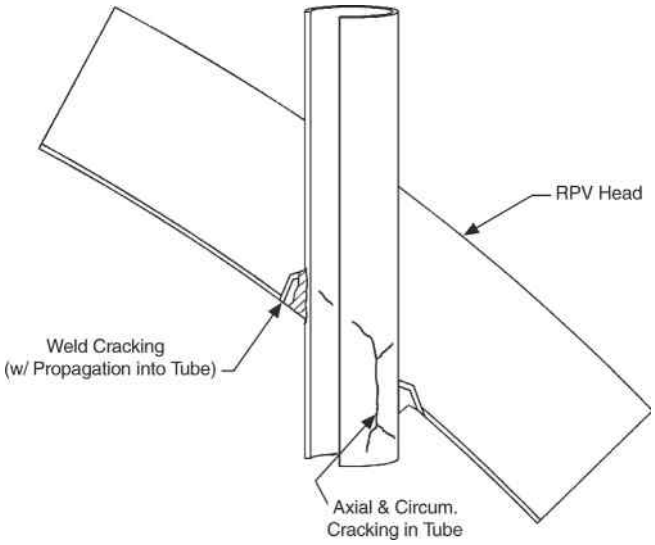


FIG. 21.11 SCHEMATIC OF RPV TOP-HEAD NOZZLE GEOMETRY AND NATURE OF OBSERVED CRACKING

that the circumferential nozzle defects found there were in fact the result of grinding during fabrication rather than service-related cracking. Nevertheless, the occurrence of circumferential cracking adds a new safety perspective to the RPV top-head nozzle cracking problem, because of the potential for such cracks to grow to a critical length and ultimately lead to ejection of a nozzle from the vessel, although a large circumferential flaw covering more than 90% of the wall cross section is typically calculated for nozzle ejection to occur because of the relatively thick wall typical of RPV top-head nozzles.

PWSCC in PWR RPV inlet/outlet nozzles could also potentially develop circumferentially oriented flaws, which could ultimately lead to pipe rupture. To date, observed cracking has been primarily axial with relatively small circumferential components. With time, however, PWSCC in large piping butt welds might be expected to follow trends similar to the IGSCC cracking issue in BWRs [42]. In the BWR case, cracking and leakage were initially seen only as axially oriented cracks in smaller diameter piping. With time, however, axial and circumferential cracking were observed in pipe sizes up to and including the largest diameter pipes in the system. Considering the potential existence of weld repairs during initial construction of the plants and the associated high residual stresses that they produce in both axial and circumferential directions, significant circumferential cracking may eventually be observed in large-diameter PWR pipe-to-nozzle butt welds.

Because of the concern for PWSCC in PWR piping dissimilar metal butt welds, methods for predicting the critical crack size for rupture in such welds have received attention [59]. Axial PWSCC flaws in these welds are limited to the width of the alloy 82/182/132 weld material. Experience has confirmed that the PWSCC cracks arrest when they reach the PWSCC-resistant low-alloy steel and stainless steel materials [50]. Therefore, the maximum axial crack lengths are limited to a few inches at most (much less than the critical axial flaw length), except for the small number of cases involving alloy 600 safe ends or alloy 600 pipe/tube (CRDM and BMI nozzles), where axial cracks initiating in the weld could potentially propagate into the alloy 600 base metal. Thus, critical crack size calculations for PWR piping dis-

similar metal butt welds typically assume one or more circumferentially oriented PWSCC flaws.

In 2007, EPRI sponsored a detailed investigation of the growth of circumferential PWSCC flaws in PWR pressurizer nozzle dissimilar metal butt welds [59]. Using finite-element methods, this study examined the effect of an arbitrary crack profile on crack growth and subsequent crack stability and leak rate versus the standard assumption of a semi-elliptical crack profile. The crack stability (i.e., critical crack size) modeling of the EPRI study was based on a standard limit load (i.e., net section collapse) approach as applied to an arbitrary crack profile around the weld circumference [65]. The potential for an EPFM failure mode was considered using a Z-factor approach specific to piping dissimilar metal welds [66]. Finally, the role of secondary piping thermal constraint stresses in the rupture process was investigated on the basis of available experimental pipe rupture data [67], elastic-plastic finite-element analyses of a pipe with an idealized through-thickness crack [59], and pressurizer surge line piping models applied to evaluate the maximum capacity of the secondary loads to produce rotation at a cracked pressurizer surge nozzle [59].

21.6.3 Boric Acid Wastage Due to Larger Leaks

Small concentrations of boron are added to the primary coolant water in PWR plants in the form of boric acid to aid in controlling core reactivity. At the start of an operating cycle with new fuel, the boron concentration is typically about 2,000 ppm or less. The concentration of boron is reduced with fuel burnup to about 0 ppm at the end of an operating cycle when fuel is ready to be replaced. Work by EPRI and others to determine the probable rate of corrosion of low-alloy steel by boric acid is documented in the EPRI Boric Acid Corrosion Guidebook [43]. This document shows that the corrosion rate of low-alloy steel by deareated primary coolant (inside the pressure vessel and piping) with 2,000 ppm boron is negligible. The corrosion rate for low concentration (2,000 ppm) aerated boric acid is also very low. However, when high-temperature borated water leaks onto a hot surface, the water can boil off leaving concentrated aerated boric acid. The corrosion rate of low-alloy steel by hot concentrated aerated boric acid can be as high as 10 in./year under some conditions.

As evidenced by the significant volume of material corroded from the Davis-Besse reactor vessel head, boric acid corrosion has the potential to create significant safety risk. Figure 21.12 shows cross-section and plan views of the corroded region of the Davis-Besse head shown in Fig. 21.8. As indicated, a large volume of the low-alloy head material was corroded, leaving the stainless steel cladding on the inside of the vessel head to resist the internal pressure. Part-depth cracks were discovered in the unsupported section of cladding.

Based on available evidence, it was determined that the leakage that caused the corrosion had been occurring for at least 6 years. While it was known that boric acid deposits were accumulating on the vessel top head surface, the utility attributed the accumulations to leakage from spiral-wound gaskets at the flanged joints between the CRDM nozzles and the CRDMs. The accumulations of boric acid had not been removed due to poor access to the

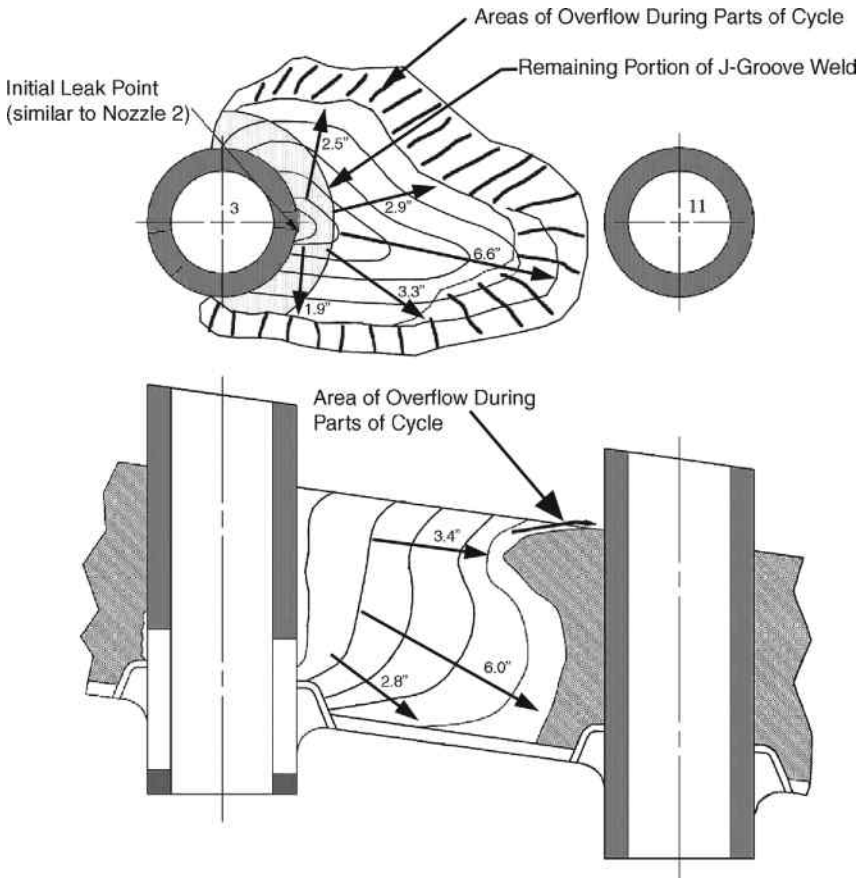


FIG. 21.12 PLAN AND CROSS-SECTION THROUGH CORRODED PART OF DAVIS-BESSE REACTOR VESSEL HEAD

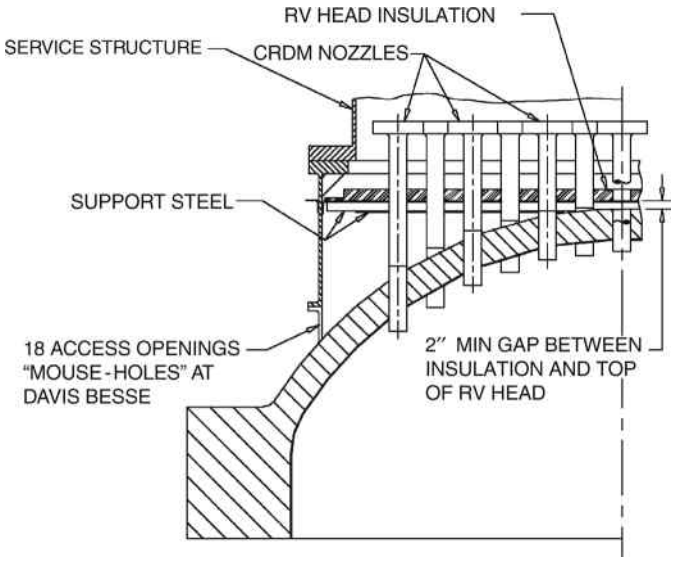


FIG. 21.13 CROSS-SECTION THROUGH DAVIS-BESSE REACTOR VESSEL HEAD

enclosed plenum between the top of the vessel head and the bottom of the insulation, as shown in Fig. 21.13.

The transition from relatively benign conditions, such as shown in Figs. 21.7 and 21.10, to severe conditions, which created the cavity shown in Figs. 21.8 and 21.12, is believed to be a function of the leakage rate. A PWSCC crack that first breaks through the nozzle wall or weld will initially be small (short), resulting in a low leak rate. It is believed that the small leak rate will not lower the metal surface temperature enough to allow liquid conditions to exist. As the crack grows in length above the J-groove weld and the annulus between the nozzle and head widens, the leak rate is expected to increase to the point where boric acid on the surface near the leak remains moist or where the leaking borated water locally cools the low-alloy steel material to the point where the surface will remain wetted and allow boric acid to concentrate.

Over the period from 2002 through 2011, EPRI sponsored a series of tests and analytical modeling to more accurately determine the conditions where the leakage produces wetted conditions that can cause high boric acid corrosion rates and where the leakage results in essentially benign dry boric acid deposits. The test program culminated with full-scale mockups of leaking CRDM and BMI nozzles. The implications of the EPRI test program were assessed in MRP-308 [90], which compared the material loss rates observed in the testing as a function of leak rate versus that assumed in the modeling work. MRP-308 concluded that the current inspection requirements for alloy 600 reactor vessel top head penetrations (ASME Code Case N-729-1 [63]) and alloy 600 reactor vessel bottom head penetrations (ASME Code Case N-722-1 [64]) are conservative and adequate to ensure an acceptably small effect on nuclear safety for the boric acid corrosion concern associated with PWSCC of these components. In other words, the possibility of a leaking nozzle resulting in structurally significant wastage is sufficiently remote given the current inspection requirements.

Conditions such as occurred at Davis-Besse can be prevented by a three-step approach. Firstly, perform nondestructive examinations of the nozzles frequently enough to catch PWSCC cracks before they grow through wall. Secondly, clean the external surfaces of preexisting boric acid deposits from other sources and perform bare metal visual inspections at frequent enough intervals to detect leaks at an early benign stage. Thirdly, if the risk is believed high or inspections are difficult or costly, replace the susceptible parts or apply a remedial measure to reduce the risk of PWSCC leaks.

21.7 DEGRADATION PREDICTIONS

21.7.1 Crack Initiation

Initiation of PWSCC in laboratory test samples and in PWR steam generator tubing has been found to follow standard statistical distributions such as Weibull and log-normal distributions [44–47]. These distributions have been widely used for modeling and predicting the occurrence of PWSCC in PWRs since about 1988, and continue to be used for this purpose.

The parameters of a statistical distribution used to model a given mode of PWSCC, such as axial cracks in CRDM nozzles, only apply to the homogeneous set of similar items that are exposed to the same environmental and stress conditions, and only to the given crack orientation being modeled. For example, axial and circumferential cracking are modeled separately since the stresses acting on the two crack orientations are different.

In general, two parameter Weibull or log-normal models are used to model and predict the future occurrence of PWSCC. An initiation time, which sometimes is used as a third parameter, is not generally modeled, because use of a third parameter has been found to result in too much flexibility and uncertainty in the predictions.

PWSCC predictions are most reliable when the mode of cracking is well developed with results for detected cracking available for three or more inspections. In this situation, the fitted parameters to the inspection data are used to project into the future. When no cracking has been detected in a plant, rough predictions can still be developed using industry data. This is generally done using a two-step process. The first step involves developing a statistical distribution of times to occurrence of PWSCC at a selected threshold level (such as 0.1%) for a set of plants with similar designs. Data for plants with different temperatures are adjusted to a common temperature using the Arrhenius equation (see Table 21.1). The distribution of times to the threshold level is used to determine a best estimate time for the plant being modeled to develop PWSCC at that threshold level. Techniques are available to adjust the prediction to account for the time already passed at the plant without detecting the mode being evaluated. Once the best estimate time for occurrence at the threshold level is determined, future cracking is projected from that point forward using the median rate of increase (Weibull slope or log-normal standard deviation) in the industry for the mode of PWSCC being evaluated.

21.7.2 Crack Growth

Numerous PWSCC crack growth studies have been performed on thick-wall alloy 600 material in PWR environments at test temperatures that span the range of typical PWR operating temperatures. In 2002, these tests were reviewed and summarized under sponsorship of EPRI [26,48]. The EPRI study (MRP-55) concluded that PWSCC crack growth rates for thick-wall alloy 600 base metal behave in accordance with the following relationship:

$$\dot{a} = \exp\left[-\frac{Q_g}{R}\left(\frac{1}{T} - \frac{1}{T_{ref}}\right)\right]\alpha(K - K_{th})^{\beta} \qquad (21.1)$$

where

$\dot{a}$ = crack growth rate at temperature T in m/sec (or in./hr)
Q_g = thermal activation energy for crack growth = 130 kJ/mole (31.0 kcal/mole)
R = universal gas constant = 8.314×10^{-3} kJ/mole-K (1.103×10^{-3} kcal/mole-R)
T = absolute operating temperature at location of crack, K (or R)
T_{ref} = absolute reference temperature used to normalize data = 325°C = 598.15 K (617°F = 1076.67 R)
α = crack growth amplitude
$\dot{a}$ = 2.67×10^{-12} at 325°C m/s; for K in units of MPa$\sqrt{\text{m}}$
$\dot{a}$ = 4.21×10^{-7} at 617°F m/s; for K in units of ksi$\sqrt{\text{in}}$
K = crack tip stress intensity factor, MPa$\sqrt{\text{m}}$ (or ksi$\sqrt{\text{in}}$)
K_{th} = crack tip stress intensity factor threshold = 9 MPa$\sqrt{\text{m}}$ (8.19 ksi$\sqrt{\text{in}}$)
β = exponent = 1.16

Temperature dependence is modeled in this crack growth rate equation via an Arrhenius-type relationship using the aforementioned activation energy of 31 kcal/mole. The stress intensity factor dependence is of power law form with exponent 1.16. Laboratory PWSCC crack growth rate data for thick-wall Alloy 600 material exhibit considerable scatter, with the highest and lowest data points deviating by more than an order of magnitude from the mean. A 75th percentile curve (see Figure 21.14) was recommended for use in deterministic crack growth analyses [26,48], and this curve is included in Section XI for disposition of PWSCC flaws in RPV top-head nozzles (Non-mandatory Appendix O). In addition, probabilistic crack growth rate studies have been performed of top head nozzles using the complete distribution [49]. An additional factor of 2 has been applied to the 75th percentile value when analyzing crack growth exposed to leakage in the annular gap between the nozzle and the head, to allow for possible abnormal water chemistry conditions that might exist there [26,48].

Similar crack growth rate testing has been conducted for alloys 82 and 182 weld metals. The weld metal crack growth data are sparser and exhibit similar statistical variability. A review of weld metal PWSCC crack growth data has also been completed under EPRI sponsorship [61,62]. This study (MRP-115) showed that Alloy 182/132 weld metal crack growth obeys a similar relationship to that shown above for alloy 600 base metal, but with crack growth rates on average about four times higher than the alloy 600 curve for stress intensity factors greater than about 20 ksi$\sqrt{\text{in}}$ (see Figure 21.14). Similar to the heat-by-heat analysis for the wrought material, a weld-by-weld analysis was performed on the available worldwide laboratory crack growth rate data for the weld materials (see Figure 21.15). The EPRI study (MRP-115) concluded that PWSCC crack growth rates for alloy 82/182/132 weld metal behave in accordance with the following relationship, where no credit for a stress intensity factor threshold greater than zero was taken because of insufficient data on this parameter:

$$\dot{a} = \exp\left[-\frac{Q_g}{R}\left(\frac{1}{T} - \frac{1}{T_{ref}}\right)\right]\alpha\, f_{alloy} f_{orient} K^{\beta} \qquad (21.2)$$

where:

$\dot{a}$ = crack growth rate at temperature T in m/s (or in./h)
Q_g = thermal activation energy for crack growth = 130 kJ/mole (31.0 kcal/mole)
R = universal gas constant = 8.314×10^{-3} kJ/mole-K (1.103×10^{-3} kcal/mole-R)
T = absolute operating temperature at location of crack, K (or R)
T_{ref} = absolute reference temperature used to normalize data = 598.15 K (1076.67 R)
α = power-law constant

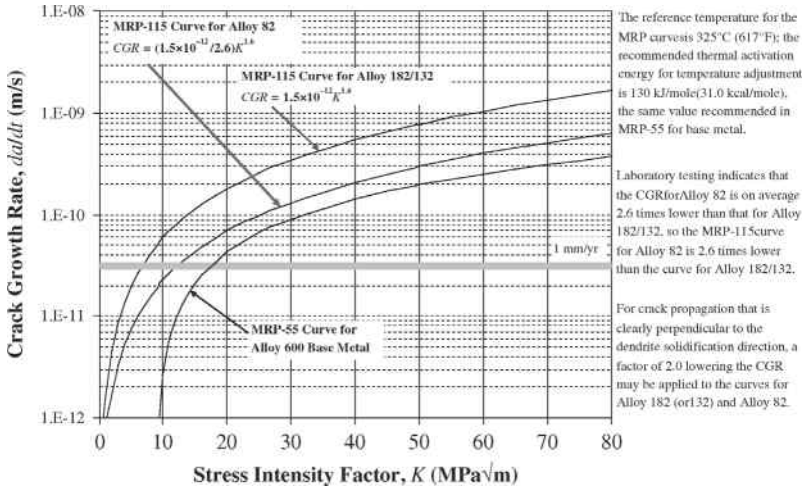


FIG. 21.14 DETERMINISTIC CRACK GROWTH RATE CURVES FOR THICK-WALL ALLOY 600 WROUGHT MATERIAL AND FOR ALLOY 182/132 AND ALLOY 82 WELD MATERIALS [61,62]

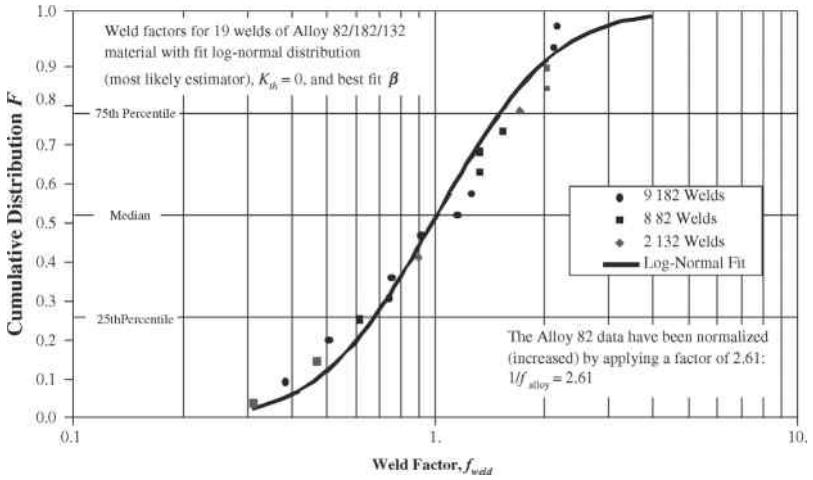


FIG. 21.15 LOG-NORMAL FIT TO 19 WELD FACTORS FOR SCREENED MRP DATABASE OF CGR DATA FOR ALLOY 82/182/132 [61,62]

$= 1.5 \times 10^{-12}$ at 325°C for $\dot{a}$ in units of m/s and K in units of MPa$\sqrt{\text{m}}$ (2.47×10^{-7} at 617°F for $\dot{a}$ in units of in./h and K in units of ksi$\sqrt{\text{in}}$)

f_{alloy} = 1.0 for Alloy 182 or 132 and 1/2.6 = 0.385 for Alloy 82

f_{orient} = 1.0 except 0.5 for crack propagation that is clearly per-pendicular to the dendrite solidification direction

K = crack-tip stress intensity factor, MPa$\sqrt{\text{m}}$ (or ksi$\sqrt{\text{in}}$)

β = exponent = 1.6

Deterministic crack growth rate predictions have been performed for axial and circumferential cracking in RPV top- and bottom-head nozzles and in piping butt welds [49,50]. The above crack growth rate expressions has been included in Non-mandatory Appendix C of Section XI for disposition of flaws in PWR piping butt welds fabricated using Alloy 82 or 182. Welding residual stresses are a primary factor contributing to crack growth in all these analyses. Stress intensity factors versus crack size, considering residual stresses plus operating pressure and thermal stresses, are first computed in these studies. These are then inserted into the appropriate crack growth relationship (alloy 600, 82, or 182) at the component operating temperature and integrated with time to predict crack size versus operating time at the applicable temperature.

Figure 21.16 shows typical crack growth predictions for a circumferential crack in a steep angle RPV top-head (CRDM) nozzle. (Nozzles in the outer rings of vessel heads having the steepest angles between the nozzle and the head have been found to be controlling in terms of predicted growth rates for circumferential cracks). The analysis depicted in Fig. 21.16 assumed a through-

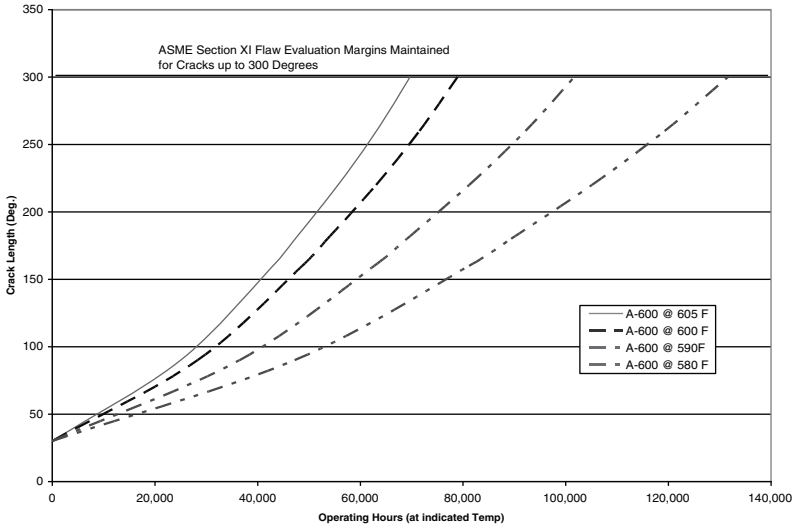


FIG. 21.16 CRACK GROWTH RATE PREDICTIONS FOR CIRCUMFERENTIAL CRACKS IN RPV TOP-HEAD NOZZLE AT VARIOUS ASSUMED OPERATING TEMPERATURES WITH INITIAL CRACK ASSUMPTION = 30° THROUGH-WALL CRACK AT MAXIMUM STRESS AZIMUTH IN HIGH ANGLE NOZZLE

wall, 30° of circumference crack in the most limiting azimuthal location of the nozzle at time zero, and predicted the operating time for it to grow to a size that would violate ASME Section XI flaw evaluation margins with respect to nozzle ejection (~300°). It is seen that, even for relatively high RPV temperatures, operating times on the order of 8 years or greater are predicted for circumferential nozzle cracks to propagate to a size that would violate ASME Section XI safety margins.

Figure 21.17 shows similar crack growth predictions for a postulated circumferential crack in a large-diameter nozzle butt weld. Stress intensity factors were computed in this analysis for a 6-to-1 aspect ratio crack in a large-diameter RPV inlet/outlet nozzle, ranging in depths from 0.1 in. to 2.2 in. The nozzle was conservatively assumed to have a large, inside surface repair, and the crack was assumed to reside in the center of that repair (i.e., in the most unfavorable residual stress region of the weld). The predicted crack growth in this case is fairly rapid for a typical outlet nozzle temperature, 602°F, propagating to 75% through-wall (the upper bound of ASME Section XI allowable flaw sizes in piping) in about 3 years. Conversely, if no weld repair were assumed, little or no crack growth would be predicted over the plant lifetime. For this same crack, including the effect of the repair, the predicted time for a 0.1 in. deep crack to grow to 75% through-wall at a typical inlet nozzle temperature (555°F) is about 11 years.

The strong effect of operating temperature is apparent in both crack growth analyses. The outlet nozzle analysis also demonstrates the detrimental effect of some types of weld repairs that were performed during construction at some plants.

As mentioned above in para. 21.6.2, in 2007, EPRI sponsored a detailed investigation of the growth of circumferential PWSCC flaws in PWR pressurizer nozzle dissimilar metal butt welds [59]. Indications of circumferential flaws in the pressurizer nozzles at a U.S. PWR in 2006 raised questions about the need to accelerate refueling outages or take mid-cycle outages at other plants for the purpose of inspection or mitigation. Using finite-element methods, this study examined the effect of an arbitrary crack profile on crack growth and subsequent crack stability and leak rate versus the standard assumption of a semi-elliptical crack profile. The crack growth calculations considered the stress intensity factor at each point along the crack tip to predict the evolution in flaw size and shape over time. The MRP-216 study [59] supported the viability of leak detection as a means to preclude the potential for rupture for the pressurizer nozzle dissimilar metal welds in a group of nine U.S. PWRs originally scheduled to perform performance demonstration initiative (PDI) inspection or mitigation during the spring 2008 outage season. This crack growth modeling approach showed in the cases considered that the classical assumption of a semi-elliptical crack shape results in a large overestimation of the crack area and thus an underestimation of crack stability at the time when the crack penetrates to the outside surface.

21.7.3 Probabilistic Analysis

Because of the large degree of statistical scatter in both the crack initiation and crack growth behavior of PWSCC in alloy 600 base metal and associated weld metals, probabilistic fracture mechanics (PFM) analyses have been used to characterize the phenomenon in terms of the probabilities of leakage and failure [49] for partial penetration-welded nozzles (including RPV top head nozzles and bottom-mounted nozzles) and piping dissimilar metal butt welds. An example analysis for RPV top head nozzles incorporates the following major elements:

(a) computation of applied stress intensity factors for circumferential cracks in various nozzle geometries as a function of crack length and stresses
(b) determination of critical circumferential flaw sizes for nozzle failure

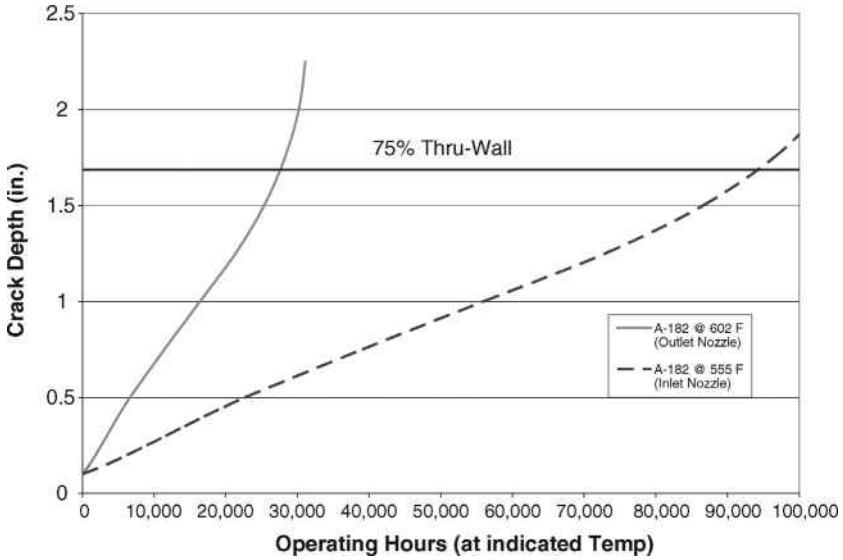


FIG. 21.17 CRACK GROWTH RATE PREDICTIONS FOR CIRCUMFERENTIAL CRACKS IN RPV MAIN COOLANT LOOP DISSIMILAR METAL NOZZLE BUTT WELD AT OPERATING TEMPERATURES TYPICAL OF REACTOR INLET AND OUTLET NOZZLES WITH INITIAL CRACK ASSUMPTION = 0.1″ × 0.6″ INSIDE SURFACE CRACK AT MAXIMUM STRESS AZIMUTH IN NOZZLE WITH ASSUMED INSIDE SURFACE WELD REPAIR

(c) an empirical (Weibull) analysis of the probability of nozzle cracking or leakage as a function of operating time and temperature of the RPV head
(d) statistical analysis of PWSCC crack growth rates in the PWR primary water environment as a function of applied stress intensity factor and service temperature
(e) modeling of the effects of inspections, including inspection type, frequency, and effectiveness

A series of PFM analysis results is presented in [49], which covers a wide variety of conditions and assumptions. These include base cases, with and without inspections, and sensitivity studies to evaluate the effects of various statistical and deterministic assumptions. The model was benchmarked with respect to field experience, considering the occurrence of cracking and leakage and of circumferential cracks of various sizes. The benchmarked parameters were then used to evaluate the effects of various assumed inspection programs on probability of nozzle failure and leakage in actual plants. A sample of the results is presented in Figs. 21.18 and 21.19.

Figure 21.18 shows the effect of inspections on probability of nozzle failure (Net Section Collapse, or ejection of a nozzle) for head operating temperatures ranging from 580°F to 600°F. A no-inspection curve is shown for each temperature. Runs were then made assuming NDE inspections of the nozzles. Inspections were assumed to be performed at intervals related to head operating temperature (more frequent inspections for higher head temperatures, less frequent for lower temperatures). It is seen from the figure that the assumed inspection regimen is sufficient to maintain the nozzle failure probability (per plant year) below a generally accepted target value of 1×10^{-3} for loss of coolant accidents due to nozzle ejection.

Figure 21.19 shows similar results for the probability of leakage from a top-head nozzle. It is seen from this figure that the same assumed inspection regimen maintains the probability of leakage at or about 6% for the cases analyzed. Analyses similar to those reported in Figs. 21.18 and 21.19 have been used, in conjunction with deterministic analyses, to define an industry-recommended inspection and corrective action program for PWR top heads that

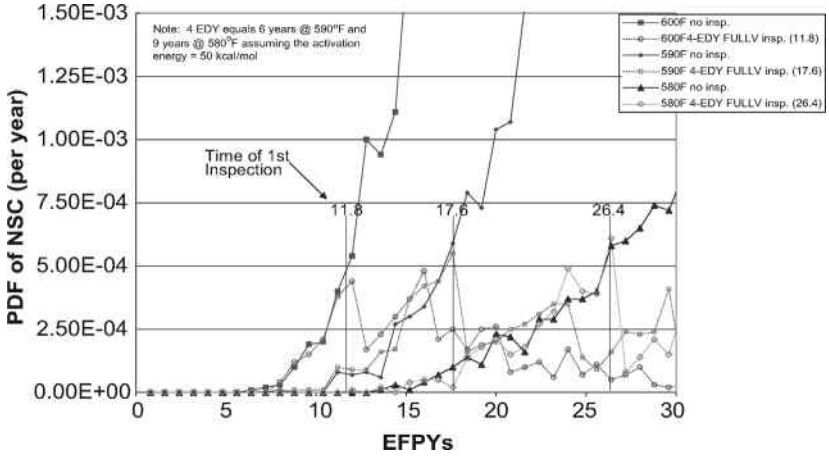


FIG. 21.18 PROBABILITY OF NOZZLE FAILURE (NSC) AS A FUNCTION OF VARIATIONS IN TOP-HEAD TEMPERATURE AND INSPECTION INTERVALS

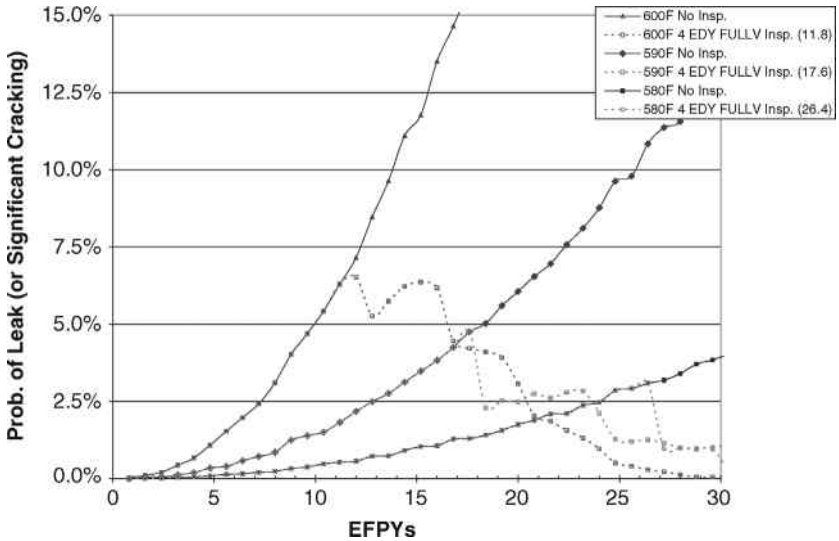


FIG. 21.19 PROBABILITY OF NOZZLE LEAKAGE AS A FUNCTION OF VARIATIONS IN TOP-HEAD TEMPERATURE AND INSPECTION INTERVALS

results in acceptable probabilities of leakage and failure. This work also constituted the basis for the inspection requirements incorporated in ASME Code Case N-729-1 [63].

As a second example, probabilistic analyses have been performed for PWSCC susceptible butt welds in pressurizer nozzles, as part of the effort documented in MRP-216 [59]. Analyses established the current expected flaw distribution based on pressurizer nozzle DMW inspections (Table 21.2), and estimates were made of the probability of cracking versus flaw size and of crack growth rate versus time. A plot of the available flaw data as of 2008 from Table 21.2 plus some points representing non-U.S. experience in terms of crack length as percentage of circumference (abscissa) versus crack depth as percentage of wall thickness (ordinate), is illustrated in Figure 21.20. Axial indications plot along the vertical axis (l/circumference = 0) in this plot, with leaking flaws plotted at a/t = 100%. Circumferential indications plot at non-zero values of l/circumference, at the appropriate a/t. Clean inspections are plotted randomly in a 10% box near the origin, to give some indication of inspection uncertainty. Also shown on this plot are loci of critical flaw sizes based on an evaluation of critical flaw sizes presented in Ref. [59]. 50th and 99.9th percentile plots are shown. It is seen from this figure that all of the flaw indications detected were far short of the sizes needed to cause a rupture. The probabilistic analysis also addressed the small but finite probability that larger flaws may exist in uninspected nozzles, plus the potential for crack growth during future operating time until all the nozzles are inspected (or mitigated).

A more recent example of a probabilistic approach to analysis of PWSCC is the eXtremely Low Probability of Rupture (xLPR) software package [103] being developed by U.S. NRC staff, working cooperatively with EPRI through a memorandum of understanding. U.S. NRC Standard Review Plan (SRP) 3.6.3 describes Leak-Before-Break (LBB) assessment procedures that can be used to assess compliance with the 10 CFR 50 Appendix A, General Design Criterion (GDC) 4 requirement that primary system piping exhibit an extremely low probability of rupture. SRP 3.6.3 does not allow for assessment of piping systems with active degradation mechanisms, such as PWSCC. PWSCC has been detected in alloy 82/182 welds in piping systems that have been granted LBB approvals. The modular-based xLPR software constitutes a comprehensive piping system assessment methodology to directly assess compliance with the regulations. The xLPR project will model the effects and uncertainties of relevant active degradation mechanisms and the associated mitigation activities. The resulting analytical tool is intended to be comprehensive with respect to known and significant materials challenges, vetted with respect to the technical bases of models and inputs, flexible enough to permit analysis of a variety of in-service situations, and adaptable such as to accommodate evolving and improving knowledge.

21.8 REPAIRS

When cracking or leakage is detected in operating nuclear power plant pressure boundary components, including the reactor vessel, repair or replacement may be performed in accordance with ASME BPVC Section XI [51]. Section XI specifies that the flaws must be removed or reduced to an acceptable size in accordance with Code-accepted procedures. For PWSCC in RPV alloy 600 components, several approaches have been used.

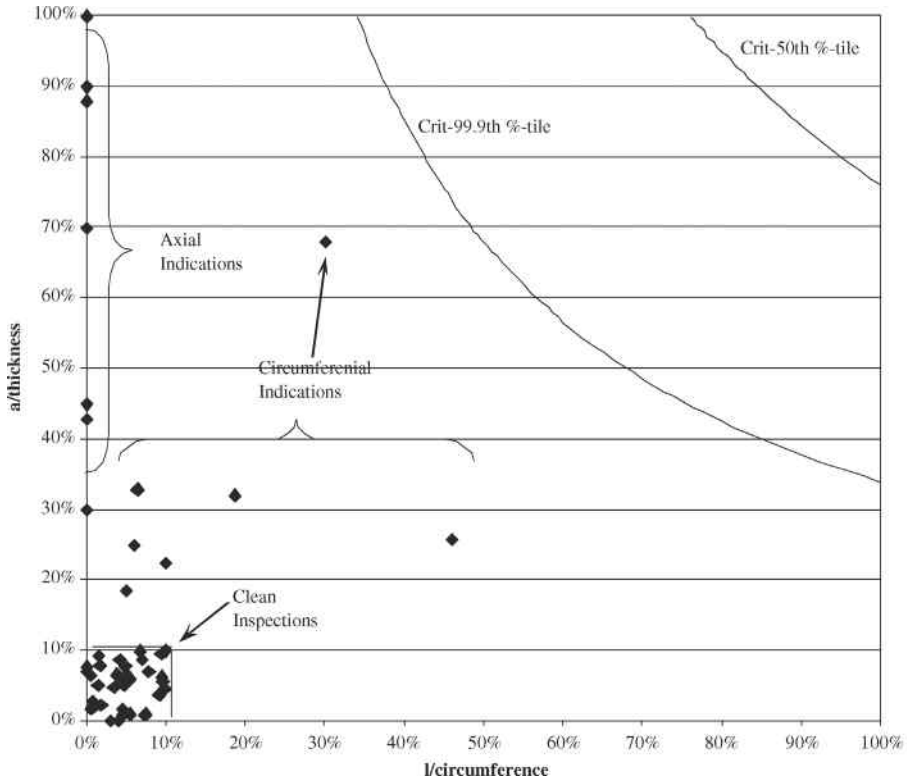


FIG. 21.20 PRESSURIZER DISSIMILAR METAL BUTT WELD FLAW INDICATIONS COMPARED TO CRITICAL FLAW SIZE PROBABILITY ESTIMATES

21.8.1 Flaw Removal

For relatively shallow or minor cracking, flaws may be removed by minor machining or grinding. This approach is permitted by the ASME Code to eliminate flaws and return the component to ASME Code compliance. However, this approach generally does not eliminate the underlying cause of the cracking. There will still be susceptible material exposed to the PWR environment that caused the cracking originally, and in some cases the susceptibility might be aggravated by surface residual stresses caused by the machining or grinding process. Thus, simple flaw removal does not mitigate the possibility of a further occurrence of PWSCC. However, in the short term, for example where future component replacement is planned, it may be a preferred approach for interim operation.

21.8.2 Flaw Embedment

Surface flaws are much more significant than embedded flaws from a PWSCC perspective, because they continue to be exposed to the PWR primary water environment that caused the crack and that can lead to continued PWSCC flaw growth after initiation. Accordingly, one form of repair is to embed the flaw under a PWSCC-resistant material. Figure 21.21 shows an embedment approach used by one vendor to repair PWSCC cracks or leaks in top-head nozzles and welds. The PWSCC-susceptible material, shown as the cross-hatched region in the figure, is assumed to be entirely cracked (or just about to crack). PWSCC-resistant material, typically alloy 52 weld metal, is deposited over the susceptible material. The assumed crack is shown to satisfy all ASME BPVC Section XI flaw evaluation requirements, in the absence of any growth due to PWSCC, since the crack is completely isolated from the PWR environment by the resistant material. Note that the resistant material in this repair must overlap the susceptible material by enough length in all directions to preclude new cracks growing around the repair and causing the original crack to be reexposed to the PWR environment. Although this repair approach has been used successfully in several plants, there have been incidents in which nozzles repaired by this approach during one refueling outage have been found to be leaking at the subsequent outage. These occurrences were attributed to lack of sufficient overlap of the repair, because it is sometimes difficult to distinguish the exact point at which the susceptible material ends (for instance the end of the J-groove weld butter and the beginning of the RPV cladding in Fig. 21.21).

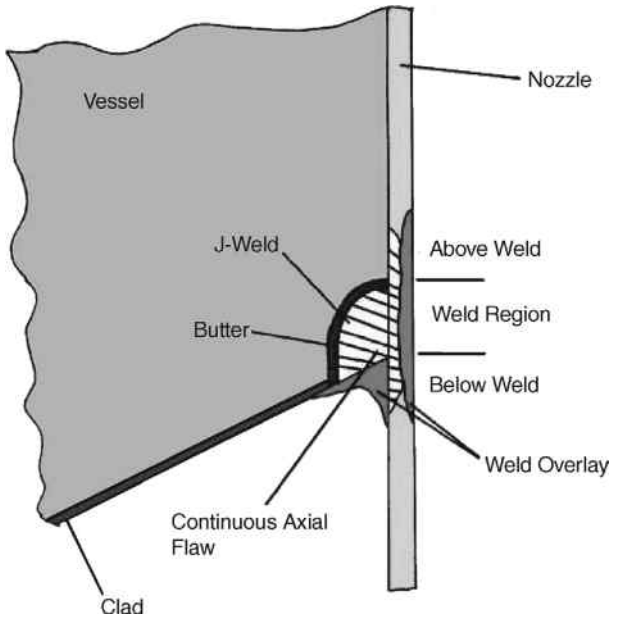


FIG. 21.21 SCHEMATIC OF RPV TOP-HEAD NOZZLE FLAW EMBEDMENT REPAIR

21.8.3 Piping Weld Overlay

Another form of repair that has been used extensively to repair cracked and leaking pipe welds is the weld overlay (WOL). Illustrated schematically in Fig. 21.22, WOLs were first conceived in the early 1970s as a repair for IGSCC cracking and leakage in BWR main coolant piping. Over 500 such repairs have been applied in BWR piping ranging from 4 in. to 28 in. in diameter, and some weld overlay repairs have been in service for over 25 years, with no evidence of any resumption of the IGSCC problem. Although WOLs, shown in Fig. 21.22, do not eliminate the PWSCC environment from the flaw as in the flaw embedment process, the repair has been shown to offer multiple improvements to the original pipe welds, including the following:

(a) structural reinforcement
(b) resistant material
(c) favorable residual stress reversal

Weld overlays also offer a significant improvement in inspection capability, because once a weld overlay is applied, the required inspection coverage reduces to just the weld overlay material plus the outer 25% or 50% of the original pipe wall, often a much easier inspection than the original dissimilar metal weld (DMW) inspection.

Weld overlay repairs have been recognized as a Code-acceptable repair in ASME Section XI Code Case N-504-4 [52] for austenitic stainless steel piping and Code Cases N-740-2 [72] and N-754-1 [73] for alloy 82/182 dissimilar metal welds. The U.S. NRC [102] has made use of N-504-4 as a repair for stainless steel piping conditional on meeting the provisions of Section XI, Nonmandatory Appendix Q, "Weld Overlay Repair of Class 1, 2, and 3 Austenitic Stainless Steel Piping Weldments." Inspection credit for mitigation of alloy 82/182 dissimilar metal butt welds in PWR piping through weld overlays is included in ASME Code Case N-770-1 [70].

Code Case N-740-2 [72] covers full structural weld overlays for repair or pre-emptive mitigation of alloy 82/182 dissimilar metal piping welds. The 360° weld reinforcement of a full structural weld overlay repair is designed to be capable of supporting

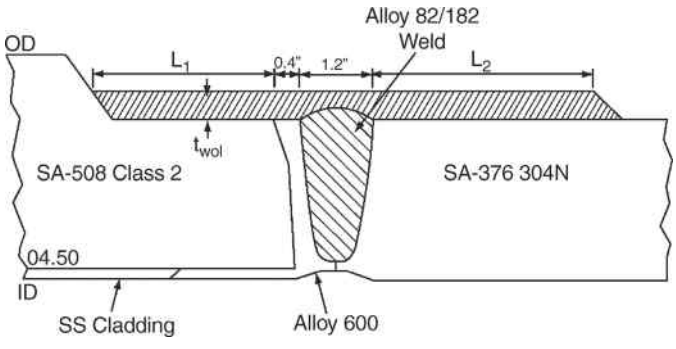


FIG. 21.22 SCHEMATIC OF WELD OVERLAY REPAIR APPLIED TO RPV OUTLET NOZZLE

the design loads, without consideration of the piping, component, or associated weld beneath the weld reinforcement. Code Case N-754-1 [73] covers optimized structural weld overlays (OWOLs) for repair or pre-emptive mitigation of alloy 82/182 dissimilar metal piping welds. In contrast to the full structural weld overlay, the OWOL design assumes structural support of the outer 25% of the wall thickness of the piping, component, or associated weld beneath the 360° weld reinforcement. The purpose of the OWOL design is to reduce the thickness of the overlay reinforcement compared to that for a full structural WOL, thus reducing the application time.

The weld overlay repair process was first applied to a PWR large-diameter pipe weld (on the Three Mile Island 1 pressurizer to hot-leg nozzle) in the fall of 2003. Since that time, as part of the MRP-139 inspection effort described in para. 21.5.6, about 250 weld overlays have been applied to pressurizer nozzle dissimilar metal butt welds. Part of the reason for this trend is that many pressurizer nozzles were unable to be volumetrically inspected to achieve the required examination coverage in their original configuration. By applying weld overlays, in addition to mitigating the welds, their inspectability was enhanced such that post overlay ultrasonic exams could be performed in accordance with applicable requirements. Technical justification for the WOL process as a long-term repair is documented in Ref. [53]. Requirements for weld overlays in PWR systems, including their use as mitigation as well as repair, is documented in MRP-169 Rev. 1-A [60].

21.8.4 Piping Weld Inlay/On-lay

Weld inlays and on-lays of PWSCC-resistant weld material (typically alloy 52 weld metal) eliminate the exposure of susceptible material on the piping inner diameter to primary water. For on-lays, the weld material is deposited in multiple passes on top of the existing susceptible material, while inlays first require the excavation of the surface of the existing weld and surrounding area before PWSCC-resistant weld metal is deposited. Design and examination requirements for weld inlays and on-lays as methods to mitigate PWSCC flaws or the potential for PWSCC flaws are defined in ASME Code Case N-766-1 [74]. Inspection credit for mitigation through weld inlays and on-lays is included in ASME Code Case N-770-1 [70]. As of October 2013, U.S. NRC authorization is required for such inspection credit to be taken at a U.S. PWR.

21.8.5 Weld or Component Replacement

Finally, the flawed weld or component may be replaced in its entirety. In PWR top-head nozzles, mid-wall reapairs have been implemented extensively by relocating the pressure boundary from the original PWSCC-susceptible J-groove weld at the inside surface to a new weld at the midwall of the RPV head (see Fig. 21.23).

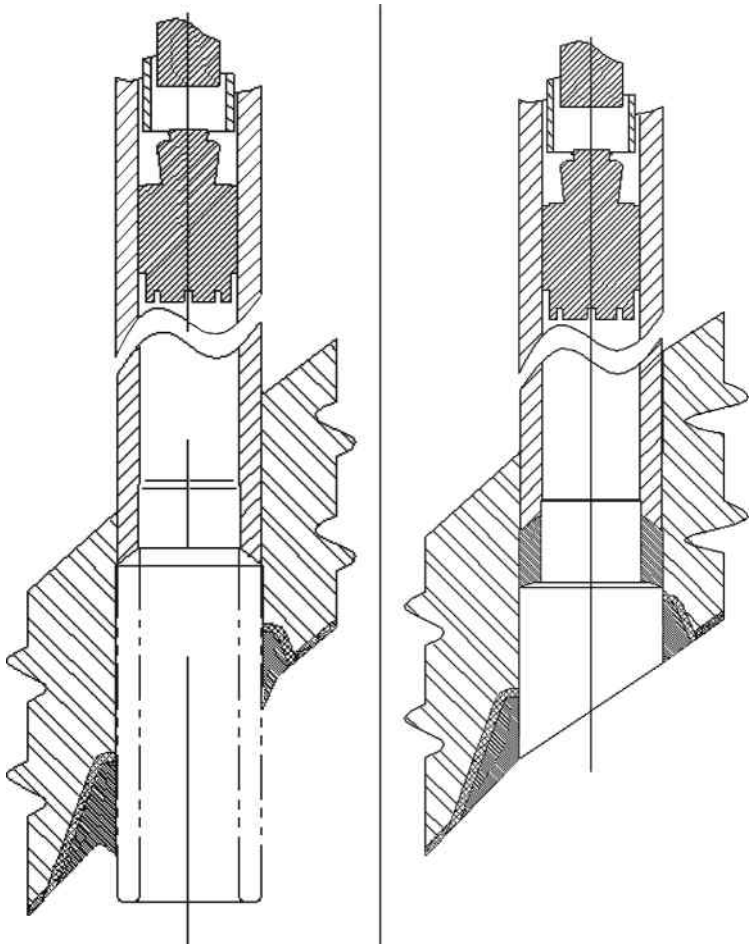


FIG. 21.23 SCHEMATIC OF RPV TOP-HEAD NOZZLE WELD REPLACEMENT REPAIR

With this repair approach, the PWSCC-susceptible portion of the original J-groove weld and buttering is left in the vessel, but it is no longer part of the pressure-retaining load path for the nozzle. The lower portion of the original nozzle is first removed by machining to a horizontal elevation above the J-groove weld (left-hand side of Fig. 21.23). A weld prep is produced on the bottom of the remaining portion of the nozzle, and a new, horizontal weld is made between the original nozzle and the bore of the RPV head (righthand side of Fig. 21.23). The new weld is made with PWSCC-resistant material (generally alloy 52 weld metal), and the surface of the weld is machined for NDE. The repair process still leaves some portion of the original PWSCC-susceptible alloy 600 nozzle in place, potentially in a high residual stress region at the interface with the new weld. However, a surface treatment process, such as roll peening or burnishing, has been applied to this interface in many applications to reduce potential PWSCC concerns. Experience with this repair process has been good, in terms of the absence of subsequent leakage from repaired nozzles.

In contrast to the mid-wall repair, the OD weld pad repair moves the structural boundary to the outer surface of the vessel. Following removal of the outboard portion of the original nozzle by drilling or machining, a weld pad is deposited around the nozzle hole on the vessel outside surface using alloy 52 and the ambient temperature temper bead technique in accordance with ASME Section XI Code Case N-638 [93]. The weld pad is drilled to suit installation of a new half-nozzle, and a J-groove weld prep is machined into the weld pad. The new alloy 690 half-nozzle is installed into the hole in the vessel, welded to the weld pad using alloy 52, and the weld is inspected.

As discussed in para. 21.4.4 and shown in Figure 21.24, an OD weld pad repair approach was applied to the two leaking BMI penetrations at South Texas 1 in 2003. This repair method has also been used for repair of other types of small-bore nozzles in PWRs, such as pressurizer instrumentation nozzles. For a modified version of this repair, the "small pad" repair [100], the nozzle is installed before the pad is welded, and a contour-tracking welding tool is used to join the nozzle to the vessel with a single weld.

Other weld repair approaches have been applied to alloy 600 partial-penetration welded nozzles in PWR components [101]. For example, in some cases the existing nozzle is completely removed and a corrosion resistant liner is rolled into the penetration. In the case of a rolled liner, the ID end is seal welded to the cladding and the OD end terminates at the J-groove weld for the pad to prevent contact of carbon or low-alloy steel with primary water. Installing a welded plug may be an option in cases that the function of the nozzle is not needed. For repair designs that leave exposed carbon or low-alloy steel, the amount of corrosion due to exposure to borated water must be assessed.

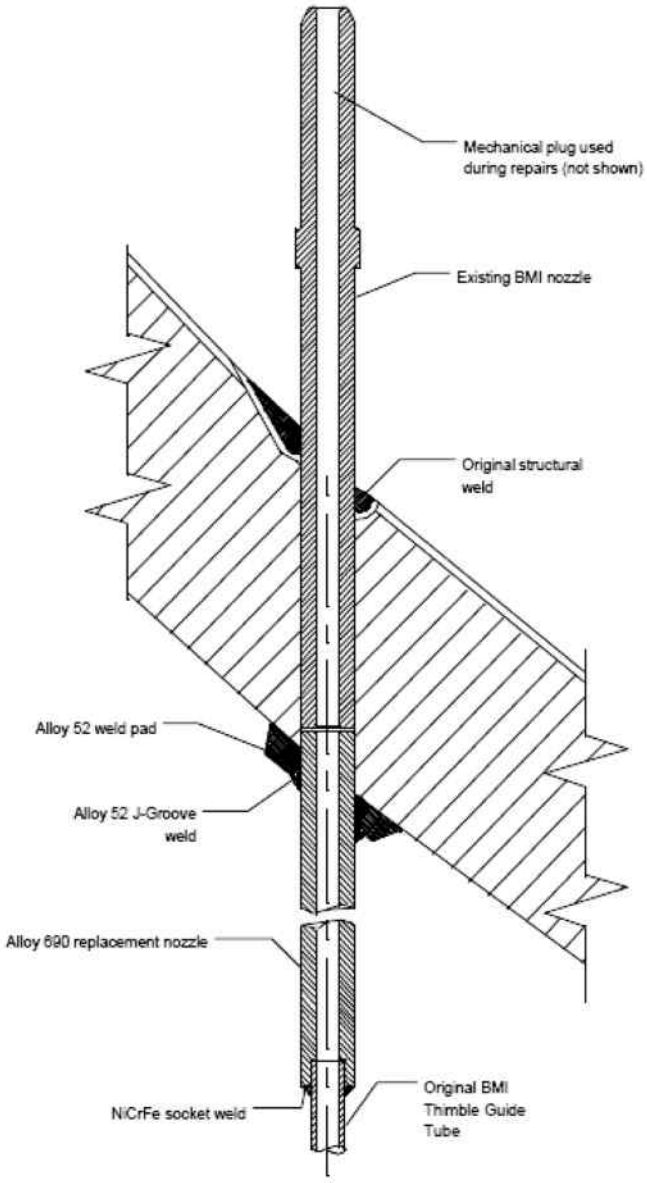


FIG. 21.24 HALF-NOZZLE REPAIR METHOD USED FOR BMI NOZZLE REPAIR [106]

21.8.6 Mechanical Nozzle Repair

The mechanical nozzle seal assembly (MNSA) provides both sealing and structural support for small-bore nozzle connections. Starting in 1993, it was developed as an alternative to weld repair for leaks in J-groove welds of alloy 600 instrumentation nozzles and pressurizer heater sleeves, and it can also prevent potential leakage at susceptible nozzle sites. MNSA installation is faster than welded repairs, MNSAs can be installed with water in the vessel (core offload is not required), and no PT or UT is required as part of the repair operation. As of 2005, MNSAs had been installed at more than 10 plants in the U.S. since 1998. In 2005, Westinghouse indicated that the MNSA-2 device has been qualified for use in repair of BMI penetrations [99].

The MNSA is designed to seal off leakage from the annulus between the instrumentation nozzle and vessel wall. A secondary function is to restrain the instrumentation nozzle from ejecting should the nozzle-to-vessel weld fail completely. To install the MNSA, an annulus is machined into the base metal surrounding the existing nozzle and studs are threaded into the vessel. A gland compresses a graphite seal ring in the annulus while also sealing to the existing nozzle. A structural retainer presses against the end of the nozzle to transfer structural loading from the original weld to the retainer and studs as shown in Figure 21.25.

Note that in the past, MNSAs were often considered to be a temporary repair measure, and, in practice, they have generally been used for a limited period until a weld repair could be planned and performed. However, in October 2010, the NRC unconditionally

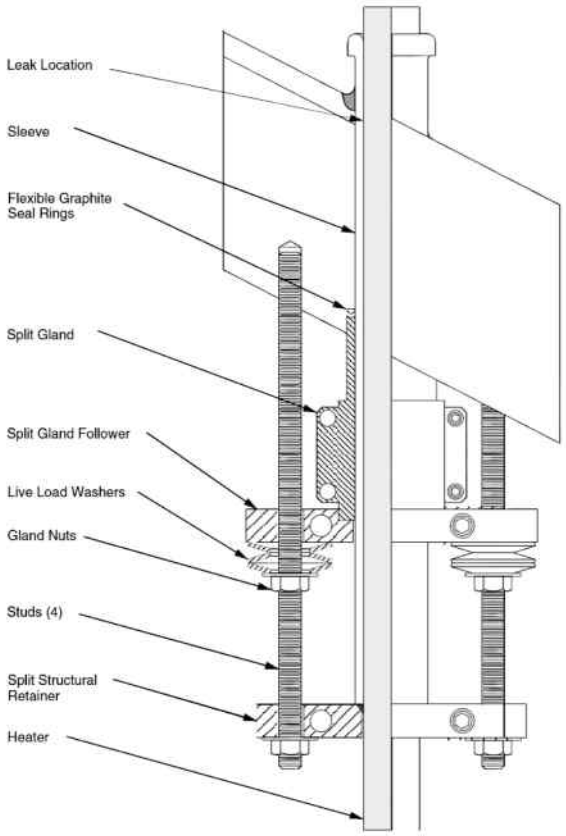


FIG. 21.25 SCHEMATIC OF MECHANICAL NOZZLE SEAL ASSEMBLY REPAIR [101]

accepted ASME Code Case N-733 [94]. Code Case N-733 supports use of MNSAs on all Class 1 NPS 2 and smaller nozzles. It specifies visual inspection every refueling outage and dismantling and reassembly of a sample every 10 years. Evidence of leakage during testing and upon startup is unacceptable, and leakage is classified as unidentified leakage. As described in N-733, there are a number of requirements that must be met for qualification and use of a MNSA in a specific application.

21.9 REMEDIAL MEASURES

21.9.1 Water Chemistry Changes

Three types of water chemistry changes that could affect the rate of PWSCC are zinc additions to the reactor coolant, adjustments to dissolved hydrogen concentration, and adjustments to lithium concentration and pH. The factors are described below.

(a) *Zinc Additions to Reactor Coolant.* Laboratory tests indicate that the addition of zinc to reactor coolant significantly slows down the rate of PWSCC initiation [69]. The best evidence available indicates that the mitigative effect of zinc is not a strong function of concentration [69]. The effect of zinc on crack growth rate is not as certain, with some tests indicating a significant reduction in crack growth rate but others indicating no change. Some laboratory tests and analysis of steam generator tube degradation trends indicate a significant mitigative effect of zinc on PWSCC initiation as well as PWSCC crack growth rates. Although zinc addition has been demonstrated to slow crack growth for the low stress intensity factors calculated for alloy 600 steam generator tubes, less benefit is measurable at higher stress intensity factors like those typical for thick-wall components [69].

(b) *Adjustments of Hydrogen Concentration.* The EPRI PWR Primary Water Chemistry Guidelines require the dissolved hydrogen concentration in the primary coolant to be kept between 25 and 50 cc/kg [28]. However, interim staff guidance and the forthcoming revision to the guidelines revise the dissolved hydrogen range to 25–60 cc/kg. As discussed in the Guidelines and summarized above in para. 21.3.4, hydrogen optimization has been demonstrated to have a substantial mitigative effect on the growth rate of PWSCC in alloys 600/82/182, especially for alloy 182. Available data do not show a conclusive effect of hydrogen concentration on the time to PWSCC initiation, largely due to the degree of scatter in the data. For alloy 182, MRP-263 [69] predicts a substantially greater improvement factor for increased dissolved hydrogen concentration at reactor hot-leg operating temperatures versus that at cold-leg temperatures. This effect is due to the shift in the electrochemical potential corresponding to the Ni/NiO transition with changes in temperature. Laboratory data demonstrate that the PWSCC crack growth rate is maximum near the electrochemical potential corresponding to the Ni/NiO transition. EPRI reports MRP-263 [69] and MRP-307 [98] quantify the benefits of zinc addition and hydrogen optimization, and may be applied as a basis to modify the inspection intervals for PWR pressure boundary components susceptible to PWSCC.

(c) *Adjustments of Lithium Concentration and pH.* As discussed in para. 21.3.4, some tests indicate that the relative time to PWSCC initiation is decreased by increases in lithium concentration and pH, e.g., by factors ranging from about 1.15 to 2.0. On the other hand, increases in lithium and pH provide proven benefits for reducing the potential harmful deposit buildup on fuel cladding surfaces and for reducing shutdown dose rates [28]. Based on these opposing trends, plants can select a lithium/pH regime that best suits their needs, i.e., does not involve substantial risks of aggravating PWSCC, while still providing benefits for reducing fuel deposits and shutdown dose rates. An additional consideration is that the use of zinc can provide a stronger benefit than the possible deficit associated with increases in lithium and pH, and, thus, can make use of a combined zinc adjustment and increase in lithium and pH attractive.

21.9.2 Temperature Reduction

One remedial measure applied in the field for RPV top-head PWSCC has been modification of the reactor internals package to increase bypass flow through the internals flange region and, thereby, reduce the head temperature. The lower head temperature is predicted to reduce the rates of crack initiation and growth based on the thermal activation energy model, as shown in Table 21.1. However, plant experience shows that alloy 600/82/182 components may still experience PWSCC at reactor cold-leg temperatures. The plant experience shows that materials and fabrication-related factors can result in PWSCC at temperatures lower than otherwise expected.

21.9.3 Surface Treatment

EPRI has sponsored tests of a range of mechanical remedial measures for PWSCC of alloy 600 nozzles. Results of these tests were reported by Rao at the Fontevraud 5 Symposium [54]. The remedial measures test program consisted of soliciting remedial measures from vendors, fabricating full-diameter and wall-thickness ring specimens from archive CRDM nozzle material, installing specimens in rings that locked in high residual stresses on the specimen inside surface, applying the remedial measures to the stressed surface, and then testing the specimens in doped steam with hydrogen overpressure at 400°C (750°F). The specimens were removed from the autoclave at intervals and inspected for SCC. A complicating factor in interpreting the test results is that not all of the specimens were fabricated from the same heat of material. Therefore, there were differences in material PWSCC susceptibility in addition to differences in remedial measure effectiveness. The methods used to correct for differences in specimen PWSCC susceptibility are discussed in the paper.

The remedial measures fell into three main effectiveness groups.

(a) most effective

(1) abrasive water jet remediation
(2) electro mechanical nickel brush plating
(3) shot peening

(b) intermediate effectiveness

(1) electroless nickel plating
(2) GTAW weld repair
(3) laser weld repair

(c) least effective

(1) EDM skim cutting
(2) laser cladding
(3) flapper wheel surface polishing

More recently, the U.S. industry has investigated water jet (i.e., cavitation) peening and laser peening as PWSCC mitigation methods for alloy 82/182 piping butt welds (especially at reactor vessel outlet and inlet nozzles), alloy 600 BMI penetrations, and alloy 600 RPV top-head penetrations. These types of peening have been widely implemented for SCC mitigation in dozens of PWR and BWR power systems in Japan for over 10 years, as well as globally in many other industries to address SCC and other degradation mechanisms. As of 2013, two U.S. PWRs have announced plans to peen reactor vessel main loop nozzles.

Peening is a surface treatment that generates long-lived compressive residual stresses at the surface, thereby preventing the future initiation of SCC. Both water jet peening and laser peening generate high pressures at the metal surface, creating permanent local strains. Due to the constraint provided by the thick-wall component, the result is a layer of compressive residual stress at the treated surface. The residual stress profile also tends to arrest SCC and fatigue crack growth of any existing cracks located in the compressive stress zone. It has been shown by testing and operational experience [81] that the compressive stresses that result from peening improve material performance with respect to SCC, fatigue failures, and foreign object damage.

The EPRI Materials Reliability Program (MRP) has published a series of reports supporting the use of peening to mitigate PWSCC, including the technical basis document for peening (MRP-267 Rev. 1 [81]), a topical report defining appropriate inspection intervals for use with peening (MRP-335 Rev. 1 [71]), and guidelines for specifying and implementing peening in a PWR plant (MRP-336 [97]). MRP-267 Rev. 1 presents the results of extensive laboratory work performed by the peening vendors and others supporting the effectiveness and lack of unacceptable side effects of the peening processes covered. The MRP-335 Rev. 1 topical report is specific to alloy 600 RPV top-head penetrations and alloy 82/182 dissimilar metal butt welds in PWR piping such as at reactor vessel outlet and inlet nozzles. As of 2013, appropriate in-service inspection requirements for these components subsequent to peening application are under consideration by ASME Section XI committees. MRP-336, which applies more generally, provides guidance to assist in development of specifications for procurement of peening services for mitigation of PWSCC. Also included is guidance regarding 10 CFR 50.59 evaluations of the use of peening as a mitigation method for PWSCC.

It is emphasized that surface treatment mitigation like peening and, to a significant extent, zinc addition are effective because of their capability to prevent or delay PWSCC crack initiation. Thus, their effectiveness tends to be reduced to the extent that they are applied after PWSCC initiation has already occurred. Thus, there is an incentive that these methods be applied in the relative near-term before PWSCC flaws have the opportunity to initiate.

21.9.4 Stress Improvement

To mitigate against the IGSCC problem in BWR piping, many plants implemented residual stress improvement processes. These were performed both thermally (induction heating stress improvement or IHSI) and by mechanical means (mechanical stress improvement). As described above, residual stresses play a major role in susceptibility to both IGSCC and PWSCC because piping butt welds may leave significant residual stresses at the inside surfaces of the pipes, especially when weld repairs were performed during construction. Both stress improvement processes have been demonstrated to reverse the unfavorable residual stresses, leaving compressive stresses on the inside surface of the pipe, which is exposed to the reactor environment. Mechanical stress improvement has also been applied to PWSCC-susceptible butt welds in PWR piping, primarily dissimilar metal welds at vessel outlet and inlet nozzles, such as the V.C. Summer outlet nozzle cracking problem described above. As long as the stress improvement process is applied when cracking has not initiated or grown to unacceptable depths, it clearly constitutes a useful remedial measure that can be applied to vessel nozzles, eliminating one of the necessary factors for PWSCC.

In addition to being an option for preemptive mitigation, mechanical stress improvement may be applied as a corrective measure to address PWSCC flaws detected in an alloy 82/182 piping butt weld. As a prerequisite for crediting PWSCC mitigation via mechanical stress improvement, there is a standard requirement that an examination be performed showing that there are no crack indications on the ID surface deeper than 30% of the wall thickness or having a total circumferential extent greater than 10% of the circumference [58,95,96]. The requirement that any flaws have a depth no greater than 30% of the wall thickness ensures that such flaws are effectively mitigated by the process, considering factors such as the uncertainty in the flaw depth, the uncertainty in the depth of the compressive residual stress zone, and the effect of operating load stresses. Use of mechanical stress improvement to correct a weld with a flaw deeper than 30% of the wall thickness would require an application-specific calculation to show that the flaw would be effectively mitigated.

One of the benefits of the weld overlay process described above to repair PWSCC-cracked butt welds is that it reverses the residual stress pattern in the weld, resulting in compressive stresses on the inside surface. Thus, WOL is being applied in some cases preemptively, before cracking is discovered. Applying a preemptive WOL in this manner produces similar remedial benefits to those described above for the stress improvement processes, but also places a PWSCC-resistant structural reinforcement on the outer surface of the pipe. So, if the favorable residual stresses were for some reason ineffective in arresting the PWSCC phenomenon, the PWSCC-resistant overlay would still provide an effective barrier against leakage and potential pipe rupture. Moreover, the revised inspection coverage requirements specified for WOLs apply to such preemptive overlays, providing the added benefit of enhanced inspectability [70].

21.9.5 Head Replacement

The most obvious way to address RPV top-head cracking issues is head replacement. As of 2013, approximately 60% of operating PWRs in the United States have replaced their heads. Such head replacements take advantage of the lessons learned to date regarding the PWSCC phenomenon, and the new heads are produced so as to eliminate all PWSCC-susceptible materials, replacing them with resistant materials (alloy 690 and associated weld metals alloys 52 and 152). RPV head replacement is a key aspect of strategic planning to address the alloy 600 problem in PWRs, and may be considered as part of a coordinated alloy 600 maintenance program that addresses steam generator, pressurizer, and piping issues as well as the RPV.

21.10 STRATEGIC PLANNING

Within constraints posed by regulatory and industry requirements, utilities are free to develop a strategic plan that ensures a low risk of leakage, ensures an extremely low risk of core damage, and results in the lowest net present value (NPV) cost consistent with the first two criteria. Development of a strategic plan for RPV top-head nozzles was described by White, Hunt, and Nordmann at the 2004 ICONE-12 conference [55]. The strategic planning process was based on life cycle management approaches and NPV economic modeling software developed by EPRI [56,57].

The main steps in the strategic planning process are as follows:

(a) predicting time to PWSCC
(b) assessing risk of leaks
(c) assessing risk of rupture and core damage due to nozzle ejection
(d) assessing risk of rupture and core damage due to boric acid wastage
(e) identifying alternative life cycle management approaches
(f) evaluating economically the alternative management approaches

While the paper and following discussion are based on RPV top-head nozzles, the same basic approach can be applied to other components, such as BMI nozzles and piping butt welds.

21.10.1 Predicting Time to PWSCC

Predictions of the time to PWSCC crack initiation are described in para. 21.7.1. The predictions are typically based on a statistical distribution such as a two-parameter Weibull or log-normal model. Predictions are most accurate if based on plant-specific repeat inspections showing increasing numbers of cracked nozzles. If such data are not available, then predictions are typically based on data for other similar plants (e.g., design, material, operating conditions) with corrections for differences in operating time and temperature.

21.10.2 Assessing Risk of Leaks

The risk of leakage at a particular point in time (typically refueling outage number) is typically determined by a probabilistic (Monte-Carlo) analysis using the distribution of predicted time to crack initiation (para. 21.7.1), crack growth (para. 21.7.2), and other probabilistic modeling techniques (para. 21.7.3). The probabilistic analysis should include a sensitivity study to identify the most important analysis input parameters, and these important parameters should be reviewed to ensure that they can be substantiated by available data.

21.10.3 Assessing Risk of Rupture and Core Damage Due to Nozzle Ejection

The risk of nozzle ejection (net section collapse) is determined using methods such as described in para. 21.6.2.

21.10.4 Assessing Risk of Rupture and Core Damage Due to Boric Acid Wastage

The risk of failure of the low-alloy steel reactor vessel head by boric acid wastage is determined using methods such as described in para. 21.6.3.

21.10.5 Identifying Alternative Life Cycle Management Approaches

An important step in developing a life cycle management plan is to identify the alternative approaches that can be considered. These alternatives can include the following:

(a) continue to inspect and repair indefinitely without applying remedial measures.
(b) apply remedial measures, such as lowering the vessel head temperature by increasing bypass flow through the vessel internals flange, adding zinc to the primary coolant, and peening the wetted surface of nozzles and welds to leave the material surface with a compressive residual stress.
(c) replace the vessel head as quickly as possible.
(d) replace the vessel head shortly after detecting the first PWSCC cracks.
(e) use other approaches identified.

Each of these alternatives must be studied to determine the difficulty of application, the likely effectiveness, and the effect of the change on required inspections. For example, head replacement may involve the need to cut an access opening in the containment structure or to procure a new set of CRDMs to allow the head changeout to be performed quickly, so as to not adversely affect the refueling outage time. If openings must be cut in containment, consideration should also be given to the possible need to cut other openings in the future, such as for steam generator or pressurizer replacements. Consideration must also be given to the disposal of a head after it is replaced.

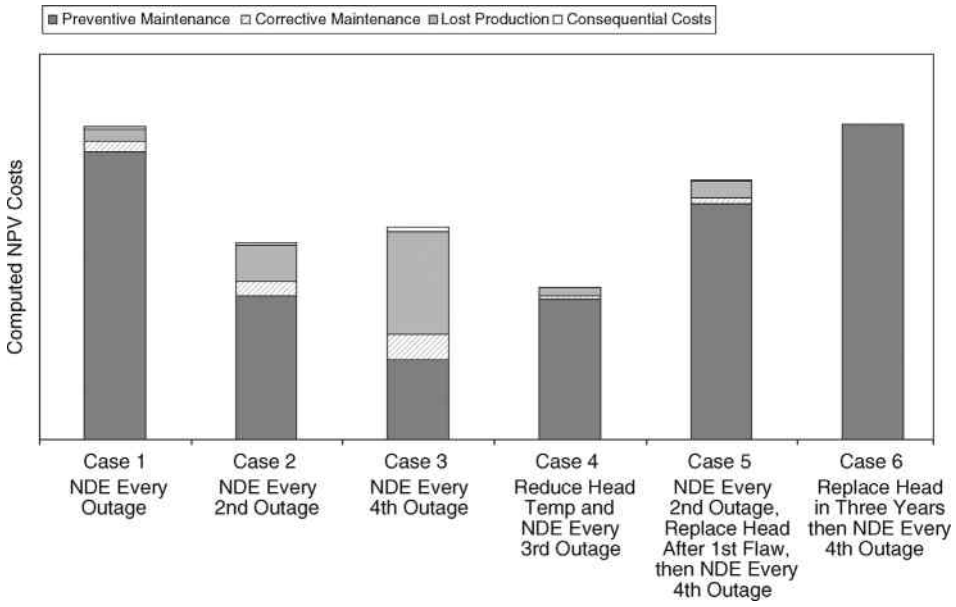


FIG. 21.26 TYPICAL RESULTS OF STRATEGIC PLANNING ECONOMIC ANALYSIS FOR RPV HEAD NOZZLES

21.10.6 Economic Evaluations of Alternative Management Approaches

Most life cycle management evaluations include economic analyses to determine the NPV cost of each alternative. The NPV cost is the amount of money that is required today to pay all predicted future costs, including the effects of inflation and the discount rate. Inputs to an LCM economic analysis typically include the following:

(a) costs of planned preventive activities including inspections, remedial measures, and replacements.
(b) predicted failure mechanisms (e.g., cracks, leaks, and rupture) and failure rates.
(c) costs for corrective maintenance in the event of a failure including the cost to make the repair, the estimated value of lost production, and an allowance for consequential costs such as increased regulatory scrutiny. Consideration should be given to the fact that response to some cases of detected PWSCC can result in lost production and consequential costs higher than the cost to replace or mitigate the affected component.

Figure 21.26 shows typical results of a strategic planning analysis with economic modeling.

The final step in the economic evaluation is to review the predictions in light of other plant constraints, such as planned plant life, potential power uprates, budget constraints, and the availability of replacement heads. In many cases, the alternative with the lowest predicted NPV cost may not represent the best choice.

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CHAPTER

22

PRA AND RISK-INFORMED ANALYSIS

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22.1 INTRODUCTION

Over the past 20 years, nuclear power plant design and operating practices have entered into an evolutionary period of change from the experience-based, deterministic requirements established by expert opinion to one that also includes a formalized application of risk importance determinations. This chapter traces the development of nuclear power plant probabilistic risk assessment (PRA) from its initial evolution as a means for evaluation of public safety through the recognition of its use to identify important safety concerns and ultimately to its use in helping to determine risk importance and the appropriate allocation of resources and in-service activities. It also discusses the current status of Codes and Standards that provide rules and guidance for the development of probabilistic risk analysis to support nuclear power plant applications.

The chapter addresses several specific topics of interest to Section XI and also covers related activities in place or underway to risk inform Code requirements for in-service testing and Code design rules. Also included is a discussion of how the risk-informed methods developed for nuclear activities are now being used to help allocate resources for the protection of critical national assets to enhance homeland security.

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22.2 BACKGROUND

The consideration of risk has always been implicitly or explicitly a part of ASME's development of Codes and Standards. With traditional engineering methods, design factors are incorporated into Codes and Standards to manage this risk based on expert judgment. The emergence of PRA technology now provides the opportunity to better focus Codes and Standards requirements on the most important risks.

Application of PRA technology to nuclear power safety considerations began over 30 years ago, when the Atomic Energy Commission initiated the Reactor Safety Study that was reported in WASH 1400 [1]. This study adapted methods previously used by the Department of Defense and by National Aeronautics and Space Administration (NASA) to predict the effect of failures of small components in large, complex systems. Two plants were analyzed in detail to predict the effect of failures of small components in large and complex nuclear systems. Initial use of the results of this study involved a general comparison of the public risk from nuclear power with risks from other natural phenomenon and industrial accidents, which indicated that risks from potential U.S. nuclear power plant accidents were small compared to other risks encountered in a complex technological society. The study did conclude that for the plants analyzed, accidents initiated by transients or small loss of coolant accidents (LOCAs) were more likely to cause a core meltdown than the traditional large break design-basis LOCAs. The Reactor Safety Study also identified a wide variety of accident sequences and ensuing equipment failures (initiators and/or operator errors) that have the potential to cause core meltdown.

While it was evident to the authors of the WASH-1400 [1] study that the methodology and results had a large potential to improve, the regulation and licensing of nuclear power plants by focusing attention on significant safety issues, it was unclear how the methodology should be integrated into the regulations [2]. In addition, an independent review group appointed by the U.S. Nuclear Regulatory Commission (NRC) issued a report in September 1978 [3] that concurred that the risks from nuclear power appeared to be very low, but questioned many of the assumptions and conclusions of the study. This report and other public controversies surrounding the use of nuclear power caused the NRC commissioners to withdraw endorsement of the Executive Summary of the Reactor Safety Study. It was not until the accident at Three Mile Island (TMI) and subsequent plant risk evaluations that the importance of the PRA methodology in identifying vulnerabilities and the relative safety importance of plant systems and components was appreciated.

As a result of the TMI accident, follow-up investigations were performed by various groups, including a Presidential Commission [4] and a special group appointed by the NRC commissioners [5].

[1]The original authors of this chapter that appeared in the "Companion Guide to the Volume 3 ASME Boiler & Pressure Vessel Code, Second Edition" were Sidney A. Bernsen, Fredric A. Simonen, Kenneth R. Balkey. This chapter had been updated in the subsequent Third Edition by Sidney A. Bernsen, Kenneth R. Balkey, Raymond A. West and Ralph S. Hill III. – Editor

Also, the Industry Degraded Core Rulemaking (IDCOR) program was initiated by the industry through the Atomic Industrial Forum to respond to the question of whether existing nuclear plants met severe accident safety goals and if specific plants had unrecognized vulnerabilities. These studies identified some unique vulnerabilities to severe accidents. Generally, the undesirable risk from these unique features was reduced by low-cost changes in procedures or minor design modifications. All these studies confirmed the general insights of the Reactor Safety Study [1].

The next major effort was the NRC's evaluation of five light water reactor (LWR) designs in the NUREG-1150 study [6] published in 1990. This study assessed the health risks to the public from not only internal initiators but also from earthquakes and fires. It also examined the uncertainties in the estimated risks by assigning uncertainties to input parameters and models and then propagating them to uncertainties in core damage frequency, magnitudes of radioactive releases, and public health effects. NUREG-1150 [6] concluded that commercial nuclear power plants imposed even smaller risks on the public than had been predicted in WASH-1400 [1]. A significant conclusion from these risk studies was that only a relatively small number of safety-related plant components (as defined by deterministic regulatory criteria) are significant contributors to risk. For example, Specter in a briefing to the NRC commissioners in 1992 [7] pointed out that after ranking components according to their contribution to core damage frequency, of ~100,000 active components in a power plant, "50 to 500 or ≤0.5% of the total number control/determine about 90% of the Core Damage Frequency (CDF)." By focusing more resources, for example, quality assurance, regular testing, preventive maintenance, on these 500 components and by allocating less resources to the other 99,500 components, utilities could simultaneously enhance the safety of their power plants and reduce Operating and Maintenance costs.

Observations of this nature also served as the motivation for work by ASME initiated in the late 1980s to factor risk information into the requirements of Codes and Standards. Recognizing the need for risk-informed methods in the formulation of policies, codes, standards, and guides, ASME organized multidisciplinary research task forces on risk-informed in-service inspection (RI-ISI) and in-service testing (IST). These research groups, financially supported by both domestic and international organizations from industry and government, including the U.S. NRC, worked to determine appropriate risk-informed methods for developing inspection and testing guidelines for several applications.

Initial pilot plant applications were used to demonstrate the proposed methods. A series of ASME publications [8–13] presents this work for nuclear and industrial applications. From this work, ASME was able to demonstrate that risk-informed methods offered the potential to technically enhance existing in-service inspection (ISI) and IST programs by relating inspection and test requirements to the failure modes of a component and associated risks. Development of Codes and Standards using these new insights could provide alternative requirements that were more attractive to users when compared to the prescriptive set of general requirements that had been developed using traditional engineering judgment based on some implicit risk considerations. Risk-informed strategies could be structured to enhance the examinations and tests for high safety significant (HSS) components and to reduce unnecessary requirements for the low safety significant (LSS) components. The ASME determined that these enhancements could be performed using a plant's existing PRA blended with appropriate expert judgment and operational experience. Implementation of these methods would offer the ability for industry and the regulator to better focus and allocate limited resources to the high safety significant components thereby enhancing overall plant safety. ISI and IST programs would also now be better correlated with PRA results and risk insights for each nuclear plant.

Given these promising results, ASME worked with the NRC, owners, and industry groups during the last decade to implement risk-informed ISI and IST approaches into ASME Codes and Standards, NRC Regulatory Guides, and industry documents. Subsequent sections of this chapter discuss the ASME risk-informed Codes and Standards in more detail.

22.3 ASME PRA STANDARD ASME/ANS RA-Sb-2013

All of the risk-informed applications rely to a great extent, but not entirely, upon the results of a Probabilistic Risk Assessment applicable to the facility being evaluated. As noted above, PRAs have evolved over a period of more than 30 years from relatively simple limited scope evaluations to rather complex, full scope modeling of the plant. During this time, there was no standard to determine the technical capability, fidelity, and adequacy of the PRA. As codes, standards, and regulatory applications evolved, there was clearly a need to develop standards for the adequacy of a PRA to support these applications. As a result, a new standard project to develop an appropriate PRA Standard was initiated by the ASME Board on Nuclear Codes and Standards (BNCS) in 1998 The initial standard, ASME RA-S-2002, was published in 2002 [14] and the first Addendum was issued in 2003 as ASME RA-Sa-2003 [15]. A second addendum was issued in 2005 as ASME RA-Sb-2005 [16] and a third addendum was issued as ASME RA-Sc-2007 [17] in August 2007.

Revision 1 of this standard was issued in early 2008. As discussed in Section 22.3.1, this revision, designated ASME/ANS RA-S1-2008 [18], combines the requirements of ASME RA-S-2002 and its three addenda with the requirements of two related standards initially issued by the American Nuclear Society.

The two related standards were Fire PRA and External Events PRA. The first Addenda to ASME/ANS RA-S–2008 was issued in 2009 [19]. The ASME/ANS Joint Committee on Nuclear Risk Management (JCNRM) came into existence after Addendum (a) was issued. This Addenda, ASME/ANS RA-Sb-2013 [Addenda (b)], is a second revision; it supersedes all previous revisions. The JCNRM is responsible for ensuring that this Standard is maintained and revised, as necessary. This responsibility includes appropriate coordination with and linkage to other standards under development for related risk-informed applications. The JCNRM intends to release the next edition of the Standard in 2015.

22.3.1 Evolution and Objectives of PRA Standard

The ASME Board on Nuclear Codes and Standards began considering the development of a consensus standard for the use of PRA in risk-informed decision-making in the summer of 1997. The BNCS and the ASME Council on Codes and Standards evaluated this consideration with regard to ASME safety criteria and activities associated with risk-informed applications. Given the advancements in developing risk-informed Code Cases issued by the Boiler and Pressure Vessel Committee and the Operations and

Maintenance Committee, it was determined that a need existed for a Standard to address the PRA capability necessary to support ASME applications of this emerging technology. After approval by the ASME Council on Codes and Standards, an initial Project Team was formed in early 1998 to develop a PRA Standard that would provide a foundation for existing and future risk-informed applications for commercial LWR nuclear power plants. In parallel, a Standards Committee, the Committee on Nuclear Risk Management (CNRM),[2] was formed to direct the work, provide for consensus approval, and manage maintenance and future development.

The Project Team was comprised of key individuals with the direct knowledge and experience needed to produce a technically adequate document under the ASME Codes and Standards Redesign Process. A unique part of this process was the review of two drafts of the Standard by experts inside and outside the ASME Committee structure. Several thousand comments were addressed by the Project Team and incorporated within the Standard where they were considered to be appropriate.

Concurrent with the development of the standard, the U.S. nuclear industry developed a peer review process for assessing the technical capability and adequacy of a PRA to support risk-informed regulatory licensing applications [20]. The guidelines of NEI 00-02 were considered in the development of the PRA Standard to facilitate application to facilities that had already been reviewed to the Nuclear Energy Institute (NEI) guidelines.

Subsequent to the publication of RA S-2002 intensive reviews by industry teams, the NRC identified numerous areas where clarification or qualification of its requirements was considered desirable. As a result, a significant effort was undertaken to consider this input and adopt suggestions considered necessary or desirable. The result was Addendum "a" published in December 2003 as ASME RA-Sa-2003.

During the later part of 2003, the PRA Standard was subject to trial use during review of existing PRAs. This experience identified a number of additional areas where clarification or formatting changes would help in its application. As a result, a Project Team was formed, including members who had been involved in these applications, to develop proposed changes for incorporation in Addendum "b" of the Standard issued in 2005 and Addendum "c" issued in August 2007.

The initial scope of ASME RA-S addressed the determination of core damage frequency and large early release only for internal events (excluding fire) occurring at full power, since this was the most highly developed and used area of PRA application. Concurrent with the ASME development of RA-S, the American Nuclear Society was preparing comparable standards covering external events, internal fires, and low power and shutdown conditions. Over the last few years, the two societies as well as the Nuclear Regulatory Commission and industry recognized the value of combining the requirements in a single standard, and agreements were reached to develop this document as a revision to RA-S that is designated ASME/ANS RA-S1-2008 [18, 19]. The initial issue of this revision adds internal fire and external events to the scope. Low power and shutdown requirements will be added in a future addendum.

[2]CNRM has the following approved charter. "To develop, revise and maintain standards and guides on risk management techniques, including PRA for nuclear power plants and other nuclear facilities."

22.3.2 Introduction and Scope

The RA-Sb-2013 PRA Standard is comprised of 10 parts as follows:

(1) General Requirements for a Level 1 PRA, including large early release frequency
(2) Requirements for Internal Events at-Power PRA
(3) Requirements for Internal Food at-Power PRA
(4) Requirements for Fires at-Power PRA
(5) Requirements for Seismic Events at-Power PRA
(6) Requirements for Screening and Conservative Analysis of Other External Hazards at-Power
(7) Requirements for High Winds events at-Power PRA
(8) Requirements for External Flood events at-Power PRA
(9) Requirements for Other External Hazards at-Power PRA
(10) Seismic Margin Assessment Requirements at-Power

Technical and Peer Review Requirements for Level 1 and LERF PRA for low power and shutdown, including internal and external events (except internal fires) will be included at a future date.

Part 1 of the PRA Standard provides an introduction defining scope and applicability and a brief overview of the remaining content. It includes acronyms and definitions, as specifically used in the standard, and requirements that are essentially applicable to all parts of the standard such as the elements of a risk assessment application process, configuration control, and general requirements for performing a PRA and peer reviews.

The objectives of the standard are to provide requirements for probabilistic risk assessments used to support risk-informed decisions for commercial nuclear power plants, and to prescribe methods for applying these requirements for specific applications. In addition, it provides requirements for configuration control of the PRA and a peer-review process to assess how well a PRA meets the requirements of the standard. The scope is limited to commercial light water nuclear power plants. It establishes requirements for Level 1 analysis[3] and a limited Level 2 analysis sufficient to evaluate the large early release[4] frequency, and is intended for a wide range of applications that require a corresponding range of PRA capabilities.

PRA applications vary with respect to which risk metrics are employed, which decision criteria are used, the extent of reliance on the PRA results in supporting a decision, and the degree of resolution required of the factors that determine the risk significance of the proposed changes. Furthermore, existing PRAs differ in terms of their scope and level of detail. To support these variations, the standard provides requirements for three capability categories, as shown in Table 22.1 (Table 1.3-1 of ASME/ANS RA-S1-2008), each representing an increasing level of fidelity and detail.

While initial development of the standard focused on operating nuclear power plants, a need has been identified to support the New Build fleet. In particular, 10 CFR Part 52 plants (Licenses, Certifications, and Approvals For Nuclear Power Plants), requires that applicants for Design Certification and Combined Licenses provide a description of the plant-specific probabilistic risk

[3]A Level 1 analysis includes the identification and quantification of the sequences of events leading to the onset of core damage, for example, core damage frequency.

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

TABLE 22.1 BASES FOR PRA CAPABILITY CATEGORIES (*Source:* ASME/ANS RA-Sa-2009)

Attributes of PRA	I	II	III
1. Scope and Level of Detail: The degree to which the scope and level of detail of the plant design, operation, and maintenance are modeled.	Resolution and specificity sufficient to identify the relative importance of the contributors at the system or train level (and for Fire PRA, at a fire area level), including associated human actions [Notes (1) and (2)].	Resolution and specificity sufficient to identify the relative importance of the significant contributors at the component level (and for Fire PRA, at a physical analysis unit level including fire protection program and design elements) including associated human actions, as necessary [Notes (1), (2), (3), and (4)].	Resolution and specificity sufficient to identify the relative importance of the contributors at the component level (and for Fire PRA, for specific locations within fire areas or physical analysis units, including fire protection program and design elements) including associated human actions, as necessary [Notes (1), (2), (3), and (4)].
2. Plant-specificity: The degree to which plant-specific information is incorporated such that the as-built and as-operated plant is addressed.	Use of generic data/models acceptable except for the need to account for the unique design and operational features of the plant.	Use of plant-specific data/models for the significant contributors.	Use of plant-specific data/models for all contributors, where available.
3. Realism: The degree to which realism is incorporated such that the expected response of the plant is addressed.	Departures from realism will have moderate impact on the conclusions and risk insights as supported by good practices [Note (5)].	Departures from realism will have small impact on the conclusions and risk insights as supported by good practices [Note (5)].	Departures from realism will have negligible impact on the conclusions and risk insights as supported by good practices [Note (5)].

NOTES:
(1) The terms "fire area" and "physical analysis unit" are defined in 1-2.2. Fire areas are defined in the context of regulatory compliance documentation. Physical analysis units are subdivisions of a fire area used for the purposes of the Fire PRA.
(2) The Fire PRA capability categories are distinguished, in part, based on the level of resolution provided in the analysis results. There is a gradation in resolution from fire areas for Capability Category I to specific locations within a fire area or physical analysis unit for Capability Category III. This distinction should not be confused with the task of plant partitioning (see 3-1.7.1). A Capability Category III Fire PRA could, for example, partition the plant at a fire area level and yet resolve fire risk contributions to the level of specific fire scenarios within each fire area. This approach would satisfy the intent of the Capability Category III basis in this regard. The term "fire protection program and design elements" as used here is intended to broadly encompass fire protection systems, features, and program provisions implemented in support of fire protection defense-in-depth. The term is intended to encompass active systems such as fire detection and suppression systems, passive features such as fire barriers, programmatic elements such as administrative controls, as well as other aspects of the fire protection program such as the manual fire brigade and post-fire safe shutdown.
(3) The definition for Capability Categories II and III is not meant to imply that the scope and level of detail includes identification of every component and human action, but only those needed for the function of the system being modeled.
(4) The term "fire protection program and design elements" as used here is intended to broadly encompass fire protection systems, features, and program provisions implemented in support of fire protection defense-in-depth. The term is intended to encompass active systems such as fire detection and suppression systems, passive features such as fire barriers, and programmatic elements such as administrative controls, as well as other aspects of the fire protection program such as the manual fire brigade and postfire safe shutdown.
(5) Differentiation from moderate, to small, to negligible is determined by the extent to which the impact on the conclusions and risk insights could affect a decision under consideration. This differentiation recognizes that the PRA would generally not be the sole input to a decision. A moderate impact implies that the impact (of the departure from realism) is of sufficient size that it is likely that a decision could be affected; a small impact implies that it is unlikely that a decision could be affected, and a negligible impact implies that a decision would not be affected.

assessment (PRA) and its results (10 CFR Part 52.79(a)(46) "Contents of applications; technical information in final safety analysis report"). A writing group has been formed which has been tasked with developing an Appendix to the standard that identifies which parts of the standard can be met during different stages of pre-operation and what interim steps can be taken when applicable information is not currently available. For example, operating data would not be available at the Design Certification or Combined License application phases.

22.3.3 Application of the PRA Standard

Section 3 of Part 1 of the PRA Standard covers the methodology for applying PRA information to risk-informed decision-making and is located in the standard preceding the delineation of specific PRA requirements provided in Section 4 to emphasize several points such as follows:

- Risk-informed decision-making involves more than comparing PRA results.
- Different risk-informed decisions can require PRAs of differing scope, level of detail, and fidelity of results.
- PRAs that do not meet all the technical requirements of the standard may be used to support risk-informed decisions.
- A PRA meeting all the technical requirements of the standard may not be sufficient for some risk-informed decision-making.

Section 3 describes the activities to determine the capability of a PRA needed to support a particular risk-informed application and identifies actions to be taken when a PRA is found deficient. This process is outlined in the flowchart of Figure 22.1 (Fig. 1.3.1 from the standard). The process recognizes that many PRAs are incomplete and even those complying with the standard may not adequately model or analyze conditions necessary to fully evaluate the risk impact of a proposed application. Hence methods for assessing the risk importance of those elements not included in the PRA are identified.

22.3.4 Technical Requirements

Section 4 of Part 1 of the PRA Standard contains the general technical requirements for PRAs used to support risk-informed decision-making. It also includes general requirements for the use

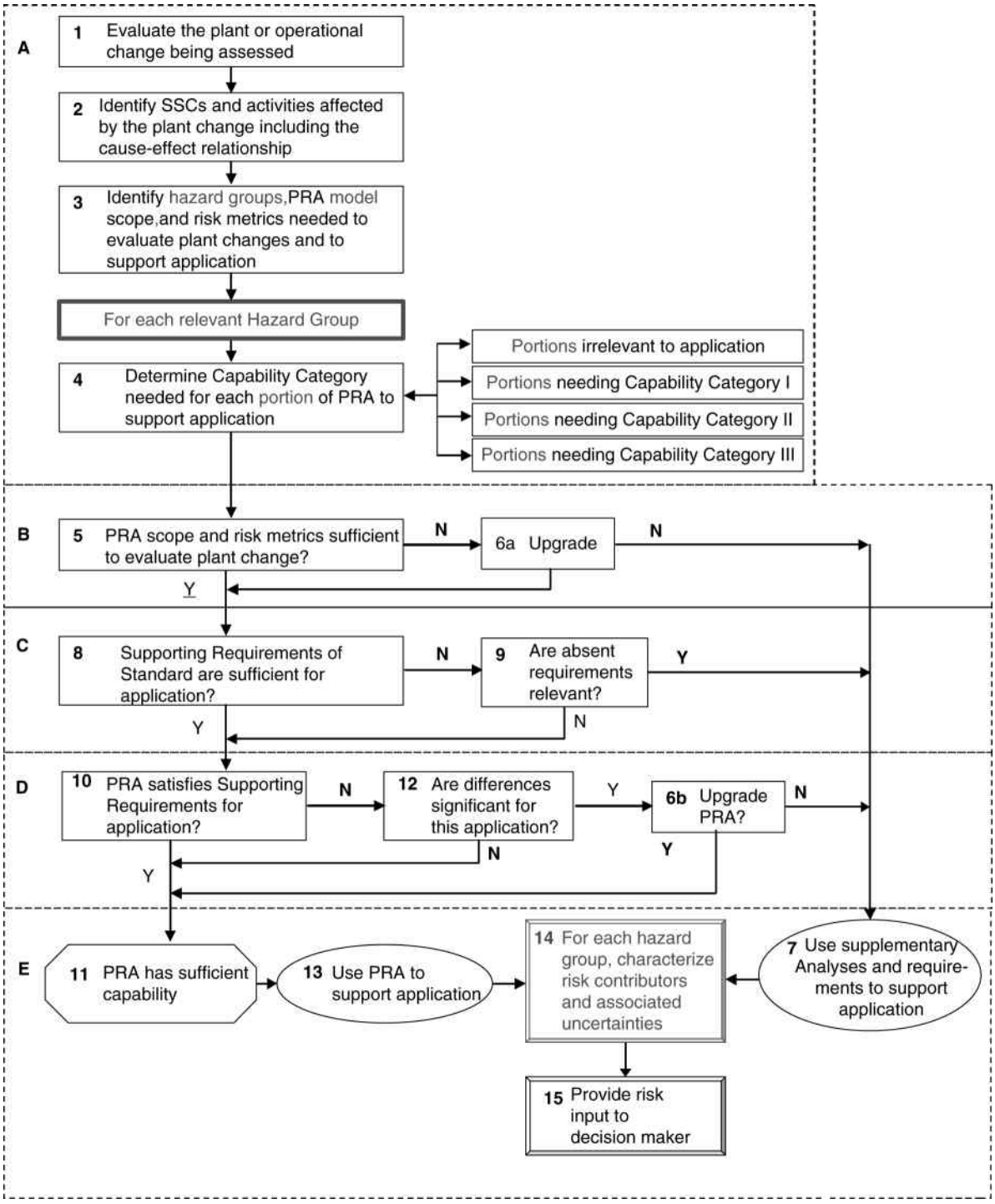


FIG. 22.1 FLOW CHART FOR EVALUATING THE CAPABILITY OF PRA

of expert judgment to resolve specific technical issues for verification of analyses and calculations. The detailed technical requirements of PRAs constitute the major portion of Section 4 and these are delineated in the subsequent parts of the standard.

22.3.5 Configuration Control

Section 5 of Part 1 of the PRA Standard provides requirements for configuration control. It includes requirements for

(1) monitoring PRA inputs and collecting new information,
(2) maintaining the PRA consistent with the as-built, as-operated plant,
(3) considering the cumulative impact of pending changes when applying the PRA,
(4) maintaining configuration control of computer codes used to support PRA quantification, and
(5) documentation of the Configuration Control Program.

22.3.6 Peer Reviews of PRAs

A unique part of the standard is the requirement in Section 6 of Part 1 for Peer Reviews of the PRA to independently assess whether the methodology and its implementation meet the requirements of the standard. Requirements for the qualifications and independence of the peer review teams are enumerated and a typical scope for the content of the review is provided. The Section contains requirements for documenting Peer Review Team results, including exceptions and deficiencies with respect to the requirements of the Standard, and identification of strengths and weaknesses in the PRA. Provisions for follow-up peer reviews of significant changes in the PRA are also included.

22.3.6.1 Content of Other Parts Each of the other parts of the standard contains a brief introduction followed by sections defining the detailed technical requirements and peer review scope for the area covered. Since many of the technical requirements are essentially the same for each part, Part 2 contains this material, and the requirements sections of the other parts refer to those in Part 2 with amplification, amendment or clarification, as necessary.

The technical requirements of Part 2 include the following:

(1) Initiating event analysis
(2) Accident sequence analysis
(3) Success criteria
(4) Systems analysis
(5) Human reliability analysis
(6) Data analysis
(7) Internal flooding
(8) Quantification
(9) Large early release analysis

For each of these elements, a set of objectives is presented defining its scope. These are followed by a set of high-level requirements (HLRs) that apply to all PRAs covered by the standard, and these, in turn, are followed by supporting requirements (SRs) that fully implement the related HLRs. Differentiation of the requirements for the three PRA capability categories is provided at the SR level.

The SRs are defined in terms of action statements that are intended to identify what is required. In general, however, they do not define or prescribe how to accomplish the requirement. In some cases, examples are provided or acceptable methods are referenced. It is recognized that a diversity of acceptable approaches have been used to develop existing PRAs and that the standard should neither preclude these nor prevent the development of technological innovations in the future.

22.4 ASME B&PV SECTION XI IN-SERVICE INSPECTION

22.4.1 Overview

The ASME BNCS chose Code Cases to incorporate risk-informed research results for ISI requirements in Section XI of the Boiler & Pressure Vessel Code [21]. In the case of ISI, three Code Cases for inspection of piping systems and their revisions, Code Case N-560, N-560-1, and N-560-2 [22–24]; Code Case N-577 and N-577-1 [25, 26]; and Code Case N-578 and N-578-1 [27, 28], have been approved through the efforts of Section XI of the ASME Boiler & Pressure Vessel Code. These Cases and their revisions were subsequently combined for incorporation as Nonmandatory Appendix R, "Risk-Informed Inspection Requirements for Piping" [29], in the 2005 Addenda of ASME Section XI. The results of research programs, industry developments, and pilot plant applications on risk-informed technology have formed the technical bases for initiating the Code changes.

The current U.S. efforts on risk-informed in-service inspection are focused so far on the selection of welds (and other locations) for Section XI in-service inspections. Changes to Section XI inspection frequencies and nondestructive examination (NDE) methods could be addressed in the future. The intent of RI-ISI has been to make no changes to augmented ISI programs such as for inner granular stress corrosion cracking (IGSCC), primary water stress corrosion cracking (PWSCC), and for flow-assisted corrosion (FAC). The selection of components for Section XI inspections can cover all piping systems in a plant or can be partial in scope such as only for Class 1 systems. Systems not addressed by RI-ISI continue to be inspected by the traditional ASME Section XI requirements. Other provisions of Section XI, including visual examinations and leak tests, are generally not impacted by the RI-ISI process.

The pilot plants for ISI began to receive NRC approval in 1998. The majority of the industry has now developed plant-specific programs with at least one of the methodologies contained in the Code Cases, their revisions, or in Nonmandatory Appendix R cited above. To support obtaining NRC approval of these risk-informed in-service inspection programs, the industry, represented by the NEI, developed program submittal templates. These templates were used to meet the guidance contained in NRC Regulatory Guide 1.178 [30] that was developed for plant-specific, risk-informed decision-making for ISI. The above ASME information and results were utilized by the NRC in the development of this guidance document and its revision, and these ASME applications provided useful examples during the development and revision of NRC Regulatory Guide 1.174 [31].

The set of risk-informed Code Cases differ from the majority of Code Cases in that these Cases generally define substantially new approaches, relative to application of the Code. Thus, they tend to be significantly longer, so that sufficient detail can be provided regarding requirements for the technical approach to be used, such as the acceptance metrics and metric target values, PRA capability, and use of expert decision-making panels. However, the Code Cases did not include a strategy for dealing with existing augmented and other programs such as IGSCC, PWSCC, FAC, and pitting. None of these Code Cases provided system-level guidelines for change-in-risk evaluations to ensure that the risk from individual system failures would be kept small and dominant risk contributors would not be created. This situation has now been resolved within the Code by the publication of rules contained in Nonmandatory Appendix R [29].

As of now, Nonmandatory Appendix R [29] has not been endorsed by the NRC and another Code Case N-716 [32] has been developed to continue the implementation of operating experience that has been gained through all the efforts described above. It contains a rigorous dependence on the plant-specific PRA in the development of a risk-informed in-service inspection program and has established streamlined criteria for two pilot plant applications, which have been approved by the NRC.

Revision 1 to ASME Code Case N-716 was recently approved by ASME and is contained in draft USNRC Regulatory Guide 1.147 [33, 58]. Revision 1 of Code Case N-716 incorporates lessons learned from the pilot plant applications as well as thirty other plant applications of the Code Case. Additionally, this revision

to the Code Case expands the scope of applicability beyond piping welds to include Pressure Retaining Welds in Pressure Vessels, Pressure Retaining Nozzle Welds in Vessels, Pressure Retaining Bolting > 2" Diameter and Pressure Retaining Welds in Pumps & Valves.

22.4.2 Development of Code Cases and Code Rules for In-Service Inspection

ASME Section XI formed a Task Group on Risk-Based Examination in 1992 to follow-up on the developments of the ASME Research Task Force on Risk-Based Inspection, which were described in guidance documents and by results of some initial pilot studies. After review of the early research results, ASME Section XI formed the Working Group on Implementation of Risk-Based Examination in 1993. This working group was recently renamed the Working Group on Risk-informed Applications to more fully represent the group's charter and mission. The initial efforts developed three Code Cases related to risk-informed ISI requirements for piping as follows:

- Case N-560, Alternative Examination Requirements in Class 1 B-J Piping Welds, Section XI, Division 1 [22]
- Case N-577, Risk-Informed Requirements for Class 1, 2, and 3 Piping, Method A, Section XI, Division 1 [25]
- Case N-578, Risk-Informed Requirements for Class 1, 2, or 3 Piping, Method B, Section XI, Division 1 [27]

These Cases included both the methods for selecting the examination locations in nuclear plant piping systems and provided the applicable examination requirements. The Cases brought forward two key insights: (1) the identification of the potential sites for degradation in piping systems based on operating experience and on probabilistic fracture mechanics (PFM) evaluations, and (2) the identification of areas of high consequences (e.g., core damage) given a pipe failure using insights gained from plant PRA models.

A key feature of RI-ISI is the team effort aspect of the process. The team is drawn from the plant/utility staff with first-hand knowledge of the plant, typically consisting of (1) an ISI engineer, (2) a piping system engineer, (3) a materials engineer, (4) system engineers, and (5) PRA specialists. The PRA aspects of RI-ISI are an essential part of the process and are usually covered by PRA specialists from the utility. Steps of the RI-ISI Code Cases that require PRA applications are similar to procedures used for other PRA-based activities such as compliance with requirements of the NRC Maintenance Rule [34] and thus involve familiar types of calculations for a PRA specialist. Applications of the RI-ISI Code Cases have also benefited from the use of outside facilitators from owners groups or consulting organizations that contribute their knowledge of the RI-ISI process to compliment the plant-specific knowledge of the utility staff.

The Section XI Code Cases presume that a suitable PRA exists for the plant being addressed. NRC staff reviews have considered potential shortcomings of the plant's PRA. The ASME PRA Standard can also serve to ensure that PRAs are of sufficient quality. There are no known cases where the PRA has not been of a quality that would not support the RI-ISI applications. An expert panel process is included in one method to review the selection of components for ISI and to address concerns where a PRA may not adequately deal with components of interest.

While the Code Cases themselves provide all the requirements and procedures needed to develop a Section XI inspection program, there are topical reports [35, 36] for all the three RI-ISI Code Cases that provide more detailed guidance that can contribute to the successful application of the Code Cases.

Figure 22.2 shows the essential elements of a RI-ISI process (specifically for Code Case N-577, but generally applicable to the other Code Cases) that begins with a definition of scope of the program to be covered by the risk-informed process (i.e., piping systems to be addressed). There is then a detailed breakdown of each piping system into segments that are to be subjected to a ranking process. The ranking process begins with two types of evaluations that are performed in parallel. Consequences are evaluated by application of the PRA for the plant being addressed. Structural failure probabilities for the piping segments are evaluated based on service experience and from applications of structural reliability models. The risk evaluation then combines results from the consequence and failure probability calculations, and provides input to the assignment of each pipe segment to a risk categorization. The process includes a high-level review (e.g., expert panel) that addresses other factors, as listed on Figure 22.2 (e.g., defense in depth, consideration of uncertainties, limitations in the scope of the PRA, and so on). The final step is the selection of structural elements (e.g., welds) for inspections and the implementation of the ISI program. A feedback loop is included to guide periodic updates to the RI-ISI program to reflect new information from plant operating experience and changes to the estimated consequences coming from revisions to the plant PRA.

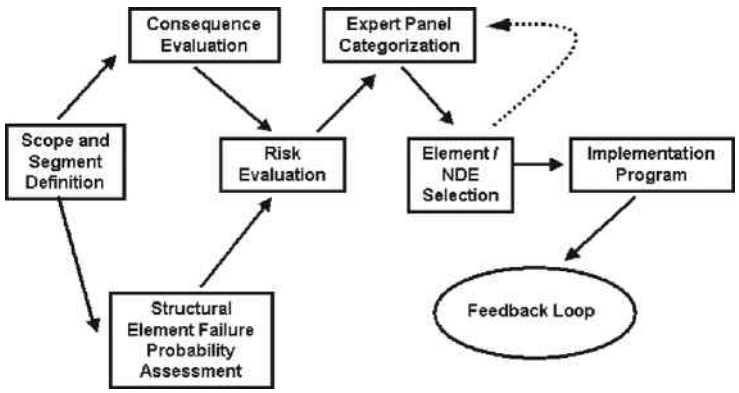


FIG. 22.2 OVERALL RISK-INFORMED ISI PROCESS

22.4.3 Code Case N-560

Code Case N-560, "Alternative Examination Requirements for Class 1, Category B-J Piping, Section XI, Division 1," was first issued in 1996 [22]. This Case provides risk-informed requirements for ISI that may be applied to all Class 1 piping or to individual systems subject to Category B-J examination requirements. It should be emphasized that Code Cases N-577 [25] and N-578 [27] can be applied to all of the piping systems of a plant or alternatively to limited scope applications such as to only address particular piping systems or classes of piping systems. The piping not addressed by RI-ISI continues to be inspected by the usual Section XI requirements. Code Case N-560 was developed to respond to utility interest in gaining the benefits of RI-ISI (reduced inspection costs and reduced worker radiation exposures) without the full costs of performing the extensive evaluations needed to develop a full-scope RI-ISI program.

The examination program of Code Case N-560 is based on a total number of inspected elements (e.g., welds) consisting of not less than 10% of Category B-J piping welds in each system, excluding socket welds, which are to be inspected during each inspection interval. Structural elements of the piping systems correspond to welds, fittings, or other specific piping locations. Each element contains an examination volume determined in accordance with the requirements of this Case.

A key feature of Code Case N-560 is the risk-informed process (known as Method B) that is used for the selection of piping segments and piping structural elements in systems that will be scheduled for ISI. Elements are selected based on results of a relative ranking process that identifies the more risk-important segments in the system with regard to failure probabilities and consequences of failure. Elements are selected from the pipe segments that fall into the highest risk group.

The piping within a system is divided into segments that have common failure consequences and susceptibility to common degradation mechanisms. Potential failure modes for each pipe segment are identified, and the failure effects for each mode are evaluated. The evaluations consider potential break sizes, isolability of the breaks, indirect effects, initiating events, system impact/recovery, and system redundancies. A failure modes and effects analysis assigns each pipe segment to one of the three impact groups: initiating event, system degradation, or combination of these two impacts. The consequence categories (high, medium, or low) are selected using PRA-based impact group tables that perform an initiating event impact group assessment, a system impact group assessment, and a combination impact group assessment. Containment performance is also assessed, particularly to address potential pipe failures that can increase the potential for an unisolated loss-of-coolant accident (LOCA) outside containment. The plant PRA is used with the impact group tables to determine the consequence categories. No specific requirements are provided in Code Case N-560 to evaluate the adequacy of the PRA. However, the ASME Standard for PRA adequacy can be applied, or it can be established that the PRA meets PRA adequacy requirements approved by the regulatory authority having jurisdiction over the plant site.

The ranking process addresses relevant degradation mechanisms and industry failure experience with the systems and components. The following factors are considered for the identification of degradation mechanisms: piping design characteristics, fabrication practices, operating conditions, industry-wide service experience, results of prior examinations, and presence of prior repairs. The Code Case provides a table of degradation mechanisms and outlines attributes and susceptible piping regions associated with thermal fatigue, stress corrosion cracking, localized corrosion, flow-sensitive areas, and water hammer.

Further information is provided to categorize the degradation mechanisms (high, medium, or low) in accordance with their potential to cause large pipe breaks or small leaks.

Using the results of the consequence and degradation mechanism categorizations, a risk matrix is used to combine the results to assign each pipe segment to one of the seven risk categories that are then grouped into high, medium, and low risk groups. Elements are selected starting with the elements in the high risk group and working toward the low risk group, until a total number of elements equal to 10% of the category B-J piping welds, excluding socket welds, has been selected. Examinations may be concentrated on systems with more high-risk segments as per guidance given in the Case with additional consideration given to access, radiation exposure, and other attributes.

Once the structural elements have been selected for examination, a change-in-risk calculation is performed to ensure that the proposed change in the inspection program reduces risk or is risk neutral. The examination methods and techniques are determined in accordance with a Table of Examination Categories for Category B-J, Class 1 Piping. In general, the ASME Section XI standards for inspection schedules, acceptance standards, repair/replacement, system pressure tests, record, and report requirements are directly utilized by reference to the appropriate Code paragraphs. The selected elements are examined during subsequent examination intervals. Any modifications to the list of selected elements are based on changes in industry operating experience, changes in plant design or operation, new metallurgical knowledge, or prior examination results.

Further details on this application of Method B are provided in EPRI TR-112657 Revision B-A by the Electric Power Research Institute (EPRI) [36], which has been approved by the U.S. Nuclear Regulatory Commission. Code Case N-560-2 [24], which was approved in 2000, reflects the revision to the original Case to incorporate the lessons learned from the pilot plant and follow-on applications. A second Code Case N-560-1 [23] was also published to incorporate a Method A for performing the risk ranking of pipe segments. However, this version of the Case has never been used because a later revision to Code Case N-577-1 [26], which is discussed next, superseded the need for this alternative Code Case.

22.4.4 Code Case N-577

Code Case N-577, "Risk-Informed Requirements for Class 1, 2, and 3 Piping, Method A, Section XI, Division 1" was first issued in 1997 [25]. This Case provides risk-informed requirements for ISI of Class 1, 2, and 3 piping. For Class 1 and 2 piping, the requirements are an alternative to the requirements of Categories B-F, B-J, C-F-1, and C-F-2. Application of the Case may result in the examination of some Class 3 piping. Piping in systems evaluated as part of the plant PRA, but outside the current ASME Section XI examination boundaries, may also be included.

A key feature of this Code Case N-577 [25] is a risk-informed selection process, known as Method A and described in Appendix I of the Case. This process establishes the piping segments and piping structural elements in systems that will be scheduled for ISI. The Owner's Level 1 PRA and its evaluated safety function (i.e., core damage protection) and the numerical risk measure associated with that safety function (core damage frequency) provide the necessary information for the system boundaries to be used in this process. If a piping system, or portions thereof, provides an

additional safety function such as containment integrity, then insights from the Owner's Level 2 PRA may be used along with its associated risk measure and safety function (large early release frequency). Use of PRA insights beyond the Level 1 PRA for the determination of system boundaries are documented, reviewed, and approved by a plant expert panel. The scope and quality of the PRA should realistically reflect the as-built, as-operated, and as-maintained plant and should reflect operating experience at the plant. As per Code Case N-577 [25], the PRA shall meet the guidelines of the "PSA Applications Guide" [37]. Alternatively, the PRA may meet the regulatory requirements of a document approved by the regulatory authority having jurisdiction over the plant site that provides requirements for PRA adequacy.

Estimates of the failure probability of piping segments are required inputs to the risk calculations. Piping failure rates are analogous to the active component failure rates used in the PRA, where the rate is the number of observed failures divided by the number of years. Historical or service data, expert judgment, or validated PFM calculations are used to estimate the piping segment failure probabilities. The PFM calculations are the primary method used to estimate failure probabilities for Code Case N-577 [25] unless the piping materials and operating characteristics assessed are not compatible.

The core damage frequencies and large early release frequency values are estimated for each piping segment, by combining the PRA consequence and the failure probability estimates. The values are then summed to obtain a total pressure boundary risk for the piping systems of interest. Risk importance measures are applied to identify piping segments as being high or low safety significant. The risk evaluation is reviewed by a plant expert panel, along with other deterministic and safety insights to make the final determination of the safety significance of each piping segment.

Structural elements in the HSS segments are selected for examination. Structural elements (e.g., welds) in HSS segments with known or postulated degradation mechanisms are subject to 100% examination. Structural elements in the HSS systems or portions of the HSS systems with low failure potential are selected using a sampling plan that achieves at least a 95% confidence of not exceeding an estimated leak frequency defined from industry operating experience based upon the best estimate failure probabilities. All piping segments, including LSS segments, are subject to system pressure tests and visual VT-2 examinations. Once the structural elements have been selected for examination, a change-in-risk evaluation is performed to ensure that the piping risk is reduced or remains neutral when the plant moves from the current ISI program to a risk-informed program. The examination methods and techniques that are to be used for the inspections of areas or volumes are determined in accordance with the requirements provided in a Table of Risk-Informed Piping Examinations provided in the Code Case. In general, the ASME Section XI standards for inspection schedules, acceptance standards, repair/replacement, system pressure tests, and record and report requirements are directly utilized by reference to the appropriate Code paragraphs.

The selected elements are examined during subsequent examination intervals. Examinations that reveal flaws or other relevant conditions exceeding the acceptance standards result in additional inspections. The additional examinations include piping structural elements with the same postulated failure mode and the same or higher failure potential. The number of additional elements equals the number of piping structural elements with the same postulated failure mode originally scheduled for inspection for that fuel cycle.

Risk-informed ISI selections are reevaluated each inspection period to account for new information that could alter the program. Such information includes changes to the PRA, inspection results, new failure modes experienced by the industry, repair/replacement activities, or operational changes.

The Code Case N-577 [25] was approved in 1997 with the understanding that it would be revised to incorporate the lessons learned from a pilot application to the Surry Unit 1 nuclear power plant and other follow-on plant applications. Further details on this application of Method A to Surry Unit 1 are provided in WCAP-14572, Revision 1-NP-A by Westinghouse [35], which has been approved by the U.S. Nuclear Regulatory Commission. Code Case N-577-1 [26], which was approved in 2000, reflects the revision to the original Case to incorporate the lessons learned from the pilot plant and follow-on applications.

22.4.5 Code Case N-578

Code Case N-578, "Risk-Informed Requirements for Class 1, 2, and 3 Piping, Method B, Section XI, Division 1" was also first issued in 1997 [27]. Like Code Case N-577 [25], this Case provides risk-informed ISI requirements for Class 1, 2, and 3 piping. For Class 1 and 2 piping, these requirements are an alternative to the requirements of Categories B-F, B-J, C-F-1, and C-F-2. Application of this Case may result in a requirement for examination of some Class 3 piping. This Case may be applied to all Class 1, 2, and 3 piping systems, an individual Class of piping (e.g., Class 1 piping), or to individual systems. Piping in systems evaluated as part of the plant PRA, but outside the current ASME Section XI examination boundaries, may also be included.

This Case uses exactly the same risk-informed process, known as Method B, as previously presented for Code Case N-560 [22]. The only additional clarification in Appendix I to Code Case N-578 [27] is related to the inspection sample sizes to address all classes of piping.

For piping segments determined to have degradation mechanisms other than those included in the existing plant FAC and IGSCC Inspection Programs, a prescribed number of locations are examined as part of the risk-informed program. For those segments in Risk Category 6 or 7, volumetric and surface element examinations are not required. All elements, regardless of risk category, are pressure and leak tested. The elements within each risk category are further ranked for examination as per guidance in the Case with considerations of access, radiation exposure, and other attributes.

Once the structural elements have been selected for examination, a change-in-risk evaluation is performed to ensure that the change in piping risk is a risk reduction or is risk neutral. Like Code Case N-577 [25], the examination methods and techniques for the examination areas or volumes are determined in accordance with the requirements provided in a Table for Risk-Informed Piping Examinations in the Case. In general, the ASME Section XI standards for inspection schedules, acceptance standards, repair/replacement, system pressure tests, and record and report requirements are directly utilized by reference to the appropriate Code paragraphs.

The selected elements are examined during subsequent examination intervals. Examinations that reveal flaws or other relevant conditions exceeding the acceptance standards are extended to include additional examinations. The additional examinations address piping structural elements with the same postulated failure mode and the same or higher failure potential. The number of additional inspected elements equals the number of piping

structural elements with the same postulated failure mode originally scheduled for that fuel cycle.

The affected portions of the risk-informed in-service inspection program are reevaluated, as new information effecting implementation of the program becomes available. Examples include piping system design changes, industry-wide failure notifications, and prior examination results.

The Code Case was originally approved in 1997 with the understanding that it would be revised to incorporate the lessons learned from pilot application to the James A. Fitzpatrick and Arkansas Nuclear One–Unit 2 nuclear power plants and other follow-on plant applications. Further information on the detailed application of Method B is provided in EPRI TR-112657 Revision B-A by the Electric Power Research Institute [36], which has been approved by the U.S. Nuclear Regulatory Commission. Code Case N-578-1 [28], which was approved in 2000, reflects the revision to the original Case to incorporate the lessons learned from the pilot plant and follow-on applications.

22.4.6 Nonmandatory Appendix R

Nonmandatory Appendix R, Risk-Informed Inspection Requirements for Piping, ASME Section XI, 2005 Addenda [29], was developed from the operating experience of the plants that have implemented Code Cases N-560, N-560-2, N-577, N-577-1, N-578, and N-578-1 [22, 24–28]. Some of the significant differences between the Code Cases and the Appendix are the addition of the following requirements:

(1) Adequacy of the PRA (e.g., reference to the ASME PRA Standard RA-Sb-2005) [17].
(2) Preservice examination requirements related to high and low safety significant items and specific criteria for these examinations when conducted as part of repair/replacement activities.
(3) Additional examination requirements related to high and low safety significant items.
(4) How to credit augmented examinations.
(5) Consistent change in risk evaluations.

The Section XI, Working Group on Implementation of Risk-Based Examination included all of these requirements into the Appendix to resolve NRC conditions that had been placed on individual plant programs based on the use of the Code Cases.

22.4.7 Code Case N-711

Code Case N-711, "Alternative Examination Coverage Requirements for Examination Category B-F, B-J, C-F-1, C-F-2, and R-A, Piping Welds, Section XI, Division 1," was approved by ASME in 2006 [38]. This Case uses risk insights to define alternative examination coverage requirements to Table IWB-2500-1 (examination categories B-F and B-J) and Table IWC-2500-1 (examination categories C-F-1 and C-F-2) and to examination category R-A as used in risk-informed ISI programs.

The existing examination figures of IWB and IWC were developed over 30 years ago and are reflective of the state of knowledge at the time. There has been minimal or no change to these figures since that time. Advances in fracture mechanics and evaluations, material susceptibility, operating experience, as well as insights from risk-informed technology all lead to a more complete understanding of piping system integrity, putting the Code in a position to identify more informed examination requirements.

Code Case N-711 provides a technically justified means for taking the first step in evaluating limited coverage examinations. It establishes criteria based on risk-informed principles to determine if the limited Code examination captured the volume of primary interest, thus assuring component reliability. As such, it provides a more robust means of determining the most prudent examination locations, volumes, and areas. From an administrative standpoint, this Case uses a prescriptive process for the evaluation of limited coverage while focusing relief requests on those locations that merit them. The Case provides the technical justification for establishing that an acceptable level of quality and safety are being met as required by 10 CFR 50.55a.

22.4.8 Code Case N-716

Code Case N-716, "Alternative Piping Classification and Examination Requirements, Section XI, Division 1," was approved by ASME in 2006 [32]. The Case represents the next step in the use of risk-informed insights, design basis principles, and operating experience for defining Section XI requirements. The Case builds upon the experience gained within ASME, the industry, and the NRC in developing and performing risk-informed and treatment activities. Because of this experience, an increased emphasis, in this Case, has been laid on each individual plant's flooding analysis for determining the safety significance of those items selected for examination. Two pilot plants that have applied the Code Case are Grand Gulf BWR and DC Cook PWR. Both of these pilot plants submitted their programs to the NRC, and they have been approved. Revision 1 to ASME Code Case N-716 was recently approved by ASME and is contained in draft USNRC Regulatory Guide 1.147 [33, 58]. Revision 1 of Code Case N-716 incorporates lessons learned from the pilot plant applications as well as thirty other plant applications of the Code Case. Additionally, this revision to the Code Case expands the scope of applicability beyond piping welds to include Pressure Retaining Welds in Pressure Vessels, Pressure Retaining Nozzle Welds in Vessels, Pressure Retaining Bolting > 2" Diameter and Pressure Retaining Welds in Pumps & Valves.

22.4.9 Code Case N-747

Code Case N-747, "Reactor Vessel Head-to-Flange Weld Examinations, Section XI, Division 1," was approved by ASME in 2006 [39]. This Case provides an alternative to the volumetric and surface examination requirements for the reactor vessel head-to-flange weld contained in Section XI, Table IWB-2500-1, Examination Category B-A, Item No. B1.40. This alternative requires that after a preservice or in-service ultrasonic examination has been performed with no defect found, only the surface examination requirements of B1.40 need to be met. The Category B-P pressure tests and visual examinations normally conducted in conjunction with refueling outages will also continue. Note that this weld is not a dissimilar metal or Alloy 600 weld, and is full penetration.

This Case provides an option to reduce undue burden while maintaining plant safety by eliminating the requirement for concurrent surface and volumetric examination of the reactor vessel head-to-flange weld. This alternative is based on nearly 40 years of plant operation experience, analytical results that indicate that flaw initiation, growth, and fracture are unlikely, and evaluations that show risk is extremely low.

22.5 ASME B&PV SECTION XI REPAIR AND REPLACEMENT

ASME Code Case N-660, "Risk-Informed Safety Classification for Use in Risk-Informed Repair/Replacement Activities" [40], and Code Case N-662 "Alternative Repair/Replacement Requirements for Items Classified in Accordance with Risk-Informed Processes" [41] were developed to expand the breadth of risk-informed requirements for pressure-retaining items. The Code Cases, which were built from the prior ASME Section XI risk-informed ISI developments, were undertaken in conjunction with NRC's risk-informed regulation efforts. The NRC has worked with the industry on risk-informing Title 10 Code of Federal Regulations Part 50 (10 CFR 50) as outlined in SECY-98-300 by the NRC [42]. The Nuclear Regulatory Commission's basic proposal has been to allow modification of some of the special treatment requirements of 10 CFR 50. Background information is given in a technical paper published and presented at the 10th International Conference on Nuclear Engineering [43]. The discussion below also summarizes the technical basis for the two Code Cases.

22.5.1 Background on Risk-Informed Regulation Initiative–Option 2

The Nuclear Regulatory Commission's basic proposal was to allow modification of some of the special treatment requirements of 10 CFR 50 using a risk-informed approach. This proposed approach is defined as Option 2 in the SECY-98-300 NRC paper. Option 1 continues risk-informed changes on a case-by-case basis, and Option 3 proposes to directly risk-inform the technical requirements in 10 CFR 50. Special treatment requirements are current requirements imposed on structures, systems, and components (SSCs) that go beyond industry-established requirements for equipment classified as commercial grade. The requirements provide additional confidence that the equipment is capable of meeting its functional requirements under design basis conditions.

Special treatments include additional design considerations, qualification, change control, documentation, reporting, maintenance, testing, surveillance, and quality assurance requirements above those that occur with typical industry practices. Some of the requirements of ASME Section XI are considered special treatment (e.g., Repair/Replacement Program meeting Appendix B of 10 CFR 50). Following earlier NRC efforts via an Advanced Notice of Public Rulemaking in 2000 and issuance of a Proposed Rule for Public Comment in 2003, the NRC issued a final new rule 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Plants" [44] in the *Federal Register* in November 2004. A parallel task by the NEI to develop guidance on how to perform the risk-informed safety classification process portion of the rulemaking has proceeded via NEI 00-04, Revision 0, "10 CFR 50.69 SSC Categorization Guideline" [45]. The NRC has also issued Regulatory Guide 1.201 [46] for trial use that endorses the NEI 00-04 document and provides additional guidance for categorizing SSCs to meet the requirement of Section 50.69. The ASME Code Cases are discussed in these documents. Since the inception of commercial electrical generation by nuclear power, SSCs have been classified on a deterministic basis. The first criterion is related to whether the SSC is safety related (requiring special treatment) or not safety related (commercial quality requirements apply). The definition of *safety related* in 10 CFR 50 is those structures, systems, and components that are relied upon to remain functional during and following design basis events to assure

(1) the integrity of the reactor coolant pressure boundary,
(2) the capability to shut down the reactor and maintain it in a safe shutdown condition; or,
(3) the capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposures comparable to applicable guideline exposures.

These criteria led to the applicable ASME Code classification for the SSC. The classification requirements are defined in 10 CFR 50 and Regulatory Guide 1.26. In brief, if the SSC is part of the reactor coolant pressure boundary, it is Class 1. If the SSC has functions that add makeup to the reactor coolant system, it is Class 2. Finally, if the SSC has functions that remove heat directly or from support systems critical to the reactor coolant system (e.g., auxiliary feedwater removes heat from the reactor core via the steam generators, emergency diesel heat exchangers), it is Class 3.

These deterministic rules do not factor the probability of the SSC being required to function, nor its reliability. For instance, the containment spray system in a pressurized water reactor (PWR) plant provides a source of cooled water to the atmosphere of the containment. This is typically, in turn, injected into the reactor coolant system via high-pressure safety injection pumps. The containment spray system is only credited for large break LOCAs and for keeping the containment pressure within design limits for main steam and feedwater breaks inside containment. The primary means of heat removal for a small break LOCA are the steam generators. Therefore, the containment spray system is only required for highly unlikely events. In contrast, the auxiliary feedwater system provides makeup to the steam generators whenever the normal main feedwater system is no longer available. The main feedwater system can be lost by a number of means. Loss of main feedwater is a much more likely event than a large break loss-of-coolant accident. Therefore, a demand for the auxiliary feedwater system is more likely than for the containment spray system. Despite this, in the current deterministic methodology, the containment spray system is Class 2 while the auxiliary feedwater system is Class 3. In contrast, the risk-informed process utilizes an integrated decision-making process that uses both risk insights and traditional engineering insights. This is possible due to recent advances in technology and compilations of operating reactor experience. An Owner can determine the safety significance of each of their SSCs using plant-specific PRA models combined with operating and industry experience.

22.5.2 Scope of Code Cases

The risk-informed repair/replacement activities are currently addressed in Code Cases N-660 [40] and N-662 [41]. Case N-660 provides the requirements to determine the safety significance for pressure-retaining items and their associated supports subjected to repair/replacement activities. Case N-662 provides the requirements for how to treat items that have been classified by Case N-660.

The scope of the Code Cases covers both items and their associated supports currently classified as Code Class 1, 2, or 3, and items that are currently non-Section XI in accordance with the risk-informed safety classification requirements established by the regulatory authority having jurisdiction over the plant site. Core support structures and Class MC (metal containment) and CC (concrete containment) items are not currently included in the scope of the Code Cases since a basis to evaluate these items has

not been demonstrated with the proposed risk-informed safety classification process. Therefore, as experience is gained in classifying passive items related to the Class MC and CC boundary, the scope of the Case will be expanded when appropriate.

22.5.3 Code Case N-660

The Code Cases for risk-informed in-service inspection of piping describe two approaches to determine safety significance. Each Code Case addresses the consequence of component failure and its failure potential. While in-service inspection programs have been successfully developed using both techniques, the long-range objective is to provide a single process that can be applied universally. As such, the two existing techniques were analyzed for commonality. The object is to allow the Owner to utilize as much of an existing risk-informed in-service inspection analyses as possible.

Because of limitations in the methods for estimating failure probabilities, a decision was made by ASME Section XI to base the process on conditional consequence given a failure, which removed the concern with large uncertainties regarding failure estimates. Essentially, the proposed process initially sets the failure probability of any component to unity (1.0). The conclusion does not contradict the previous risk-informed ISI work, as it is acknowledged for inspection purposes that a failure assessment is necessary to allow examination resources to be allocated to the areas most likely to fail. As such, future risk-informed ISI work on nonpiping components will require the development of new failure estimate techniques or new component failure databases for each component type. The process has been limited specifically to considerations of Code repairs and replacements, and has been refined to eliminate consideration of failure probability.

The goal of the consequence assessment is to provide a method to consistently rank the consequences of failure. The ranking philosophy uses four "bins" to rank the effect of the failure as either high, medium, low, or none. The high category represents events with significant impact on plant safety and the low category represents those events with minimal impact on plant safety. The none category represents those locations that are typically defined as "abandoned in place." The consequence ranking methodology can be summarized as follows:

- **High Consequence** Pressure boundary failures resulting in events that are important contributors to plant risk and/or pressure boundary failures that significantly degrade the plant's mitigation ability.
- **Low Consequence** Pressure boundary failures resulting in anticipated operational events and/or pressure boundary failures, which do not significantly impact the plant's mitigation ability.
- **Medium Consequence** This category is included to accommodate pressure boundary failures that fall between high and low rank.
- **None Consequence** This category includes failures that have no effect on risk.

Using this approach, the consequences that an Owner may have previously determined via Code Cases N-577 and N-578 to develop their risk-informed ISI piping programs can be directly mapped to the above consequence bins. (Owners who only did a Code Case N-560 application will have limited benefit since Class 1 items are usually high safety significant, and the reduced structural integrity requirements will not be applicable.) In instances where quantitative PRA consequence results are available for either Code Case N-577 or N-578 programs, a table is provided in Code Case N-660 that provides guidance to be used for this assignment related to conditional core damage probability (CCDP). Conditional large early release probability (CLERP) values have been determined to be 0.1 of the CCDP values.

These CCDP and CLERP ranges are specified in an EPRI Topical Report [36] and are determined based on the estimates of the total risk associated with the failure. Using a conservative estimate of total pressure boundary failure frequency for the plant of 1E-2 per year, CCDP and CLERP ranges were selected to guarantee that all locations ranked in the low consequence category do not have a potential CDF impact greater than 1E-8 per year or a potential LERF impact greater than 1E-9 per year. The boundaries between the high and medium consequence categories are set to correspond to the definitions of small CDF and LERF values of 1E-6 and 1E-7 per year. The assumption that these are suitably small values is consistent with the decision criteria for acceptable changes in CDF and LERF found in Regulatory Guide 1.174 [31]. The medium category covers the area between the high and low categories. The consequence evaluation in Code Case N-660, which is compatible with either Code Case N-577 or N-578, can be applied for piping segments that may not have been included in an Owner's risk-informed ISI program. However, some new requirements are included in Code Case N-660 that go beyond the respective evaluations in Code Cases N-577 and N-578 dealing with piping segments, functions, and design, operational, or risk considerations not modeled in the PRA.

Each PRA model inherently has some limitation with regard to its use in any application. Certain components may not be specifically modeled or the model may not address certain safety functions (e.g., shutdown risk). These limitations need to be addressed to allow a more complete decision-making process with regard to risk-informed classification. Fortunately, considerable work in this regard was performed for the South Texas Project's exemption request from special treatment requirements. The Code Case adapts excerpts from a letter dated July 19, 2000 to STP Nuclear Operating Company from the NRC [47]. The corresponding Code Case sections are designed to be used in conjunction with the analysis provided by a PRA or as a stand-alone insight for the integrated decision-making process. If any of the conditions in (a) or (b) below are true, the piping is classified HSS.

For piping segments, functions, and design, operational, or risk considerations that are not explicitly modeled in the PRA, the following are evaluated:

(1) Failure of the piping segment will significantly increase the frequency of an initiating event, including those initiating events originally screened out in the PRA, such that the CDF or LERF would be estimated to increase more than 1E-6/year or 1E-7/year, respectively.
(2) Failure of the component will compromise the integrity of the reactor coolant pressure boundary.
(3) Failure of the component will fail a high safety significant function, including consideration of operator actions used to mitigate an accident.
(4) Failure of the component will result in failure of other safety significant piping segments (e.g., through indirect effects)
(5) Failure of the piping segment will prevent or adversely affect the plant's capability to reach and/or maintain safe shutdown conditions.

In addition to being high safety significant in terms of their contribution to CDF or LERF, components might also be HSS in

terms of other risk metrics or conditions. Therefore, the following conditions shall be evaluated:

(1) The piping segment is a part of a system that acts as a barrier to fission product release during severe accidents.
(2) The piping segment supports a significant mitigating or diagnosis function as addressed in the Emergency Operating Procedures or the Severe Accident Management Guidelines.
(3) Failure of the piping segment will result in unintentional releases of radioactive material in excess of plant off-site dose limits as defined by 10 CFR Part 100.

A review is also performed to ensure that defense-in-depth and safety margins are maintained.

Components classified in accordance with Code Case N-660 are classified as either HSS or LSS. Piping segments determined to be a high consequence category by ranking shall be considered HSS. The Owner may further refine the classification ranking by more extensive application of the process. These analyses are required to be documented.

Piping segments assigned to the medium consequence category by the consequence evaluation are determined as HSS or LSS by considering the classification evaluation and the other relevant information provided for determining classification. Any piping segment initially determined to be a medium consequence category and that is subject to a known active degradation mechanism is classified HSS.

Piping segments determined to be as consequence category low or none (no change to base case by the consequence evaluation), or not modeled, shall be determined HSS or LSS using the other relevant information.

A component support or snubber is assigned the same classification as the highest ranked piping segment within the piping analytical model in which the support is included. A trial application of the risk-informed safety significance process of proposed ASME Code Case N-660 was completed for the Chemical Volume & Control System (CVCS) and the Feedwater (FW) System at the Surry Power Station Unit 1. In this application the CVCS and FW systems were chosen to represent one system where a significant number of safety-related items are expected to be LSS and another system where a number of nonsafety-related items are expected to be HSS. More than 50% of the items in the CVCS were determined to be LSS following a review of additional considerations (piping segments not modeled, defense-in-depth, and adequacy of safety margins) by the Surry Unit 1 integrated decision-making panel (IDP). As expected, a significant number of nonsafety-related items in the FW system were determined to be HSS. This result was consistent with the Surry Unit 1 risk-informed ISI program where nondestructive exams have been added to these piping segments (see previously cited Westinghouse Topical Report [35]. It was concluded that application of the process across many plant systems should result in more than 50% of safety-related items being determined to be LSS with a few isolated cases of nonsafety-related items being HSS.

In summary, ASME Code Case N-660 offers the opportunity to define the risk-informed safety classification for pressure-retaining items and then to apply appropriate treatment for repair/replacement activities.

22.5.4 Code Case N-662

To establish treatment options for the Risk-Informed Safety Classifications determined by ASME Code Case N-660, the early versions of the Case N-662 simplistically addressed two classifications, Section XI Code versus nonclass and HSS versus LSS. During committee work, it was determined that the vast majority of systems that are classified as Section XI Code are also safety related and that nonclass systems are typically nonsafety related. Nevertheless, many plants had some minor overlap between Section XI Code and nonsafety related and nonclass and safety related. For the special treatment requirements of 10 CFR 50 systems not covered by ASME Codes (e.g., electrical, instrumentation items), there are two classifications of concern, namely, safety related versus nonsafety related, and HSS versus LSS.

The requirements ensure that items will meet their functional design requirements. For Section XI Code items, the revised approach represents a decrease in requirements. However, for HSS nonclass items, they represent an increase in requirements beyond how the Owner is probably technically treating the items at the present time. Although these are increased requirements, the "Structural Integrity" requirements of the Code Case match those of commercial practices. Therefore, in most applications, the only increase in requirements for HSS nonclass items will be related to documentation of the repair/replacement activities, Authorized Inspector involvement, and possibly more rigorous failure analyses.

HSS nonclass items are in the scope of structural integrity requirements because they were deterministically classified as nonsafety related or non-Section XI, but such that the risk-informed process concludes that they make a significant contribution to plant safety. Examples of these items could include the station blackout emergency diesel, start-up feedwater pumps, or those items that function for PWR "feed and bleed" capability. Based on their safety significance, some additional Code requirements are appropriate to ensure that over the life of the plant, they maintain their function or are evaluated for impact on plant safety and possible increased requirements when they fail.

LSS Section XI Code safety-related items were included in the scope of structural integrity requirements because they were deterministically determined to be safety related or Section XI Code Class, and thus had importance in deterministic space. The risk-informed process has determined the items to be of low safety significance, but they must be given special treatment so as to remain functional. Examples would be the previously mentioned containment spray system for a PWR or the hydrogen recombiners installed in large dry containments. The principle of this Code Case is to ensure that these items have sufficient Code requirements such that they are still expected to meet functional requirements, albeit at a reduced level of assurance.

HSS items have minimal coverage in Code Case N-662. HSS items and their associated supports classified as Code Class 1, 2, or 3 have no exclusions. They must meet the full requirements of IWA-1400(n) for documentation of a Quality Assurance Program, IWA-4000 Repair/Replacement Activities, and IWA-6210(e) Owner's Report for Repair/Replacement Activities of ASME Section XI. These requirements apply because both the deterministic and risk-informed processes classify these items as important for reactor safety. No reductions in the special treatment requirements for these items are appropriate.

Nonclass LSS and nonsafety-related LSS Class 1, 2, or 3 items are exempt from IWA-1400(n), IWA-4000, and IWA-6210(e) requirements because both the deterministic and risk-informed processes have classified them as low safety significant. Code Case N-662 does require the Owner to meet a nationally recognized code or standard and Owner's Requirements for these items.

New Structural Integrity treatment requirements for repair/replacement activities have been developed, which represent the main purpose of Code Case N-662. These new requirements obviously apply for HSS nonclass items because the risk-informed process has demonstrated that they are important to plant safety. The Code Case, however, represents a significant reduction in both technical and administrative requirements for the LSS Section XI Code safety-related items.

The following paragraphs summarize the key elements of the new structural integrity treatment requirements in relation to the respective ASME Section XI subarticles for repair/replacement activities:

IWA-4110 Scope These requirements are invoked because they define the scope of what work is covered by repair/replacement activities (e.g., welding, brazing, defect removal). It also defines the range of items that the requirements apply to, that is, the pressure boundary, or component support function. Code Case N-662 requirements do not apply to active functions such as opening and closing of valves or development of pump head, or to nonmechanical functions such as electrical supply or instrumentation and control.

IWA-4120 Applicability This subarticle provides a list of items that are not covered by the rules of Section XI (e.g., valve operators, instruments).

IWA-4130 Alternative Requirements These requirements were derived from the current Small Item Applicability rules in IWA-4131 such as tubing, sleeves, and welded plugs. For LSS items, the key is to provide a reasonable assurance of functional adequacy. This is accomplished by requiring the items to meet the technical requirements of the Construction Code selected for use in the repair/replacement activity. Administrative requirements are not to be met because, for this scope of items, they have been typically lessened in the Construction Codes (e.g., NDE, marking). Consideration of their small size along with their LSS classification leads to a reasonable requirement of only meeting technical requirements. For HSS items, the user must meet the requirements of the Code Case, but as with existing Section XI requirements, the use of an Authorized Inspection Agency (AIA) and administrative requirements of the Construction Code are exempted.

IWA-4140 Responsibilities For Code Case N-662, the Owner does not need to comply with IWA-4142, in that their Repair/Replacement Program need not comply with 10 CFR 50 Appendix B or ASME NQA-1 Quality Assurance Program. This approach is deemed acceptable because the HSS non-Section XI items have been performing for years without the benefit of an Appendix B or NQA-1 program. Their existing performance results will be the input for the risk classification process. An Appendix B or NQA-1 program has controlled the LSS items within the scope of Section XI, but their low safety significance allows them to simply comply with the Owner's procedure development requirements. Despite not having to comply with Appendix B or NQA-1, the Owner is required to apply a graded approach to Quality Assurance based on the safety significance of the item. This is required in paragraph (3)(a) of the Case. Specific controls will be developed in Owner's programs subject, as always, to be reviewed by the jurisdictional and regulatory authorities. A specific plan for each repair/replacement activity is to ensure that critical Code-related actions (e.g., specifying Construction Code, defect removal requirements, and examination acceptance criteria) are performed and documented. Functionality of the items is ensured because the critical Code requirements are met. Nevertheless, the level of pedigree (i.e., full compliance with Appendix B or NQA-1) is not quite as high, and thus the cost to the Owner can be lower. The Owner is not required to use a unique repair/replacement plan document for each repair/replacement activity. The requirements may be embedded in work control documents. The Owner and the Authorized Nuclear In-service Inspector (ANII) must work together to determine what documentation is signed by the ANII to signify their acceptance of the activity.

IWA-4150 Repair/Replacement Program The Repair/Replacement Program is not necessary because the Code Case defines the minimum set of requirements the Owner must meet. Although no specific program requirements are established, the Owner does need to ensure that for each repair/replacement activity performed under the scope of this Case, all requirements are met.

Alternative Provisions (Similar to) Verification of Acceptability The failure analysis intent of IWA-4160 is met in principle by requirements in the Code Case. If the repair/replacement activity is being performed due to the item having failed to satisfy structural integrity requirements, the Owner must perform an evaluation to determine suitability of the item subjected to the repair/replacement activity. The Code Case further requires that corrective provisions be instituted if the requirements of the original item are determined to be deficient (e.g., improper material, inadequate provisions for erosion or fatigue failure). The Owner must correct the deficiency and not just replace the item in kind. In addition, U.S. Owners are required to monitor system performance at a much more aggressive level. The Owner's normal maintenance and operations process was augmented with the implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" [34].

IWA-4170 Inspection Third party inspection is required for all repair/replacement activities. The committee had mixed thoughts on this issue, particularly given that secondary plant work is not covered by an ANII and there is no significant personnel or nuclear safety issues arising from this work. However, after much discussion, the committee voted to include ANII requirements because it provides an effective level of oversight for this new process of risk-informing repair/replacement requirements.

IWA-4180 Documentation Although not contained in the list of mandatory IWA-4000 subarticles and sub-subarticles, IWA-4180 is invoked at appropriate places in Code Case N-662. Generic application of IWA-4180 is not required. Use of Form NIS-2–Owner's Report for Repair/Replacement Activity is not required because it was deemed not to provide sufficient value to warrant the cost.

IWA-4200 Items Used for Repair/Replacement Activities Items used for repair/replacement activities, alternative provisions for IWA-4200, follow the pattern established throughout the Code Case N-662. The Case allows items used for repair/replacement activities for which structural integrity requirements apply to meet commercial practices using three options:

(1) Comply with the original Construction Code and Owner's Requirements as required by IWA-4220 Code Applicability. Included within the Owner's Requirements are the original temperature, pressure, mechanical loads, and other loading conditions that are the basis for the design. It is expected that the item will still meet seismic requirements if they were required for the original item, but the level of documentation of the analyses or qualifications does not have to be as high.
(2) Meet the requirements of the applicable nationally recognized Code or Standard for that item. For example, a vessel that meets ASME Section III nuclear requirements could be

replaced with an industrial vessel that meets ASME Section VIII requirements. If this option is selected, the Owner must meet all of the technical and administrative requirements of the nationally recognized Code. Structural Integrity Requirements ensure that the item will meet its design basis and the assumptions used in the associated risk-informed process. To ensure that there are no "technical gaps" between the original Construction Code and the alternative Code, a reconciliation of material, fabrication, and examination requirements, as compared to the design requirements, must be performed because of the wide range of available Construction Code options. This reconciliation is not required for components because they are constructed to a consistent set of comprehensive rules.

(3) Allow material, parts, piping subassemblies, appurtenances, complete valves or pumps, and component supports (i.e., no vessels or complete piping systems) to meet the technical requirements of the Construction Code for the item being replaced. Administrative requirements of the Construction Code need not be met. The purpose of this option is to allow the Owner to procure materials to technical Code requirements, but avoid the costly NCA-3800 material procurement controls. This option allows for less administrative requirements, while not reperforming design analyses, which would be required in the second option when selecting an alternative Code or Standard.

There are two final requirements for replacement items. Deletion or revision of original loading requirements (e.g., seismic, wind, tornado) reflected in the Owner's Requirements, via reconciliation, based solely on a change in classification of the item is not allowed. Under the provisions of 10 CFR 50.69 [44], Owners are not allowed to revise their design bases (e.g., seismic, environmental qualification inputs). They can only use alternative special treatment provisions to implement those requirements. The second requirement is to meet the fracture toughness requirements of the original Construction Code, or later Edition or Addenda of the Construction Code, to meet functional adequacy.

IWA-4300 Design These provisions cover configuration control of specifications and design reports, analysis, or evaluations; Class 1 mechanical joints; and rerating requirements. The Case requires that the Owner conform to design control provisions to ensure that changes will not impact the ability of the item to meet its function assumed in the risk analysis.

IWA-4400 Welding, Brazing, Defect Removal, and Installation Inclusion of these requirements is vital to ensure that well-controlled fabrication processes are used for these activities. Studies have shown that most failures occur due to poor practices during construction or installation of items that result in defects being left in weld joints. In many instances, this Case reduces NDE requirements; therefore, it is important that the fabrication processes are sound. As an alternative to the Construction Code requirements of IWA-4411, the Owner may meet the requirements of other nationally recognized Codes or Standards with the following considerations:

- The Owner must comply with all the provisions of IWA-4400 except for alternatives to the Construction Code contained in IWA-4411. These provisions provide a minimum set of requirements to ensure that welding, brazing, defect removal, and installation processes are adequately controlled.
- The Owner may still use the provisions of IWA-4211(b) to revise Owner's Requirements.
- The IWA-4460 requirements for mechanical and thermal metal removal and the IWA-4422 examination requirements for defect removal areas must still be met.
- The Owner can still use IWA-4600 alternative welding methods as allowed by IWA-4411(e) and (f). The requirements for tube plugging were only invoked on reactor coolant pressure boundary plugs (e.g., steam generators) due to the fact that Owners have been routinely plugging other types of heat exchangers (e.g., service water, nonessential cooling water) outside of Code requirements with reasonable success.

Another option is defined in Code Case N-662 with practicality provisions for nonclass RISC-2 items for the IWA-4400 requirements. The Owner is allowed to use alternative design techniques and materials than those proscribed in existing nationally recognized Codes and Standards. This approach provides the freedom to use unique design concepts and a wide range of available materials. The Owner must demonstrate the acceptability of the final design by analysis, evaluation, or testing, and document this in accordance with IWA-4300. With this provision, the requirements on RISC-2 items are still being increased, yet flexibility is provided where Code repairs could lead to significant unavailability. This improvement in safety offsets the risk of allowing Owners to conduct repairs outside of Code provisions.

IWA 4500 Examination and Test This subarticle invokes the requirements that are selected in accordance with this Case. In other words, if the Owner used B31.1 for the repair/replacement activity, they must use B31.1 for the NDE. The Case does not remove the option in IWA-4520(c), allowing alternative examination methods provided the Inspector is satisfied that the results are demonstrated to be equivalent or superior to the specified method, because the Case invokes IWA-4500 with exceptions, but not disallowing this option. Preservice examinations depend on what requirements currently exist in the Owner's program. This situation invokes examination requirements for items that may never have had required examinations based on the item now being included in the plan due to risk-informed examinations. It also provides for not examining an item when the risk-informed process has excluded it. There are no risk-informed preservice requirements for pumps, valves, and vessels. Consistent with existing Code requirements, the Owner only performs preservice examinations when the item has been selected for in-service inspection in that interval. A system leakage test is required, in lieu of a hydrostatic pressure test. The system leakage test will typically be as effective in demonstrating functional performance as a hydrostatic pressure test and can be performed at significantly lower cost.

In summary, ASME Code Case N-662 offers the opportunity to define the risk-informed safety classification for pressure-retaining items and then to apply appropriate treatment for repair/replacement activities. The Code Case was revised [NN] in 2011 to update applicability to the 2010 Edition, 2011 Addenda of the Code.

22.6 ASME OPERATION AND MAINTENANCE CODE

The ASME Operations and Maintenance (O&M) Committee chose Code Cases to incorporate risk-informed research results as alternative IST requirements for the ASME OM Code [48]. In the

IST area, the ASME O&M has developed the following series of Code Cases: OMN-3 [49], OMN-4 [50], OMN-7 [51], OMN-10 [52], OMN-11 [53], and OMN-12 [54]. Code Cases OMN-3, OMN-4, and OMN-7 were incorporated into a new Subsection ISTE of the ASME OM Code. Code Cases OMN-11 and OMN-12 formed the basis for new Mandatory Appendices III and IV which were incorporated into Subsection ISTE by reference. The results of research programs, industry developments, and pilot plant applications on risk-informed technology have formed the technical bases for initiating the Code changes.

The intent of risk-informed IST is to change the ASME requirements for testing mechanical components mandated by 10 CFR 50.55 using risk insights in combination with traditional engineering deterministic information. Risk-informed IST focuses testing on those components determined to be HSS and relaxes the testing requirements for those components identified as LSS.

The various ASME O&M Committee pump and valve working groups were assigned a task to develop testing strategies for HSS and LSS components under their jurisdiction. Primarily, the task was assigned to the pump, motor-operated valve, air-operated valve and check valve working groups. The concept of risk-informed application to differentiate components into two populations was a new concept to those groups. Given the short time frame requested of the task, the working groups approached the task by utilizing existing Code and/or Code Cases as the basis with only minimal changes in methods and/or frequency. A summary of these Code Cases is provided below.

The pilot plants for IST began to receive NRC approval in 1998. The remainder of the industry has developed plant-specific programs or is budgeting resources to initiate work on at least one of these applications at the present time. To support this major initiative, the NRC has developed Regulatory Guide 1.175 [55] for plant specific, risk-informed decision-making for IST. NRC utilized the above ASME information and results in the development of these guidance documents, and these ASME applications provided useful examples during the development of NRC Regulatory Guide 1.174 [31].

In-service testing programs are intended to identify potential malfunctions of equipment before they can lead to unanticipated incidents or accidents. All aspects of in-service testing, including where, when, and how to test, affect the benefits of the test in enhancing equipment and plant reliability. In-service tests are currently based on mandated requirements, such as those for nuclear power plant components in the ASME OM Code, technical specification requirements, and NRC regulations. Most in-service test requirements are based on past experience and engineering judgment and have only an implicit consideration of risk-informed insights, such as component failure rates and consequence impacts for the specific operating conditions, equipment functions, and environment.

The ASME OM Committee sponsored a major risk-informed initiative in the area of IST over the last several years. This initiative was intended to lead to the development of a number of code cases providing alternative requirements to the ASME OM Code. Initial emphasis during 1993 through 1995 was on the establishment of a methodology by an ASME research effort that led to the publication of ASME CRTD Vol. 40-2 [11]. From 1996 to 2001, this research methodology was converted into a series of Code Cases.

The ASME OM Committee formed a Task Group on Component Importance Ranking in 1996 to follow the developments of the ASME Research Task Force on Risk-Based In-service Testing Guidelines that included issuance of guidance documents and some initial pilot studies. The Task Group's focus was on categorization of ASME components. The individual component organizations of ASME OM (check valves, motor-operated valves, air-operated valves, and pumps) were responsible for the development of test methods and frequencies for the high safety significant components and the low safety significant components. This resulted in the initial development of the following Code Cases:

- Case OMN-3, Requirements for Safety Significance Categorization of Components Using Risk Insights for In-service Testing of LWR Power Plants [49]
- Case OMN-4, Requirements for Risk Insights for In-service Testing of Check Valves at LWR Power Plants [50]
- Case OMN-7, Alternative Requirements for Pump Testing [51]
- Case OMN-11, Risk-Informed Testing for Motor-Operated Valves [53]
- Case OMN-12, Alternative Requirements for In-service Testing Using Risk Insights for Pneumatically and Hydraulically Operated Valve Assemblies in Light Water Reactor Power Plants [54]
- Case OMN-10, Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for In-service Testing of LWR Power Plants [52].

Code Cases OMN-4, OMN-7, OMN-11, and OMN-12 reference the categorization requirements of OMN-3, whereas Code Case OMN-10 is unique in that it includes both the categorization process as well as the testing requirements. The major elements of each Code Case are described below.

22.6.1 Code Case OMN-3 for Risk Categorization

The component importance ranking Code Case was designated OMN-3 and published with the 1998 Edition of the ASME OM Code. The Code Case provides the methodology for ranking components into the high and low safety significant categories and evaluating the change-in-risk from the proposed testing program. Code Case OMN-3 discusses the use of the plant-specific PRA for component ranking, the use of a plant expert panel, the philosophy of the testing strategies for high and low safety significant components, the evaluation of the aggregate risk, and the use of feedback and corrective actions.

Regarding the scope of the program, the current IST program requirements use ASME Code Class 1, 2, and 3 as the bounding scope, because those requirements are referenced via 10 CFR 50.55a. The scope of the current ASME Code for IST includes those components that are required to perform a specific function in

(1) shutting down the reactor to the safe shutdown condition,
(2) maintaining the safe shutdown condition, or
(3) mitigating the consequences of an accident.

The pump and valve components addressed in a risk-informed IST application include all components currently incorporated within the existing IST program. Any components (pumps and valves) modeled within the PRA with failure modes identifiable through IST should also be included in the scope. Components included in a shutdown analysis (either a shutdown PRA or other analysis) and those that are necessary to ensure the maintenance of the reactor primary coolant system pressure boundary may also be included in the scope.

During implementation of the risk-informed IST program, additional pumps or valves not already included in the current IST program may be identified as high safety significant components; in such cases, those components should also be included in the IST program.

The overall risk-informed IST process in Code Case OMN-3 is consistent with the NRC RG-1.175 [55]. The process includes the following:

- Component Risk Determination–using the PRA to categorize components
- Component Safety Categorization–to blend probabilistic, deterministic, and operational insights into the process using a plant expert panel
- Test Strategy Formulation–determination of appropriate test methods and frequencies for the two categories of components
- Evaluation of Aggregate Risk–requantification of the PRA to determine the impact on safety from the revised IST program
- Testing Program–guidance for IST programs, implementation, and update process
- Performance Monitoring–review and evaluation of tests and component performance
- Feedback and Corrective Actions review of IST program for potential program changes and corrective action for each of the above programmatic elements, as appropriate.

For component risk categorization using a plant-specific PRA, there are a number of probabilistic risk ranking measures that are available to the industry. The final safety classification of components into HSS and LSS categories is performed by the plant expert panel using additional deterministic insights and information.

Sensitivity studies are performed to ensure that the risk changes are insensitive to the reliability of the components included in the low safety significant category. The sensitivity studies performed are identified in Regulatory Guide 1.175 [55] and the ASME Code Case OMN-3. Sensitivity studies are performed to provide additional clarification and justification and to consider (1) data and uncertainties, (2) human factors, (3) test and maintenance unavailability variations, (4) low safety significant failure rates, (5) PRA truncation limits, and (6) common cause failure considerations.

The risk importance measures provide a sound basis for determining the plant risk for normal power operation and the required response to internal initiating events. However, a blended process of traditional engineering analysis and judgment with the PRA is part of the risk-informed IST methodology. Considerations that also need to be incorporated into the component safety significance assessment, for a final risk-informed IST determination, include the segment importance for external events (seismic, fire, and external flood), performance of safety functions during shutdown modes, the importance to design basis analysis and other accident scenarios, and operation and maintenance insights that should be taken into account.

In the risk-informed IST process, a plant expert panel (similar to the expert panel used for the Maintenance Rule but focused on IST) makes the final determination of the risk significance of components. Two safety significance categories (HSS and LSS) are defined. The plant expert panel is responsible for the review and approval of all risk-informed categorization results by utilizing their expertise (including knowledge of plant operations, design and licensing basis, plant-specific and industry data) and PRA insights to develop the final list of categorized components.

The plant expert panel is trained and indoctrinated in the specific requirements of the Code Case and of the PRA analysis. The panel includes expertise in the following areas:

- Plant operation
- Safety analysis
- Probabilistic risk assessment
- Maintenance
- Licensing
- ASME in-service testing
- Quality Assurance

Meetings are held with the plant expert panel to review the available information and to make the final determination of safety significance. Once the determinations of safety significance are made and the testing strategies are defined for the high and low safety significant components, the overall risk change (the aggregate effect) of relaxing all testing strategies for low safety significant components is calculated using the PRA model. The final selection of test intervals for the component groups depends on additional qualitative arguments (including any compensatory measures) and the NRC Regulatory Guide requirements.

A performance monitoring plan is developed to ensure that the following criteria are met:

- Sufficient tests are conducted to provide meaningful data.
- The in-service tests are conducted such that incipient degradation can reasonably be expected to be detected.
- The Owner will trend appropriate parameters to provide reasonable assurance that the component will remain operable over the test interval.

A performance monitoring plan is sufficient to ensure that degradation is not significant for components placed on an extended test interval, and that failure rates assumed for these components will not be significantly compromised. The plant-specific feedback and corrective action process are also modified as part of the program to ensure component performance is captured and any changes in ranking are considered. Periodic evaluations of the program are recommended.

22.6.2 Code Case OMN-4 for Treatment of Check Valves

Code Case OMN-4, "Requirements for Risk Insights for In-service Testing of Check Valves at LWR Power Plants," was first issued in 1998. This Code Case uses the features of the check valve Condition Monitoring Program Mandatory Appendix (ASME OMN Code-1996, Appendix II, Check Valve Condition Monitoring Program) to define the testing strategy for the high safety significant check valves. For the LSS check valves, the Code Case recommends either a code test as per Subsection ISTC or a Condition Monitoring Program. No specifics on test intervals are provided in the Code Case. However, through the use of the Condition Monitoring Appendix, the HSS population will be arranged into groups that determine the test intervals. For the LSS components, ISTC recommends a bidirectional exercise test with the intervals specified in the ASME Subsection ISTC as either quarterly, at Cold Shutdown, or at the maximum, at refueling outages.

As stated in the ASME OMN-4 white paper [56], the coupling of OMN-3 with OMN-4 "results in a good mix of requirements that actually complement each other."

22.6.3 Code Case OMN-7 for Treatment of Pumps

Code Case OMN-7, "Alternative Requirements for Pump Testing," which provides testing requirements for pumps, was issued in 1999. For pumps categorized as HSS, the frequencies and improved test methods of the ASME OMN-Code 1995 Edition through 1996 Addenda are required. The HSS pumps are further divided into Group A and Group B pumps. Group A pumps are pumps that are operated continuously or routinely during normal operation, cold shutdown, or refueling operations. Group B pumps are pumps in standby systems that are not operated routinely except for testing. The testing requirements and intervals are based on these groups.

For LSS pumps, these same Code requirements are specified. However, the frequency of testing may be reduced for these components. In addition, comprehensive pump testing is not required, although the other improved requirements of the Code are applicable. An additional requirement for testing LSS pumps at high flow once every 5 years or three refueling outages was included to help ensure that hydraulic degradation does not go undetected.

22.6.4 Code Case OMN-11 for Treatment of Motor-Operated Valves

Code Case OMN-11, "Risk-Informed Testing for Motor-Operated Valves," which provides the testing requirements for motor-operated valves, was issued in 2001 [53]. Code Case OMN-11 establishes the requirements for MOV testing based on the component design basis requirements and functional margin. All MOVs are exercised on an interval not to exceed 1 year or one refueling cycle. Changes in functional margin over time are evaluated to determine the test intervals. Code Case OMN-11 had already included a section on risk-informed criteria for MOV testing, but was not prescriptive in how this was to be accomplished.

The HSS motor-operated valves in OMN-11 are tested in accordance with Code Case OMN-11 using a mix of static and dynamic MOV performance testing using the established frequencies of OMN-1. LSS motor-operated valves are grouped and tested as per Code Case OMN-11 with an initial test frequency of three refueling cycles or 5 years until sufficient data exist to determine a more appropriate test frequency.

The risk-informed testing requirements specified in Code Case OMN-11 have been incorporated into Mandatory Appendix III to Subsection IST.

22.6.5 Code Case OMN-12 for Treatment of Pneumatic and Hydraulic Valves

Code Case OMN-12, "Alternative Requirements for In-service Testing Using Risk Insights for Pneumatically and Hydraulically Operated Valve Assemblies in Light Water Reactor Power Plants," was also issued in 2001. It took much longer to develop this Code Case since there was no specific guidance in the ASME OMN Code on these types of valves.

The Code Case requires that the test frequencies for HSS valves be determined based on an evaluation of the data or should be every two refueling cycles or 3 years, whichever is longer. Valve exercising is to occur once each fuel cycle. For LSS valves, the test frequency is based on component history, safety function, and manufacturer recommendations. Valve exercising is to occur once each fuel cycle.

The risk-informed testing requirements for air-operated valves of Code Case OMN-11 have been incorporated into Mandatory Appendix IV to Subsection IST which will be published in the next edition of the ASME OM Code.

22.6.6 Code Case OMN-10 for Snubbers

Code Case OMN-10, "Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for In-service Testing of LWR Power Plants," was issued in 2001. In late 1996, the major risk-informed IST initiative was broadened to include snubbers. An EPRI risk-informed IST pilot project for snubbers was established with seven pilot plants. This group of pilot plants tested the draft categorization methodology and provided feedback that was incorporated into the Code Case OMN-10.

This Code Case did not use the categorization of OMN-3 but provided another process for the categorization of snubbers. First, for all the systems in the plant in which there are safety-related snubbers, the systems are classified as high or low risk systems based on quantitative or qualitative analysis. An expert panel is also employed in the process similar to OMN-3.

The criteria for categorizing snubbers differ from those in Code Case OMN-3. The decision criteria are set up as mandatory inclusion criteria and nonmandatory exclusion criteria. The inclusion criteria (Level A) for HSS snubbers are as follows:

- All snubbers protecting the following components: steam generators and reactor coolant pumps in PWRs and recirculation pumps in boiling water reactors (BWRs).
- All snubbers protecting components in systems with PRA importance ranking Fussell-Vesely (FV) >0.05 or, if evaluated at the component/train level, all snubbers supporting the components in trains with PRA importance ranking FV >0.005 or risk achievement worth (RAW) >2.

The exclusion criteria (Level B) for LSS snubbers are as follows:

- All snubbers that support the component with an importance ranking FV <0.005 and a RAW < 2.
- All snubbers associated with unmodeled components and associated with components that would likely be unmodeled in Levels 1, 2, 3, and shutdown PRAs, including both internal and external events.

Testing strategies and frequencies are then developed based not only on the ranking of HSS or LSS snubbers, but also on the type of environment for the snubber. A *harsh* environment is defined for those operating environments where the snubber is exposed to higher temperatures, vibration, or other service condition variables that would result in a predicted service life of more than 10 years. A *benign* environment is defined for those operating environments where the snubber is exposed to lower temperatures, minimal vibration, or other service condition variables that would result in a predicted service life of less than 10 years.

The frequencies of testing are then based on the two categories and use a sampling plan, similar to the current ISTD Code sampling plan, based on the population of snubbers. For HSS snubbers in a harsh environment, all snubbers must be either tested or replaced every 6 years, whereas for HSS snubbers in a benign environment and for LSS snubbers in a harsh environment, all snubbers must either be tested or replaced every 10 years. No requirement is made for LSS snubbers in a benign environment.

Because the safety-significance categorization process of Code Case OMN-10 was different than the process on Code Case

OMN-3, Code Case OMN-10 was never accepted by the NRC and Code Case OMN-10 was not incorporated into OM Code Subsection ISTE.

22.6.7 OM Code Subsection ISTE, "Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants

Subsection ISTE was first published in the 2009 Edition of the OM Code. The initial version of ISTE incorporated the component safety-significance categorization requirements of Code Case OMN-3, the pump testing requirements of Code Case OMN-7, the check valves testing requirements of Code Case OMN-4, and the motor-operated valve test requirements of Mandatory Appendix III. The subsection referred to a Mandatory Appendix IV, Testing Requirements for Pneumatically Operated Valves, which will be published in the next edition of the ASME OM Code.

22.7 REGULATORY AND INDUSTRY INTERACTIONS

Risk-informed activities have involved extensive interactions between regulatory staff and industry organizations as described in the sections below.

22.7.1 Regulatory Acceptance and Recognition

The Nuclear Regulatory Commission has been supportive of the risk-informed activities of ASME Codes and Standards and has provided guidance consistent with the provisions of the relevant Code Cases. For example, the NRC has developed Regulatory Guides 1.175 [55] and 1.178 [30] for plant-specific, risk-informed decision-making for IST and ISI, respectively, that have provisions consistent with OMN-3 [49] and B&PV Code Cases N-577, N-577-1 [25, 26], and N-578, N-578-1 [27, 28]. In addition, with the exception of [33] NRC has not generically endorsed any of the ASME B&PV Code Cases related to risk-informed in-service inspection. These Code Cases N-560, N-560-1, N-560-2, N-577, N-577-1, N-578, and N-578-1 are listed as unacceptable in Regulatory Guide 1.193 [57]. The conditions cited in the Regulatory Guide that make these Cases unacceptable are as follows:

(1) The Code Cases do not address inspection strategy for existing augmented and other inspection programs such as IGSCC, FAC, MIC, and pitting.
(2) The Code Case does not provide system-level guidelines for change-in-risk evaluation to ensure that the risk from individual system failures will be kept small and dominant risk contributors will not be created.

Understanding these conditions, plant owners developed their risk-informed in-service inspection programs using one of the Code Cases listed above. These conditions were addressed by the owners on a plant-specific basis to the satisfaction of the NRC. The fact that almost 95% of the plants in the United States now have some type of NRC approved risk-informed in-service inspection programs in place set the direction for ASME to solve the issue. ASME decided that the best approach was to address these limitations in their development of Nonmandatory Appendix R [29] to ASME B&PV Code Section XI. Because of this decision, the only complete set of requirements that ASME now has for a risk-informed in-service inspection program is contained in the Appendix. ASME has no plans to further revise the existing Code Cases listed above and they will remain as generically unacceptable to the NRC. Nonmandatory Appendix R is expected to be approved by the NRC in a future rulemaking.

For the OM risk-informed Code Cases, the NRC has divided them into several different levels of approval. Only one Code Case OMN-10 [52] is listed as unacceptable in Regulatory Guide 1.193 [57] and Code Case OMN-7 is approved without conditions in Regulatory Guide 1.192 [59]. All the other OM risk-informed Code Cases, OMN-3, OMN-4, OMN-11, and OMN-12, are conditionally approved in Regulatory Guide 1.192 [59].

NRC's endorsement of ASME-RA-S-2002 and the 2003 and 2005 Addenda has been timely and explicit through the development of Regulatory Guide 1.200 [60]. This Regulatory Guide describes one acceptable approach for determining whether the quality of the PRA, in total or the parts that are used to support an application, is sufficient to provide confidence in the results, such that the PRA can be used in regulatory decision-making for light water reactors. The guidance is intended to be consistent with the NRC's PRA Policy Statement and subsequent, more detailed, guidance in Regulatory Guide 1.174 [31]. It is also intended to reflect and endorse guidance provided by standards setting and nuclear industry organizations.

Both Regulatory Guides 1.200 and 1.174 have been updated to reflect updates in ASME/ANS standards and industry guidance Current revision of Regulatory Guide 1.200 is Rev. 2 [xn] and current revision of Regulatory Guide 1.174 is Rev.2 [xn].

This Guide contains an Appendix that identifies the acceptability of the standard with a number of clarifications and a limited number of qualifications. Clarifications are essentially items where the NRC staff has no objection to the provisions of the standard but has offered comments to clarify the requirement. Qualifications are cases where the staff does not object to the requirement if the qualifications identified are addressed in following the standard. RG 1.200 also includes an Appendix endorsing, with qualifications, the industry peer-review process in NEI 00-02 and subsequent plans for self-assessments against the criteria in the ASME PRA Standard that were not addressed during the NEI peer review.

The NRC issued this regulatory guide for trial use in February 2004, and five trial applications were conducted. The NRC subsequently revised the guide to incorporate lessons learned from the pilot applications. The NRC also revised the appendices to address the changes made in the professional society PRA Standards and industry PRA guidance documents. The NRC then issued the revised guide (including its associated appendices) for public review and comment as Draft Guide-1161 in September 2006. The staff subsequently reviewed the stakeholder comments and, where appropriate, revised the guide accordingly. Revision 1 of RG 1.200 was issued in January 2007. Subsequently, "Clarification to RG 1.200, Rev.1," was issued by the NRC to provide additional explanation to clarify the staff's regulatory position on the treatment of sources of uncertainty and assumptions as stated in Revision 1. Revision 2 to RG1.200 was issued in 2009 and provided USNRC's viewpoint on the most recent version of the PRA standard [19] which as previously discussed addresses not only internal events but also includes internal flood, internal fire, seismic, wind, external flood and other external hazards.

As discussed in Section 22.5.1, the NRC issued rule 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Plants," on November 22, 2004 [44]. ASME Code Cases that provide

requirements related to this initiative are addressed in the statement of considerations for rule 10 CFR 50.69.

After trial application of Code Case N-660 on several systems, it was identified that the Code Case contained several excess conservatisms and lacked clarity in some instances. A draft Code Case was developed (N-752) that addressed these issues as well as incorporated treatment language taken directly from the 10 CFR 50.69 rule (i.e. for low safety significant SSCs). This draft Code Case was piloted as a risk-informed repair/replacement activity by Arkansas Nuclear One, Unit 2 and was approved by the USNRC in 2009 [61]. This updated classification and treatment methodology is currently being used by the industry's 10 CFR 50.69 pilot plant (Voglte Units 1 & 2, [62]) which is schedule for USNRC approval in early 2014.

22.7.2 Related Industry Developments

The nuclear industry has provided extensive support in the development of risk-informed Codes and Standards, not only through the commitment of knowledgeable individuals to participate in the standards committees, but by providing support of technical investigations, pilot activities, and production of implementing documents. Through the Electric Power Research Institute, industry provided guidance on the use of a PRA (PSA) in risk-informed applications [37]. Also, industry, through the NEI, published guidance on peer reviews [20] that contained useful input on PRA technical elements and peer-review practices for the development of ASME RA-S-2002. Industry has conducted numerous pilot tests of the various risk-informed codes and standards and these tests have provided valuable feedback and improvements. These pilot activities have demonstrated that application of risk-informed techniques is an iterative process requiring cooperative efforts of the industry, regulatory body, and the Codes and Standards community to arrive at practical and cost-effective methods.

22.8 FUTURE PLANS FOR RISK-INFORMED ACTIVITIES

The Board on Nuclear Codes and Standards has full responsibility for managing ASME activities related to codes, standards, and accreditation programs directly applicable to nuclear facilities and technology. This effort includes full administrative and technical responsibility for the following Standards Committees:

- Operations & Maintenance
- Nuclear Cranes
- Nuclear Air & Gas Treatment
- Nuclear Quality Assurance
- ASME/ANS Joint Committee on Nuclear Risk Management
- Qualification of Mechanical Equipment
- Construction of Nuclear Facility Components (BPV III)
- Inservice Inspection (BPV XI)
- Council on Standards and Certification

Risk-informed activities related to nuclear power have been underway for several decades. Specific ASME Codes and Standards products came under development in the early 1990s. In recent years the pace of development has quickened with new products being developed by ASME, the nuclear industry, and NRC to support broader and more pervasive applications of the technology. A key driver has been NRC's plans to risk inform the nuclear power plant safety regulations in 10 CFR Part 50. These and future activities are discussed in the next section.

22.8.1 BNCS Risk Management Strategic Plan

In January 2000, the BNCS set up a task group to assist the Board in responding to the NRC's plans for a multiphased program to increasingly risk inform the rules for licensing nuclear power plants contained in 10 CFR 50 (Code of Federal Regulations Title 10–Part 50). The task group was originally named the Risk-Informed Part 50 Task Group (RIP-50 TG). Over the next 2 years, the task group was increasingly assigned the role of developing a coordinated BNCS approach to respond to NRC and nuclear industry risk-informed initiatives. In early 2002, the task group was renamed the Risk Management Task Group, and its membership was expanded to include one or more representatives for all committees under the technical supervision of BNCS that were involved in risk-informed activities. Development of a Risk Management Strategic plan became an important activity. An initial BNCS approved version was completed in early 2002. This plan was adopted as a part of the overall BNCS Operational Plan and is maintained as a living document that is reviewed and updated prior to each BNCS meeting. The latest version of the BNCS Risk Management Strategic Plan can be always obtained from the ASME BNCS website–www.asme.org. The high-level mission and goal of the planning effort are as follows:

> **Mission** Factor risk as well as performance in all ASME Nuclear Codes and Standards as appropriate to further ensure, on a worldwide basis, that they protect public health and safety and meet the needs of users.
>
> **Goal** To determine the need and provide risk-informed, performance-based ASME Nuclear Codes and Standards for the benefit of users.

In 2013, the BNCS Risk Management Strategic Plan was incorporated into the Nuclear Risk Management Coordinating Committee Integrated Risk Management Milestone Plan. This plan is discussed further in the following sections.

22.8.2 B&PV Code Initiatives

Safety Classification An activity has been initiated, in conjunction with the ASME Committee on Nuclear Risk Management, to develop a Section III Code Case N-720 that provides requirements for risk-informed safety classification and treatment for design. This Case uses Section XI Code Case N-660, "Risk-Informed Safety Classification for Use in Risk-Informed Repair/Replacement Activities," as a basis for development of this Section III Case. Code Case N-720 will be consistent with the recently issued NRC Rule 10 CFR 50.69 and will reflect lessons learned from implementation of Code Case N-660 in commercial nuclear pilot plant repair and replacement projects. Similar risk-informed safety classification efforts are also being initiated by the American Nuclear Society to address nuclear plant safety classification criteria, and both the ASME and ANS work is being reviewed by the Nuclear Risk Management Coordinating Committee.

Reliability-Based Load and Resistance Factor Design Methods for Piping A research project was initiated in late 2002 with the objective of developing the technical basis for reliability-based load and resistance factor design of ASME Section III, Class 2/3 piping. Intermediate results from this project were published in ASME research report, CRTD-86, "Development of Reliability-Based Load and Resistance Factor Design (LRFD) Methods for Piping," in 2007 [63]. This report provides the technical basis for LRFD methods for Class 2/3 piping for primary

loading that include pressure, deadweight, seismic, and accidental loading. The outcomes of the project include design models and equations and partial safety factors that can be used to compose LRFD guidelines and criteria. The research provides a proof of concept of the LRFD for the design of piping. Such design methods should lead to consistent reliability levels and can initially be used in parallel with current design procedures. However, further work is needed and the report makes seven specific recommendations for project completion:

(1) The project has only evaluated stresses in a pipe due to internal pressure, sustained weight, and seismic and mechanical loading and their combinations. Fatigue and thermal loads, in combination with the primary loads, need to be included in the LRFD formats.
(2) The probabilistic characteristics of the basic random variables for both the load and the strength play a vital role in reliability assessment and reliability-based design for piping components. Quantification of the probabilistic characteristics of these variables is an essential element for developing LRFD rules. The characteristics can be developed from laboratory testing of mechanical properties of materials and measurements in plants for dimensions and tolerances.
(3) Sensitivity analysis and the effect of correlation between the load and strength random variables.
(4) Identification of a target range for reliability levels to compute the partial safety factors.
(5) Computations of partial safety factors for use in LRFD design formats.
(6) Sample LRFD guidelines and rules for piping summarizing target reliability levels, strength factors, and load factors.
(7) Comparative design examples from actual nuclear plant configurations to illustrate the use of load and strength factors in selected LRFD-based design equations.

Section XI A number of activities are underway in Section XI to extend risk-informed in-service inspection requirements to cover all Section XI systems, components, and their supports. In addition, Code Case N-716 [32] has been revised to incorporate the lessons learned from the pilot plant applications and to extend the scope of the Case to include other components connected to the piping. Ultimately, all this new experience will be added into Nonmandatory Appendix R [29]. There is also an effort to consider how to develop requirements for new plants to use risk-informed in-service inspection program requirements in the future.

22.8.3 Systems-Based Code

Current ASME Nuclear Codes and Standards rely primarily on deterministic and mechanistic approaches to design of components, including piping systems. The design code is a separate volume from the code for ISI and both are separate from the code for IST. Work is in progress to develop an ASME Nuclear Systems-Based Code, which would include a planned evolution that integrates the various nuclear codes and standards and adopts a risk-informed approach across a facility life cycle, encompassing design, construction, operation, maintenance, and closure. Figure 22.3 offers a conceptual development.

The U.S. Nuclear Regulatory Commission is considering development of a risk-informed performance-based and technology neutral alternative licensing process for new reactor designs [64]. A dynamic or "living" facility-specific PRA is integral to a technology neutral risk-informed performance-based licensing process. The design processes used today are predominately deterministic and not risk informed. Revised design processes, reflecting risk insights derived from a "living" PRA, that evolves along with the design are needed.

It is envisioned that a Systems-Based Code design process would be based on risk-informed probabilistic methodologies that cover a facility's life cycle from the start of conceptual design through decontamination and decommissioning [65]. The methodology would use a "living" PRA to identify target reliabilities for facility systems and components. Target reliabilities would be used in system and subsystem simulation analyses to determine the optimum combination of initial system and component construction reliability, maintenance frequency, and inspection frequency

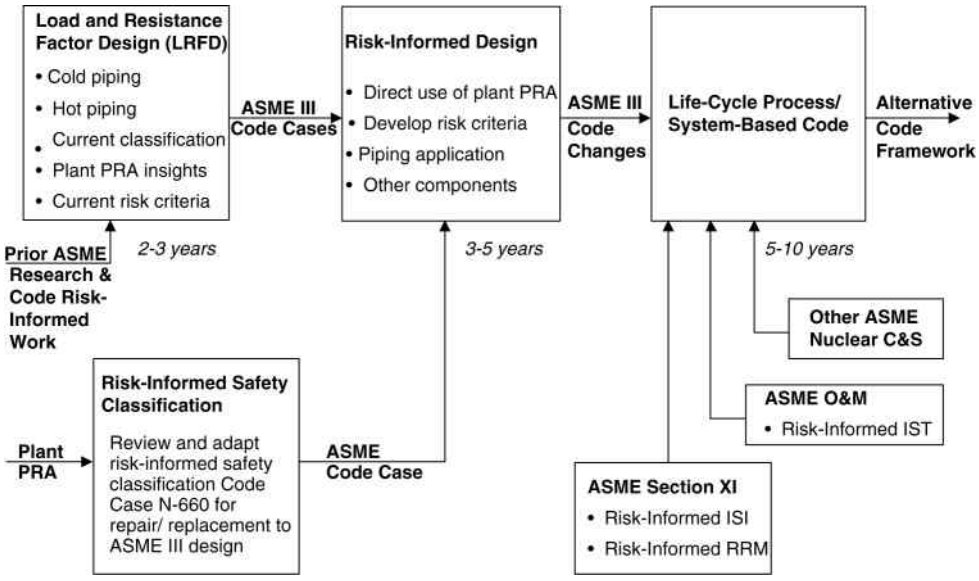


FIG. 22.3 POTENTIAL EVOLUTION TO NUCLEAR SYSTEMS CODE

for both active and passive components. The target reliabilities would also be used for systems-based code margin exchange for passive components to reduce excessive level of margins to appropriate levels resulting in a more flexible structure of codes and standards that improves facility reliability and cost.

The concept of code margin exchange or "Systems-Based Code" has been initiated and promoted by Japanese nuclear experts. This approach recognizes that the current material, design, construction, inspection, and maintenance codes are well established, independent, and self-complete. Each code provides safety margins to assure integrity. Through the current design process, margins accumulate and can become excessive resulting in overly conservative and costly designs. The Systems-Based Code concept introduced by Professor Asada [66, 67] and further developed by Asayama et al. [68, 69], proposes to resolve this problem. The Systems-Based Code is a design process that reduces the excessive level of margins for passive (pressure boundary and structural integrity) functions to appropriate levels based on design to target reliability. It embraces expansion of technical options beyond what current codes and standards allow and exchange of margin among the technical options. Margin exchange utilizes the flexible structure of codes and standards and optimizes both reliability and cost.

22.8.4 Related ASME Standards

As shown in the BNCS Risk Management Strategic Plan, ASME has identified a number of current and planned risk-informed standards activities. In addition, the American Nuclear Society has issued one standard and has two others under development that relate to these activities. Now that the concept of grading the treatment of structures, systems, and components using their risk importance has achieved general acceptance, there is an apparent need to define the treatment requirements for SSCs of lower importance. While this has been a primary objective of the ISI and IST risk-informed Code Cases, to date no other codes and standards have developed similar graded treatment approaches. The ASME Nuclear Quality Assurance (NQA) Committee has prepared a draft standard addressing this need and plans to complete it in 2008. To date, no other ASME nuclear standards committees have initiated similar action.

22.8.5 Other Standards Development Organizations

As discussed in Section 22.3.1, the American Nuclear Society's (ANS) Risk-Informed Standards Committee (RISC) developed the following standards. After the ANS RISC Committee merged with the ASME Committee on Nuclear Risk Management, the joint committee incorporated these standards into ASME/ANS RA-Sa-2009 and these ANS standards were withdrawn.

- PRA methodology for treatment of earthquake and other external events (ANSI/ANS-58.21-2007) initially published in 2003 and revised in 2007 [70].
- PRA methodology for internal fire (ANSI/ANS-58.23-2007) published in 2007 [71].

Additional risk informed probabilistic based standards developed or under development by ANS include:

- ANS-2.8, Design Basis Flooding
- ANS-2.30, Assessing Capability for Surface Faulting
- ANS-2.31, Estimating Extreme Precipitation
- ANS-3.87, Drills/Exercises for Emergency Preparedness
- ANS-20.1, Safety/Design Criteria for Fluoride Salt Cooled High Temperature Reactor
- ANS-50.1, Design Criteria for Light Water Reactors
- ANS-54.1, Design Criteria for Liquid Metal Reactors
- ANS-57.2, Design Requirements for LWR Spent Fuel Storage
- ANS-57.3, Design Requirements for LWR New Fuel Storage

Other Standards Developing Organizations (SDOs) are considering development of standards to support risk-informed approaches to assure coordinated development and consistency of content and use, ASME and ANS assisted in the formation of a Nuclear Risk Management Coordinating Committee. This Committee coordinates the development and maintenance of codes and standards that address risk management and risk-informed decision-making for nuclear power plants and other nuclear facilities, and the transportation and storage of spent nuclear fuel. This coordination is established to avoid redundancy and facilitate utilization of the resulting codes and standards. The current membership includes the following:

- American Nuclear Society
- ASME
- Institute of Electrical and Electronics Engineers
- U.S. Nuclear Regulatory Commission
- U.S. Department of Energy
- Nuclear Energy Institute
- Electric Power Research Institute
- Pressurized Water Reactor Owner's Group
- Boiling Water Reactor Owner's Group
- National Aeronautics and Space Administration

Other interested SDOs will be invited to join as they become involved in the development of related standards. Among the currently proposed strategic actions for this group are the following:[5]

- Assure that current and emerging standards are developed and maintained to meet the needs of the user and are consistent and compatible so that they can be readily applied.
- Integrate the risk-informed methodology set forth in PRA Standards into other application-specific codes and standards, as appropriate.
- Facilitate the implementation and use of nuclear risk-related standards required to meet the identified needs of the user community.
- Evaluate alternatives and recommend actions intended to optimize the number and mix of separate standards necessary to implement a full scope of risk-informed applications and to avoid redundancy.
- Work with the Nuclear Regulatory Commission in the development of its plans to implement 10 CFR 50.69 and future plans for risk-informed regulation of the nuclear power industry.
- Define appropriate training and qualification initiatives for users of risk-informed standards, including Integrated Decision-Making Panels.
- Identify needs, priorities, and timing for development of new or modification of existing standard(s) to address unique PRA requirements for new reactors.

[5]Edited selections from the NMRCC Strategic Plan dated May 5, 2005.

- Determine the need for a standard to develop a risk-informed safety classification scheme, particularly to assist the advanced and new reactor designs.

In 2013, members of the Nuclear Risk Management Coordinating Committee developed the NRMCC Integrated Risk Management Milestone Schedule as an information and guidance document to enhance coordination and integration of risk management activities of NRMCC member entities. This integrated schedule includes activities to revise existing initiatives and standards and new initiatives and standards. It provides integration of these activities by identifying dependencies between the various activities.

22.8.6 Emerging Security Applications

Used for many years by the nuclear power as well as other industries, risk analysis is now being used to assist in determining measures to protect the nation's critical assets against acts of terrorism. Several key critical infrastructure sectors, such as nuclear reactors and spent fuel storage, chemical plants, refineries, and liquefied natural gas tanks, are being evaluated in an initial phase of work involving risk analysis via the ASME Innovative Technologies Institute, LLC with the U.S. Department of Homeland Security. The project will provide particular guidelines for risk analysis in each of these areas. Chapter 56, "Post 9–11 Related Issues" provides more information on these developments.

22.9 SUMMARY AND CONCLUSIONS

As a result of significant efforts over the past 20 years, PRA and risk-informed technology have been significantly incorporated into ASME Nuclear Codes and Standards, as also summarized in "Risk Initiatives in ASME Nuclear Codes and Standards" [72]. An ASME PRA Standard–ASME RA-S-2002 along with Addenda RA-Sa-2003, RA-Sb-2005, and RA-Sc-2007 provides a standard to determine the technical capability, fidelity, and adequacy of plant PRAs for use in nuclear power plant applications. A combined ASME/ANS RA-S1-2008 was approved in February 2008 incorporating internal fire and external events and will add low power and shutdown considerations within a year [19]. This combined standard was endorsed by the U.S. NRC in Regulatory Guide 1.200, Revisions 2 & 3. The combined Standard represents a truly international effort as committee members included knowledgeable individuals from Japan, the International Atomic Energy Agency, United Kingdom, and Mexico. More than 10 ASME Code Cases have been completed, approved, and implemented to support the application and use of risk-informed technology for plant inservice inspection and in-service testing programs that reduce unnecessary burden while maintaining or enhancing safety. These efforts continue to be coordinated with corresponding regulatory and industry initiatives, including those of other standards development organizations. Future plans are outlined to expand the application of risk-informed methods to new areas such as design, risk-informed safety classification, and consideration of a systems-based code. The use of risk-informed technology will continue to provide benefits to support the safe operation of today's reactors and to provide more effective processes for the design, construction, and operation of advanced reactors.

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CHAPTER

23

STANDARDIZATION OF VALVES, FLANGES, FITTINGS AND GASKETS (ASME B16 STANDARD)

James Philip Ellenberger

23.1 B16: OVERVIEW OF THE B16 COMMITTEE

The Committee that has evolved into B16 [1] started life as a group of different organizations. All were becoming active in the early 1900's. This is the period when the ASME was asked and began to publish the Boiler and Pressure Vessel Codes. All of this activity was the result of the horrendous problems of boiler explosions that had wrecked the nation in the period after the Civil war.

The very early organization for standards rather than codes was the Committee of Manufacturers on Standardization Pipe Fittings and Valves. It existed from 1908 till 1924 when it evolved into MSS (Manufacturers Standardization Society) which exists even today. That Committee was a part of the Valves and Fittings Institute which closed in 1910 while the Committee continued. This committee then collaborated with the US government, The National Association of Steam and Hot Water Fitters and the ASME in a committee to write standards. This committee evolved into the B16 Committee as it operates today.

This evolvement coincided with the evolution of the American National Standards Institute (ANSI). That group was the American Engineering Standards Committee (1918–1037), then the American Standards Association (1928–1965). Finally in 1969 it became what we know today as The American National Standards Institute (ANSI). During this time many standards were being developed by afore mentioned joint committees. The ASME was the secretariat and the jointly developed standards were developed by the joint committee and sold by all of the members as American National Standards. It was in 1982 that the American Standards committee was recognized as an ASME committee operating under the ANSI procedures.

It may seem strange to some that it took so long for this set of joint committees to become an ASME only committee. However, realizing that manufacturers and fitters play an important role in the development of standard dimensions for a product explains some of the slowness. Each manufacturer may have proprietary processes or designs. The manufactures must agree on the dimensions that comply with the standards. Those in engineering must agree on the methods the manufacturers use to provide the safety inherent in the codes that may adopt the particular standard in question. ASME is constituted to internally to develop standards by the ANSI process which requires consensus from all parties i.e. Engineers, users, manufacturers, public etc. That process is more difficult with a single class of membership as some of the early groups chose to remain. The evolution progressed as it should have.

This may be pointed out by directing to the basic ANSI requirement that no single interest group may dominate the adoption process. Within ASME there are several groups identified by category of interest. They are:

Manufacturer (AK)
Distributor (AD)
Material manufacturer (AM)
Consumer/User (AW)
Designer/Constructor (AC)
Regulatory (AT)
Insurance/Inspection (AH)
General Interest (AF)

This 'no-domination' means that no single group can have a majority. As pointed out earlier, it is important to have manufacturers involved in the standards process for the type of B16 standards. Since B16 standards are responsible for several manufacturers who want to be and are involved in the development process.

B16 has the scope to develop standards for valves, flanges, fittings and gaskets and some responsibility for actuators. This diversity of subject matter is different from, say something like a B31 code [2]. The code is actually a standard but it is usually divided into sub tiers, or groups, according to discipline such as design, fabrication, and materials. The paragraphs of B31 [2] are for specific types of piping systems. Each of these paragraphs would have some common as well as requirements specific to the type of piping system it represents.

A B16 standard might have application for any or all of the different piping systems in that each system might require a valve or a flange etc. As a result, the standard for the particular component or product such as a flange or a fitting would require the full set of

requirements for such elements as material, and design of that component. The B16 standard would also include some set of dimensions or dimensional requirements. Some will have requirements regarding pressure temperature ratings so the codes that adopt the standard can know how that standard might fit into the codes requirements.

It is important for the users to understand and remember that the fundamental reason that these codes and standards are developed is to establish a level of safety that the users, regulators and insurers as well as their inspectors can rely upon. The secondary and equally as useful as the safety requirements are the dimensional requirements. Those requirements allow the user to have pre-knowledge of what they will be using in their system in terms of sizes, pressure temperature ability of the chosen product. This allows the use of those components in the planning and design stages where they might not be known until they are acquired and then some additional design effort might be required. It also allows the manufacturer of the components to build these components in an economical manner rather than an ad hoc fashion.

It is true that the codes must provide for design of components that are not covered by such a standard or do not meet the dimensional or other requirements of an existing standard. This does occur in many systems such as Boiler and Pressure Vessel and in piping for those systems. It is in those cases that the user becomes aware of the economic benefit of Standards.

23.2 ORGANIZATION OF B16

As described in the overview B16 is not about one single subject component. Each standard with a B16 title has a type of component or a group of related components as its subject. Its scope describes the components it covers. At the present time the active B16 standards have a total of Thirty-two named standards. This means the sub tier committees are organized around a type of component such as flange, fitting or valve. In some cases they have different standards for materials where the manufacturing process or use is significantly different.

The sub tier committees are known by a letter designation. They also have a name describing the type of standards they write or maintain. These committees are described in the following list. It also shows that many individual standards are their specific responsibilities.

(1) Subcommittee B Threaded Fittings (Except Steel) & Cast Iron Flanges and Flanged Fittings. This committee has 9 standards
(2) Subcommittee C Steel Flanges and Flanged Fittings. This committee has 4 standards. It shares pressure temperature rating responsibility with Subcommittee N
(3) Subcommittee F Steel Threaded and Welding Fittings. This committee has 4 standards
(4) Subcommittee G Gaskets for Flanged Joints. This committee has 2 standards
(5) Subcommittee J Copper and Copper Alloy Flanges, Flanged Fittings and Solder Joint Fitting. This committee has 8 standards.
(6) Subcommittee L Gas Shutoffs and Valves. This committee has 4 standards
(7) Subcommittee N Steel Valves and Face to Face and End to End dimensions of Valves. This committee has 3 standards. It also shares pressure temperature ratings for flanged valves with Sub committee C
(8) B16 also has responsibility with ANSI for six (6) ISO tags

Before discussing the individual committees and their standards a few general items for discussion are in order. As noted at the beginning, some of the standards in B16's profile are old in the sense that some version of that standard has been in existence for nearly or over a hundred years. This is also true of the Section One (I) of Boiler Code [3]. However it is not generally true of the rest of the ASME codes. Many, in comparison, are new. B31.12 [4] came into existence only in the 21st century, where as many others in the middle to late 20th century.

This is not to say all B16 standards are old. It is to say that new standards come along as new types of components become popular enough to demand standardization. The pressure technology community has many components that are not standardized.

One of the best definitions of a standard is "A standard is a pre-engineered solution to a common problem." The codes, for instance, are descriptions of how to engineer, design and fabricate etc. systems and or elements of a system that are not considered common. This also does not limit such codes to only special situations. Hot water heaters, for example are a specific form of a heated pressure vessel but are most common with many standardized sizes, components and relief devices for safety.

Thus a new B16 standard is not something that never happens. It is simply that once such a component becomes common enough to require a standard that standard may last a long time as it evolves with the improving technology. One would be a little disingenuous to imply that many of the components covered by B16 have rapidly changing and evolving technology. Pipes for instance were known and used by humans in early civilizations and because we have no records most likely were known in some form since prehistoric times.

Certainly, the pipe material has evolved from the lead of Roman times, through wooden, clay, steel, plastics and many other materials. We also have found that methods of production have changed. It is also true that over the years the temperature and pressures that these systems and their components are used have changed. They have changed in both directions.

Some systems are at very high temperatures and some systems are at cryogenic temperatures. The pressures both internal and external to the component have changed as well. Yet some of the fundamental engineering principles have remained the same for centuries. Even so as these environments have changed we have to adjust the rules that keep the components workable. It was the increasing frequency of boiler explosions due to temperature and pressure increases as steam system grew that caused the ASME to be invited to develop the Boiler and all of its successor codes and standards.

That being said, it becomes obvious that one of the major duties of the members of the B16 standard committees is to maintain the standard. That maintenance involves not only being aware of the changes and or new materials and their strengths and weaknesses but how those changes inter act with the requirements of the current standard. The goal is to maintain the safety of the component. A secondary goal is also to maintain as best possible the dimensional stability of the component so that it is as best possible interchangeable with the existing or previously installed components.

To this end one primary piece of work in the standard is to maintain it as current to all known environments and uses as possible. To that extent the goal of the main committee is to have each standard be no more than five years old. That is the current cycle of renewing editions. As such the year of the current edition and the expected year of the next edition is a primary gage of the work. When reporting on each committee and standard those elements are reported and will be in the paragraph.

It is true that some changes are wrought only through controversy. Some changes are demanded by new knowledge and those move much faster through the process. That process is designed to make sure that there is an opportunity for all of the people involved to be consulted and their concerns addressed. A simple majority is not enough. A consensus is required and there are at least four levels of review to discover and address these concerns before a new edition is published.

Unlike many other ASME standards or codes B16 as has been pointed out has a set of unique standards that have different requirements. Nevertheless, each standard has a relative standard table of contents. The complexity of the components in terms of design, dimensions, testing required and other elements can vary the amount of contents. The standards may have a great deal of difference in the number of pages because of this different complexity. This difference may come from the number of types of components. This includes number of figures or tables that are required to describe the differences. Each standard can have a different method of pressure temperature rating. This may also vary according to the different materials that are useable within the standard. Also there can be a different number of appendices to the standard both mandatory and nonmandatory.

Rather than repeat this for each standard this write-up will establish a typical contents page for the reader. It is assumed that the differences as described above and below will allow the reader to understand what generally can be expected from a particular standard.

At the very beginning there is a forward. This forward can be very important to the new user of the standard. It gives an abbreviated history of what has happened during the life of the standard. It discusses how it started, what has changed in terms of added or dropped over the successive editions of that standard. In an edition where several changes have been made there might even be a summary of the changes to that edition.

The second standard element would be a listing of the roster of the committees involved in this standard. This includes the Subcommittee that performed the actual work of revision through discussion, research and ballot. A Standard's Main Committee that reviews the work of the subcommittee ensures to see if all the requirements of consideration and technical review have been met. When those elements have been completed, the work is reviewed by a Board on Pressure Technology to be sure procedural protocol was followed. The issue is then sent to ANSI for public review. Any comments from that review are responded to and the edition is then ready to be published. There is also a discussion of how any person may correspond with the B16 committee. This is particularly important if the individual has an inquiry about any portion of the specific standard.

Then there is the Table of Contents of the Standard. This portion is essentially about the text explaining the requirements of the standard. That table describes the sections of the standard and their subject. There may be a varying number of paragraphs within each section. They are generally the same basic sections in the order presented here. Below is a table describing a generic Table of Contents.

23.3 GENERIC TABLE OF CONTENTS

The actual Table may vary from this generic listing but it should give the reader an understanding of what to expect. One of the major differences is that some choose to put the extra requirements in a section, such as an appendix. This is because experience has shown that some extra requirements are used each time while some are optional. An example of this would be where there is more than one class of component like a standard class or a special class. These decisions are basically left to those in the subcommittee as they are presumed to know the frequency the issue needs to be addressed. It is time to discuss each of the sub committees and their standards in turn.

TABLE 23.1 GENERIC TABLE OF CONTENTS

Scope	This describes what the standard covers such as type, size, shape and any deviation.
Pressure-temperature ratings	This varies according to the method of rating the standard employs.
Size and type	This varies quite a bit depending on the variety within the components defined in the scope.
Marking	This describes the required marking within the standard as well as the order it may be omitted
Material	Some standards list specific materials accepted, some list ASTM categories but all define what materials are accepted
Dimensions	These are tables that establish the critical dimensions required by the standard for each size and type
Tolerances	In additions to min & max dimensions in the dimensional table many have specific and additional general tolerances
Testing	This may cover proof testing or production testing
Other	Some standards have sections for other requirements; some use mandatory appendices for additional requirements

TABLE 23.1 GENERIC TABLE OF CONTENTS (CONT.)

Figures	A listing of figures used in the standard and their location A standard may have many or few figures
Tables	A listing of tables and their location as in figures it may be many or few depending on sizes and types
Mandatory appendices	Since all standards are now metricated this has at least an appendix for US customary dimensional tables. There is also an appendix for other references used in the standard
Nonmandatory	There is usually a quality control suggestion plus other explanatory and helpful appendices

23.4 SUBCOMMITTEE B: THREADED FITTINGS (EXCEPT STEEL), FLANGES AND FLANGED FITTINGS

You were directed to the text in some comments. The salient facts are these standards have been around for a long time with the minor exception of the two numbered B16.42 and B16.45. Those two have only been around for a few years and they represent a few of the changes that are taking place in this set of standards.

These standards have had very little if any dimensional changes in the past decades. The changes that have been made are minor technical changes as the details making the product and other similar changes have evolved.

One could say the major changes are in the base materials where most of the changes have occurred and will be occurring in the near future. The careful reader will note that the fittings are cast fittings. That technology has changed tremendously in the past few decades. When B16.1 was first introduced, by its various methods as mentioned in the overview, cast iron was the material available. Foundries that made cast Iron were ubiquitous.

While there are versions of cast iron which can be described, with apologies to the metallurgical experts, as it is a material that is strong in compression and much weaker in tension. It can be considered as brittle in opposition to having ductility. In other words its yield point and ultimate strength are close together. In pressure codes when they set the allowable stresses cast iron is set at 0.1 of ultimate tensile or other lower factor.

This, of course limits as it should, the uses where it is probable. In fact some other standard setting bodies including B16 have set standards with wrought and forged rather than cast materials that have similar sizes and dimensions that can be used at higher temperatures and pressures. Still cast iron has valid uses and the standards remain.

The next development was to develop malleable cast iron. Again with apologies to the metallurgical literati this malleability is developed by special heat treatment of the iron. It achieves stronger less brittle material. It is purported to be the easiest to machine of the cast materials. As a comparison codes in setting their allowable stresses use a factor of 0.2 against the ultimate. By that measure it is twice as strong as cast iron. One can see from the titles that there are several standard specifically for that material.

Newer yet is a cast material ductile iron. This is accomplished in the melting and molding process. It was once called nodular Iron since the carbon in the metal matrix is essentially spread through the material in small nodules. One could call it a hybrid type steel. It is considered the strongest. In the fitting world it is made most often by offshore foundries. Some of these offshore producers make and sell ductile iron fittings of the B16.4 type. Currently there is no US standard for this material in that type of fitting and that is the pressure that is developing to make a US standard for that. There is controversy, for instance ISO 49 does not allow ductile iron.

Since many of the uses of these standard are involved with Water supply and Potable water that creates another issue for these standards. California law AB and the new federal standard that is due to come into effect Jan 4, 2014 reduce dramatically the amount of lead that can be used in contact with such water. Many of the threaded standards still allow galvanized hot dipped coatings. That includes the allowance of Prime Western zinc. That zinc will not pass the new federal or old California requirements.

There is electrolytic zinc which will meet the new requirements. It is the grade most often used. However the standard allows the other so some changes there are required. Hot dipping is preferred as it has a .0034 thickness as opposed to a plating thickness of .001. A dilemma is pointed to. One just needs to note the discrepancy between the 2014 effective date of the federal standard and the estimated date of the new standards. They are not necessarily in agreement.

One might also comment it is a relatively common type of problems when standards of one type affect standards elsewhere. There are necessarily offsets in dates. It is the kind of dilemma that makes the referencing of the editions in the standard that you are using and the editions that you are referencing. It is a problem that can cause dilemma such as the one just described. Other similar problems will be mentioned as we traverse through the B16 cataloug.

Needless to point out that the standards in this group are evolving slowly, but they are evolving. This could be marked as the oldest and therefore the slowest. However, note that B16.1 fittings have dimensions that have flowed through to other standards. A B16.1 flange can be bolted to a B16.5 flange of the same size and class. Already we have pointed to standards that have different than cast materials that use cast material from subcommittee standards. The world of standards is connected in many strange and wonderful ways.

TABLE 23.2 THREADED FITTINGS (EXCEPT STEEL), FLANGES AND FLANGED FITTINGS

Standard	Name	Estimated Next Edition	Comment
B16.1-2101	Gray iron pipe flanges and fittings	2015	Oldest and least likely to have major change
B16.3-2011	Malleable iron threaded fittings	2016	Pressure on malleable see text below
B16.4-2011	Gray iron threaded fittings	2016	Difference in material with B16.3
B16.12-2009	Cast iron threaded drainage fittings	2014	
B16.14-2010	Ferrous pipe plugs, bushings & locknuts w/ pipe threads	2015	
B16.15-2011	Cast copper alloy threaded fittings	2016	Copper alloys might have lead
B16.39-2009	Malleable iron threaded pipe unions	2014	Malleable iron has pressure to change see text below
B16.42-2011	Ductile iron pipe flanges and flanged fittings	2016	Material change from gray iron
B16.45-1998(2006)	Cast iron fittings for solvent drainage systems	2014	In major rewrite due to changes in requirements

23.5 SUBCOMMITTEE C: STEEL FLANGES AND FLANGED FITTINGS

23.5.1 Discussion of flanges

Flanges in these standards are generally able to be used in higher temperature and pressure systems because they are, as the title of Committee says of steel. The scope of B16.5 carries through the other flange standards this committee has jurisdiction over 'in sub paragraph (b) of the scope' it says the standard is limited to

(1) *Flanges and flange fittings made from cast or flanged forged materials. This is further limited by the materials recognized in the standard. It does allow blind flanges and certain reducing flanges to be made from plate materials*

In the final paragraph of the scope it points out that the standards include requirements and recommendations regarding flange bolting, gaskets and joints. The recommendations are relatively unique in a standard. This is because a single flange by itself is not worth much in a system. It is only when a flange is attached to another flange that it begins to be functional.

This means that the manufacturer of a flange has no real control over the bolting used in the field, the gasketing or sealing used between the flanges or the manner in which the flange is assembled and tightened. Each of those elements and their use and implementation is a defining factor in the ultimate effectiveness of the flanged joint. The flange alone is not self-contained.

In fact an engineer trying to determine the effectiveness of a flanged joint has to use all of the factors including pressure and temperature in determining whether the assembly when under pressure will perform its function. In fact many analysis procedures check both the ambient and the at temperature condition. It is for this reason that the B16.5 standard goes to fairly extensive links in recommending what bolting and gasketing will work in which joints. In fact, a large deviation from such recommendations may make the flanged assembly in the field ineffective.

Another difference is that there are several types of flanges and flange facings which, in general, determine the kinds of gasket used. These types can be broken into the various types by the way they are attached to the pipe. The most well known type is the Welding neck flange. This flange is welded to the end of the pipe and then becomes integral with the pipe in reacting to the loads on the system. Smaller flanges may be threaded and or Socket welded to the pipe. They might be classified as semi integral as they work with the pipe. Another type is a slip on. This type is, in general, slipped over the pipe and attached to the external walls of the pipe.

The last type is lapped. The main feature of this flange is that it is not explicitly attached to the pipe. The main use of this type is when the pipe is of an exotic material and the user for reasons wants to use a lesser material for the flange itself. This requires the use of a "stub end" on the pipe which will keep the flange from sliding off the end of the pipe until it is assembled with its mating flange.

TABLE 23.3 STEEL FLANGES AND FLANGED FITTINGS

Standard	Name	Estimated Next Edition	Comment
B16.5-2013	Pipe flanges and flanged fittings NPS2.5-24	2018	Shares PT ratings with B16.34-36-47
B16.36-2009	Orifice flanges	2014	Similar to B16.5 with orifice pressure taps for measuring flow
B16-47-2013	Large diameter steel flanges NPS 26-60	2018	Two series that are compatible with MSSSP-44 and API 605
B16.48	Steel line blanks	2015	For blanking a pipe between flanges

Needless to say each type would not have identical dimensions in all respects. All the necessary different dimensions are listed in the tables. So that depending on size and other technical considerations each type of flange is listed, if applicable, in each class.

23.5.2 Pressure Temperature Ratings

The foregoing discussion sets the scene and inadvertently asks the question "how, then is one to determine at what temperature and pressure can I use a flange that is rated as complying with the standard?" It was in answering this question that the class system was born.

Basically the systems are labeled Class 150, 300, 400, 600, 900, 1500 and for certain sizes 2500. These class numbers have no specific meaning. As the class number gets higher a flange rated in that class would, in general, have a higher pressure rating at a certain temperature. In a special design you would get some different dimensions for each material as well as each temperature and pressure. This is true even with the same bolting and gasketing on the flange.

To solve this dilemma the writing committee broke the applicable materials into material groups based on similarity of mechanical properties of the materials in a group. At the present time there are nearly 50 basic groups with an average of less than three materials per group.

When making a pressure temperature chart each group has its own chart. In the chart all of the classes are listed and the allowed pressure for each temperature (in 50° to 100° steps, depending on metric or US customary tables).

There is a Non Mandatory appendix A in B16.5 telling how that chart was developed. A careful reading of that appendix shows that the actual pressure allowed is dependent on temperature, and class plus some more or less unexplained but derivable standard factors. That means that one would have to determine which class a specific material would be placed in, to use the appendix to rate an unlisted material. It is important to note that the unlisted material would not be recognized as a B16 flange. One of the future projects of the committee is to develop a method that would allow someone who wanted to use an unlisted material to have a method that would allow that.

This is a long standing request to the committee. Progress s is being made. It should be noted that the committee is currently kept reasonably busy by keeping up with changes in current listed materials. ASTM seems to be busy changing materials from one classification, say from majority non-iron materials to majority iron group material. This makes a great amount of paper work changes for name designation but not much technical change. In other words, a great deal of paper work.

Not much has been said about flanged fittings. These do not have many technical changes. It would seem that many of these have been replaced by fabricated groups of fittings rather than the large cast fittings, the group anticipated. The overall dimension can normally be held with a fabrication. However, fabrication becomes a code issue for the piping codes not the standard.

B16.36 could be described as a B16.5 flange with the tapping orifice so they can be used to measure the differential pressure and thus the flow in a piping system.

B16.47: This dimensionally is SP-44 (series A) and API-605 (Series B) with B16.5 materials and requirements. The API standard is no longer supported as this one is to be replaced it. The MSS standard is pointed toward higher yield materials not recognized by B16 and therefore continues as a viable standard for those material which are usually in pipe lines.

B16.48 is a standard for blanks when one wants to stop a flow in a pipeline. That is different than a blind flange which terminates a flanged pipe. This replaces API-590 which is no longer supported by API.

23.6 SUBCOMMITTEE F: STEEL THREADED AND WELDING FITTINGS

23.6.1 Discussion of the Standards

B16.9 has been around a long time. It was originally tees, long radius elbows and other conventional fittings in sizes NPS 1/2" to 48". As time has passed it has incorporated both short radius elbows and 3D elbow. Crosses, reducers and Street elbows have been converted to steel material from the original cast materials. It has included long and short stub ends.

One of the more recent additions was a section on segmented elbows. These are elbows that can be cut to different degrees of bend during or after manufacture. It is noted that if the cut is made in the field such elbows will no longer comply with the standard. "Segmentable" essentially means the inner diameter of the elbow is consistent within tolerance throughout the entire bend eliminating the ovality that often occurs in the interior of the bend.

In the last edition the committee upgraded the proof test procedure to, among other things, encourage multiple tests of a given geometry across sizes of that geometry and add specificity to the documentation of such tests. There is still work to be done on the test assembly and what is similar geometry.

The pressure rating is by a code accepted mathematical procedure or at the manufacturer's option a proof test. In either case the proof is that the fitting is at least as strong as the NPS schedule and size it is marked for.

B16.11 is another long time standard. It covers threaded and socket-welding fittings. It is noted that it is primarily for NPS 4 and smaller pipe. A careful reading shows that the vast majority of sizes would be at NPS 2 and smaller. This is primarily in contrast with B16.7 where the majority of fittings would be above NPS 2. Those who understand pipe welding would recognize that is a result of the fact that butt-welding of smaller pipe is much more difficult, whereas, socket-welding and threading are relatively easier and more efficient.

The major upcoming project for this standard is corrosion protection. These fittings, being smaller, are made and stocked in large quantity. They are subject to corrosion especially in the carbon steel grades. The committee is searching for consensus on whether it is a responsibility of the standard to specify a method of protection and if so which method. The method in general use is a zinc phosphate coating. This type of coating is in common use in other industries. However, there is no consensus within the committee. In addition there is a desire to add certain other types of fittings to the standard that are not currently included.

B16.25 is a standard to define acceptable weld preparations for butt-welding ends of all types. Many other standards either refer to this document or use its requirements in theirs. One of the more

TABLE 23.4 STEEL THREADED AND WELDING FITTINGS

Standard	Name	Estimated Next Edition	Comment
B16.9-2012	Factory made wrought steel buttwelding fittings	2017	Started out in 1921
B16.11-2011	Forged fittings socket –welding and threaded	2016	Mainly NPS 4 and below
B16.25-2011	Butt-welding ends	2017	Weld preparation dimensions for all types of end weld joints
B16.49-2012	Factory made steel butt-welding induction bends for transportation and distribution systems	2017	Relatively new and for specific systems with more stringent requirements

frequent uses is to define the acceptable tapers when the two ends have different thicknesses. It does not get many changes unless weld processes change.

B16.49 is a recently developed standard for the pipeline industry. That industry has many uses for bends of different diameters than the short, long and 3D bends included in B16.9. Induction bending is also a recent development as a bending process. It has distinct advantages in the ability to bend different bend radii. It has some complexities in control of the process and results of the bend. So a new standard with requirements addressing the complexities was developed. A new project to develop a similar standard to be called B16.53 with less stringent requirements is under development. However, there has been extreme difficulty in reaching a consensus and it may require abandoning the project.

23.7 SUBCOMMITTEE G: GASKETS FOR FLANGED JOINTS

Both Standards B16.20 and B 16.21 are relatively stable dimensionally. They develop their dimensions based on the facing dimensions of The Flange standards promulgated by subcommittee C. These dimensions are probably the most stable dimensions in those standards.

The major concern of either standard would be the materials used in the gaskets. There is a relatively constant effort to develop new gasketing materials that will affect better seals. For those familiar with gaskets they are familiar with the two base gasket parameters use in flange analysis. They are known as M and Y. These factors are long standing and basically empirical but are a concern when selecting either an old or installing a new gasket material.

23.8 SUBCOMMITTEE J: COPPER AND COPPER ALLOY FLANGES, FLANGED FITTINGS AND SOLDER JOINT FITTINGS

23.8.1 Discussion

It is obvious that these standards are for materials which are of copper and its alloys. The threaded copper fittings assigned to subcommittee B are the notable exception. In the case of flanges they generally follow the bolting patterns of the other material flange standards.

The major problem currently facing some of these standards is the previously mentioned federal regulation that will require copper and copper alloys that come in contact with potable water to be lead free. There is a maximum amount of lead that can be in the alloy however many of the common alloys have higher amounts of lead in their chemical content. These alloys have been in existence for many years. One can estimate a possible larger problem for makers of water valve components. Several valves have these high lead components such as components in waterworks valves.

TABLE 23.5 GASKETS FOR FLANGED JOINTS

Standard	Name	Estimated Next Edition	Comment
B16.20-2012	Metallic gaskets for pipe flanges ring-joint, spiral-wound and jacketed	2017	Probably the most frequently used types of current gaskets
B16.21-2011	Nonmetallic flat gaskets for pipe flanges	2014	This covers the rest of the gaskets recognized

TABLE 23.6 COPPER AND COPPER ALLOY FLANGES, FLANGED FITTINGS AND SOLDER JOINT FITTINGS

Standard	Name	Estimated Next Edition	Comment
B16.18-2012	Cast copper alloy solder joint pressure flanges	2017	The first copper non threaded standard
B16.22-2012	Wrought copper and copper alloy solder and joint pressure fittings	2017	Latest edition revised some ratings and values in tables
B16.23-2011	Cast copper alloy solder joint drainage flanges-DWV	2016	
B16.24-2011	Cast copper alloy flanges and flanged fittings all B16.5 classes	2016	Working on clearer definition of pressure ratings
B16.26-2011	Cast copper alloy fittings for flared copper tubes	2016	One of several of these standards working on the lead free alloy problem
B16.29-2012	Wrought copper and wrought copper alloy solder joint drainage fittings	2017	Working on standardizing lengths
B16.50-2001	Wrought copper and copper alloy braze joint pressure fittings	2013	There was an edition in 2008 that had no revisions
B16.51-2011	Cast and wrought copper and copper, alloy pressure connect	2016	Another of the standards affected by the lead-free upcoming requirements

23.9 SUBCOMMITTEE L: GAS SHUTOFFS AND VALVES

The careful reader will note the pressures involved are low. These standards are for distribution systems. Distribution systems operate at lower pressures than gas transport systems which normally operate at high pressures, some in the thousands of psi. Distribution systems are essentially in metropolitan and or residential districts. In all of this type of systems these must be designed in a way to isolate a particular area. Certainly the residential shutoffs isolate a residence and in case of a problem one must be able to isolate a region.

23.10 SUBCOMMITTE N: STEEL VALVES AND FACE TO FACE AND END TO END DIMENSIONS OF VALVES

23.10.1 Discussion

One can note that B16.10 has the intent to expand the sizes of valves they establish, the face to face and end to end dimensions. The expansion comes as valve sizes tend to grow. The task is a difficult one both for the manufacturers and the standards writers. The standards must be sure that they don't exclude a particular manufacturer's product without valid reason. They must survey manufacturers to be sure they have all the variety of valves of the

TABLE 23.7 GAS SHUTOFFS AND VALVES

Standard	Name	Estimated Next Edition	Comment
B16.33-2012	Manually operated metallic gas valves for use in gas systems up to 125 psig	2017	Sizes NPS $^1/_2$" through 2"
B16.38-2012	Manually operated metallic gas valves for use in gas systems up to 125 psig	2017	For NPS sizes 2" through 12"
B16.40-2008	Manually operated thermoplastic gas shutoffs and valves in gas distribution systems	2013	This standard is being revised to polyethylene only new standards are being developed for other material
B16.44-2012	Manually operated metallic gas valves for use in above ground systems up to 5 psi	2017	This standard up to date

TABLE 23.8 STEEL VALVES AND FACE TO FACE AND END TO END DIMENSIONS OF VALVES

Standard	Name	Estimated Next Edition	Comment
B16.10-2009	Face to face and end to end dimensions of valves	2014	The intention is to increase the size range of valve covered up to NPS 60”
B16.34-2013	Valves flanged, threaded and welding end	2015	See the discussion on this standard

type that are available. At the same time the manufacturer of a valve covered by the standard wants to meet the dimensions specified in the standard.

B16.34 is the only current B16 valve standard. API and MSS both have valve standards that cover valves. However, in general they either cover valves not included in B16.34 or are supplemental to it. Actually B16.5 originally had valves included in its flange coverage but valves were split away from B16.5 as the needs for more detail and other than flanged valves grew. The flange standards B16.5 and B16.47 as well as B16.36 still share pressure temperature ratings with B16.34. For this reason the standards make every attempt to publish a new edition concurrently with each other. When they are published with much difference in timing those ratings get out of synchronization and this causes problems for the users.

B16.34 does make valves other than flanged valves so in its publication there are materials not in the flange standards. B16.34 also has requirements for non-destructive examination and other requirements not required in flanges. Valves have moving parts and internal components that are less straightforward in the design and application so they need more detailed requirements.

Two of the issues that the N committee is addressing, and to a lesser extent the flange standards, have to do with materials that are listed and the maximum pressures that are allowed. The material issue is most vexing. It is a long and laborious process to get a new material into the standards. The new approach is to allow the manufacturers, when they want to use a currently unlisted material, to develop a “Case” for that material. Then the case can be reviewed and adopted by the committee using the data developed by the manufacturer and select a material group and allow that case to be used. This is intended to cut the time to introduce a new material to the standard so that it can be used as a B16.34 Valve.

The other issue is related to material and pressure rating. In the rating process there is a ceiling pressure above which a material cannot be rated. As a convenience for the user the rating process is described in a non-mandatory appendix. The ceiling pressure chart was developed some time back. It is a metaphor for what the ASME BPV code has in its appendix for rigidity. At some point the deflection of the flange may become more damaging to the sealing of the flange than the stress generated. Some newer materials could feasibly have a higher sealing pressure than the current chart anticipates. The committee is researching methods to verify this and create some kind of allowance for that potential.

Lastly all current materials are metallic. There is a growing availability of plastic valves. The committee has an active task force to develop a standard for thermoplastic material valves. They have progressed to the point where they have identified the specific materials which might be included and are working on a draft version of a standard for such valves. It is anticipated that this standard will develop and publish in increments of material types and valve types.

So the reader can now see that the B16 committee is actively working on all fronts of standards within its purview.

23.11 REFERENCES

1. For B16 Standards: Refer to Tables 2.3, 23.3, 23.4, 23.5, 23.6, 23.7 and 23.8.
2. ASME B31.3 Process Piping Code, 2012 Edition.
3. ASME Boiler and Pressure Vessel Code Section I, *Power Boilers*; The American Society of Mechanical Engineers.
4. ASME B31.12, *Hydrogen Piping and Pipelines* 2008 Edition, The American Society of Mechanical Engineers.

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CHAPTER

24

PART A: LESSONS LEARNED BASED ON SECTION VIII, DIVISION 1

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PART A: LESSONS LEARNED BASED ON SECTION VIII, DIVISION 1

24A.1 ABSTRACT

The technology for pressure equipment design continues to advance each and every day. The American Society of Mechanical Engineers (ASME) has been keeping pace with these advances over the last 100 years. Specifically, the ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 [1] has become the International benchmark standard for pressure vessel design for a multitude of industries. In response to these ever-growing industries and their unique design requirements the document has grown in scope, technology, and size. Organization, maintenance, and use of a document of such magnitude have become a real challenge, especially with a writing style and format that is not readily adaptable to change. This chapter provides commentary into what are generally thought to be the more relevant issues of ASME Section VIII, Division 1 that need attention to better serve its users and to provide recommendations to resolve these issues.

24A.2 INTRODUCTION

ASME established a committee in 1911 to develop standard rules for the construction of steam boilers and other pressure vessels. The initial issue of the ASME Code was in 1915 titled "Rules for the Construction of Stationary Boilers and for Allowable Working Pressures, 1914 Edition". The title was later shortened to "Boiler Construction Code, 1914 Edition" (Section I). In 1925, the first issue of "Rules for Construction of Unfired Pressure Vessels" (Section VIII) was released. With the release of the 2013 Edition of the ASME Boiler & Pressure Vessel Code, Section VIII Rules for Construction of Pressure Vessels, Division 1, (VIII-1) the code book is now in its 88th year of existence. Over this period, the code book has evolved into an International benchmark standard. It has well served its wide ranging users including the refining, petrochemical, and commercial industries to name a few, and has incorporated the leading edge technologies of its time to strengthen its foundation since its inception in 1925. However, with any document of such longevity which is continually being interpreted, revised, and updated with new technologies, it can be expected to have developed some problems over time.

It is not the author's intent to scrutinize the efforts of the hundreds of volunteers who have contributed to the VIII-1 document. After all, the author is an active member of the committee and takes great pride and ownership of his responsibility to the community of which he serves. Instead, the intent is to highlight areas of the document that are thought to need attention to better serve its users and also to provide suggestions as to the possible options to improve the document. There are six areas provided for discussion; size of the document, writing style and organization, technical issues, technical background of the rules, common rules, and example problems.

24A.3 DOCUMENT SIZE

24A.3.1 Overview

The VIII-1 code has adopted many new rules and has provided valuable design guidance over its history. It has grown from its literal "handbook-size" release in 1925 to in excess of 700 pages, including several dozen Mandatory and Non-Mandatory appendices. This does not include the vast number of Code Cases nor Interpretations that have been issued throughout the years to assist in pressure vessel design. Not to mention that the allowable stress tables were relocated from VIII-1 into Section II Part D in 1992. In other words, the VIII-1 code has become bloated.

For several reasons, VIII-1 has grown to this magnitude, including introduction of new technologies, additional design details due to the application to multiple industries, fabrication and inspection advances, and the use of wide ranging materials. So the natural growth of VIII-1 can be expected. However, it is the combination of all these reasons coupled with a tired organizational structure that compounds the problem. This along with the resistance to the removal of past or outdated design rules when more advanced rules are introduced is of real concern.

It should be noted that document size only becomes an issue with poor organization. Large documents can be written that are highly technical and user-friendly, but to produce such a standard required excellent organization and a clean and consistent writing style. An example of such a document is API 579-1/ASME FFS-1, *Fitness-For-Service* [2]. This document is large and contains highly technical content and yet is recognized as being user-friendly. The success in the user community of this document API 579-1/ASME FFS-1 was used as the model for the 2007 Edition of the ASME B&PV Code, Section VIII, Division 2 (VIII-2) based on the successful feedback from the user community.

24A.3.2 Vast Scope of Vessels

As previously referenced, VIII-1 over its existence has evolved into an International benchmark standard. It has become the go–to standard for the design of a wide variety of vessel types with varying fabrication methods and with a multitude of applicable materials. Fabrication types include; welded, forged, brazed, and layered construction. The wide array of materials and their requirements include cast iron, carbon and low alloy steel, high alloys, to name a few and also include requirements for vessels constructed of impregnated graphite. The rules provided in VIII-1 are applicable to the complex reactors used in the refining industry to the mass produced air compressors found on store shelves. It is this vast scope of pressure vessels and associated requirements that has been the prime contributor to the overwhelming size of VIII-1. Simply put, due to the success of VIII-1, it has become its own worst enemy. It has become everything to everyone.

Many of the design details, fabrication, inspection, and examinations requirements found in VIII-1 are applicable to a narrow scope of vessels. Large sections of the document are unused by many of the users and fabricators in existence today. This not only makes the document chock-full of design rules and details, but complexity is added in the organization, writing, application, and use of the general requirement sections of VIII-1. To help simplify the design effort required by many fabricators of pressure vessels, reduce the size of the document, and perhaps more importantly focus the needs and requirements of these industries, it has been recommended that a new separate code should be developed to specially address the unique construction features associated with mass produced vessels.

24A.4 WRITING STYLE AND ORGANIZATION

The writing style and organization of VIII-1 is representative of an aging document that has been maintained in a patch-work-like manner. That is to say, the individual subsections of the document are not conducive to change nor the introduction of new rules. Therefore, any new addition to VIII-1 is either placed in a less than desirable location or more typically introduced in an appendix. Often time logical placement of a new rule is not possible due to the constraints imposed by the established paragraph referencing style. While in other instances, this same style of paragraph referencing has led to holes in the numbering sequence. As a result, VIII-1 has grown to include 40 Mandatory appendices and 25 Non-Mandatory appendices.

The vast array of Mandatory appendices is not organized in any specific manner which further complicates the navigation of the document. The appendices are a compilation of intertwined design rules, definitions, inspection practices, examination techniques, quality control system requirements, capacity conversions for safety valves, material requirements, and the list goes on. The organization of the Non-Mandatory appendices is no better with various design rules, suggested good practices for linings and the design of supports and attachments, general information for the installation and operation of pressure vessels, dated design considerations for bolted flange connections, guidance for the preparation on design reports, and were once the home of example problems.

The writing style and organization of VIII-1 is recognized to the extent that in the development of VIII-2, one of the key objectives was to develop a new writing style and organization. The new writing style minimized the use of narrative passages and emphasized the use of structured paragraphs, tables, equations and figures. Other known issues with the layout of VIII-1 include:

- Circular paragraph referencing.
- Location of figures and tables throughout the subsections, rather than placed at the end of a subsection.
- Lack of design procedures.
- Overuse of narrative descriptions for design rule limitations rather than simple mathematical expressions.
- Illogical placement of new rules so as to maximize existing paragraph integrity; e.g., the tubesheet design rules are presented in Subsection C, Requirements Pertaining to Classes of Materials, under Part UHX.
- Placement of design rules in nomenclature.

With the above noted issues, it should come as no surprise that the navigation through and use of VIII-1 is extraordinarily difficult for the inexperienced, and quite frankly even the experienced users. The user of VIII-1 is not provided with a consistent road map outlining a clear concise path as to the organization of the general, design, fabrication, inspection and examination, and material requirements necessary for proper vessel design. Compounding the problem is the required maintenance, interpretation, and updating of the document by the committee's volunteers, which has become a real challenge.

24A.5 TECHNICAL ISSUES

24A.5.1 Over-use of the U-2(g) clause

Paragraph U-2(g) states that VIII-1 does not contain rules to cover all details of design and construction. When complete details are not given in VIII-1, it is intended that the Manufacturer, subject to the acceptance of the Inspector, shall provide details of design and construction which will be as safe as those provided by the rules of VIII-1. Paragraph U-2(g) essentially permits the engineer to design components in the absence of rules in VIII-1 with the criterion that the design margin in VIII-1 be maintained. The requirement "be as safe as" is difficult to quantify because the actual design margin for a particular failure mode is not provided in VIII-1. As discussed below, this requirement may be satisfied by using VIII-2, Part 4 or Part 5, as applicable, in conjunction with the allowable stress and weld joint efficiency of VIII-1.

Design rules in construction codes are typically based on: analytical derivations, test results, and experience based on evidence of satisfactory performance. In addition, when design rules are developed, ease of use is balanced with required accuracy.

Ease of use — Over conservatism may make assessment rules useless or expense.

Accuracy — Effort and time to implement may be prohibitive.

Design margins in construction codes for pressurized equipment are typically set to prevent ductile rupture or plastic collapse. For example, in VIII-1 a design margin is used to determine the allowable stress. For time-independent behavior this margin is the minimum of the ultimate strength divided by 3.5 and the yield strength divided by 1.5; the ultimate and yield strength at room temperature and at the design temperature are considered in establishing this margin. The factors, such as 3.5 applied to the ultimate strength and 1.5 applied to the yield strength, represent the design margin to prevent ductile rupture or plastic collapse. However, to ensure "safe operation", other failure modes such as those shown below are addressed in VIII-1 directly or indirectly by rules.

- Brittle Fracture
- Local Strain
- Structural Instability (elastic or plastic buckling)
- Fatigue
- Incremental Collapse (ratcheting)
- Creep Rupture
- Creep Buckling
- Creep-Fatigue Interaction

Design margins exist in these rules as well as the calculation procedures incorporated into VIII-1. Many of these rules are made conservative for ease of application, are based on test results with variability, or are service experience based. Since the rules are used in conjunction with an allowable stress (that already contains a margin), the exact design margin for a component is difficult to establish. Therefore, design margins may be considered as follows:

Explicit Design Margins – Margins that can be directly identified, e.g. margins placed on material strength parameters, and

Implicit Design Margins – Margins that result from design rule conservatism for ease of application, and from design margin requirements imposed because of test results and service experience.

Many of the design-by-rule requirements in VIII-2, Part 4 represent a next generation of those rules in VIII-1 and many of the implicit margins in VIII-1 design procedures have been maintained in VIII-2, see Table 24A.1. In addition, the design-by-analysis provisions in VIII-2, Part 5 represent a next generation to the design rules in VIII-2 up to the 2004 Edition, 2006 Addenda. Therefore if the VIII-1 explicit margins on the strength parameters, i.e., the allowable stresses from VIII-1, are used in conjunction with the design-by-rule or design-by-analysis procedures in VIII-2, then vessels constructed in accordance with this practice are judged to be "be as safe as" those constructed to VIII-1. To support this notion, VIII-1 Code Case 2695 permits the use of VIII-2 design rules with VIII-1 allowable stresses with some limitations, see Table 24A.2.

Some of the paragraphs in VIII-1 where U-2(g) is invoked are shown below. In all instances, the design-by-rule or design-by-analysis procedures in VIII-2, Part 4 and Part 5, respectively, in conjunction with the allowable stresses and weld joint efficiency in accordance with VIII-1 may be used to qualify a component to meet the requirements of U-2(g).

- UG-19, special shapes, see UG-19(f).
- UG-29, cautionary note cover lateral buckling of stiffening rings.
- UG-34, Footnote 20 covering special consideration that shall be given to the design of shells, nozzle necks, or flanges to which noncircular head are attached.
- UG-36, reverse curve reducers, see UG-36(e)(5)(c).
- UG-39, reinforcement required for openings in flat heads, see UG-39(c)(3).
- Mandatory Appendix 1-5 covering rules for conical reducer sections and conical heads under internal pressure see 1-5(g).
- Mandatory Appendix 1-6 covering dished covers, see 1-6(h).
- Mandatory Appendix 1-7 covering large openings in cylindrical and conical shells, see 1-7(b)(1)(c).
- Mandatory Appendix 1-8 covering rules for conical reducer sections and conical heads under external pressure see 1-8(b), 1-8(c), and 1-8(e).
- Mandatory Appendix 1-10 covering the alternative design method for design of reinforcement for large openings in pressure vessels under internal pressure, see 1-10(d).
- Mandatory Appendix 9 covering jacketed vessels, see 9-1(e).
- Mandatory Appendix 13 covering vessels of noncircular cross section, see 13-1(c), 13-1(d).
- Mandatory Appendix 24 covering design rules for clamps, see 24-1(e).
- Mandatory Appendix 26 covering design rules for bellows expansion joints, see 26-4.1(f).

24A.5.2 Design Procedure for Combined Loading

The loadings to be considered as part of pressure vessel design in VIII-1 are provided in paragraph UG-22. A partial listing includes; internal and external pressure, axial weight, wind, snow and seismic reactions, and fatigue. However, VIII-1 falls short in two key areas; it does not provide the user with a means to combine the loadings nor does it provide a design procedure to evaluate such combination of loadings.

There are many user defined design specifications (recommended practices) floating around industry, which overlay the requirements of VIII-1. Many of these design specifications provide what are generally thought to be the most relevant load case combinations, each with adjustments considering the particular industry, service, and

TABLE 24A.1 COMPARISON OF DESIGN RULES BETWEEN VIII-2 AND VIII-1

Paragraph in Section VIII, Division 2	Comments Pertaining to Section VIII, Division 1
4.1	General Requirements, harmonized with VIII-1, i.e. MAWP introduced, etc.
4.2	Design Rules for Welded Joints, a restrictive subset of rules in VIII-1, UG & UW
4.3	Design Rules for Shells Under Pressure, mostly new technology
4.4	Design Rules for Shells Under External Pressure and Allowable Compressive Stresses, almost identical to CC2286 with exception of stiffening ring requirements at cone-to-cylinder junctions
4.5	Design Rules for Shells Openings in Shells and Heads, new technology
4.6	Design Rules for Flat Heads, identical to UG-34
4.7	Design Rules for Spherically Dished Bolted Covers, identical to Appendix 1-6 and Appendix 14 except Soehern's stress analysis method for Type 6D Heads is included
4.8	Design Rules for Quick Actuating (Quick Opening) Closures, identical to UG-35.2
4.9	Design Rules for Braced and Stayed Surfaces, a restrictive subset of rules in paragraph UG-47(a)
4.10	Design Rules for Ligaments, identical to paragraph UG-53
4.11	Design Rules for Jacketed Vessels, a more restrictive subset of rules in Appendix 9
4.12	Design Rules for Non-circular vessels, identical to Appendix 13 but re-written for clarity
4.13	Design Rules for Layered Vessels, identical to Part ULW
4.14	Evaluation of Vessels Outside of Tolerance, new technology per API 579-1/ASME FFS-1
4.15	Design Rules for Supports and Attachments, new for VIII-2 using existing technology
4.16	Design Rules for Flanged Joints, almost identical to Appendix 2
4.17	Design Rules for Clamped Connections, identical to Appendix 24
4.18	Design Rules for Shell and Tube Heat Exchangers, identical to Part UHX
4.19	Design Rules for Bellows Expansion Joints, identical to Appendix 26

Notes:
1. During the VIII-2 re-write project, an effort was made to harmonize the design-by-rule requirements in VIII-2 with VIII-1. AS shown in this table, based on this effort, the design rules in VIII-2 and VIII-1 are either identical or represent a more restrictive subset of the design rules in VIII-1.
2. In the comparison of code rules as presented in this table, the term identical is used but is difficult to achieve and maintain because of coordination of ballot items on VIII-1 and VIII-2. There may be slight differences, but the objective is to make the design rules identical. The restrictive subset of the rules in VIII-1 was introduced in VIII-2 mainly in the area of weld details. In general, it was thought by the committee the full penetration welds should be used in most of the construction details of a VIII-2 vessel.

geographic location. The American Society of Civil Engineers Standard ASCE/SEI 7 [3] also provides a series of load case combinations based upon a load factor and resistance design (LFRD), which has been incorporated into VIII-2, Part 4 and Part 5. Although VIII-1 does not consider LFRD, this set of load case combinations can quite easily be modified to suit the VIII-1 design philosophy, thereby providing the user a foundation of combinations of which to build upon.

While it is not practical to provide a design procedure that contains closed form solutions for all possible combinations of loadings, it is puzzling that VIII-1 does not provide a closed form solution for the most common combination of pressure with supplemental loads producing axial, bending, and shear stresses. Especially since these types of solutions are provided in many pressure vessel design handbooks. VIII-2, Part 4 provides a design procedure that addresses the combination of loadings and can be adapted to VIII-1 design with minimal effort. In fact, PTB-4-2013, *ASME Section VIII-1 Example Problem Manual* [4] provides an example of how this can be achieved.

24A.5.3 Nozzle Reinforcement Rules

The traditional area replacement design method of UG-37 has been in VIII-1 since its inception. Since that time, design rules (and/or considerations at one point) for large opening nozzles were introduced to VIII-1 in the late 1940s early 1950s and are currently located in Appendix 1-7. The supplemental rules were introduced with the experience gained in the fabrication of large diameter openings with respect to the distortion and localized stresses that are developed around thin shell large opening nozzles. More recently in the 2007 edition of VIII-1, the adoption of Code Case 2168 (WRC

TABLE 24A.2 ASME BPV CODE CASE 2695

Code Case 2695

Allowing Section VIII, Division 2 Design Rules to Be Used for Section VIII, Division 1 Pressure Vessel Section VIII, Divisions 1 and 2

Inquiry: Under what conditions may the design-by-rule requirements in Part 4 of Section VIII, Division 2 be used to design the components for a Section VIII, Division 1 pressure vessel?

Reply: It is the opinion of the Committee that the design-by-rule requirements in Part 4 of Section VIII, Division 2 may be used to design the components for a Section VIII, Division 1 pressure vessel, provided the following conditions are met:

a) The allowable design tensile stress shall be in accordance with UG-23 of Section VIII, Division 1.

b) The weld joint efficiency shall be established in accordance with UW-11 and UW-12 of Section VIII, Division 1.

c) Material impact test exemptions shall be in accordance with the rules of Section VIII, Division 1.

d) If the thickness of a shell section or formed head is determined using Section VIII, Division 2 design rules, the following requirements apply:

1) For design of nozzles, any nozzle and its reinforcement attached to that shell section or formed head shall be designed in accordance with Section VIII, Division 2.

2) For conical transitions, each of the shell elements comprising the junction and the junction itself shall be designed in accordance with Section VIII, Division 2.

3) For material impact test exemptions, the required thickness used in the coincident ratio defined in Section VIII, Division 1 shall be calculated in accordance with Section VIII, Division 2.

e) The fatigue analysis screening in accordance with Part 4, paragraph 4.1.1.4 of Section VIII, Division 2 is not required. However, it may be used when required by UG-22 of Section VIII, Division 1.

f) The provisions shown in Part 4 of Section VIII, Division 2 to establish the design thickness and/or configuration using the design-by-analysis procedures of Part 5 of Section VIII, Division 2 are not permitted.

g) The Design Loads and Load Case Combinations specified in Part 4, paragraph 4.1.5.3 of Section VIII, Division 2 are not required.

h) The primary stress check specified in Part 4, paragraph 4.1.6 of Section VIII, Division 2 is not required.

i) Weld Joint details shall be in accordance with Part 4, paragraph 4.2 of Section VIII, Division 2 with the exclusion of Category E welds.

j) The fabrication tolerances specified in Part 4, paragraph 4.3 and 4.4 of Section VIII, Division 2 shall be satisfied. The provision of evaluation of vessels outside of tolerance per Part 4, paragraph 4.14 of Section VIII, Division 2 is not permitted.

k) The vessel and vessel components designed using these rules shall be noted on the Manufacturer's Data Report.

l) All other requirements for construction shall comply with Section VIII, Division 1.

m) This Case number shall be shown on the Manufacturer's Data Report.

Bulletin 335 [5]) was inserted into Appendix 1-9 of the current VIII-1 with the justification that the area replacement rules can be excessively conservative for some geometries. These rules are provided as an alternative to the area replacement rules of UG-37 though they are confined to a fairly constricted matrix of geometries and only applicable to internal pressure. Interestingly enough, the authors of WRC Bulletin 335 comment on some peculiar findings regarding the supplemental reinforcement rules of Appendix 1-7 for large diameter openings and specifically cite a paper that documents a vessel that failed during hydrostatic test due to when the large opening rules of Appendix 1-7 were satisfied. Further observations are left to the reader. Finally, the inclusion of yet another alternate design method of nozzle reinforcement, based on the pressure-area method, was introduced to VIII-1 in 2008. It is widely accepted in the ASME code committees that these pressure-area rules are superior to those provided elsewhere in VIII-1 and in fact, are the only nozzle reinforcement rules used in VIII-2.

So the question is raised, do we need three sets of nozzle reinforcement design rules? To be fair, it is appropriate to provide the justification of those with the opinion that the area replacement rules of UG-37 are adequate and should remain as the default rules. Simply stated; the rules have been satisfactorily used for many years without a cited catastrophic incident, the design rules are relatively simple to apply (though it can be argued that the rules are often left to interpretation of the user and their respective geometry); and computer program developers and the users of VIII-1 are familiar with the requirements and their application and any change would produce unintended hardship. While these arguments have justification

(more in certain areas than others), the fact remains that there are several design rules within VIII-1 that can be replaced by one simplified and thought superior design method, thus eliminating the need for further interpretation, maintenance, and updating of the referenced sections by committee members.

24A.5.4 Ellipsoidal and Torispherical Head Rules

There are a number of issues that need to be addressed when discussing the design rules for ellipsoidal and torispherical head rules of VIII-1. However, to help organize these issues, it is thought appropriate to first discuss the rules as they are presented in VIII-1. The design rules for formed heads subject to internal pressure are provided for specific geometries, that is to say, the design rules of UG-32 are only applicable to 2:1 ellipsoidal heads and torispherical heads with a knuckle radius 6% of the inside crown radius. However, formed heads with other geometric parameters are permitted and VIII-1 provides for the design of these head types through a general solution for all geometries of ellipsoidal and torispherical heads. These equations are provided in Mandatory Appendix 1-4(c) and 1-4(d), respectively. The design equations found in this appendix are similar to those of paragraph UG-32 with the exception that the constant coefficients provided in UG-32 (for specific geometries) are replaced with variables K and M. The variables K and M are stress intensification factors used in the design equations for ellipsoidal and torispherical heads, respectively, and are provided in both equation and tabular form.

With the above presentation provided, a discussion of the issues is now appropriate. Since the 2:1 ellipsoidal head and torispherical head with a knuckle radius 6% of the inside crown radius (often referred to as a standard ASME Flanged and Dished Head) are generally accepted as the most common encountered head types used in pressure vessel design, it can be assumed the pressure vessel committees at the time thought it logical to provide design rules of such specificity. However, with the general solutions also provided in VIII-1 the question is raised, do we need both? If general solutions are available to cover all practical geometries of these formed heads, wouldn't it be more useful to simply provide one set of equations in paragraph UG-32? Or stated differently, what is the rationale from a user or committee volunteer standpoint to maintain both sets of rules?

Another issue raised is with the presentation of the stress intensification factors, K and M. These variables are presented in both equation and tabular form which can lead to inconsistent results. For example, tabular values for the equation of K, are provided in Table 24A.1, but the heading of this table states, "Use the Nearest Value of D 2h; Interpolation Unnecessary". If one user calculates the value of K directly from the equation and another uses the approximate value via Table 24A.1, inconsistent results are guaranteed. Similarly, the variable M is provided in equation form and in Table 24A.2 with the same heading as provided in Table 24A.1. Again inconsistencies will result. While the magnitude of "error" may not be considered significant for a design, the movement towards computerization of the code rules will result in potential inconsistent design values between software packages, and even hand calculations, all of which may be acceptable but provides for a source of skepticism and loss of confidence to the users of the particular software. With the availability of a design equation, why do we need to provide tabular values?

Though not mentioned in the above regarding the presentation of the design rules for formed heads in paragraph UG-32, it is critical to note that a limitation of acceptance was placed on the use of the ellipsoidal and torispherical head rules in the 2004 Addenda. This limitation is expressed through the ratio of head thickness, t, to crown radius, L, $L/t < 500$ ($t/L \geq 0.002$). For heads that fall outside of this range, supplemental design rules are required to be satisfied in addition to those of paragraph UG-32. These supplemental rules are found in Mandatory Appendix 1-4(f)(1) and 1-4(f)(2) for torispherical and ellipsoidal heads, respectively. These rules were introduced to provide a check against local buckling in the knuckle region of the heads under internal pressure.

As documented in WRC Bulletin 501 [6], it has been known for some time that the VIII-1 UG-32 design rules for torispherical heads provide inconsistent design margins over a range of geometric parameters and materials. It has been documented for certain combinations of geometry and material, these rules provide less margin against failure as other rules of VIII-1, while over a considerable range of geometric parameters and materials, these rules result in higher safety margins than intended. While the optimum vessel design would provide the same margins for all components of a vessel, the use of a higher safety margin for one component will not contribute to the overall safety of a vessel.

Although the rules of UG-32 have proven mostly safe enough for larger values of $L/t > 500$, there have been reports of knuckle wrinkling and buckling in these "thinner" heads under test pressures. This fact was proven with the test data provided in WRC Bulletin 444 [7], which indicated heads with L/t 500 could fail by buckling. Though not a catastrophic failure, any wrinkling (buckling) in the knuckle region is considered a failure and is to be prevented. Up to the 2003 Addenda, VIII-1 rules did not consider buckling as a mode of failure. To extend the range of $L/t < 500$ ($t/L \geq 0.002$), VIII-1 added a check for buckling, based on the proposed method of WRC Bulletin 444, et al. as located in Appendix 1-4(f). While implementation of this supplemental check not only introduces a discontinuity at $L/t = 500$, it still does not address the possibility of buckling in heads with ratios of $L/t < 500$ ($t/L \geq 0.002$), which are the current rules in paragraph UG-32.

VIII-2, Part 4 provides one set of design rules very close to that presented in WRC 444 (similarly with Appendix 1-4 of VIII-1) for all ellipsoidal and torispherical heads. It is recommended that these rules replace those currently found in UG-32 with the elimination of Appendix 1-4. A documented history of the design rules for ellipsoidal and torispherical heads found in VIII-1, Code Cases and WRC Bulletins is provided in WRC Bulletin 501 and is recommended to the reader.

24A.5.5 Low Temperature Operation (UCS-66)

One of the more challenging set of rules of VIII-1 to follow is that of the impact testing exemptions for carbon and low alloy steels found in paragraphs UCS-66 and UCS-67. Simply, the rules are an attempt to provide justification to not require impact testing of carbon and low alloy steels for operation at low temperatures, to protect against catastrophic brittle fracture. Based on the combination of material thickness and classification, a minimum design metal temperature (MDMT), is determined. If this calculated temperature (actual MDMT) is below the required temperature (required MDMT) then impact testing is not required. Rules are also provided to further reduce the actual MDMT based on an approach that can be thought of as trading stress, pressure, or thickness for temperature.

While the intent of the rules is sound and somewhat simple, the presentation of the rules often leads to confusion. Figure UCS-66.2 is a general flow diagram which was developed to establish a step-by-step design procedure to decipher the contents of paragraph UCS-66(a)(1) through (a)(5) and paragraph UCS-66(b)(1) through (b)(3).

However, the diagram is presented at a very general level with much of the required information needed contained in non-sequential paragraphs, General Notes and Notes of Figure UCS-66, and Notes of Figure UCS-66.2. In an effort to help sort through the reference paragraphs and figure a logic diagram was developed in PTB-4-2013 to not only provide the user with a roadmap through the referenced procedure, but also to highlight the complexity with which paragraphs UCS-66(a) and (b) are presented.

As documented above, the presentation of the impact testing exemption rules of UCS-66 and UCS-67 leave a lot to be desired. A brief summary of the issues considered most concerning and their possible resolution are highlighted below.

- The narrative nature of presentation of the rules should be replaced with a clear and concise design procedure. The presentation of the example problems and logic diagrams in PTB-4-2013 can be used as a starting point.
- Non-specific or vague references to other sections of the code for applicability and limitations should be replaced with specific references to paragraphs.
- Use of the dual meaning applied to the term MDMT often confuses the user as to which is being considered, the required or actual temperature. This problem is alleviated in API 579-1/ASME FFS-1 through the use of the terms critical exposure temperature (CET) to denote the required temperature and minimum allowable temperature (MAT) denoting the actual temperature.
- The rules of UCS-66(b) do not explicitly state which component's coincident ratio, R_{ts}, to use when looking at welded assemblies comprised of more than two components, i.e. nozzle-to-shell weld joints. This issue can be remedied by determining the maximum allowable working pressure (MAWP) of the reinforcement zone and then determine the ratio of reinforcement zone MAWP to that of the vessel MAWP to determine the overall value of R_{ts}, $R_{ts} = MAWP_{reinf}/MAWP_{vessel}$. This would require an iterative approach for VIII-1, but it is not a difficult calculation especially with the computerization of the rules.
- Clarification in the application of paragraphs UCS-66(b)(2), and (b)(3) for the exemption of impact testing for required temperatures colder than –55°F to –155°F:
  - The exemption of impact testing noted is only applicable to base metals.
  - The significance of $R_{ts} \leq 0.35$ in that it is assumed that weld residual stress is considered to be lowered proportionately to that of the applied stress in the component, when this is certainly not the case.
- Clarification in the application of paragraph UCS-67 for the determination of when impact testing of weld procedures is required for. The value of MDMT used in this paragraph is left to the user and is based upon differing criteria. This not only is a source of confusion for the user, but often could lead to very different requirements placed on the designer to justify impact testing exemption. The reader is encouraged to obtain the June 2013 Edition of *Pressure Points*, the Official Newsletter of HSB Global Standards [8]; therein contains a written summary and description of the logic behind the text of paragraph UCS-67.
- The treatment of materials that are subject to impact testing based on a material specification per paragraph UCS-66(g) is questioned. Paragraph UCS-66(b) permits the lowering of the MDMT through the use of R_{ts}, for materials that are impact tested as part of the material specification. However, the 30°F reduction in the MDMT based on the PWHT credit afforded by paragraph UCS-68(c) is not permitted for materials that are impact tested as part of the material specification. Though not explicitly stated, the direct reference to the materials of Figure UCS-66 prohibits the materials of UCS-66(g) from inclusion. This logic is questioned as any application of PWHT will reduce overall weld residual stress, though a loss of material toughness may occur.
- The use of UG-20(f) to trump the requirements of UCS-66 should not be permitted. As an example, per paragraph UG-20(f) an MDMT of –20°F can be applied to vessels constructed of carbon steel (P-No. 1 Gr. No. 1 or 2) of Curve B, C, or D material, less than one inch thick, if hydrostatically tested and neither shock nor cyclic loading governs the design. However per the rules of UCS-66, a Curve B material of one inch thickness has an unadjusted MDMT of 32°F. This is a substantial gap of 52°F and brings into question the validity of the exemption provided.

24A.5.6 Radiographic and Ultrasonic Examination (UW-11, UW-12)

The VIII-1 rules for radiographic and ultrasonic examination and the corresponding weld joint efficiency used in pressure vessel design are provided in paragraphs UW-11 and UW-12. Paragraph UW-11 provides rules and requirements based upon the type of radiography employed. The extent of radiography required of welded butt joints is determined based on vessel service, material thickness, and welding process. With the exception of paragraph UW-11(a)(5), the joint efficiency used in design depends only on the type of weld joint and the degree of examination of the joint and does not depend on the degree of examination of any other joint. Whether radiography is mandatory or optional, the amount of radiography performed on each butt welded joint together with the joint type is used to determine the joint efficiency to be applied in the various design equations, as described in paragraph UW-12. The application of these rules is fairly straight forward when the vessel is subject to full radiography or spot radiography alone. However, it is with the introduction of the combination of full and spot radiography, as documented in paragraph UW-11(a)(5), where the primary source of confusion is targeted.

These rules have generally been presented in the same manner since 1986. This is significant to note as major revisions to these paragraphs were introduced as a result of the recommendations made by the Special Working Group (SWG) on Stress Multipliers formed in 1982. This SWG was created to address the growing influx of inquiries submitted to Subcommittee VIII, which indicated a lack of understanding and acceptance of the then-current rules. To address the confusion of the then-current rules, the original basis of the proposal submitted by the SWG was to consider the radiography of each joint separately and obtain a joint efficiency corresponding to the extent of radiography performed. However, this approach was not found with favor for several Subcommittee VIII members as this would permit a vessel to have non radiographed circumferential joints and full radiographed longitudinal joints. After several attempts to gain approval of the original proposal, with the SWG believing the elective concept of considering each joint separately to be consistent with the overall philosophy of VIII-1, modification to the proposal was made. The revised proposal, which did gain committee approval, did not permit without penalty, more than one level of radiographic examination difference between longitudinal butt joints and the intersecting circumferential joints in vessel section or heads. Thus the birth of paragraph

UW-11(a)(5)(b). In 1987, ASME published an article titled, *Revised Rules for Stress Multipliers* [9], which summarized the rationale behind the creation of the SWG, their research efforts, and finally their recommendations which were adopted into VIII-1. It is not the intent here to comment on the work that went into the recommendations of the SWG, but rather to focus on the impact of the rules on today's user of VIII-1.

With the background information provided in the referenced article, the basis of the arbitrary nature of paragraph UW-11(a)(5)(b) is clarified. However, there are a number of issues associated with this paragraph specifically, the organization of paragraph UW-11 in general, exemptions provided to nozzles and communication chambers, and vague references to other paragraphs of VIII-1 which have been the source of confusion for many users. A brief summary of the issues considered most concerning and their possible resolution are highlighted below.

- Successful interpretation of the rules seems to be predicated on the user's knowledge of the VIII-1 rules as they have been previously presented and have been modified over the years, i.e. experienced based.
- The location and content of paragraph UW-11(a)(5) is not consistent with the lead paragraph, UW-11(a), Full Radiography. Only the Category A and D welds in the shells and heads of vessels are subject to full radiography while the intersecting Category B and C welds are subject to spot radiography. The application of paragraph UW-11(a)(5) does not fall within the criteria established by VIII-1 for the requirement of full radiography; service, material thickness, and welding process (see paragraphs UW-11(a)(1), (a)(2), (a)(3) and (a)(6)). The application of paragraph UW-11(a)(5) should be considered as an option, not a requirement tied to full radiography.
- The requirement of paragraph UW-11(a)(5)(b) noting "spot radiographs required by this paragraph shall not be used to satisfy the spot radiography rules as applied to any other weld increment" is a direct result of the recommendations of the stated SWG; however, for a vessel subject to the rules of UW-11(a) requiring full radiography, what could these spot radiograph weld increments be applied to?
- Although the basis of the exemption of radiography provided in paragraph UW-11(a)(4) for circumferential butt joints (Category B and C) in nozzles and communicating chambers that neither exceed NPS 10 nor 1.125 inch wall thickness is subjective at best, the rule as written provides confusion considering the following.
  - If no radiography is performed due to the exemption, does the corresponding joint efficiency of a Type No. 3 butt joint result in 0.60 as provided in paragraph UW-12? If an exemption is provided for, it would seem to make sense that the corresponding joint efficiency would not be penalized, but this is not apparent in the text of the paragraph.
  - If a nozzle is that of a seamless pipe greater than NPS 10, the rules of UW-11(a) would require full radiography of the Category B and C welds and the joint efficiency obtained from paragraph UW-12 would be established as 1.0 for the use in the circumferential stress calculations of the nozzle. This appears to be more stringent treatment for nozzles than what is applied to the main seams of the shell or head of a vessel.
  - If the same nozzle described above is attached to a shell subject to the rules of UW-11(b) requiring spot radiography, would it be required that the Category B and C welds in the nozzle be subject to full radiography in order to obtain a joint efficiency of 1.0 for use in the circumferential stress calculations of the nozzle? This surely is more stringent treatment for nozzles than what is applied to the main seams of the shell or head of a vessel.
- The requirements of radiographic and ultrasonic examination should be treated separately, each with its own distinct lead-in paragraph. This would help to highlight the additional ultrasonic examination requirements placed on the welded joints made of select welding processes.
- Non-specific or vague references to other sections of the code for applicability and limitations should be replaced with specific references to paragraphs, see UW-11(a)(8).
- Without full understanding of the extent of examination used in fabrication, use of the rules of VIII-1 to evaluate in-service equipment for re-rate applications can be extremely difficult.

An additional requirement of VIII-1 located in paragraph UG-116, Required Marking, states that vessels shall be marked with a representative marking denoting the extent of the radiographic or ultrasonic examination that it received. In practice, the markings are designated in accordance with the requirement of the following paragraphs.

- "RT 1" for satisfaction of paragraph UW-11(a),
- "RT 2" for satisfaction of paragraphs UW-11(a)(5) and (a)(5)(b),
- "RT 3" for satisfaction of paragraph UW-11(b), and
- "RT 4" when none of the markings "RT 1", "RT 2", or "RT 3" is applicable.

While in theory this designation will provide the user with a quick reference as to the extent of radiography performed on a particular vessel, in practice the only beneficial marking is that of "RT 1" which identifies compliance with full radiography. Due to the variability as to where the spot radiographs are taken (which is left to the Manufacturer) and the fact that these radiographs may be retained or discarded, provides the user with very little information as to which weld joints received examination. In fact, it is thought most vessels would be more appropriately marked with the "RT 4" designation with user defined design specifications which overlay the requirements for VIII-1.

It was noted in the referenced ASME article that the SWG considered revision of the Manufacturer's Data Report to account for the various joint efficiencies in the main body of the report. However, it was decided that due to the many possible combinations, multiple joint efficiencies and their locations with respect to the vessel itself, the information should be provided in the "Remarks" section of the report. Sadly, there is very little evidence of this section of the report being used to clarify the details of examination. The example problems provided in PTB-4-2013 which detail the radiographic examination and the associated joint efficiencies rules of VIII-1, use a vessel sketch or "weld map approach" coupled with a structured table to accurately document each of the welded joints. The table is structured to record the pertinent information used in the assignment of the joint efficiency for use in the various design equations. This type of approach can

be readily used as a starting point to help establish a set of design requirements to better record the examination and resulting joint efficiencies.

24A.6 TECHNICAL BACKGROUND OF CODE RULES

The technical background for the design rules in VIII-1 is sorely lacking. As provided for in previous sections of this chapter, technical insight and background data may be covered in technical papers or publications; however, there is not a single source that provides a roadmap to the background of the VIII-1 rules. The good news is that many of the design rules in VIII-2 were developed using the principles of VIII-1. Users of VIII-1 interested in finding out the technical background of the VIII-1 rules should obtain a copy of ASME PTB-1-2013. This document contains the VIII-2 criteria and commentary on the technical background to the rules in this code.

24A.7 COMMON RULES

24A.7.1 Background

In the development of VIII-2, an effort was made to harmonize the design-by-rule requirements in this new code with VIII-1. Based on this effort, the design rules in VIII-2 are either identical to the rules in VIII-1 or represent a more restrictive subset of the design rules in VIII-1. A comparison of the design-by-rule procedures in VIII-2 compared with VIII-1 is shown in Table 24A.1.

Based on the development of the new VIII-2, ASME has initiated a Common Rules effort to standardize the design-by-rule procedures in the VIII-1, VIII-2, and VIII-3 Construction Codes. Common Rules are defined as those rules in VIII-1, VIII-2, and VIII-3 that are identical and difficult to maintain because of complexity (i.e. either computationally or editorially complex), and frequent updating because of the introduction of new technologies. Common rules typically occur in the design-by-rule or design-by-analysis parts of the code; but also exist in material, fabrication, and examination requirements.

The overall objective of the ASME Common Rules initiative is to have the design-by-rule and design-by-analysis procedures in VIII-2, and reference these procedures from other ASME Codes. However, as a first step in the process the Common Rules Task Group has decided to introduce classes of vessels into future versions of the code. The idea is that for Class 1 to represent VIII-1 construction and Class 2 to be the current VIII-2 construction. The idea of vessel classes was originally proposed in the VIII-2 rewrite, but was abandoned because of the difficulty in developing requirements for materials and examination. The VIII Committee is investigating an approach such that for Class 1 vessels the examination rules from VIII-1 will be incorporated into VIII-2. This is thought to be a mistake as the current VIII-2 examination rules have been harmonized with European practice and are easy to follow, while the VIII-1 rules incorporate the RT designations that are difficult to follow and contain many inconsistencies.

24A.7.2 ASME Code Case 2695

In recognition of the similarities and the use of the latest technology in developing the design-by-rule part of VIII-2, ASME has issued Code Case 2695 that permits the use of VIII-2 design rules with VIII-1 allowable stresses with some limitations. Code Case 2695 is shown in Table 24A.2. In addition, the VIII Committee is currently evaluating a revision to Code Case 2695 with the intent to incorporate additional nozzle and weld details to address typical construction used for mass produced vessels. This is thought to be another mistake as VIII-2 was always intended for construction of Engineered Vessels. Mass produced vessel construction should be confined to VIII-1; or alternatively, a new code could be developed to specifically address the unique requirements of mass produced vessels.

24A.8 EXAMPLE PROBLEMS

24A.8.1 Appendix L

The example problems contained in the various paragraphs and Non-Mandatory Appendix L of VIII-1 have been removed with the 2013 Edition of VIII-1. The examples found in Appendix L were limited in scope, did not provide a structured design procedure to facilitate user-friendliness, contained design rules that were not covered in the body of the Code, and in some cases were incomplete with regard to the actual design requirements for vessel design. Therefore, as part of the action to remove the examples from VIII-1, a concurrent effort was undertaken to develop a standalone example problem manual which would remedy the shortcomings noted and to be structured to facilitate ease of updating to keep current with the changes incorporated in future editions of VIII-1.

24A.8.2 ASME PTB-4-2013

The first edition of ASME PTB-4 *Section VIII — Division 1 Example Problem Manual* was published in 2012. The first edition of the manual provided examples based on the contents of the 2010 Edition of VIII-1. In 2011, ASME transitioned to a two year publishing cycle for the B&PV Codes without the release of addenda. The release of the 2011 Addenda was the last published by ASME and numerous changes to VIII-1 were adopted. The second edition, PTB-4-2013, was updated to reflect the design changes included in the 2013 Edition of VIII-1. Two new sections were introduced covering examples for tube-to-tubesheet welds and required markings of pressure vessels. Additionally, some formatting modifications were made to facilitate better use of the example manual.

The emphasis placed on the development of PTB-4-2013 included:

- Incorporate a step-by-step design procedure. This requirement fills an important gap in that it provides a procedure which will aid the user to verify that the calculation is performed correctly.
- Since most of the design calculations in VIII-1 do not have a design procedure, the design procedures of VIII-2 were used with appropriate references and substitutions made to VIII-1 requirements.
- To promote the concept of common rules, many of the examples are performed using both VIII-1 and VIII-2 design rules to provide a comparison of results and to see the benefits of the design rules of VIII-2, as applicable.
- Provide commentary, when appropriate, to discuss limitations or short-comings of the VIII-1 design rules and provide guidance to resolve these issues.
- Promote a consistent format to each example problem to facilitate user-friendliness.

It is the intent that PTB-4 will become a living document and be updated in accordance with the established ASME publishing cycle.

24A.9 SUMMARY

The technology for pressure equipment design continues to advance on a daily basis. Historically, VIII-1 has well served its wide ranging users and has incorporated the leading edge technologies of its time to strengthen its foundation since its inception. Because VIII-1 has over the years become the International benchmark standard for pressure vessel design for a multitude of industries, its natural growth can be expected. But with any document of such longevity which is continually being interpreted, revised, and updated with new technologies, it can be expected to have developed some problems over time. The combination of all these reasons coupled with a dated organizational structure that is not conducive to maintenance, change nor the introduction of new rules that only compounds the problem.

This chapter brought to light several areas of the VIII-1 document that are thought to need attention to better serve its users; size of the document, writing style and organization, technical issues, and technical background of the rules – with none more important than the writing style and organization of the document which has become a real stumbling block for organized change. This chapter also provided several possible options and recommendations thought to improve the document. Additionally, updates were provided as to the actions being taken by the Code committees in response to user concerns with regard to common rules and the development of a standalone example problem manual.

The technology for pressure equipment design continues to advance on a daily basis – it is therefore imperative that ASME keep pace and provide living B&PV Codes that can be readily and efficiently adapted to reflect these changes.

24A.10 REFERENCES

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PART B: LESSONS LEARNED BASED ON SECTION VIII, DIVISION 2

24B.1 ABSTRACT

The technology for pressure equipment design continues to advance each and every day. The ASME Boiler and Pressure Vessel Code has been keeping pace with these advances over the last 90+ years. As far back as the 1960's it was recognized that the special requirements for design of pressure vessels operating at pressures over 2000 psi (13.7 MPa) called for special rules, and ASME issued Section VIII, Division 2, Alternative Rules for Pressure Vessels (VIII-2) [1]. Since that time, the understanding of failure mechanisms and advances in material science, nondestructive testing, and computer-aided design have progressed to the stage where a new approach was needed not only in the content of design codes, but in the way they are presented and organized. This chapter provides an overview of the new VIII-2 published in 2007, and explores the technical concepts included and the new format designed for ease of use. Included are results of test exercises sponsored by ASME giving actual applications of the new Code for design of vessels. In addition, user experience with VIII-2 is described.

24B.2 INTRODUCTION

In 1998 the ASME Boiler and Pressure Vessel Committee authorized a project to rewrite the VIII-2 pressure vessel code. This decision was made shortly after the design margin on ultimate tensile strength was lowered from 4.0 to 3.5 in Section I and Section VIII, Division 1 (VIII-1) [2]. ASME saw the need to update VIII-2 to be more competitive with other international standards, and in lieu of revising the existing standard, the decision was made to perform a clean sheet rewrite. By doing so it was felt that not only could the standard be modernized with regard to the latest technical advances in pressure vessel construction, but it could be structured in a way to make it more user-friendly for both users and the committees that maintain it.

24B.3 DEVELOPMENT OBJECTIVES

To remain technically competitive, and to facilitate incorporation of new technology and future updates, ASME decided to develop a new pressure vessel code. This code will replace the existing Section VIII, Division 2 Code, 2004 Edition. The new code, VIII-2, was developed primarily to address construction of engineered pressure vessels that will result in significant cost savings for many vessels. The primary development objectives for VIII-2 were:

- Structure/Organize Section VIII considering the following:
  - Division 1 – Basic Pressure Vessels (Maintenance/Enhancements)
  - Division 2 – Engineered Pressure Vessels (New VIII-2)
  - Division 3 – High-Pressure Vessels (Maintenance/Enhancements)
- Optimize code rules to balance technology, user-friendliness, and jurisdictional acceptance
- Develop a new organization and introduce a clear and consistent writing style to facilitate use
- Separate administrative and technical requirements
- Develop rules to facilitate computer implementation
- Incorporate PED and other international requirements
- Incorporate SI and US Customary and Metric units

24B.4 DEVELOPMENT PROCESS

Traditionally, the development of new standards by ASME is carried out by volunteers who populate the different committees responsible for any given standard. The last major standard developed in this way was Section VIII, Division 3 (VIII-3) [3], which took nearly 15 years to complete. Recognizing that the user community may not have the patience to wait 15 or more years for this needed update to VIII-2, ASME decided to use an outside organization to develop the first draft of the new standard. The project was awarded to the Pressure Vessel Research Council (PVRC), who in turn formed the Task Group on Continued Modernization of Codes to oversee the development of the new VIII-2 code. PVRC created a development team made up of professionals with both engineering and technical writing expertise to develop new technology and the initial drafts of the new VIII-2. The lead investigators of the development team were from The Equity Engineering Group, Inc.

A Steering Committee made up of ASME Section VIII members was formed to provide technical oversight and direction to the development team with the goal of facilitating the eventual balloting and approval process. ASME also hired a Project Manager (PM) to manage all of the activities required to bring this new standard to publication. Some of the PM's responsibilities included:

- Coordinating balloting process to Subcommittees and BPV Standards Committee,
- Addressing accreditation issues relative to a possible overlap of the old and new VIII-2,
- Managing validation of all equations, and overseeing development of an examples manual,
- Coordinating beta testing of the standard,
- Arranging presentation forums during the ballot process, and
- Working with ASME publication to prepare the first edition of the new standard.

The project began with the development of a detailed table of contents containing every paragraph heading that would appear in the new standard, and identifying the source for the content that would be placed in this paragraph. In preparing such a detailed table of contents, the lead authors were able to quickly identify areas where major development effort was required to produce updated rules.

24B.5 ORGANIZATION OF NEW CODE

24B.5.1 Overview

The organization of the new VIII-2 is very different from the current standard, utilizing a flat modular structure to facilitate future revisions and additions. The standard is made up of nine parts.

- Part 1 — General Requirements
- Part 2 — Responsibilities and Duties
- Part 3 — Material Requirements
- Part 4 — Design-by-Rule Requirements
- Part 5 — Design-by-Analysis Requirements
- Part 6 — Fabrication Requirements
- Part 7 — Examination Requirements
- Part 8 — Pressure Testing Requirements
- Part 9 — Overpressure Protection

In addition to these nine parts, normative and informative annexes are utilized within each Part, eliminating the use of mandatory and nonmandatory appendices that are traditionally placed in the back of the standard.

24B.5.2 Part 1 — General Requirements

Part 1 addresses the scope of the standard with respect to the types of pressure vessels covered, as well as the definition of the geometric boundary for the stamped item. In addition, this Part covers units of measurement, reference standards, technical inquiries, and global definitions. Similar to other ASME Boiler and Pressure Vessel standards, US Customary, SI or local customary units may be used to demonstrate compliance with the standard. Guidance for the use of US Customary and SI Units is also provided.

24B.5.3 Part 2 — Responsibilities and Duties

Part 2 consolidates responsibilities and duties of the user, Manufacturer, and Authorized Inspector. The most significant change in this area has to do with Registered Professional Engineer (RPE) certification of the Manufacturer's Design Report (MDR) and the User's Design Specification (UDS). An alternative to RPE certification is provided which will facilitate the use of the new VIII-2 outside of North America. This alternative will require that the engineer certifying either the UDS or MDR has the requisite technical and legal stature, and jurisdictional authority to certify such a document.

One other significant change concerns maintenance of records. The Manufacturer needs to supply to the user the complete technical file containing all pertinent documentation related to the construction of the vessel, as well as retain these records for a minimum period of three years after the vessel is stamped. Some of the records that must be retained by the Manufacturer are:

- User's Design Specification,
- Manufacturer's Design Report,
- Manufacturer's Data Report, and
- Manufacturer's construction records, including welding procedure specifications, procedure qualification records, records of all heat treatments, results of all production test plates, NDE procedures, results of all NDE examination, etc.

24B.5.4 Part 3 — Material Requirements

Part 3 contains several significant enhancements relative to the existing VIII-2.

- The allowable stress basis is set to the minimum of the Ultimate Tensile Strength (UTS) divided by 2.4, UTS/2.4, at room temperature, and the Yield Strength (YS) divided by 1.5, YS/1.5, at both the room temperature and design temperature, for design temperatures below the creep range. This aligns the new VIII-2 with current European pressure vessel standards.
- Allowable stresses are provided for design in the creep range using the allowable stress criteria of Section VIII, Division 1.
- The toughness rules were updated and the minimum Charpy V-Notch impact test requirement was set to 27 J (20 ft-lbs). In addition impact test exemption curves for carbon and low alloy steel are now provided with and without the influence of Postweld Heat Treatment (PWHT). Finally the option to establish the Minimum Design Metal Temperature (MDMT) using fracture mechanics methodology has been added.
- A master stress-strain curve has been developed which utilizes the yield strength, ultimate tensile strength, and elastic modulus as functions of temperature to introduce a temperature dependence. This stress-strain curve is used when applying the design-by-analysis rules of Part 5, as well as when performing buckling calculations when it is necessary to determine the tangent modulus.
- Two sets of design fatigue curves are provided:
  1. Smooth bar design fatigue curves using the same design methodology as presented in Appendix 5 of the original VIII-2, and
  2. Welded joint design fatigue curves utilizing the new Master S/N Curve and the Structural Stress Method for determining the equivalent structural stress.

24B.5.5 Part 4 — Design-By-Rule Requirements

The VIII-2 rewrite contains both design-by-rule and design-by-analysis options. Numerous enhancements were made to the design-by-rule procedures, several of which are highlighted below:

- A new format was introduced to present the design rules in a manner to enhance readability and facilitate computer implementation of the required calculations.
- The Maximum Allowable Working Pressure (MAWP) concept, consistent with VIII-1 is introduced.
- Weld joint efficiencies are introduced in the VIII-2 rewrite permitting for the first time less than 100% volumetric examination for main vessel welds.
- Design-by-rule for the creep range is provided.
- Introduction of explicit design rules for combined loadings (i.e., pressure, weight, wind and earthquake), as well as adoption of the ASCE/SEI 7 [4] Load Combination Methodology.
- New design rules for cylindrical shells, spherical shells and heads, ellipsoidal heads, and torispherical heads.
- External pressure rules based on Code Case 2286 and utilizing the tangent modulus derived from the master stress-strain curve given in Part 3.
- New opening reinforcement rules based on pressure-area stress calculation.
- New rules for conical transition subject to internal/external pressure and supplemental loads.
- Inclusion of design rules for layered vessels.
- Inclusion of design rules for stayed construction, jacketed vessels, noncircular vessels, and vessel supports.
- Inclusion of bellows and tubesheet design rules based on Part UHX from VIII-1.

24B.5.6 Part 5 — Design-By-Analysis Requirements

The design-by-analysis section was reorganized based on the mode of failure as follows:

- Protection against plastic collapse,
- Protection against local failure,
- Protection against collapse from buckling, and
- Protection against failure due to cyclic loading.

Another significant change is that the minimum wall thickness can be established using design-by-analysis in lieu of the design-by-rule requirements in Part 4. This is a significant departure from the philosophy that existed in the original VIII-2.

Some other enhancements to Part 5 are shown below.

- Continued use of stress classification and the Hopper Diagram.
- Introduction of Structural Stress concepts that provide a new fundamental method to compute membrane and bending stresses using FEA that is mesh insensitive. This structural stress method is also used when performing a fatigue analysis of welded joints.
- New procedure for elastic-plastic design using FEA and the Master Stress-Strain curve.
- New requirements for design based on local failure strain using the Master Stress-Strain curve, replacing the existing limits on triaxiality.
- Explicit design-by-analysis procedures for evaluating collapse from buckling including knock-down factor for shell imperfections.
- New method for fatigue assessment based on Structural Stress concepts for assessment of welded joints.
- Normative annexes covering recommendations for linearization of stress results from FEA used in stress classification, design of perforated plates based on elastic stress analysis, and rules for experimental stress analysis are provided.

24B.5.7 Part 6 — Fabrication Requirements

Part 6 contains a consolidation of fabrication requirements from the original VIII-2 Part AM and Part AF, as well as some fabrication rules from VIII-1. Similar PWHT requirements are in the current VIII-2; however, new time-temperature-thickness criterion for PWHT is under development.

24B.5.8 Part 7 — Examination Requirements

Rules for examination of welded joints have been completely rewritten in Part 7. The concept of defining "examination groups" for pressure vessels, based on the practice used in several European standards has been utilized. Also with the introduction of weld joint efficiencies in the new VIII-2, the option for partial radiography is now available. However unlike the spot RT rules of VIII-1 where 1% of a weld joint is examined, when permitted in Part 7, the partial radiography rules require between 10 and 25% of the weld to be examined.

Other significant features of Part 7 include:

- Examination requirements in table format to promote ease of use and consistency in application,
- Provision for UT in lieu of RT; requirements are given regarding when manual versus automated UT shall be performed,
- More extensive visual examination requirements,
- For vessels for which the fatigue analysis is mandatory, all surfaces of pressure boundary components (internal and external) shall be examined by MT or PT following a hydrostatic pressure test, this requirement is taken from VIII-3, KE-400, and
- Part 7 also contains a normative annex outlining Inspector and Manufacturer duties for inspection and examination.

24B.5.9 Part 8 — Pressure Testing Requirements

The hydrostatic test pressure, P_T is now set in accordance with Equation (24B.1); this is now in alignment with the PED.

$$P_T = \max\left[1.43 \cdot MAWP,\ 1.25 \cdot MAWP \cdot \left(\frac{S_T}{S}\right)\right] \quad (24B.1)$$

The ratio of the allowable stress at the hydrotest temperature, S_T to the allowable stress at the design temperature, S_T, or S_T/S in Equation (24B.1) is the lowest ratio for the pressure boundary materials, excluding bolting materials, of which the vessel is constructed.

The pneumatic pressure test option is retained. However, when used, the vessel must be monitored by acoustic emission examination during the test. Finally, the Manufacturer must maintain complete records of the final pressure test.

24B.5.10 Part 9 — Overpressure Protection

Basic rules for overpressure protection are identical to those published in VIII-1. For this reason, most rules for overpressure protection in VIII-2 reference VIII-1. Rules not covered in VIII-1, such as Overpressure Protection by Design (Code Case 2211), is presented in Part 9. An annex covering best practices for the installation and operation of pressure relief devices, which is based on the latest revision to Appendix M of VIII-1, is also provided.

24B.6 ADDITIONAL DEVELOPMENT STEPS

24B.6.1 Design Validation

As stated earlier, in many respects the development of this new VIII-2 broke new ground for ASME, from subcontracting the writing of the first draft to an outside organization, to publishing the document in single column, and formatting it to satisfy ISO guidelines. But there were two other activities undertaken during this project to assure the highest quality for the first edition; these were validation of all design rules and beta testing of the document.

The new VIII-2 contains hundreds of equations and polynomial expressions for curve-fits used in the design rules. Even where rules were taken from Section VIII, Division 1, in most cases they were re-written to facilitate computerization of the rules. The net result was that to quality check each equation, figure, and polynomial factor was a major undertaking such that if committee volunteers were asked to perform this work, it would have delayed publication of the document. Instead, an independent organization experienced in writing pressure vessel design software was contracted to QA check all design rules in the new VIII-2. They performed this work by programming all of the design rules in Mathcad®, and running numerous examples. Wherever possible, existing examples from the original VIII-2 and VIII-1 were used for the validation work. In all over a thousand pages of calculations were performed, and the process did identify several errors, mostly in the curve-fit factors. This validation work also served as the starting point for the development of PTB–3, ASME Section VIII – Division 2 Example Problems Manual.

24B.6.2 Beta Testing

The VIII-2 project team set forth a number of goals with the undertaking of this project, and everyone involved were interested in receiving feedback from users of VIII-2. Normally this feedback would be received once the standard is published and used for production vessels; however, a test run prior to publication was required. To accomplish this, ASME authorized a project to beta test the standard during the last stages of approval. Invitations to participate in a beta test of the new standard were sent to several existing VIII-2 Certificate Holders. These Manufacturers were asked to select a recently completed VIII-2 vessel, and re-execute the project on paper using the new standard. A large number of companies responded to the invitation with a description of a vessel to be used in the evaluation.

The Subcommittee VIII Technical Steering Committee reviewed the different proposals and made their selections to assure that a diverse group of vessels were represented. The beta testers were asked to provide feedback in the following areas:

- Overall ease of use of the standard
- Change in wall thickness for main vessel components
- Change in vessel weight reported as a percentage change
- Change in welding, PWHT and NDE costs
- Change in production schedule reported as a percentage
- Change in overall vessel cost reported as a percentage
- Perform a fatigue analysis utilizing new structural stress method
- General observations, including reporting any problems with understanding the requirements of the code, missing or incorrect references, etc.

24B.6.3 Beta Test Results

Overall the beta test of this new standard was a resounding success and provided validation of many of the goals set forth when this project was initiated. In general:

- All of the beta testers reported the standard easy to use, and that the design rules were clear and concise.
- Several beta testers reported that they prefer the new format of the document whereby the nomenclature, figures and tables are all placed at the end of each part, and that all of the weld joint figures are assembled in one place.
- The beta test generated numerous questions on the standard, but no significant errors in the standard were identified during the test.
- As expected, significant cost savings were reported due to the increase in allowable stress for many carbon and low alloy steels. Of equal importance, most of the testers also reported a reduced amount of reinforcement required for openings resulting in a reduction in forged nozzle thickness.
- A summary of the Beta Test Results is provided in Tables 24B.1 through 24B.5.

24B.7 USE OF VIII-2 IN NEW CONSTRUCTION

To date, the vast majority of construction of vessel to VIII-2 appears to be confined to heavy wall reactors. This is due to the reduction in wall thickness associated with the new stress basis, see Figure 24B.1. In addition, storage spheres are also being constructed to VIII-2 for the same reason, see Figure 24B.2.

It should be noted that weight savings may also be achieved in more typical carbon steel and low alloy construction, see Figures 24B.1 through 24B.4. For example, at low temperatures, VIII-2 construction offers wall thickness reductions for A 516 material, see Figure 24B.3. However, significantly higher savings can be achieved by using a higher strength material such as SA 537, Class 1, see Figure 24B.4. This material is more typical of European produced materials in terms of the yield-to-tensile ratio. The allowable stress basis in VIII-2 provides a significantly higher allowable stress for higher yield-to-tensile ratio materials. Therefore, Owner-Users should consider specifying these materials for most pressure vessels. The advantage can clearly be seen comparing Figures 24B.3 and 24B.4. In Figure 24B.3, a reduction in wall thickness of 8% is achieved for SA 516, Grade 70 at 100ºF when compared to VIII-2, 2004 Edition. If the material is changed to SA 537 Class 1, a 20% reduction is achieved at 100ºF when compared to VIII-2, 2004 Edition, and a 13% reduction is achieved at 600ºF. Similar reductions in wall thickness would be realized when comparing VIII-2 to VIII-1 construction. A 13% to 20% reduction in wall thickness is significant not only in base material cost savings but also in savings in weld metal. These savings will more than offset the cost of the additional inspection required when compared to VIII-1 construction.

Six years after publication of the new VIII-2, the industry has yet to identify the thickness at which the transition from VIII-1 to VIII-2 becomes cost-competitive. VIII-2 is still most commonly used only for very high pressure, high thickness applications, or storage spheres. VIII-2 saves the user money on materials with the use of higher allowable stresses and more accurate design procedures. However, in order to justify the increase in allowable stress, VIII-2 mandates additional NDE, and a Professional Engineer's stamp or equivalent certification permitted by VIII-2 that result in an increase in the cost of the vessel. Becker [5] indicates that at a certain thickness, the material savings outweigh the additional cost, and VIII-2 becomes cost-effective. In this excellent paper, Becker compares VIII-2 to VIII-1 to determine a reasonable set of design conditions by which VIII-2 will yield a more cost-effective pressure vessel, even on some lower pressure applications.

One of the driving forces in the development of the new VIII-2 was to incorporate the latest technologies and to be more competitive when compared to other international standards. It was identified that many of the European standards resulted in vessel construction that was less costly when compared to costs associated with VIII-1 and the old VIII-2 construction. In the development of the new VIII-2, the allowable stress basis and examination methods were harmonized with European practice. In addition, design-by-rule and design-by-analysis procedures were updated to include the latest technologies. If European standards were identified as being the most cost effective and the new VIII-2 incorporate the key features of these European Standards, why isn't VIII-2 being actively used in the marketplace? ASME would be better served to find the answer to this question rather than spending volunteer time to make changes to VIII-2, see paragraph 24B.8.4, that will diminish the original objectives achieved in the development of the new version of this code.

24B.8 COMMON RULES

24B.8.1 Overview

In the development of VIII-2, an effort was made to harmonize the design-by-rule requirements in this new code with VIII-1. Based on this effort, the design rules in VIII-2 are either identical to the rules in VIII-1 or represent a more restrictive subset of the design rules in VIII-1.

Based on the development of the new VIII-2, ASME has initiated a Common Rules effort to standardize the design-by-rule procedures in the VIII-1, VIII-2, and VIII-3 Construction Codes. Common Rules are defined as those rules in VIII-1, VIII-2, and VIII-3 that are identical and difficult to maintain because of complexity (i.e. either computationally or editorially complex), and

TABLE 24B.1 SUMMARY OF BETA TEST RESULTS: STEAM SUPERHEATER

Item	Shell	Heads
Material	SA-387 Gr11 Cl 2	SA-387 Gr11 Cl 2
Design Temperature (°C)	410	410
Allowable Stress — Old (MPa)	151.38	151.38
Allowable Stress — New (MPa)	151.38	151.38
Required Thickness — Old (mm)	34.38	38.43
Required Thickness — New (mm)	34.59	33
Change in vessel weight as a %	−2	
Reduction in production time as a %	N/A	
Reduction in overall vessel cost as a %	−2.5	
Comments: 1. The new code provides a systematic approach to design with easy access to information. 2. The use of tables and figures instead of graphs leads to better and precise results. 3. The new format adopted is user friendly as it takes less time to find reference pages. 4. The design method for opening and reinforcements provides a substantial decrease in hub thickness 5. New code includes and accepts techniques such as TOFD, Phased Array which is a welcome change and will lead to definite improvements in quality and testing.		

TABLE 24B.2 SUMMARY OF BETA TEST RESULTS: 53 FT DIAMETER SPHERE

Item	Shell	Forging
Material	SA-738 Gr B	SA-387 Gr11 Cl 2
Design Temperature (°C)	120	120
Allowable Stress — Old (MPa)	195	148.9
Allowable Stress — New (MPa)	244	148.9
Required Thickness — Old (mm)	42.74	N/A
Required Thickness — New (mm)	33	N/A
Change in vessel weight (kg)	−51,000	
Reduction in production time as a %	−8	
Reduction in overall vessel cost as a %	−12.2	
Comments: 1. Overall the new Section VIII, Div. 2 code was found to be well organized and logical in its layout. The equations are located near the text where they are referenced and this reduces times spent looking for the applicable equation. 2. Having the NDE requirements summarized in a table is very helpful as are the diagrams and sketches of the welds. 3. The opening reinforcement design method is logical and intuitive.		

frequent updating because of the introduction of new technologies. Common Rules typically occur in the design-by-rule or design-by-analysis parts of the code; but also exist in material, fabrication, and examination requirements.

The overall objective of the ASME Common Rules initiative is to have the design-by-rule and design-by-analysis procedures in VIII-2, and reference these procedures from other ASME Codes. For example, the design-by-analysis procedures from VIII-2 are referenced for use from API 579-1/ASME FFS-1 [6], these rules are not reproduced. However, little progress has been made in regards to VIII-1 and VIII-3 referring VIII-2 as originally planned. The delay in using VIII-2 as a Common Rules book has resulted in continuation of duplication of rules and procedures and the subsequent non–efficient use of committee time in trying to keep these rules and procedures consistent.

24B.8.2 Comparison of VIII-1 and VIII-2 Design Rules

Since many of the design rules in VIII-2 were developed using the principles of VIII-1, it is recommended that users of this manual obtain a copy of ASME PTB-1-2013 that contains the VIII-2 criteria and commentary on the technical background to these rules. A comparison of the design-by-rule procedures in VIII-2 compared with VIII-1 is shown in Part A, Table 24A.1.

TABLE 24B.3 SUMMARY OF BETA TEST RESULTS: HYDROPROCESSING REACTOR

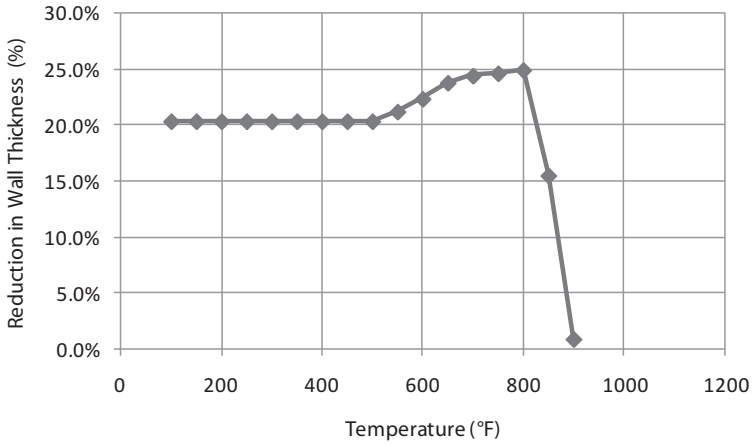
Item	Shell	Heads
Material	SA-336 F22V	SA-542 Tp D Cl 4a
Design Temperature (°C)	454	454
Allowable Stress — Old (MPa)	169	169
Allowable Stress — New (MPa)	199	199
Required Thickness — Old (mm)	290	145
Required Thickness — New (mm)	244	125
Change in vessel weight as a %	–13.8	
Reduction in production time as a %	2 weeks	
Reduction in overall vessel cost as a %	–12	
Comments: 1. The Beta Test has confirmed the quality of the new code. 2. The revised safety factors and related allowable stresses results, for some materials will result in significant savings in both time and cost.		

TABLE 24B.4 SUMMARY OF BETA TEST RESULTS: HYDROTREATING REACTOR

Item	Shell	Heads
Material	SA-542 Type D Cl 4a	SA-542 Type D Cl 4a
Design Temperature (°C)	454	454
Allowable Stress — Old (MPa)	168	168
Allowable Stress — New (MPa)	199.8	199.8
Required Thickness — Old (mm)	167	95
Required Thickness — New (mm)	141	81
Change in vessel weight as a %	–14	
Reduction in production time as a %	–4	
Reduction in overall vessel cost as a %	–8	
Comments: 1. New VIII-2 Code shows the requirements in detail for each item; therefore confusion with Code interpretations will be reduced. 2. Examination requirements for the material are more severe. Cost and delivery impact for the material will be increased when purchasing the materials.		

TABLE 24B.5 SUMMARY OF BETA TEST RESULTS: HYDROPROCESSING REACTOR

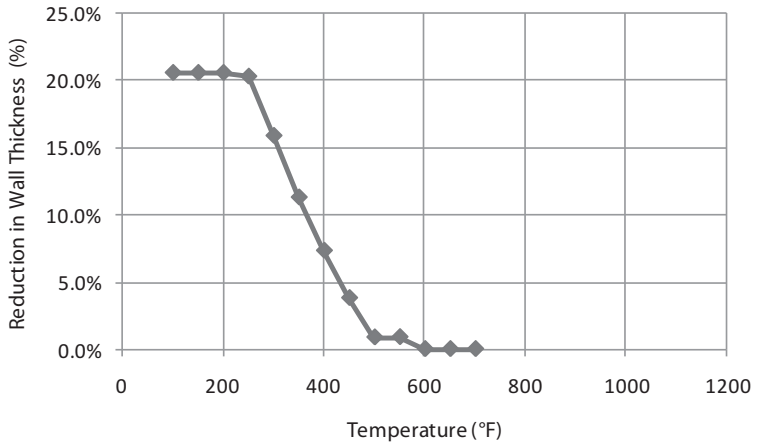
Item	Shell	Heads
Material	SA-336M F22V	SA-542M Gr D Cl 4a
Design Temperature (°C)	454	454
Allowable Stress — Old (MPa)	168	168
Allowable Stress — New (MPa)	199.8	199.8
Required Thickness — Old (mm)	304	152
Required Thickness — New (mm)	254	128
Change in vessel weight as a %	–17	
Reduction in production time as a %	–1	
Reduction in overall vessel cost as a %	N/A	
Comments: N/A		



SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON
SA 382 GRADE 22V, SMYS = 60 KSI, SMTS = 85 KSI, SMYS/SMTS = 0.71

Temperature (°F)	2004 Edition, 2006 Addenda		2007 Edition		Reduction in Wall Thickness (%)
	Allowable Stress (ksi)	Wall Thickness (in)	Allowable Stress (ksi)	Wall Thickness (in)	
100	28.3	1.079	35.4	0.860	20.3
150	28.3	1.079	35.4	0.860	20.3
200	28.3	1.079	35.4	0.860	20.3
250	28.3	1.079	35.4	0.860	20.3
300	28.3	1.079	35.4	0.860	20.3
350	28.3	1.079	35.4	0.860	20.3
400	28.3	1.079	35.4	0.860	20.3
450	28.3	1.079	35.4	0.860	20.3
500	28.3	1.079	35.4	0.860	20.3
550	28.0	1.091	35.4	0.860	21.2
600	27.6	1.107	35.4	0.860	22.4
650	27.1	1.128	35.4	0.860	23.8
700	26.5	1.154	34.9	0.872	24.4
750	25.9	1.181	34.2	0.890	24.6
800	25.2	1.215	33.4	0.912	24.9
850	24.5	1.250	28.9	1.056	15.5
900	23.6	1.299	23.8	1.287	0.9

FIGURE 24B.1 SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON: SA 382 GRADE 22V



SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON
SA 737 GRADE B, SMYS = 50 KSI, SMTS = 70 KSI, SMYS/SMTS = 0.71

Temperature (°F)	2004 Edition, 2006 Addenda		2007 Edition		Reduction in Wall Thickness (%)
	Allowable Stress (ksi)	Wall Thickness (in)	Allowable Stress (ksi)	Wall Thickness (in)	
100	23.3	1.316	29.2	1.045	20.6
150	23.3	1.316	29.2	1.045	20.6
200	23.3	1.316	29.2	1.045	20.6
250	23.3	1.316	29.1	1.049	20.3
300	23.3	1.316	27.6	1.107	15.9
350	23.3	1.316	26.2	1.167	11.3
400	23.3	1.316	25.1	1.219	7.3
450	23.3	1.316	24.2	1.266	3.8
500	23.3	1.316	23.5	1.304	0.9
550	22.8	1.345	23.0	1.333	0.9
600	22.6	1.357	22.6	1.357	0.0
650	22.3	1.376	22.3	1.376	0.0
700	22.1	1.389	22.1	1.389	0.0

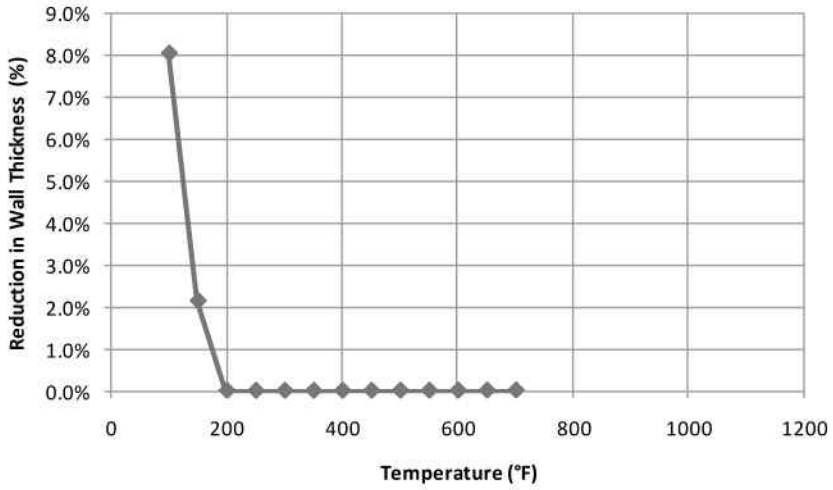
FIGURE 24B.2 SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON: SA 737 GRADE B

24B.8.3 ASME Pressure Vessel Code Case 2695

In recognition of the similarities and the use of the latest technology in developing the design-by-rule part of VIII-2, ASME has issued Code Case 2695 that permits the use of VIII-2 design rules with VIII-1 allowable stresses with some limitations. Code Case 2695 is shown in Part A, Table 24A.2.

24B.8.4 VIII-2 Committee Gone Wild

Rather than use a marketing approach to introduce the user community to VIII-2, the VIII Committee has decided to introduce classes of vessels into future versions of the code. The idea is that for Class 1 to represent VIII-1 construction and Class 2 to be the current VIII-2 construction to help promote the use of VIII-2. The notion of vessel classes was originally proposed in the VIII-2 rewrite, but was abandoned because of the difficulty in developing unique requirements for materials of construction and examination. After a detailed review, the idea of having vessel classes in VIII-2 was abandoned. The VIII Committee is now investigating an approach that would involve incorporating the examination rules from VIII-1 for Class 1 vessels directly into VIII-2. This is a major mistake as the current VIII-2 examination rules have been harmonized with European practice and are easy to follow, while



SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON
SA 516 GRADE 70, SMYS = 38 KSI, SMTS = 70 KSI, SMYS/SMTS = 0.54

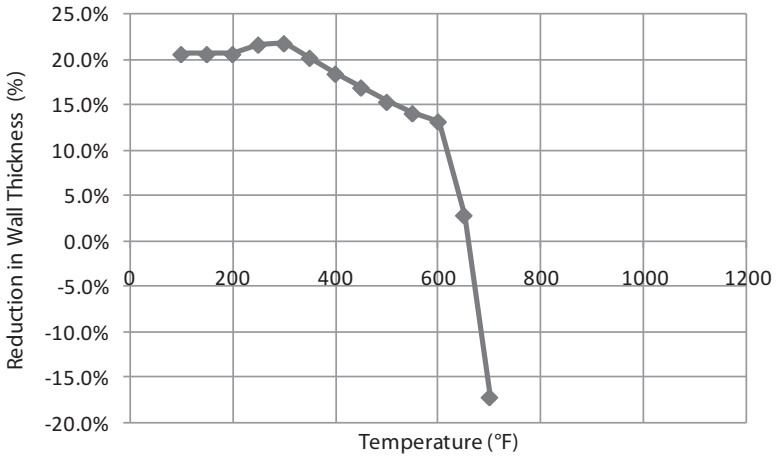
Temperature (°F)	2004 Edition, 2006 Addenda		2007 Edition		Reduction in Wall Thickness (%)
	Allowable Stress (ksi)	Wall Thickness (in)	Allowable Stress (ksi)	Wall Thickness (in)	
100	23.3	1.316	25.3	1.210	8.1
150	23.3	1.316	23.8	1.287	2.2
200	23.2	1.322	23.2	1.321	0.0
250	22.8	1.345	22.8	1.345	0.0
300	22.4	1.370	22.4	1.370	0.0
350	22.1	1.389	22.1	1.389	0.0
400	21.6	1.422	21.6	1.422	0.0
450	21.2	1.449	21.2	1.449	0.0
500	20.6	1.493	20.6	1.492	0.0
550	20.1	1.531	20.1	1.530	0.0
600	19.4	1.587	19.4	1.587	0.0
650	18.8	1.639	18.8	1.639	0.0
700	18.1	1.705	18.1	1.704	0.0

FIGURE 24B.3 SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON: SA 737 GRADE B

the VIII-1 rules incorporate the incomplete requirements and cryptic RT designations that are difficult to follow and contain many inconsistencies. In addition, and perhaps more importantly, the philosophy behind the current VIII-1 examination rules and those in VIII-2 is different; therefore, one can expect numerous technical inquiries to result.

In addition, the VIII Committee is currently evaluating a revision to Code Case 2695 with the intent to incorporate additional nozzle and weld details to address typical construction used for mass produced vessels. This is another mistake as VIII-2 was always intended for construction of engineered vessels. Mass produced vessel construction should be confined to VIII-1. Alternatively, as discussed during the VIII-2 rewrite project, a new code should be developed to specifically address the unique requirements of mass produced vessels.

ASME needs to develop a long term development plan and associated marketing strategy for Section VIII. This plan and strategy needs to consider the initial objectives in the VIII-2 rewrite and be approved by the Section VIII Code Committee. The approval by the Section VIII Code Committee is a necessity to ensure volunteer time is being prudently used considering the efforts of committee members are on a voluntary basis.



SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON
SA 537 CLASS 1, ≤ 2.5 IN, SMYS = 50 KSI, SMTS = 70 KSI, SMYS/SMTS = 0.71

Temperature (°F)	2004 Edition, 2006 Addenda		2007 Edition		Reduction in Wall Thickness (%)
	Allowable Stress (ksi)	Wall Thickness (in)	Allowable Stress (ksi)	Wall Thickness (in)	
100	23.3	1.316	29.2	1.045	20.6
150	23.3	1.316	29.2	1.045	20.6
200	23.3	1.316	29.2	1.045	20.6
250	23.0	1.333	29.2	1.045	21.6
300	22.8	1.345	29.0	1.053	21.8
350	22.7	1.351	28.3	1.079	20.2
400	22.7	1.351	27.7	1.103	18.4
450	22.7	1.351	27.2	1.123	16.9
500	22.7	1.351	26.7	1.145	15.3
550	22.6	1.357	26.2	1.167	14.0
600	22.4	1.370	25.7	1.190	13.1
650	21.9	1.402	22.5	1.363	2.7
700	21.4	1.435	18.3	1.685	-17.4

FIGURE 24B.4 SECTION VIII, DIVISION 2 WALL THICKNESS COMPARISON: SA 537 CLASS 1 ≤ 2.5 IN

24B.9 DOCUMENT FORMAT

A primary development objective for VIII-2 was to develop a new organization and introduce a clear and consistent writing style to facilitate use. The model used to achieve this was the highly successful API 579-1/ASME FFS-1. This code utilized many figures and tables and a single column format where indentation of subparagraphs is used to facilitate use of the document. This same format was used in the initial release of VIII-2. However, for VIII-2, 2011 Addenda, an alternative publication platform and style was utilized that essentially destroyed the format of the document. While maintaining a single column format, the new publication did not indent subparagraphs making the code extremely hard to read. In addition, the numbering convention was changed, all equations were center justified on the page and in some cases tables were run between pages. Despite negative feedback by Committee members and users of the document, this alternate format has been maintained in the VIII-2, 2013

Edition. The format should be reworked to match the 2007 Edition. It should be noted that the 2007 Edition was peer reviewed before and during the balloting stage and the format was universally accepted. In addition, a survey was performed regarding the document format and the overwhelming feedback was in favor of the 2007 Edition format. It is not known why this format was changed for the 2011 Addenda.

24B.10 ASME SECTION VIII — DIVISION 2 CRITERIA AND COMMENTARY

ASME PTB-1-2009 *ASME Section VIII Division 2 Criteria and Commentary* [7] was created to provide a complete description of VIII-2 including a detailed technical background, an overview of the many new features, and a summary of significant differences between the new and old versions of VIII-2. Valuable background information is provided to assist users in using the Code. It covers the 2007 Edition of VIII-2 including the 2008 and 2009 Addenda. Some of the changes planned for the 2010 Edition of the Code are also included. This document will be updated as required to keep pace with future developments in Section VIII, Division 2. The second edition, PTB-3-2013, is currently updated to reflect the design changes included up to the 2013 Edition of VIII-2.

24B.11 EXAMPLE PROBLEMS

The first edition of ASME PTB-3-2010 Section VIII – Division 2 Example Problem Manual [8] was published in 2010. The first edition of the manual provided examples based on the contents of the 2007 Edition of VIII-2 including the 2008 and 2009 Addenda. The second edition, PTB-3-2013, was updated to reflect the design changes included up to the 2013 Edition of VIII-2.

The emphasis placed on the development of PTB-3-2013 included:

- Illustrate the use of the step-by-step procedures in VIII-2. This requirement fills an important gap in that it provides a procedure which will aid the user to verify that the calculation is performed correctly.
- Provide detailed examples on the use of both the design-by-rule and design-by-analysis procedures.
- Provide detailed examples on the application of the new examination requirements.
- Provide commentary, when appropriate, to discuss the VIII-2 design rules.
- Promote a consistent format for each example problem to facilitate user-friendliness.

It is the intent that PTB-3 will become a living document and be updated in accordance with the established ASME publishing cycle.

24B.12 SUMMARY

The new VIII-2 was published on July 1, 2007, and became mandatory January 1, 2008. The majority of the goals outlined in 1999 for the rewrite have been satisfied, and the lead investigators have developed a series of WRC Bulletins to document the technical basis of the rules incorporated into VIII-2.

The new VIII-2 has been extensively used in the construction of heavy wall reactors and also for storage spheres. Despite the weight savings and associated material costs, the use of VIII-2 for other vessel construction appears to be limited.

The VIII Committee should accelerate the Common Rules idea and eliminate duplicate rules from VIII-1 and VIII-2 by providing a reference to VIII-2. In addition, a new separate code should be developed to specifically address the unique construction features associated with mass produced vessels. Rather than clutter VIII-2 with archaic and hard to use rules for a new vessel class and mass produced vessels, ASME would be better served to launch a marketing campaign to explain how Section VIII will be configured and made available to the user community.

The format of VIII-2, 2013 Edition needs to be reworked. The template used in the 2007 edition needs to be reviewed and implemented in the new publishing system so that the original intent of the document format, developed to facilitate ease, is reinstated for future release of VIII-2.

It is recommended that ASME follow the original development objectives for the re-write of VIII-2. Cryptic and hard to understand, long-winded narrative rules from VIII-1 should not be incorporated into VIII-2 because of the introduction of vessel classes for the purpose of luring users to VIII-2. Instead, ASME should accelerate the Common Rules initiative with the purpose of producing three Divisions for Section VIII:

- Division 1 – Basic Pressure Vessels (Maintenance/Enhancements)
- Division 2 – Engineered Pressure Vessels (New VIII-2)
- Division 3 – High-Pressure Vessels (Maintenance/Enhancements)

In addition, it is recommended that the VIII Committee evaluate the need to produce a new Division 4 code to address the construction of mass produced vessels. This code could be developed quickly using VIII-2 as a reference and would benefit Manufacturers in that the rules would specifically address construction requirements of these special types of vessels.

Finally, ASME should develop a marketing campaign to explain the future directions envisioned for Section VIII and develop appropriate options to facilitate the purchase of separate divisions along with VIII-2 that contains the Common Rules.

24B.13 REFERENCES

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2. ASME, ASME Boiler and Pressure Vessel Code, Section VIII, *Rules for Construction of Pressure Vessels Division 1*, ASME International, New York, N.Y.
3. ASME, ASME Boiler and Pressure Vessel Code, Section VIII, *Rules for Construction of Pressure Vessels Division 3-Alternative Rules for Construction of High Pressure Vessels*, ASME International, New York, N.Y.
4. ASCE, ASCE/SEI 7-05, *Minimum Design Loads for Buildings and Other Structures*, The American Society of Civil Engineering, The American Society of Civil Engineers.
5. Becker, J.W., "Investigation into the Benefits of Using ASME BPVC Section VIII Division 2 In Lieu Of Division 1 for Pressure Vessel Design," ASME District F - Early Career Technical Conference Proceedings, ASME District F - Early Career Technical Conference, ASME District F – ECTC 2013, November 2–3, 2013 - Birmingham, Alabama USA.

6. API, API 579-1/ASME FFS-1 2007, Fitness-For-Service, The American Petroleum Institute, Washington D.C.

7. ASME, ASME PTB-1-2009, *ASME Section VIII Division 2 Criteria and Commentary*, ASME International, New York, N.Y.

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CHAPTER

25

LESSONS LEARNED BASED ON OPERATING EXPERIENCE, SECTION XI

Gary Park

25.1 BACKGROUND

The 1960s and 1970s was a good time for the nuclear industry. The building of nuclear power plants was at an all-time high in the United States with the majority of the current operating fleet coming on-line in the late 1960s and early 1970s. While these plants were being built, the need to maintain these plants in a safe operating condition was discussed. The practice of performing inspections for fossil-fueled power plants was well established and the risk of operating fossil-fueled plant was understood. Although the nature and extent of the inspection share, in a large measure, evolved from several decades of operating experiences of many power stations, no formalized codes for conducting these inspections had been developed in the United States. Rather, a variety of rules were being imposed by the enforcement authorities having jurisdiction at the power plant sites.

The design or the pressure retaining components of the fossil-fueled power plants always considered the accessibility of those components for inspection and maintenance. In the early days of the building of nuclear power plants, it was originally thought that there could be no inspection of the reactor coolant piping because of the expected high radiation. Consequently, very limited attention was given to the needs for inservice inspection in these early designs, so systems were not provided with adequate access for inspection of many components [1].

Based on this assumption, the designers of these nuclear power plants raised the bar on the quality standards that would be used in the construction of the reactor coolant system components. American Society of Mechanical Engineers (ASME) Section III was first published in 1963 that was the start of these new founded higher quality standards. However, the Atomic Energy Commission (AEC) did not feel that this was enough to keep these new nuclear power plants safe. As early as 1966, the AEC determined that even with these higher standards being applied it would not justify the lack of inspection, particularly of the reactor coolant system. This lead to a joint effort by the AEC and industry in the development of what is now called the ASME Section XI code "Rules for Inservice Inspection of Nuclear Power Plant Components" [2].

The first edition of ASME Section XI was titled "Inservice Inspection of Nuclear Reactor Coolant Systems" and provided inspection requirements for the reactor coolant system only. In the forward of the 1970 Edition it states "*In the development of this Section of the Code an attempt was made to identify those components essential for the protection of the public health and safety.*" As the Code was revised over the years inspection requirements grew as operating experience warranted more detailed and comprehensive inspections. As one could imagine this would lead to higher costs and radiation exposure. We now need to review the past and look forward to the future and made the right decisions learning from past experience.

This technical paper will attempt to address some lessons learned from the most current operating experience and what we can do for the future as we now more into another nuclear renaissance.

25.2 THE LESSONS

For the most part, the development the code requirements contained in Section XI was reactionary to the industry issues. However, recently the development of the requirements is moving towards being proactive as opposed to reactive. Below are topics, wherein the write-up will try to provide the details and approaches that are being taken to make this new nuclear reactor building era better than before.

25.2.1 Globalization Efforts

The Board on Nuclear Codes and Standards (BNCS) has worked for some time in an effort to travel around the globe and visit potential users of the ASME Code. Several trips have been completed including China, South Korea, Canada, South Africa, Russia, Czech Republic, United Kingdom, Finland, Sweden, and France. In these visits a select membership of the BNCS provides presentations of the ASME Code and then has breakout sessions to discuss the needs and wants of each country visited. This helps place the ASME Code as a code of choice.

25.2.2 Addressing New Designs

There are several new designs of reactors that are being pushed. It started off with the Pebble Bed Reactors out of South Africa. This design is a high temperature, on-load fueled nuclear reactor in which helium heated in the core by nuclear fission drives turbomachinery directly to produce electric power. The company that

was interested in building the Pebble Bed Modular Reactor (PBMR) saw that the rules contained in ASME Section XI, Division 2 "Rules for Inspection and Testing of Components of Gas-Cooled Plants" may not be complete for this new design. The last edition of ASME Section XI, Division 2 that was published was in the 1992 Edition with the 1993 Addenda, pages 485 through 653. This was due to the lack of interest and support from the industry in keeping these rules up-to-date. Therefore, the company interested in the development of the PBMR came to the code committee meetings and started to participate in the code development process. A special task team was created to focus specifically on this new proposed design and revisions to Division 2 to accommodate the new design of the PBMR. It was essential to have members of the PBMR technology world to participate so that the final revision addresses the needs of the operating plant. This was an important factor as most of the experience within the volunteer community that participates in the code body was in the light-water reactor design. There was very little if any experience in the gas-cooled reactor design. As you will see later this lesson learned of getting the right people in the room helps in the development of the right requirements. Unfortunately, the PBMR development lost momentum and the revision to Division 2 was delayed until the Small Module Reactors emphasis emerged.

25.2.3 Operating Experience

Operating experience is one of those things that is constantly moving and for the most part the code committee can only be reactive to these types of situations. There are approximately 100 operating nuclear power plants in the United States which produces approximately 20% of the electricity. With this many operating plants in the US, the opportunity to receive operating experience information is great. To add to that number there are an additional 300 operating reactors around the world. To identify a few of the more significant operating experience Section XI made some improvements:

Intergranular Stress Corrosion Cracking (IGSCC)

There are three things that are required in order for this phenomenon to take place 1) sensitized material, 2) stress, and 3) environment. As stated in Chapter 22 IGSCC was relatively well-known, but the use of unstabilized stainless steel was used extensively in BWR components and piping. In 1974, this particular phenomenon caused the industry to spend millions of dollars. There were 15 operating boiling water reactors that were ordered to shut down due to NPS 4 bypass piping. Again in 1975 there were 23 operating boiling water reactors ordered to shut down due to cracking found in the NPS 10 piping.

The industry responded to this issue with ways to perform stress improvements to the existing piping systems. These stress improvements were 1) Mechanical Stress Improvement Process (MSIP), 2) Induction Heat Stress Improvement Process (IHSI), and 3) Water Chemistry Improvement (HWC). For those plants that didn't opt to replace their affective piping were in need to have some repair options. The industry experts along with the code committee volunteers developed welding options which included applying weld filler metal of the existing welds which eventually was called "weld overlays." These were applied to those welds that had existing IGSCC. Code Case N-504 was published to address the requirements of performing the weld overlay [3]. This code case allowed the acceptance of flaws in austenitic stainless steel piping by depositing weld overlay to increase the thickness of the pipe wall rather than by reducing the size of the flaw to meet the acceptance criteria. This was an important step in the resolution of the IGSCC issue.

Primary Water Stress Corrosion Cracking (PWSCC)

The pressurized water reactor (PWR) community may have thought that they were out of the woods when it came to stress corrosion cracking as they watched the BWR Owners fight the IGSCC issue. However, in the mid. 1990s, the PWR plant owners started to experience Primary Water Stress Corrosion Cracking. This cracking occurred in primary water systems that used Alloy 600 components with weld material of Alloy 82 and Alloy 182. Such components were widely used in the PWR industry and therefore would cost millions of dollars in recovery. However, based on the lessons learned from the BWR industry experience, there were many available options added in the tool box.

Cracks Found in the J-Groove Weld of PWR Vessel Heads

On February 16, 2002 a Pressurized Water Reactor began a refueling outage that included inspection of the nozzles that entered the reactor vessel head. The inspections were focused on the nozzles associated with the mechanism that drives the control rods, known as the control rod drive mechanism (CRDM). While conducting the inspections, it was discovered that three CRDM nozzles had indications of axial cracking, which had resulted in leakage of the reactor pressure boundary. It was decided to repair the three nozzles as well as two other nozzles that had indications of leakage. On March 6, 2002 when removing the machining apparatus that was performing the repair, one of the CRDM nozzles was mechanically agitated and subsequently displaced in the downhill direction until its flange contacted the flange of the adjacent CRDM nozzle. Upon removing the boric acid residue from around the displace nozzle a large cavity was discovered in the reactor vessel head on the downhill side of the displaced nozzle. The minimum remaining thickness of the reactor vessel head was found to be approximately 3/8". This thickness is the thickness of the stainless steel cladding on the inside of the reactor vessel head.

As you can imagine, this was a very significant issue that both the owners of operating pressurized water reactors and the ASME needed to address quickly. This was also a major industry issue wherein the Nuclear Regulatory Commission (NRC) issues several documents to understand the effects of this one pressurized water reactor to all remaining operating plants of similar design. One of the documents that were issued was a letter to the ASME with concerns that the examinations requirements contained within ASME Section XI were not adequate [4]. A subsequent letter was issued to ASME with concerns of the entire Reactor Coolant Pressure Boundary [5]. Eventually the NRC issued an order EA-03-009 which established interim inspection requirements for reactor pressure vessel heads at pressurized water reactors. In addition, communication was established with the ASME Section XI Subcommittee to develop examination requirements to improve the ability to monitor this degradation mechanism within the code.

A task group was created to work with the industry in develop the correct approach. The NRC's order, the industry's approach, along with the task group's efforts resulted in the issuance of

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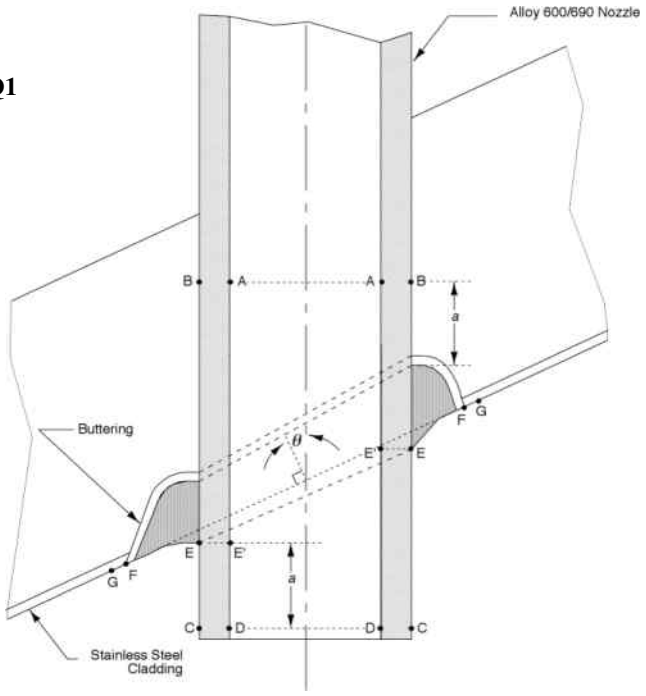


FIG. 25.1 J-GROOVE WELD – LEAKING OCCURRED IN THE PARTIAL PENETRATION WELD (Source: ASME Nuclear Technical Seminars, June 21–23, 2010 – Bethesda, MD "What Have We Learned" by Gary Park)

Code Case N-729. This code case eventually was used to replace the NRC order EA-03-009. This was an effort by all interested parties and shows that when working together significant issues can be resolved with time and effort. The lesson to be learned from this is not to point fingers but to roll up our sleeves and get to work.

25.2.4 Operating Experience

As one might imagine, within the United States the Nuclear Regulatory Agency plays an important role in the development of the inspection requirements of all operating nuclear plants in the U.S. The NRC has representatives on most committees within ASME Section XI. In addition, the ASME Boiler and Pressure Vessel Standards Committee on Nuclear Inservice Inspection (XI) Chair and Vice Chairs along with the Chair and Vice Chair of the Standards Committee on Construction of Nuclear Facility Components (III) have a meeting with the NRC Executive Staff every two years. The committee holds their August meetings in Washington DC and during the Friday of the "code week" a meeting is held at the NRC offices. Along with this bi-annual meeting, a conference call is held every six months to keep the communication open. One of the standard agenda items is to discuss the most important items that each organization is following. Each organization has a "top ten" list that is used to focus resources on. These three lists are discussed during this bi-annual meeting to make sure that everyone is aligned. This has been an open and honest attempt to keep communications with the regulator and hopefully will be something that is followed in the future. This process has been a good experience from both sides and now the ASME BPV XI Standards Committee should work harder at reaching out to the regulators around the world.

25.2.5 Knowledge and Younger Engineers

One of the issues that need to be addressed is the age of the more experienced engineers in the industry. Overall the average age of the labor force is increasing. In 1950 1 in 6 workers was over 55, in 2010 it was 1 in 5 and this is projected to be 1 in 4 in the year 2030 [6]. The U.S. Bureau of Labor Statistics projected the change in workforce by age from 2006 to 2016 in the following graph, Fig. 25.2.

Any way you look at it, this is a real concern and somehow we need to get younger engineers more involved in the development and implementation of the ASME Codes. This involves more than just the nuclear industry, but the petroleum, fossil, and other energy industries. One thing that ASME has been doing is providing training at each code week for those individuals just getting started. These training sessions give an introduction to the different ASME Code Books along with the opportunity to answer questions. Another effort that the BNCS has taken is to visit college universities and meet with engineering students. The last visit was at the University of Kentucky. During the visit a few ASME Committee Members attended one of the engineering classes and presented the students with "real life" instances where the code is implemented for design of pressure vessels. This ended up being a great way to interact with the students. I suggest that more visits be made in the future so that we can get a younger population working with the ASME Codes.

25.2.6 Development of System Based Code

The first publication of ASME Section III of the ASME Boiler and Pressure Vessel Code introduced a new concept in structural design of components through a "Design by Analysis" method. Since that time there has been no new development of new concepts [7]. The codes that we have today include extra margins. As each technical aspect (loading, material, design method, welding procedure (heat treatment), and inspection) is introduced into the design of components the margins for each of the technical aspect is added upon each other. This results in a "total integrity" for that component. The system based code is an attempt to provide options in designing a component. For example, if the total

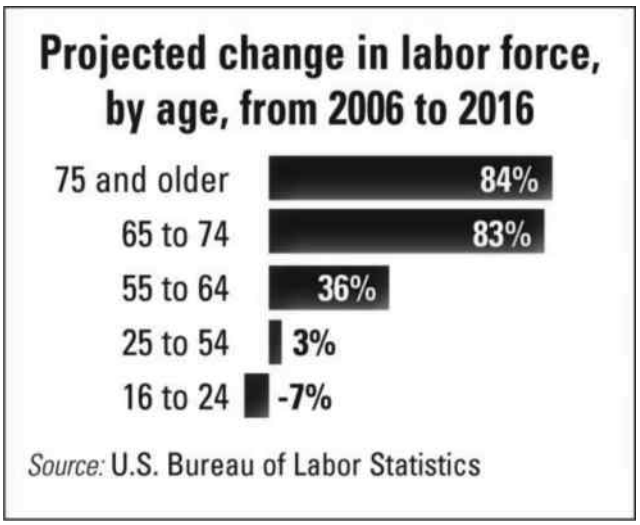


FIG. 25.2 "PROJECTED LABOR FORCE AGE" (Source: U.S. Bureau of Labor Statistics, 2006)

Q2

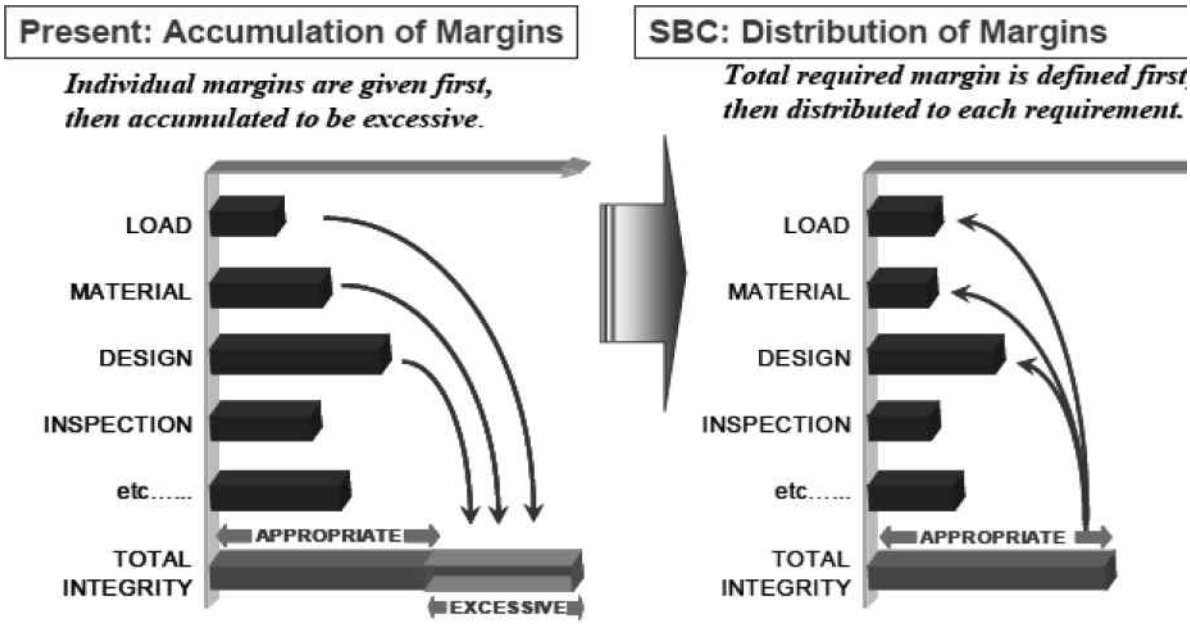


FIG. 25.3 REASONABILITY OF MARGINS FROM ACCUMULATION TO DISTRIBUTION (Source: [7])

margins for each of the technical aspects are added together the "total integrity" is very likely excessive. But with the system based code, the appropriate "total integrity" is established first and then the margins for the technical aspects are addressed. Below is an example taken from reference 7 that presents that intent of the system based code.

What the system based code is designed to do is establish the required "total integrity" feeding this back into the technical aspects of the design of the component resulting in a cost reduction with a safe component. The development of the system based code is still to be worked within the Board on Nuclear Codes and Standards so a final product is not yet available. However it is hoped that something will be published soon, particularly as new reactor designs are being produced.

25.2.7 Development of Reliability Integrity Management (RIM) Program

With a new emphasis being developed on the Small Modular Reactors (SMRs), the need to revisit the content of ASME Section XI Division 2 was needed. The project team that was working with the PBMR team needed to refocus their efforts and address the SMRs. This led the project team to consider applying the Reliability Integrity Management (RIM) Program that was being developed for the PBMR to any type of reactor. The reliability of a nuclear plant and its systems and components are determined by the design, fabrication, inspection, surveillance, operation, and maintenance procedures used to build and maintain the plant. Each of these aspects contributes to different degrees to the reliability of the plant, its systems and components. In order to have a level of reliability that satisfies both safety and economic goals, an appropriate combination of these contributors to reliability must be identified and implemented. The objective of the RIM Program is to define, evaluate, and implement strategies to ensure that reliability targets for passive metallic components are defined, achieved, and maintained through the operation life of the plant. The process for developing a RIM Program includes the following steps [8]:

1. RIM Program Scope Definition
2. Damage Mechanism Assessment
3. Plant and SCC Reliability Allocation
4. Identification and Evaluation of RIM Strategies
5. Evaluation of Uncertainties
6. RIM Program Implementation
7. Performance Monitoring and RIM Program Updates

The revised ASME Section XI Division 2 is envisioned to be technology neutral, meaning that the requirements may be applied to any reactor design. The general requirements for the implementation of the RIM Program will be contained in the text of the code with attachments being included for any specific requirements for the different reactor designs. This approach was decided with the hopes that this new technology could be introduced to the existing fleet of nuclear plants for inspection requirements. The effort in developing rules that would replace the deterministic rules that exist in the current ASME Section XI Code is certainly a step in the right direction.

25.2.8 Construction Repairs

During the construction of the nuclear power plants in the 1960s and 1970s often times nondestructive examinations (NDE) were performed and the results would not meet the established acceptance criteria. This would result in the need to perform repairs. Sometimes the repairs would be localized to remove isolated tungsten, lack of fusion, or some other welding defect. The repair would be accomplished; a follow up NDE was completed to verify that the defect was removed. The construction code may have requirements if the cavity made to remove the defect was significant and a post weld heat treatment was required. However, this was not always the case. When a post weld heat treatment was not performed the weld repair caused localized stresses,

which when the plant went in to operation, would be a factor in producing issues that could ultimately result in further repairs. But now the repair has several other issues along with performing the welding. Those would be accessibility to the repair area and radiation exposure to the plant workers. One of the actions recently approved by the ASME BPV XI Standards Committee under record 11-61 to allow the evaluation of embedded flaws detected under the Section XI preservice examinations. This would eliminate some of the repairs required during construction or repair/replacement activities. This may not be enough, the construction codes should still be looking at what ASME BPV XI has done and consider allowing evaluation of flaws found during the construction code examinations.

25.2.9 NDE Advancement

During the early 1980s the operating Boiling Water Reactors started to experience the phenomenon of Intergranular stress corrosion cracking (IGSCC) in the stainless piping. IGSCC would produce through-wall leaks in the reactor coolant piping and thus make the plant owners shut down their power plant to conduct repairs. This of course would result in capacity factor losses [9]. Many plants ended up replacing a majority of their stainless steel piping that was part of the reactor coolant system. This cost millions of dollars and exposure to the workers. It was time for the industry along with ASME to work on developing better nondestructive examination techniques to identify this degradation mechanism so that plant owners can plan and carry actions on a proactive manner as opposed to the reactive manner. The first step taken was performed by the NRC in issuing IE Bulletin No. 83-02 [10]. This bulletin raised the bar on the examination techniques being utilized and required a demonstration of the techniques on service-induced cracked pipe samples. This eventually became an agreement between the NRC, Boiling Water Reactor Owners Group (BWROG) and the Electric Power Research Institute (EPRI) which formed the IGSCC Coordination Plan, dated July 3, 1984. This was followed with performing ultrasonic examinations during the late 1980s up to the early 1990s when the ASME developed Appendix VIII of the ASME Section XI Code [11]. The new Appendix VIII was a mandatory appendix which required performance demonstration for qualification of procedures, equipment, and personnel used for ultrasonic detection and sizing of flaws in vessels, bolting, and piping welds. The Performance Demonstration Initiative (PDI) was formed by the U.S. Utilities in 1991 to implement the performance demonstration requirements of the ASME Code Section XI, Appendix VIII, Demonstration for piping, bolting and RPV shell welds, in 1994. The NRC issued a rule revision to 10 CFR 50.55a in September 22, 1999 that expedited the implementation with specific dates for implementation. The ASME Committees are still working on improvements to the different NDE techniques that are utilized. Cast Stainless Steel has been a tough material to examine and there is some hope that this can be resolved in the near future. As mentioned above, the lessons learned from the operating BWR fleet helped the PWR operating fleet resolve the cracking issues identified as PWSCC. As we continue to investigate new ways to examine the material that have been used in operating plants, the plants will be able to stay on line longer increasing the capacity factors.

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CHAPTER

26

PART A: LESSONS LEARNED: INDUSTRY EXPERIENCE OF MATERIALS

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PART B: LESSONS LEARNED: EXPERIENCE WITH NONMETALLIC MATERIALS IN STRUCTURAL/PRESSURE BOUNDARY APPLICATIONS

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PART A: LESSONS LEARNED: INDUSTRY EXPERIENCE OF MATERIALS

26A.1 INTRODUCTION

The ASME BPV Code promotes the introduction of new materials. As materials are produced to more closely fit users' requirements, new issues arise. One example is the introduction of "advanced" alloys into the B&PV Code, which represents a significant change in philosophy regarding materials' use at elevated temperatures. The inevitable acceptance of these alloys has prompted the introduction of new rules in the construction codes and new protocols in SC II that are more prescriptive than the rules and protocols adopted to govern the use of the more "traditional" materials. In view of the very significant changes in the power industry that have occurred over the last 30 years, this general trend is likely to continue. The following represent some of the lessons learned.

26A.2 EXTRAPOLATION IS PERILOUS

In 1975, Combustion Engineering and Oak Ridge National Laboratory began development of an improved 9Cr-1Mo ferritic alloy steel [1]. These efforts resulted in the development of an alloy with "small but controlled quantities of V, Nb and N" [2]. The high creep resistance of this material provided design allowable stresses well above those for the widely-used 2 $\frac{1}{4}$ Cr-1Mo steels and were approximately equivalent to those for Type 304 austenitic stainless steel up to ~650°C [3]. It also displays enhanced resistance to steam-induced oxidation and high temperature corrosion by molten ash [4].

The 1983 Adoption of the Grade 91 Code Case marked the first of the Creep Strength Enhanced Ferritic Steels (CSEF) admitted to the B&PV Code. These CSEF alloys were specifically designed for elevated temperature service with allowable stresses in the time-dependent regime based on a metastable condition of microstructure.

Most alloys (such as Grade 22) are permitted for Code use at elevated temperatures for pressure part applications only in their most

stable (i.e., relatively weak and soft) conditions. Since microstructure and hardness are not critical, control of processing is less critical for such alloys; e.g., improper heat treatment or service overheating of Grade 22 typically will not significantly degrade creep properties.

"Advanced" alloys (including 9Cr-1Mo CSEF Steels) are used in a metastable (i.e., relatively strong) condition for pressure part applications. Their microstructure is critical to creep strength and, therefore, precise process control is essential if enhanced creep strength is to be realized.

Alloys are accepted into the BPV Code for use in the time-dependent regime based on analysis of submitted creep data. The purpose of the analysis of creep data is to provide reliable predictions of how a material will behave under specific conditions of temperature and stress, a task made more difficult by the potential for instability in the advanced alloys. Considerations of the analysis include:

- Heat-to-heat variability.
  - Differences in the strength and ductility of individual heats of the same steel must be considered in order to characterize a true "average" or "minimum" behavior for an alloy;
  - Lot centering is one way to minimize the potential for non-typical heats to skew the analysis results.
- The effect of test acceleration on data integrity.
  - A minimum length of testing is required to insure accurate characterization of material behavior.
  - Considering only data for greater than ~500 hours produces more conservative and more accurate long-term (>30,000 hours) prediction than including shorter-term data.
  - Metallurgical changes that affect creep resistance may occur only after substantial service time has elapsed.
- Data analysis techniques.

The results of creep tests on many different heats of a grade of steel under different conditions of temperature and stress can be evaluated using parametric or other curve-fitting techniques to develop predictions of creep life. Typically, Larson-Miller Parameter analysis is used.

In 2004, a Subcommittee II (Subcommittee on Materials) Task Group was formed to review the problems reported with the use of Grade 91 and other CSEF steels and determine what, if any, Code action would be required. TG volunteers included materials specialists from the US, Japan, and Europe; all with extensive experience in advanced alloys. Based on the analysts' review, the allowable stresses for Grade 92 (9Cr-2W, Code Case 2179-6) were reduced as follows:

- At 1050°F: from 17.2 to 16.1 ksi (119 to 11 MPa) for thinner-walled material (tubing) and from 16.6 to 15.7 ksi (114 to 108 MPa) for thicker-walled material (piping, forgings, and forged piping).
- At 1100°F: from 13.6 to 12.3 ksi (94-85 MPa) for thinner-walled material and from 13.0 to 12.0 ksi (90-83 MPa) for thicker-walled material.
- At 1150°F: from 10.2 to 8.9 ksi (70-61 MPa) for thinner-walled material and from 9.6 to 8.6 ksi (66-59 MPa) for thicker-walled material.
- At 1200°F: from 6.9 to 5.9 ksi (48-41 MPa) for thinner-walled material and a value of 5.6 ksi (39 MPa) was established for thicker-walled material.

The TG also re-evaluated grade 122 (12 Cr-2 W). In this alloy, the effects of Z phase on long-term strength were not apparent until after approximately 30,000 hours of exposure; hence original test data did not detect the effect. Therefore, allowable stresses were reduced as follows:

- At 1050°F: from 16.8 to 14.4 ksi (116-99 MPa)
- At 1100°F: from 12.9 to 10.6 ksi (89-73 MPa)
- At 1150°F: from 9.3 to 7.2 ksi (64-50 MPa)
- At 1200°F: from 6.2 to 4.5 ksi (43-31 MPa)

Due to the potential impact of mis-processing on creep behavior, coupled with an imperfect understanding of the technical issues on the part of many manufacturers and suppliers, it has been necessary to write more prescriptive rules for the advanced alloys. For all CSEF Steels, except Grade 91, the range for PWHT has been restricted to 1350 to 1470°F. For Grade 91, the range for PWHT is further restricted to 1350 to 1425°F {(depending on the Ni+Mn content), the maximum PWHT temperature can be raised to 1470°F (see Table UCS-56-11.)}. For all CSEF Steels, a prohibition on localized heating above 1470°F without full re-normalizing & tempering or replacement of the component has been implemented.

For Grades 23, 91 & 92, limits were placed on the amount of Cold Work that can be imparted without subsequent heat treatment. (See Table UCS-79-1 and the following note: {1}) Also, for Grade 91, limits on the amount of cold strain permissible without re-normalizing and tempering are imposed by SCI PG-20.

{1} *For austenitic alloys, in PG-19 of SCI and UHA-44 of SCVIII, Div. 1 limits the amount of cold strain permitted without re-solution annealing. These limits are lower for "advanced" austenitic alloys.*

Changes were also made to Material Specifications.

- For all CSEF Steels, the temperature range for Normalizing has been restricted to 1900 to 1975°F
- For all CSEF Steels, the temperature range for Tempering has been restricted to 1350 to 1470°F

Substantial revisions were made to rules governing the treatment of castings made from the CSEF steels. Rules were added for Control of weld repairs, to include maintaining records of size and location of all major repairs. Rules were added for Control of filler metal chemistry used in weld repairs and Control of heat treatment sequencing to avoid the creation of extensive subcritically heat treated weld seams in the casting. Mandatory volumetric inspection was added.

Chemistry Issues are also important. The traditional BPV approach has been to accept a requester's suggested ranges for controlled elements. However, loose ranges to benefit producers may not provide sufficient control of final properties (e.g., Aluminum exerts a significant effect on the properties of some CSEF steels). Attempts to protect Intellectual Property (IP) rights often have limited disclosure of technical ramifications of compositional changes. However, technology improvements have made close control of elemental composition feasible.

In response to concerns identified by the TG-CSEF Steels, a substantial revision of the Requirements for the Acceptance of New Materials in the B&PV Code (Appendix 5 in Volume II, Part D) was developed and published in the 2013 edition. Some of these revised requirements are:

- The interval between successive temperatures in creep rupture tests must be chosen to facilitate accurate determination of the slope of the stress rupture curves.
  - For metastable materials, the intervals must be 50°F or less.
- The longest rupture time for each qualifying heat must exceed 10,000 hours, which qualifies material for acceptance in a Code Case.
  - Tests with rupture times shorter than 500 hours are discouraged.
  - For incorporation of an "advanced" alloy into the Code, creep rupture data extending beyond 30,000 hours, or equivalent experience, are required.
- Producers must describe important strengthening mechanisms, which should identify key elements underlying creep strength.
- Elemental ranges for key elements must reflect the ranges represented in the three test heats.
- Inquirer must explain the basis for chemistry requirements, including the extent of ranges for individual elements, including how metallurgical structure is affected (influence on essential precipitates, secondary phases, grain size, etc.).
- Heat treatment effects (strengthening mechanisms and relative stability) must be described.
- Effect of composition and heat treatment on mechanical properties must be explained.
- The inquirer must identify the intended the metallurgical structure that produces the needed mechanical properties and indicate a heat treatment protocol that will insure that the desired structure is obtained.
- Any limitations on heat treatment must be explained, including recommended temperature ranges and effects on key phases in the alloy.

It is hoped that these new requirements will avoid the need for reevaluation and reduction of allowable stresses for future new materials. This is a response to the experience for CSEF Steels.

26A.3 THE ENVIRONMENT IS ALWAYS WORSE THAN PREDICTED

The ASME BPV does not address environmental effects, but environmental resistance is a critical factor in material selection. The need for corrosion-resistant materials promotes the introduction of new alloys into the Code. Although Flue Gas Desulfurization (FGD) vessels operate at low pressures and thus are not themselves covered by Code rules, the issues associated with them illustrate a common problem associated with environmental resistance.

Wet FGD typically involves passing boiler flue gas (from coal-fired boilers) through an intense spray of limestone-water slurry. The calcium carbonate of the limestone reacts with the sulfur dioxide in the flue gas to form calcium sulfite and thus remove the sulfur from the gas stream. Because calcium carbonate and calcium sulfite are relatively non-corrosive toward stainless steels, it was initially considered that common stainless steels such as type 316L would provide adequate performance. In-service performance rapidly disproved the suitability of 316L for FGD absorber bodies. The higher-molybdenum 317L (or the still-higher molybdenum 317LM and 317LMN) alloys rapidly became the baseline alloys selected for FGD [5, 6, 7, 8]. Attempts to move to zero liquid discharge caused the buildup of corrosive impurities such as chloride that promoted corrosion and led to the subsequent use of the highly corrosion resistant 6% Mo superaustenitic and Ni–Cr–Mo nickel alloys. Studies [9, 10] then showed that with improved control of operating parameters [11] (including increased blowdown) the more economical 2205 duplex stainless steel ought to provide adequate performance. Many FGD absorbers were constructed between 2001 and 2011 using 2205 or similar alloys. Most of these experienced rapid corrosion failures. These failures were attributed to several factors, including:

- The introduction of air or oxygen sparging to force oxidation of the sulfite to the saleable Gypsum (calcium sulfate) product;
- the introduction of bromide additions to the fuel to promote mercury capture;
- the use of biologically active waters (typically untreated river, pond or well water) for hydrotesting.

Remediation of these corrosion problems frequently involved the installation of a non-metallic lining. Its prevention involved the reintroduction of the highly corrosion resistant alloys used previously or the use of the same non-metallic lining materials used in remediation.

26A.4 POST-FABRICATION CLEANUP IS MORE IMPORTANT THAN GENERALLY IS BELIEVED

The ASME Code has extensive rules about welding, but these rules are focused on ensuring strength and mechanical integrity. Post-weld cleanup of stainless steel is necessary to provide adequate environmental resistance and thus adequate performance. Post-weld cleanup comprises removal (usually via chemical treatment) of scale, heat tint and chromium depletion. If done properly, post-weld cleanup restores the corrosion resistance of the weld to levels comparable to the original base metal [12].

26A.5 PHYSICAL PROPERTIES ARE IMPORTANT

Many pressure vessels (and much other equipment) operate at elevated temperatures. This usually involves temperature fluctuations and gradients.

"Stresses (compressive, tensile or shear) due to unequal temperature distribution and non-uniform temperature gradients, cause more failures in high-temperature equipment than all other influences combined amounting . . . to about 90% of the total number of cases. And it is destructive chiefly because the engineer does not include in his design proper allowance for or provision against temperature inequalities or because the operator imposes temperature differentials which cause localized dimensional changes with accompanying stresses greater than the elastic strength of the alloy at the given temperature" [13].

ASME BPV II (Materials) publishes (in Volume II-D, SubPart 2) physical properties for use in BPV design, but the Code is not consistent in its approach toward physical properties. Section III (Nuclear Design) has long required the use of the II-D physical property values if they have been published. The 2007 and later editions of Section VIII, Division 2 also require the use of the ASME physical property values if they are published. For most other sections of code construction, use of the published values is optional but encouraged.

The foremost rule of elevated temperature design is that metals expand when heated. If this thermal expansion is restrained, it will

create stresses that may exceed the yield strength (at temperature) of the metal. Most construction alloys, and especially heat resistant alloys, have relatively poor thermal conductivity, leading to significant thermal gradients, and thus significant stresses.

In some cases, thermal expansion can be accommodated through flexibility. This brings elastic modulus into consideration.

Thinner sections are more flexible than thicker sections.

Materials with lower elastic modulus are more flexible than materials with higher elastic modulus.

Curved sections are more flexible than straight sections.

Where deflection is important higher elastic modulus may be beneficial.

Higher modulus materials are more resistant to buckling and external pressure collapse.

Higher modulus materials used in tubular heat exchangers exhibit reduced deflection under conditions of flow-induced vibration.

26A.6 IS THE MISSION OF THE B&PV CODE EVOLVING?

Industry changes have substantially reduced the ability of many suppliers, OEMs, and others to provide levels of technical oversight necessary for more complex issues facing Code users. Users have expanded the Code mission, both implicitly and explicitly — Is it required in the Code? — if not, users may feel that there is no need to do it. When problems that affect industry as a whole arise, requests are made to develop Code rules because Code increasingly is viewed as technical arbiter of last resort. The move to more prescriptive rules makes many Code "veterans" uncomfortable, but due to the increasing complexity of problems and the perceived absence of adequate resources elsewhere in industry this "mission creep" probably is inevitable.

26A.7 ACKNOWLEDGMENT

The author gratefully acknowledges the contribution of Mr. Jeff Henry in untangling the history of CSEF steels in the ASME BPV Code.

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PART B: LESSONS LEARNED: EXPERIENCE WITH NONMETALLIC MATERIALS IN STRUCTURAL/PRESSURE BOUNDARY APPLICATIONS

26B.1 INTRODUCTION

The API, ASME, AWWA, and BS have a number of codes and standards utilizing nonmetallic materials that provide construction and repair requirements.

Note that the term "construction" in ASME pressure technology applications includes design, materials, fabrication, erection, inspection, testing, and quality assurance of components.

Example construction codes are:

- API 620 Standard, Design and Construction of Large, Welded, Low-Pressure Storage Tanks
- API 650 Standard, Welded Steel Tanks for Oil Storage
- ASME B31.1 Code, Power Piping
- ASME B31.3 Code, Process Piping
- ASME B31.4 Code, Liquid Hydrocarbon Pipelines
- ASME B31.8 Code, Gas Hydrocarbon Pipelines
- ASME B31.9 Code, Building Service Piping
- ASME BPV Code, Section I, Power Boilers
- ASME BPV Code, Section III, Construction of Nuclear Facilities
- ASME BPV Code, Section IV, Heating Boilers
- ASME BPV Code, Section VIII, Pressure Vessels
- ASME BPV Code, Section X, Fiber Reinforced Plastic Pressure Vessels[1]
- ASME RTP-1 Standard, Reinforced Thermoset Plastic Corrosion Resistant Equipment[1]
- AWWA C150 Standard, Thickness Design of Ductile Iron Pipe
- AWWA D100 Standard, Welded Carbon Steel Tanks for Water Storage
- AWWA D103 Standard, Factory Coated Bolted Carbon Steel Tanks for Water Storage
- BS 4994 Standard, Specification for Design and Construction of Vessels and Tanks in Reinforced Plastics

Many of these construction codes and standards allow the use nonmetallic materials to some extent (sometimes via a Code Case). Note 1 identifies nonmetallic material construction codes and standards.

Proper use of these construction codes and standards is performed through the use of the Design Specification. Most application issues are caused by the use of a poorly written Design Specification or a poorly implemented Design Specification.

TABLE 26B.1-1 ACRONYMS

Acronyms		Explanation
API	-	American Petroleum Institute
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society of Testing and Materials
AWWA	-	American Water Works Association
BS	-	British Standards Institute
FRP	-	Fiber-Reinforced-Polymer
NDE	-	Non-Destructive Examination
NDT	-	Non-Destructive Testing
PPI	-	Plastic Pipe Institute
QA	-	Quality Assurance
RTP	-	Reinforced Thermoset Plastic

26B.2 TYPES OF NONMETALLIC MATERIALS

There are three major nonmetallic materials used in structural applications, including fluid system pressure boundary applications.

- Thermoplastic materials
- Thermoset plastic materials
- Graphite materials

26B.2.1 Thermoplastic Materials

Typical thermoplastic materials used in industrial applications are:

- Chlorinated Polyvinyl Chloride (CPVC)
- Polyethylene (PE)
- Polyphenylene (PPE)
- Polypropylene (PP)
- Polyvinyl Chloride (PVC)
- Polyvinylidene Fluoride (PVDF)

Some example specifications for thermoplastic materials are:

- ASTM D1248, Standard Specification for Polyethylene Plastic Molding and Extraction Materials (Type I, II, III, IV)
- ASTM D3350, Standard Specification for Polyethylene Plastic Pipe and Fittings Materials
- ASTM D4349, Classification System and Basis for Specification for Polyphenylene Ether (PPE) Materials
- ASTM D4976, Standard Specification for Polyethylene Plastics Molding and Extrusion Materials

Also related to these thermoplastic material specification examples are the following test methods for measuring engineering and physical properties of the thermoplastic materials:

- ASTM C177, Standard Test Method for Steady-State Heat Flux Measurement and Thermal Transmission Properties by Means of a Guarded Hot Plate Apparatus
- ASTM D224, Standard Test Method for Rubber Property – Durometer Hardness
- ASTM D256, Standard Test Methods for Impact Resistance of Plastics and Electrical Insulating Materials
- ASTM D638, Standard Test Method for Tensile Properties of Plastics
- ASTM D695, Standard Test Method for Compressive Properties of Rigid Plastics
- ASTM D696, Standard Test Method for Coefficient of Linear Expansion of Plastics
- ASTM D785, Standard Test Method for Rockwell Hardness of Plastics and Insulating Materials
- ASTM D790, Standard Test Methods for Flexural Properties of Unreinforced and Reinforced Plastics and Electrical Insulating Materials
- ASTM D792, Standard Test Methods for Density and Specific Gravity (Relative Density) of Plastics by Displacement
- ASTM D1505, Standard Test Method for Density of Plastics by the Density-Gradient Technique
- ASTM D1238, Standard Test Method for Melt Flow Rates of Thermoplastics by Extrusion Plastometer
- ASTM D1505, Standard Test Method for Density of Plastics by the Density-Gradient Technique

- ASTM D1603, Standard Test Method for Carbon Black Content in Olefin Plastics
- ASTM D1929, Standard Test Method for Ignition Properties of Plastics
- ASTM D2412, Standard Test Method for Determination of External Loading Characteristics of Plastic Pipe by Parallel-Plate Loading
- ASTM D2837, Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products
- ASTM D4218, Standard Test Method for Determination of Carbon Black Content in PE Compounds By the Muffle-Furnace Technique
- ASTM D4883, Standard Test Method for Density of Polyethylene by the Ultrasound Technique
- ASTM F2634, Standard Test Method for Laboratory Testing of Polyethylene (PE) Butt Fusion Joints using Tensile-Impact Method
- PPI TR-3, *Policies and Procedures for "Developing Recommended Hydrostatic Design Stresses for Thermoplastic Materials"*
- PPI TR-4, *Recommended Hydrostatic Strengths and Design Stresses for Thermoplastic Pipe and Fitting Compounds*

26B.2.2 Thermoset Plastic Materials

Typical thermoset plastic materials used in industrial structural applications are:

- Epoxy
- Polyester
- Vinyl Ester
- Furan
- Phenolic

One commonly used thermoset plastic material for structural applications is epoxy. Epoxy has a wide range of applications, including fiber-reinforced plastic materials and general purpose adhesives, since in general it has superior chemical resistance properties.

- ASTM D1763, Standard Specification for Epoxy Resins

One example standard specification for epoxy materials is ASTM D1763. There are several applicable test methods for determining the chemical content of epoxy polymers.

- ASTM D445, Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)
- ASTM D1544, Standard Test Method for the Color of Transparent Liquids (Gardner Color Scale)
- ASTM D1652, Standard Test Method for Epoxy Content of Epoxy Resins
- ASTM D2393, Standard Test Method for Epoxy Resin and Related Components

Thermoset plastics are widely used in structural application, especially when reinforced with fibers. Some fibers commonly used are:

- Glass
  - A-glass
  - E-glass
  - S-glass
  - E-CR-glass
  - C-glass
- Carbon
  - PAN
  - Mesophase pitch
  - Rayon
- Aramid

26B.2.3 Graphite Materials

Impregnated graphite is used for pressure vessels. The important material properties are:

- Specific grade of graphite
  - Strength of graphite
  - Pore size
  - Distribution of pores
- Impregnation agent (the polymer)

Graphite materials come in standardized configurations. One example graphite specification is:

- ASTM D7219, Standard Specification for Isotropic and Near-Isotropic Graphite

Also related to these graphite materials are the following test methods for measuring engineering and physical properties of the materials:

- ASTM C781, Standard Practice for Testing Graphite and Boronated Graphite Materials for High-Temperature Gas-Cooled Nuclear Reactor Components
- ASTM C838, Standard Test Method for Bulk Density of As-Manufactured Carbon and Graphite Shapes

ASTM C781 can be used to measure apparent porosity, thermal conductivity, coefficient of thermal expansion, tensile strength, flexural strength, compressive strength, dynamic elastic modulus, modulus of elasticity, fracture toughness, and Weibull modulus.

ASTM C838 can be used to measure bulk density.

26B.3 DESIGN SPECIFICATION

The successful application of nonmetallic materials is assured by the use of the proper material and component specifications, as well as proper test methods for measurement of engineering and physical properties. One effective way to achieve this goal is to use codes and standards as the material specification, the component specification, and the defined test method for engineering and physical properties.

26B.3.1 Contents

Some of the recommended contents for a complete Design Specification are:

- Identification of design life
- Identification of design loads:
  - Design pressure loads (maximum and minimum)
  - Design temperature loads (maximum and minimum)
  - Component weights
  - Seismic loads
    - ➢ Seismic wave passage
    - ➢ Seismic inertia
    - ➢ Permanent ground motion
  - Soil density loads (if buried)
  - Constrained expansion
  - Surface load (if buried)

- Fatigue considerations
  - ➢ Full pressure cycles
  - ➢ Partial pressure cycles
- Identification of load combinations
  - Wall thickness
  - Standard component sizes
  - Sustained loads
  - Occasional loads
- Support design

26B.3.2 Aspects of Design

The major aspects of the Design Specification are:

- Material specification
- Mechanical design (including overpressure protection)
- Fabrication (including welding, brazing, joining, and fusion)
- Examination (including a wide variety of nondestructive examination techniques)
- Testing (including hydrostatic or pneumatic testing)
- Quality assurance (including various quality control techniques)

Many of these aspects are addressed in the applicable construction code or standard.

26B.3.3 Useful References

Some references that are useful in the development of a complete Design Specification are:

- ASME BPV Code Section III, Subsection NCA General Requirements, Paragraph NCA-3252 Contents of Design Specification
- ASTM F645, Standard Guide for Selection, Design, and Installation of Thermoplastic Water Pressure Piping Systems
- Plastic Pipe Institute, Engineering *Handbook for Polyethylene* (www.plasticpipe.org)

26B.4 NONMETALLIC COMPONENTS

Typical nonmetallic components for fluid containing pressure systems include vessels, tanks, piping, pipe fittings, valves, and pumps. Also there are a number of component applications where a combination of both nonmetallic materials and metallic materials are utilized.

26B.4.1 Thermoplastic Components

Thermoplastic piping is extensively utilized throughout the industrialized world, especially in lower pressure and lower temperature applications where metallic fluid systems are prone to corrosion and erosion.

For thermoplastic materials, the following are example component specifications:

- ASTM D2683, Standard Specification for Socket-Type Polyethylene Fittings for Outside Diameter-Controlled Polyethylene Pipe and Fittings
- ASTM D3035, Standard Specification for Polyethylene (PE) Plastic Pipe (DR-PR) Based on Controlled Outside Diameter
- ASTM D3261, Standard Specification for Butt Heat Fusion Polyethylene (PE) Plastic Fittings for Pipe and Tubing
- ASTM F714, Standard Specification for Polyethylene (PE) Plastic Pipe (SDR-PR) Based on Outside Diameter
- ASTM F1055, Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Controlled Diameter Pipe and Fittings
- ASTM F2206, Standard Specification for Fabricated Fittings of Butt-Fused of Polyethylene (PE) Plastic Pipe, Fittings, Sheet Stock, Plate Stock, or Block Stock
- AWWA C906, Standard for Polyethylene (PE) Pressure Pipe and Fittings, 4 in. (100 mm) Through 63 in. (1575 mm) for Water Distribution and Transmission

Additionally, the use of standard practices, standard terminology, and engineering properties tabulated in industry published documents derived in accordance with an applicable technical code or standard can provide the Owner with the assurance of quality Design Specifications:

- ASTM D92, Standard Test Method for Flash and Fire Points by Cleveland Open Cup
- ASTM D883, Standard Terminology Relating to Plastics
- ASTM D1238, Standard Test Method for Melt Flow Rates of Thermoplastics by Extrusion Plastometer
- ASTM D1598, Standard Test Method for Time-to-Failure for Plastic Pipe Under Constant Load Pressure
- ASTM D1599, Standard Test Method for Resistance to Short-Time Hydraulic Pressure of Plastic Pipe, Tubing, and Fittings
- ASTM D1603, Standard Test Method for Carbon Black in Olefin Plastics
- ASTM D1693, Standard Test Method for Environmental Stress-Cracking in Ethylene Plastics (ESCR)
- ASTM D2290, Standard Test Method for Apparent Hoop Tensile Strength of Plastic or Reinforced Plastic Pipe by Split Disk Method
- ASTM D2122, Standard Test Method for Determining Dimensions in Thermoplastic Pipe and Fittings
- ASTM D2774, Standard Practice for Buried Installation of Thermoplastic Pressure Piping
- ASTM D2839, Standard Practice for Using Melt Index Strand for Determining Density of Polyethylene
- ASTM F412, Standard Terminology Relating to Plastic Piping Systems
- ASTM F1248, Standard Test Method for Determination of Environmental Stress Crack Resistance (ESCR) of Polyethylene Pipe
- ASTM F1473, Standard Test Method for Notch Tensile Test to Measure the Resistance to Slow Crack Growth (SCG) of PE Pipes and Resins (PENT)
- PPI TR-3, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB) and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe"
- PPI TR-4, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe"

26B.4.2 Thermoset Plastic Components

The following are example component specifications:

- ASTM D2996, Standard Specification for Filament-Wound "Fiberglass" (Glass-Fiber-Reinforced-Thermosetting-Resin) Pipe
- ASTM D2997, Standard Specification for Centrifugally Cast "Fiberglass" (Glass-Fiber-Reinforced Thermosetting-Resin) Pipe
- ASTM D3299, Standard Specification for Filament-Wound Glass-Fiber-Reinforced Thermoset Resin Chemical-Resistant Tanks

- ASTM D3517, Standard Specification for Fiberglass (Glass-Fiber-Reinforced Thermosetting Resin) Pressure Pipe
- ASTM D4021, Standard Specification for Glass Fiber-Reinforced Polyester Underground Petroleum Storage Tanks
- ASTM D4024, Standard Specification for Machine Made "Fiberglass" (Glass-Fiber-Reinforced-Thermosetting Resin) Flanges
- ASTM D4097, Standard Specification for Contact-Molded Glass-Fiber-Reinforced Thermoset Resin Corrosion-Resistant Tanks
- ASTM D5421, Standard Specification for Contact Molded "Fiberglass" (Glass-Fiber-Reinforced Thermosetting Resin) Flanges
- ASTM D5685, Standard Specification for "Fiberglass" (Glass-Fiber-Reinforced Thermosetting-Resin) Pressure Pipe Fittings
- ASTM D5813, Standard Specification for Cured-in-Place Thermosetting Resin Sewer Pipe
- ASTM D6041, Standard Specification for Contact-Molded "Fiberglass" (Glass-Fiber-Reinforced-Thermosetting Resin) Corrosion Resistant Pipe & Fittings
- AWWA C950, Standard for Glass-Fiber-Reinforced Thermosetting-Resin Pressure Pipe

Additionally, the use of standard practices, standard terminology, and engineering properties for thermoset plastic components tabulated in industry published documents derived in accordance with an applicable technical code or standard can provide the Owner with the assurance of quality Design Specifications:

- ASTM D570, Standard Test Method for Water Absorption of Plastics
- ASTM D648, Standard Test Method for Deflection Temperature of Plastics Under Flexural Load in the Edgewise Position
- ASTM D2583, Test Method for Indentation Hardness of Rigid Plastics by Means of Barcol Impressor
- ASTM F1668, Standard Guide for Construction Procedures for Buried Plastic Pipe

26B.4.3 Graphite Components

Polymer impregnated graphite components are extensively utilized throughout the chemical industry, especially in heat exchangers, due to corrosion resistance from exotic chemicals and its high thermal conductivity properties.

The fabricator typically uses certified material that is manufactured per a written procedure specification. The procedure specification must address all essential variables per ASME BPV Code Section VIII Division 1 (Part UIG-77). These essential variables are:

- Graphite material
  - Manufacturer
  - Grade
  - Density
  - Grain size
- Impregnating agent (polymer)
  - Manufacturer
  - Type
  - Density
  - Viscosity
  - Non-volatile components range
- Impregnation process
  - Process pressure range
  - Process time range
    - Vacuum
    - Pressure
    - At temperature
  - Process temperature range
  - Vacuum ranges

Additionally, the use of standard practices, standard terminology, and engineering properties for graphite components tabulated in industry published documents derived in accordance with an applicable technical code or standard can provide the Owner with the assurance of quality Design Specifications:

- ASTM C709, Standard Terminology Related to Manufactured Carbon and Graphite
- ASME C838, Standard Test Method for Bulk Density for As-Manufactured Carbon and Graphite Shapes
- ASTM D346, Standard Practice for Collection and Preparation of Coke Samples for Laboratory Analysis
- ASTM D2638, Standard Test Method for Real Density of Calcined Petroleum Coke by Helium Pycnometer

26B.5 JOINING OF NONMETALLIC COMPONENTS (AND SUB-COMPONENTS)

26B.5.1 Thermoplastic Joining

Some example ASME codes and ASTM standards applicable to the joining of thermoplastic components are:

- ASME BPV Code, Section IX, Article XXI, Plastic Fusing General Requirements
- ASME BPV Code, Section IX, Article XXII, Fusing Procedure Qualification
- ASME BPV Code, Section IX, Article XXIII, Plastic Fusing Performance Qualifications
- ASME BPV Code, Section IX, Article XXIV, Plastic Fusing Data
- ASTM C1147, Standard Practice for Determining the Short Term Tensile Weld Strength of Chemical Resistant Thermoplastics
- ASTM D2657, Standard Practice for Heat Fusion Joining of Polyolefin Pipe and Fittings
- ASTM D3261, Standard Practice for Butt Heat Fusion Polyethylene (PE) for Plastic Fittings for Polyethylene (PE) Plastic Pipe and Fittings
- ASTM F905, Standard Practice for Qualification of Polyethylene Saddle Fusion Joints
- ASTM F1055, Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing
- ASTM F1056, Standard Specification for Socket Fusion Tools for Use in Socket Fusion Joining Polyethylene Pipe or Tubing and Fittings
- ASTM F1290, Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings
- ASTM F2620, Standard Practice for Heat Fusion Joining of PE Pipe and Fittings

26B.5.2 Thermoset Plastic Secondary Bonding and Joining

Some example ASME codes and BS standards applicable to joining of thermoset plastic components are:

- ASME B31.1 Code, Power Piping, Nonmandatory Appendix III, Rules for Nonmetallic Piping and Piping Lined with Nonmetals, Paragraph III-5, Fabrication, Assembly, and Erection
- ASME B31.3 Code, Process Piping, Chapter VII, Nonmetallic Piping and Piping Lined With Nonmetals, Part 4, Fluid Service Requirements for Piping Joints
- ASME B31.9 Code, Building Services Piping, Part 3, Selection and Limitation of Components
- ASME BPV Code, Section III, Code Cases N155-2, Fiberglass Reinforced Thermosetting Resin Pipe
- ASME BPV Code, Section X, Fiber-Reinforced Plastic Pressure Vessels, Article RF-7, Special Fabrication Requirements for Joining Components
- ASME RTP-1 Standard, Reinforced Thermoset Plastic Corrosion Equipment
- BS 4994 Standard, Specification for Design and Construction of Vessels and Tanks in Reinforced Plastics

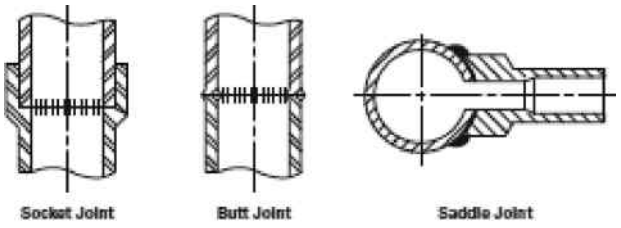


FIG. 26B.5.1-1 THERMOPLASTIC HEAT FUSION JOINING ALTERNATIVES (*Source*: ASME B31.3 Code).

26B.5.3 Graphite Joining

The graphite joining process is controlled within the ASME BPV Code Section VIII, Division 1, Part UIG, Requirements for Pressure Vessels Constructed of Impregnated Graphite, by a Certified Material Specification (UIG-77), a Certified Cement Specification (UIG-78), a Certified Cementing Procedure Specification (UIG-79), and a Cementing Technician Qualification (UIG-80).

See Figure 26B.5.3-1 for example joints for a graphite heat exchanger.

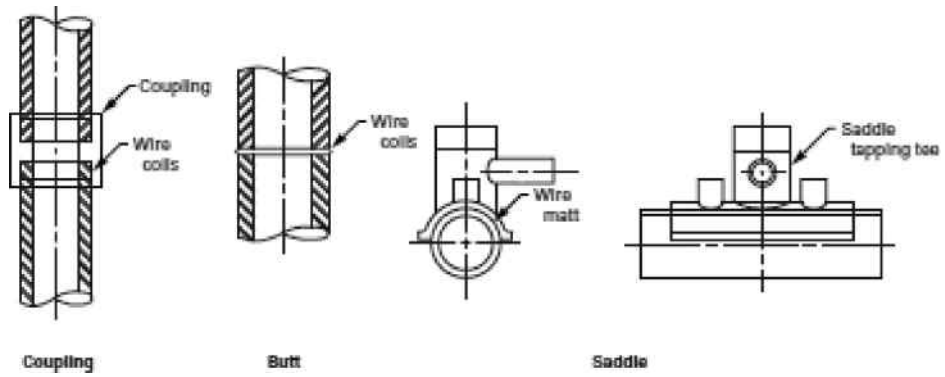


FIG. 26B.5.1-2 THERMOPLASTIC ELECTRO-FUSION JOINING ALTERNATIVES (*Source*: ASME B31.1 Code).

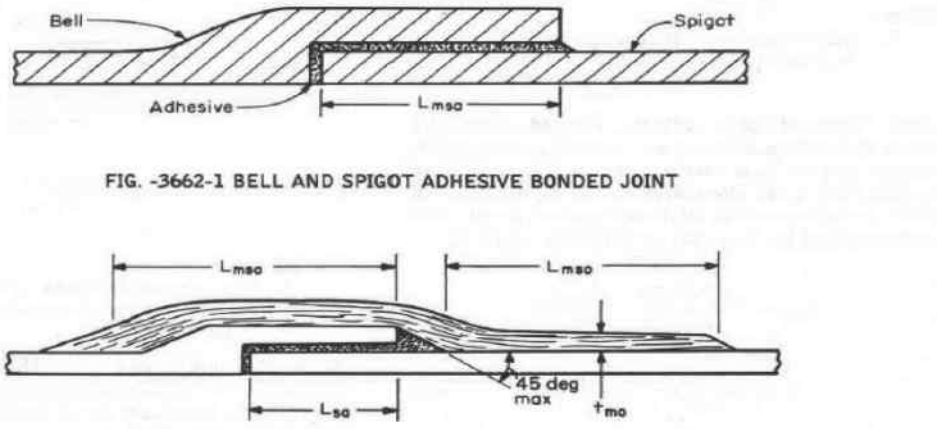


FIG. 26B.5.2-1 THERMOSET JOINING ALTERNATIVES (*Source*: ASME BPV Code Case N-155-2).

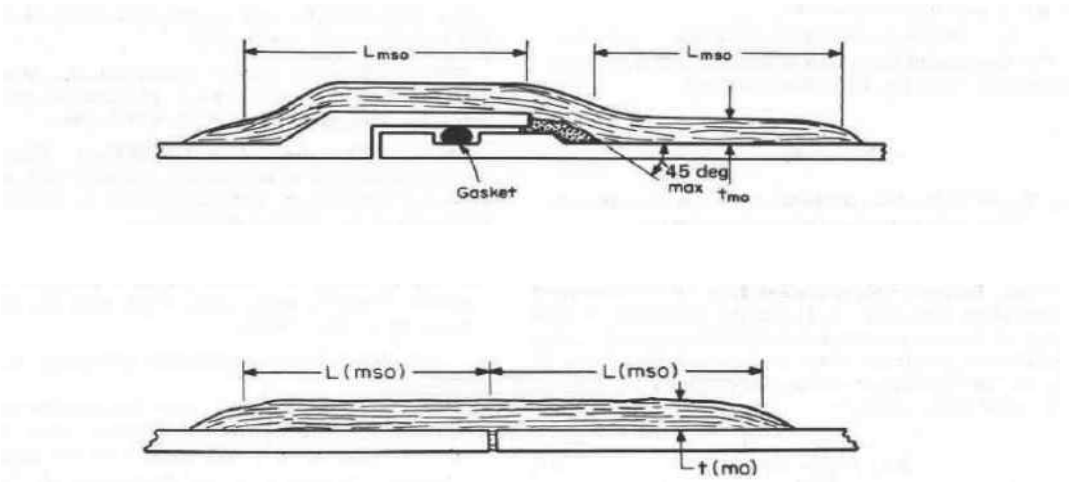


FIG. 26B.5.2-1 THERMOSET JOINING ALTERNATIVES (CONT.) (*Source*: ASME BPV Code Case N-155-2).

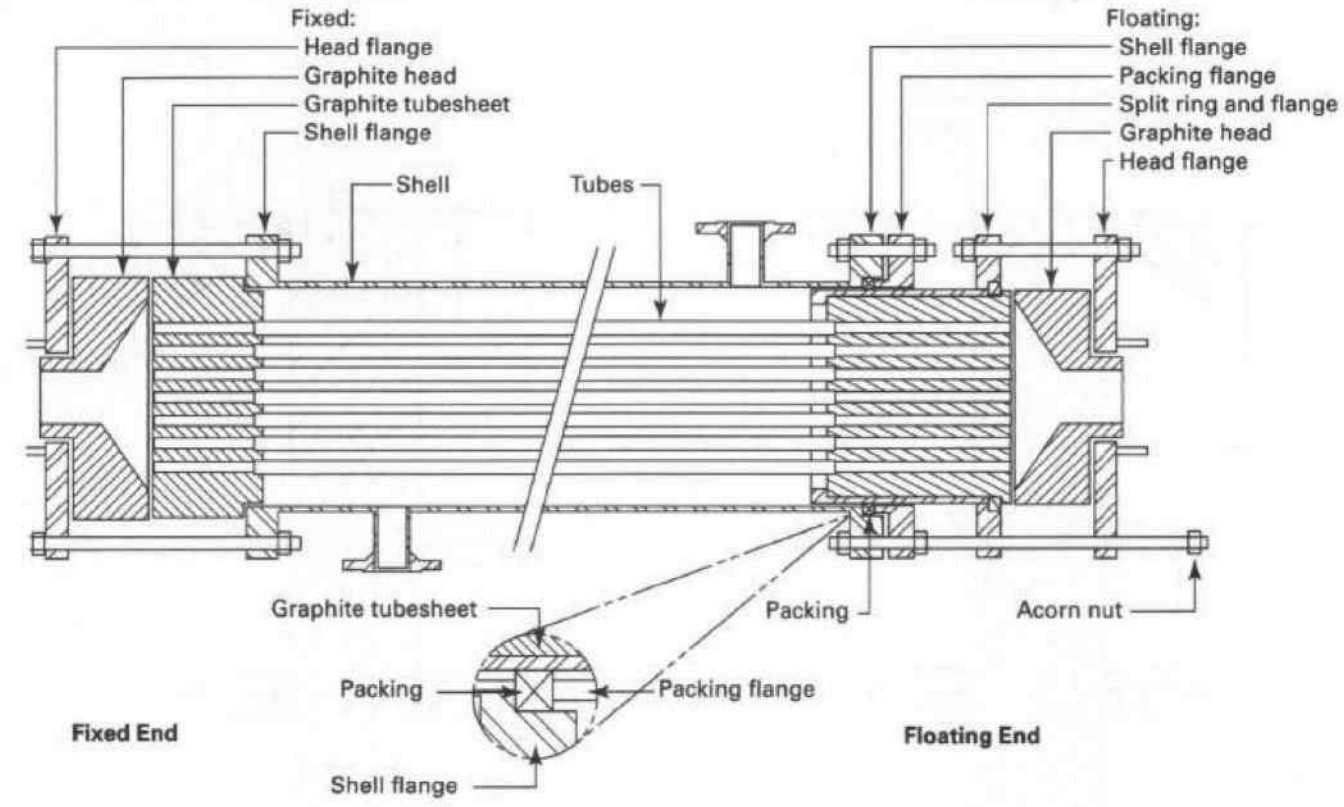


FIG. 26B.5.3-1 GRAPHITE JOINING WITHIN COMPONENT (*Source*: ASME BPV Code, Section VIII, Division 1, Part UIG).

26B.6 APPLICATION PROBLEMS

The process fluid requirements and the external environment can have a major impact on the degradation of the nonmetallic material (and the metallic material). These requirements need to be addressed in the Design Specification.

The Design Specification needs to be developed by an engineer who is knowledgeable in the application of the specific nonmetallic materials being applied. This Design Specification is required to be reviewed and certified by a Professional Engineer (P.E.), who is registered in one or more of the states of the United States of America or the provinces of Canada. Additionally this Professional

Engineer needs to be experienced in the application of the nonmetallic material being utilized for the specified nonmetallic component. The review and certification is to ensure that the work involved in the Design application is compatible with the user's Design Specification and the Fabricator's Data Report.

When a component is rerated, the rerating process needs to be performed in accordance with the requirements of the construction standard to which the pressure-retaining component was originally built.

26B.7 QUALITY ASSURANCE (QA)

QA has three major aspects:

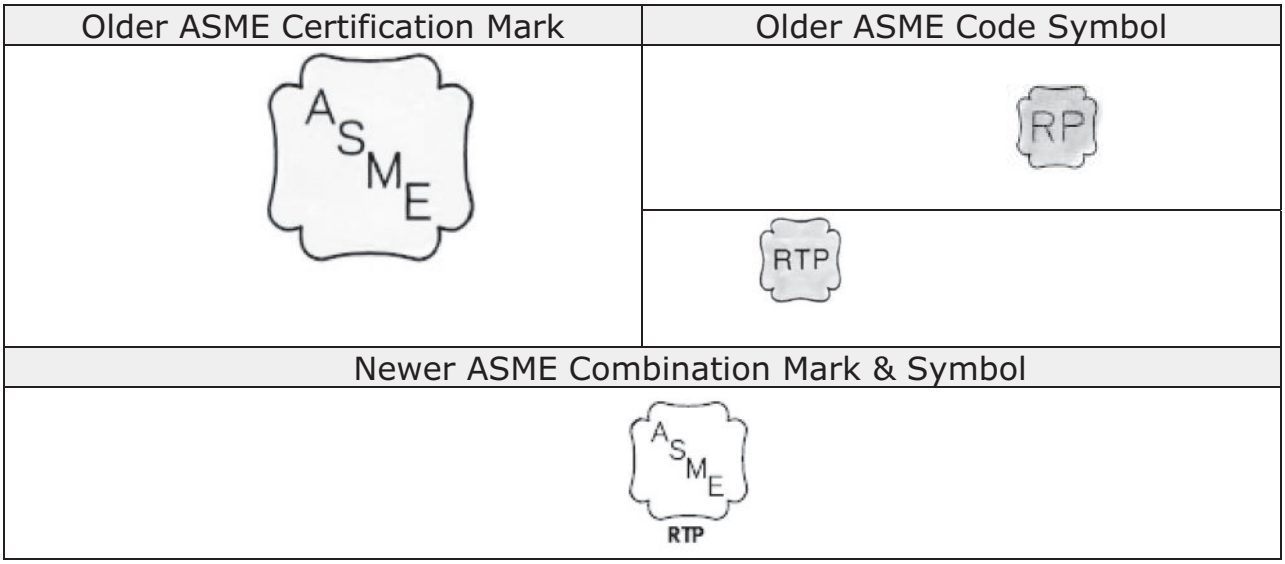
- Internal QA performed by the fabricator of the component or the erection of the fluid system at the facility site.
- Owner QA performed by the owner of the facility that is being constructed (or operated).
- Third Party QA, which is typically invoked by the construction code or the owner of the facility.

Use of third party QA is mandated by a number of ASME construction codes. Some examples are:

- Components (pressure vessels) constructed to the ASME BPV Code, Section X, have an "R" stamp or mark.
- Components (tanks) constructed to the ASME RTP-1 Standard have an "RTP" stamp or mark.
- The ASME provides the third party organization to ensure that the fabricator constructs the tank to the requirements of the ASME RTP-1 Standard.

Some example ASME Code Symbol stamps are:

The RP mark is for FRP vessels constructed to the ASME BPV Code Section X requirements. The RTP mark is for FRP tanks constructed to the ASME RTP-1 Standard.



26B.8 SENSITIVE ASPECTS OF NONMETALLIC FABRICATION PROCESSES

26B.8.1 Thermoplastic Materials

Since the thermoplastic material is typically provided by the supplier as pellets, the control of that process environment has the most impact on the quality of the final product (e.g., pipe, flange, fitting).

26B.8.2 Thermoset Plastic Materials

For a thermoset plastic material to develop its full design strength, the reinforcing fibers need to be fully saturated with the polymer. In addition excess polymer and entrained gasses (typically air) need to be removed. Also the profile of metallic and cured nonmetallic surfaces needs to be properly prepared to achieve the desired adhesion. Finally the process environment needs to be closely controlled to achieve the design product parameters.

26B.8.3 Graphite Materials

Since graphite materials are typically impregnated with thermoset polymers, control of the graphite matrix and the driving force (e.g., vacuum) to displace the gases out of the graphite matrix and replace with polymer has the most impact on the quality of the final product (e.g., heat exchanger).

26B.9 CONCLUSIONS

Use of nonmetallic piping systems in plant pipework applications can be superior to metallic piping systems, especially in corrosive environments and long service life applications.

For properly constructed nonmetallic piping systems, adherence to the requirements of the ASME, API, AWWA, and BS construction codes and standards must be insured.

The key requirement is the use of detailed Design Specifications, based on industry codes and standards.

Since volumetric and surface NDE/NDT is not always possible, developing and implementing detailed process controls is very important for a successful construction process.

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CHAPTER

27

ASME SECTION XI DEVELOPMENTS IN EVALUATION PROCEDURES FOR NUCLEAR PIPING DEGRADED BY FLAWS AND CORROSION PROCESSES IN RESPONSE TO LESSONS LEARNED

Douglas A. Scarth

27.0 OUTLINE

This chapter summarizes past and ongoing developments in flaw Acceptance Standards and analytical evaluation procedures in Section XI of the ASME B&PV Code for nuclear piping degraded by flaws and corrosion processes that are in response to industry needs and lessons learned. A significant number of revisions have been made to address intergranular stress corrosion cracking in Boiling Water Reactor Class 1 austenitic piping, and primary water stress corrosion cracking in Alloys 82, 182, and 132 dissimilar metal welds in piping in Pressurized Water Reactors. More recent revisions to Section XI, as well as developments that are under review in Section XI, to address stress corrosion cracking are described in this chapter. A major revision to the flaw Acceptance Standards was to prohibit application to planar surface flaws that are detected in piping materials that are susceptible to stress corrosion cracking and are in contact with reactor coolant environments.

A major revision to the evaluation procedures and acceptance criteria to improve consistency with piping design intent was first published in the 2002 Addenda to Section XI, and the technical basis for these changes is summarized in this chapter. Highlights of improvements to evaluation procedures and acceptance criteria for wall thinning due to flow-accelerated corrosion, as well as for temporary acceptance flaws including through-wall flaws in moderate energy Classes 2 and 3 piping systems, which are currently under review in Section XI, are described. In addition, evaluation procedures and acceptance criteria for evaluation of flaws in metallic piping buried in a back-filled trench have recently been published, and this chapter provides a description of the evaluation methods.

Changes to the pipe flaw evaluation procedures in Section XI are supported by technical basis documents, and a number of these documents are listed in the references for this chapter.

27.1 INTRODUCTION

Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code [1] provides requirements for maintaining pressure boundary integrity of components, piping, and equipment during the life of a nuclear power plant. Pressure boundary integrity includes prevention of leakage from the reactor coolant system, as well as structural integrity in terms of prevention of rupture or burst of the pressure boundary. ASME Section XI provides specific rules for evaluating flaw indications that may be detected during the service life of a nuclear piping item. Flaw evaluation procedures for piping were developed in response to an industry need to address pipe cracking events starting in the mid-to-late 1970s. Flaw evaluation procedures for austenitic piping were introduced into Section XI in the Winter 1983 Addendum. Flaw evaluation procedures for ferritic piping were subsequently introduced into Section XI in the Winter 1989 Addendum.

Evaluations of both planar and nonplanar flaws are addressed by ASME Section XI. The evaluation procedures and acceptance criteria cover failure by plastic collapse as characterized by limit load analysis, fracture due to ductile tearing prior to attainment of limit load as characterized by elastic-plastic fracture mechanics (EPFM) analysis, and brittle fracture as characterized by linear elastic fracture mechanics (LEFM) analysis. The flaw evaluation procedures include subcritical crack growth due to fatigue and

stress corrosion cracking. The evaluation procedures are based on synthesis of, and validation against, experimental results.

Committees under ASME Section XI update flaw Acceptance Standards and analytical flaw evaluation procedures on an ongoing basis in response to industry needs and lessons learned from inservice degradation of piping items as well as from user experience with Section XI. This chapter summarizes developments in flaw Acceptance Standards and analytical evaluation procedures in Section XI for nuclear piping degraded by flaws and corrosion processes. There has been a history of Intergranular Stress Corrosion Cracking (IGSCC) in Boiling Water Reactor (BWR) Class 1 austenitic piping, and Primary Water Stress Corrosion Cracking (PWSCC) in Alloy 82, 182 and 132 dissimilar metal welds in piping in Pressurized Water Reactors (PWRs). Actions to mitigate IGSCC and PWSCC have been implemented in a number of plants. At the same time, it was determined that procedures needed to be developed to evaluate flaws in piping systems susceptible to IGSCC and PWSCC. A significant number of revisions have been made to the Section XI flaw Acceptance Standards and analytical evaluation procedures to address IGSCC and PWSCC. Such revisions are published on an ongoing basis. A major revision to the evaluation procedures and acceptance criteria to improve consistency with piping design intent was first published in the 2002 Addenda to Section XI. Recent developments and work in progress to address stress corrosion cracking in piping items include crack growth rates and weld residual stresses. Improved transition temperatures for the onset of upper shelf behavior in ferritic piping to reduce conservatism have been developed.

There has also been a history of wall thinning due to flow-accelerated corrosion, as well as wall loss due to other corrosion mechanisms, in nuclear piping systems. It was determined that procedures needed to be developed to evaluate wall thinning and wall loss due to these corrosion mechanisms. Improvements to evaluation procedures and acceptance criteria for wall thinning due to flow-accelerated corrosion, as well as for temporary acceptance flaws including through-wall flaws in moderate energy Classes 2 and 3 piping systems, are in progress. In addition, based on service experience with leakage from buried piping, evaluation procedures and acceptance criteria for evaluation of flaws in buried piping have recently been published. Changes to the pipe flaw evaluation procedures in Section XI are supported by technical basis documents, and a number of these documents are listed in the references for this chapter.

In the 2007 Edition to ASME Section XI, the phrase "safety factor" was replaced with the phrase "structural factor" to maintain consistency with the same revision made to other Sections of the ASME Code. The phrase "structural factor" is used in this chapter, and should be considered synonymous with "safety factor" in Editions and Addenda prior to the 2007 Edition.

27.2 OVERVIEW OF ASME SECTION XI FOR EVALUATION OF PLANAR FLAWS

Detailed descriptions of flaw evaluation procedures in ASME Section XI, including flaw growth, are provided in Chapters 30 and 32 of Volume 2 of the Fourth Edition of the *Companion Guide to the ASME Boiler and Pressure Vessel Code* [2]. A very brief summary is provided below.

27.2.1 Basic Steps for Pipe Flaw Evaluation in ASME Section XI

The steps that are generally followed in a flaw evaluation are given below.

(a) The piping item is examined. The scope and extent of the examination, including the inspection method to be used (i.e., volumetric, surface, or visual) are defined in IWB-2500, IWC-2500 and IWD-2500 of ASME Section XI for Classes 1, 2, and 3 piping items, respectively. When an inspection signal exceeds the detection threshold limit from calibration, the flaw indication is reportable.

(b) When no reportable flaw indications are found, the piping item is acceptable with no need for further evaluation.

(c) When a reportable flaw indication is found, the flaw geometry is determined from the inservice inspection results in accordance with IWA-3300 of Section XI. Flaw dimensions must be determined by the size of a rectangle or square that fully contains the area of the flaw. The length, ℓ, of the rectangle or one side of the square is parallel to the inside pressure retaining surface of the piping item. The depth of the rectangle or one side of the square is normal to the inside pressure retaining surface of the piping item, and is denoted as a for a surface flaw and $2a$ for a subsurface flaw. Characterization of a planar circumferential flaw is illustrated in Figure 27.1, and of a planar axial flaw in Figure 27.2.

(d) Multiple flaws in close proximity are combined in accordance with the requirements of IWA-3330 of Section XI.

(e) The flaw dimensions are compared with the allowable flaw dimensions in the Section XI Acceptance Standards.

(f) When the flaw size is less than the allowable flaw size in the Acceptance Standards, the flaw is acceptable with no need for further evaluation.

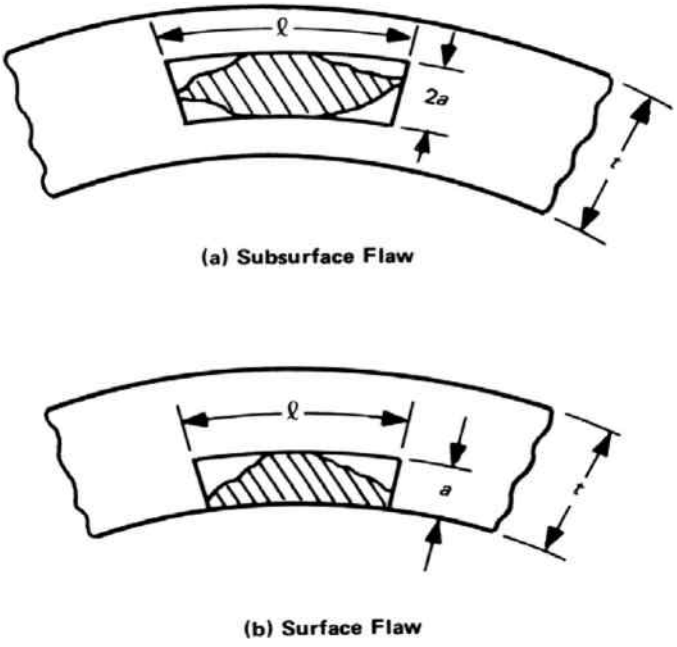


FIGURE 27.1 CHARACTERIZATION OF CIRCUMFERENTIAL PART-THROUGH-WALL PLANAR FLAWS (*Source*: Figure C-2200-1 of Appendix C of Section XI of ASME B&PV Code)

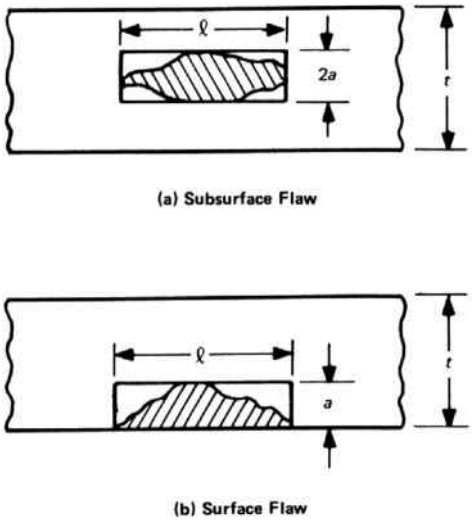


FIGURE 27.2 CHARACTERIZATION OF AXIAL PART-THROUGH-WALL PLANAR FLAWS (*Source*: Figure C-2200-2 of Appendix C of Section XI of ASME B&PV Code)

(g) When the flaw size exceeds the allowable flaw size in the Acceptance Standards, one of the following actions must be followed:

(h) The flaw may be evaluated for acceptance using analytical procedures that are provided in Section XI. The flaw must then be re-inspected prior to the end of the evaluation period.

(i) The piping item may be repaired or replaced.

Procedures and acceptance criteria that are an alternative to those in the main body of Section XI are provided in Code Cases. Code Cases generally reflect improvements to technology or a response to an immediate industry need. The contents of Code Cases are generally incorporated into the main body of the Code at a later date.

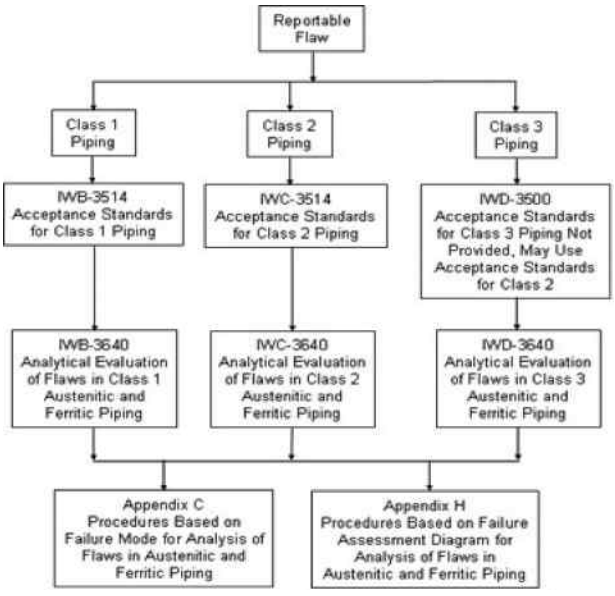


FIGURE 27.3 STRUCTURE OF PROCEDURES FOR PIPE FLAW EVALUATION IN SECTION XI OF ASME B&PV CODE

27.2.2 Structure of Pipe Flaw Evaluation Procedures

The structure of procedures for pipe flaw evaluation in the current Edition of ASME Section XI is shown in Figure 27.3. Acceptance Standards for flaws in Class 1 ferritic and austenitic piping are provided in IWB-3514 of Section XI, and for Class 2 austenitic piping in IWC-3514. Acceptance Standards for flaws in Class 2 austenitic piping may be used for Class 3 austenitic piping. Acceptance Standards for flaws in Classes 2 and 3 ferritic piping are under development, and Section XI permits use of the Class 1 Acceptance Standards for Classes 2 and 3.

For Class 1 piping, procedures and acceptance criteria for analytical evaluation of flaws in austenitic and ferritic piping in the 2001 Edition of Section XI were combined into a new IWB-3640 for both austenitic and ferritic piping in the 2002 Addenda. The nonmandatory Appendix C in the 2001 Edition for evaluation of flaws in austenitic piping, and the nonmandatory Appendix H in the 2001 Edition for evaluation of flaws in ferritic piping, were combined into a new nonmandatory Appendix C for evaluation of flaws in Classes 1, 2, and 3 austenitic and ferritic piping based on failure mode determination in the 2002 Addenda. IWB-3642 refers the Code user to Appendix C. A new nonmandatory Appendix H in the 2002 Addenda provides evaluation procedures and acceptance criteria for flaws in Classes 1, 2, and 3 austenitic and ferritic piping based on the Failure Assessment Diagram procedures of Code Case N-494-4 [3]. IWB-3643 refers the Code user to Appendix H.

For Class 2 piping, acceptance criteria for evaluation of flaws in austenitic and ferritic piping are given in IWC-3640. IWC-3642 provides acceptance criteria based on failure mode determination. IWC-3642 refers the Code user to nonmandatory Appendix C for evaluation of flaws in austenitic and ferritic piping. IWC-3643 provides acceptance criteria based on use of a Failure Assessment Diagram. IWC-3643 refers the Code user to nonmandatory Appendix H for evaluation of flaws in austenitic and ferritic piping based on use of a Failure Assessment Diagram.

For Class 3 piping, similar acceptance criteria are provided in the corresponding IWD-3600, IWD-3642 and IWD-3643, as well as Appendices C and H.

The flaw evaluation procedures cover the following nuclear grade austenitic piping materials: SA-312 TP304, SA-312 TP304L, SA-312 TP304N, SA-312 TP316L, SA-312 TP316LN, SA-376 TP316, SA-376 TP316N, SA-451 CF8M, as well as other similar austenitic piping materials and welds. The flaw evaluation procedures also cover the following nuclear grade ferritic piping materials: SA-333 Gr. 1, SA-106 Gr. B, SA-106 Gr. C, SA-105, as well as other similar ferritic piping materials and welds.

27.2.3 Analytical Evaluation Procedures and Acceptance Criteria for Planar Flaws

The analytical evaluation procedures and acceptance criteria for planar flaws are applicable to nominal pipe sizes NPS 1 (DN 25) or greater. The analytical procedures are generally applicable to straight pipe and portions of pipes and fittings within a distance of $(R_o t)^{1/2}$ of the weld centerline, where R_o is the pipe outside radius and t is the pipe wall thickness. This restriction is to limit the evaluation primarily to weldment areas of pipe and fittings where stresses determined by traditional piping stress analysis methods and Code procedures are most applicable. The following is the general approach in ASME Section XI for the analytical evaluation of a flaw in a piping item.

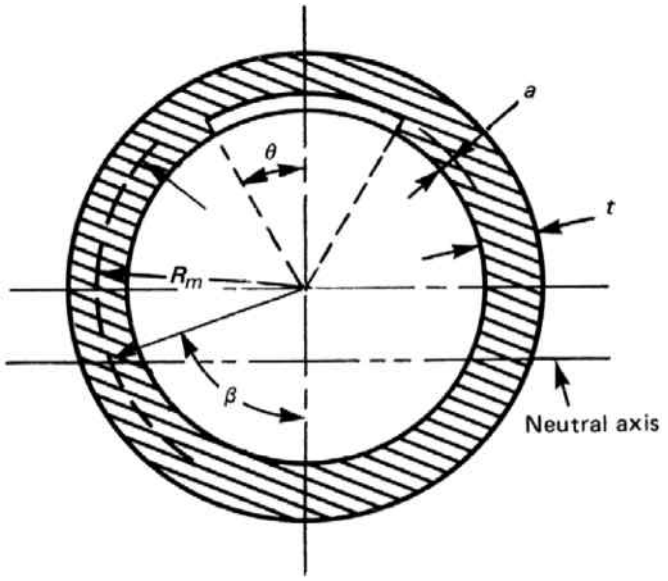


FIGURE 27.4 CIRCUMFERENTIAL PART-THROUGH-WALL PLANAR FLAW (*Source*: Figure C-4310-1 of Appendix C of Section XI of ASME B&PV Code)

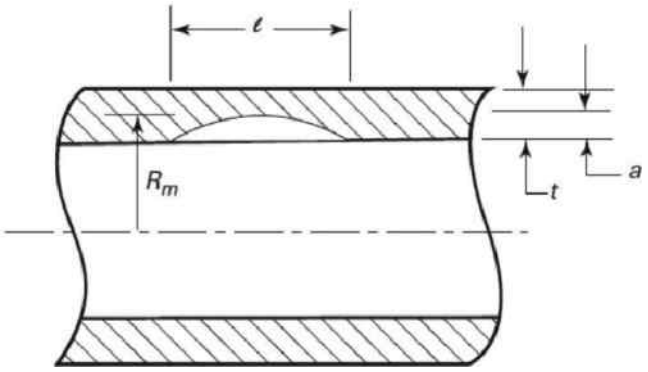


FIGURE 27.5 AXIAL PART-THROUGH-WALL PLANAR FLAW (*Source*: Figure C-4310-2 of Appendix C of Section XI of ASME B&PV Code)

(a) The flaw geometry from the inservice inspection results is idealized for the purpose of the analytical evaluation. The actual flaw is resolved into circumferential and axial components. The geometry of a circumferential planar flaw in a pipe is illustrated in Figure 27.4, and of an axial planar flaw in Figure 27.5.
(b) The stresses normal to the flaw at the flaw location for ASME Service Level A, B, C, and D Loadings are determined.
(c) Pipe material properties are determined.
(d) A subcritical flaw growth analysis is performed to establish the end-of-the-evaluation-period flaw dimensions. For planar flaws, flaw growth due to fatigue and stress corrosion cracking is determined as appropriate. Flaw growth can result in a change to the flaw depth divided by flaw length aspect ratio. Flaws in close proximity may need to be combined after predicted flaw growth. Except as noted later in this chapter, planar flaws with depth greater than 75% of the wall thickness are unacceptable. For nonplanar flaws, the end-of-the-evaluation-period minimum remaining wall thickness is determined.
(e) The allowable flaw size or allowable applied stress levels are determined.
(f) The flaw is evaluated against the acceptance criteria using the end-of-the-evaluation-period flaw dimensions.

The stresses that are used in the flaw evaluation are the local nominal stresses as calculated in the absence of the flaw. These stresses do not contain any stress multipliers, such as stress indices or stress intensification factors. The fracture mechanics methods are based on fracture models that are used in conjunction with the local nominal stresses at the flaw location.

27.3 STRESS CORROSION CRACKING IN NUCLEAR PIPING ITEMS

Starting in the mid 1970s, Intergranular Stress Corrosion Cracking (IGSCC) was detected in sensitized welds in austenitic stainless steel piping. A evaluation procedure and acceptance criteria based on limit load analysis for flaws in austenitic stainless steel piping were first published in the Winter 1983 Addendum to ASME Section XI. The evaluation procedure in the 1983 Winter Addendum was applicable to all wrought and cast austenitic piping product forms. In 1985, the flaw evaluation procedure was revised to distinguish between high toughness materials and certain lower toughness flux welds, which include shielded metal arc welds (SMAW) and submerged arc welds (SAW). For these welds, elastic-plastic fracture mechanics (EPFM) analysis methods were used. A number of revisions to these flaw evaluation procedures have since been made. Flaw evaluation procedures in Section XI that address IGSCC in BWR piping are described in detail in Chapters 30 and 32 of Reference [2]. Items that are supplemental to Chapters 30 and 32 of Reference [2] are described in this chapter.

Dissimilar metal welds such as between a ferritic steel nozzle and an austenitic stainless steel pipe or safe-end have in the past been fabricated using Alloys 82 and/or 182 weld filler metal. Alloys 600, 82 and 182 have been found to be susceptible to Primary Water Stress Corrosion Cracking (PWSCC) in PWR primary coolant environments. For example, an axial through wall crack was detected in the dissimilar metal circumferential weld at a reactor pressure vessel outlet nozzle in the V.C. Summer nuclear plant [4]. The main driving force for PWSCC in dissimilar metal welds is the high levels of weld residual stresses. In particular, the residual stresses in a repair weld are relatively large and can increase susceptibility to PWSCC. The weld with the through-wall crack in the V.C. Summer outlet nozzle was the site of weld repairs.

A significant amount of the developments in flaw evaluation procedures for piping have been made to address IGSCC in BWR piping and PWSCC in PWR piping. A detailed description of the pipe flaw evaluation procedures is provided in Chapter 30 of Reference [2], and of procedures for calculation of subcritical crack growth rate in Chapter 32 of Reference [2]. Some recent revisions are described in this chapter.

27.4 REVISIONS TO FLAW ACCEPTANCE STANDARDS

Acceptance Standards for allowable planar flaw sizes in piping are provided in Section XI to permit acceptance of relatively

small flaws without the need to perform an analytical evaluation. The Acceptance Standards are based on maintaining large margins against failure, and are based on the assumption that flaw growth will be insignificant.

27.4.1 Revisions to Acceptance Standards for Planar Flaws in Piping to Improve Consistency

Prior to the 2009 Addenda to ASME Section XI, separate Acceptance Standards tables of allowable flaw sizes were provided for austenitic and ferritic piping, as well as for flaws detected by preservice and inservice inspection. It was found that there were inconsistencies in allowable flaw sizes for austenitic and ferritic piping considering differences in fracture toughness. Inconsistencies in the treatment of a subsurface flaw that transitions into a surface flaw, as the subsurface flaw approaches that free surface, were also found. In addition, there was no reason for differences in allowable flaw sizes for preservice and inservice inspection. Revisions to the Acceptance Standards allowable flaw sizes were developed as described in Ref. [5]. The revised Acceptance Standards allowable flaw size tables eliminated these inconsistencies while maintaining the overall margins on stress in the previous allowable flaw size tables.

In the 2009 Addenda to Section XI, the existing Table IWB-3514-1 that contained Acceptance Standards of allowable planar flaw sizes for Class 1 ferritic piping, and Table IWB-3514-2 that contained Acceptance Standards of allowable planar flaw sizes for Class 1 austenitic piping, were replaced with a new Table IWB-3514-1 for flaw Acceptance Standards for Class 1 ferritic and austenitic piping for use with volumetric examination only. In the new Table IWB-3514-1, the same flaw Acceptance Standards are given for preservice and inservice examination. Prior to the 2009 Addenda to Section XI, there were no specific Acceptance Standards for Classes 2 and 3 piping in Section XI. Since the 2009 Addenda, Acceptance Standards for Classes 2 and 3 austenitic piping were also developed by applying the methodology used to develop the new Acceptance Standards for Class 1 piping. The allowable flaw depths for Classes 2 and 3 austenitic piping are the same as for Class 1. A new IWC-3514 and Table IWC-3514-1 for Acceptance Standards for flaws in Class 2 piping were added in the 2009 Addenda. Allowable flaw sizes are provided for both surface flaws and subsurface flaws for preservice and inservice examinations. Based on the similarity of Classes 2 and 3 piping, and on structural integrity considerations, Table IWC-3514-1 is also applicable to Class 3 austenitic piping.

27.4.2 Revisions to Flaw Acceptance Standards for Materials Susceptible to Stress Corrosion Cracking

The assumption of a small amount of flaw growth in the Acceptance Standards is justified when fatigue crack growth is the only crack growth mechanism. However, when stress corrosion cracking is operative, flaw growth could be significant. Based on calculations for stress corrosion cracking, a planar surface flaw could grow by stress corrosion cracking to a through-wall, leaking flaw in less than the Section XI 10-year inspection interval. For this reason, IWB-3514 of Section XI was revised in the 2006 and 2009 Addenda to prohibit use of the Acceptance Standards for planar surface flaws that are detected in piping materials that are susceptible to stress corrosion cracking and are in contact with reactor coolant environments [6]. The technical basis for this revision is summarized below.

27.4.2.1 Example Calculations of Stress Corrosion Cracking Growth of Initial Allowable Flaw Size for BWR Environment Example calculations of the amount of crack growth due to fatigue as compared with IGSCC in austenitic stainless steel piping over the service life of the component are provided in Ref. [6]. The initial flaw sizes were the allowable flaw sizes in accordance with the flaw Acceptance Standards. In the example calculations, circumferential part-through-wall planar flaws were postulated in the Primary Loop Recirculation system in a BWR, which has a service history of IGSCC. Calculations were performed for two Schedule 100 pipe sizes. The first is a nominal pipe size of NPS 12 (DN 300), with a wall thickness of 0.843 in. (21.4 mm). The second is a nominal pipe size of NPS 24 (DN 600), with a wall thickness of 1.53 in. (38.9 mm). The piping material was Type 316 stainless steel, with a normal operating temperature of 572°F (300°C). Calculations were performed for circumferential part-through-wall planar flaws with initial aspect ratios a/ℓ of 0.1, 0.3 and 0.5. Results of the IGSCC crack growth calculations for the postulated circumferential part-through-wall planar flaw with an initial aspect ratio a/ℓ in the NPS 12 (DN 300) Primary Loop Recirculation piping are given in Figure 27.6 [6]. From Figure 27.6, the initial flaw in NPS 12 (DN 300) Primary Loop Recirculation piping that are allowable according to the Acceptance Standards for surface flaws in piping were predicted to reach a depth of 80% of the wall thickness after a time period in the range of 35 months.

If fatigue was the only mechanism of crack growth, allowable flaws in NPS 12 (DN 300) Primary Loop Recirculation piping

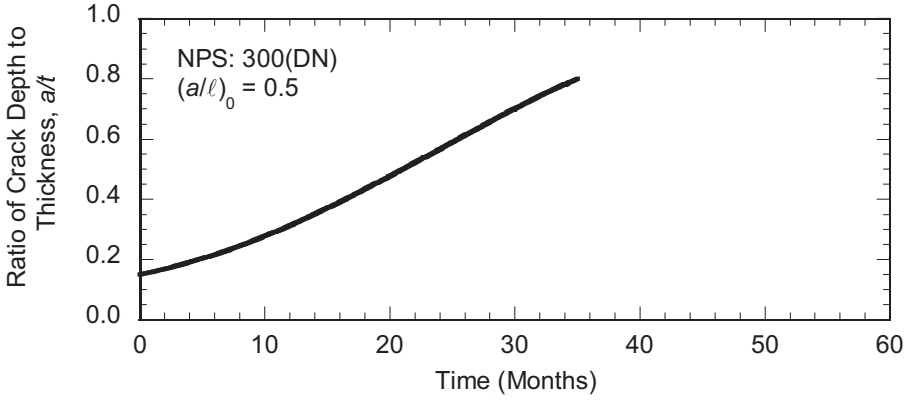


FIGURE 27.6 IGSCC CRACK GROWTH CALCULATION RESULTS FOR CIRCUMFERENTIAL FLAWS IN BOILING WATER REACTOR NPS 12 (DN 300) PRIMARY LOOP RECIRCULATION PIPING (*Source*: Figure 7 of Ref. [6])

would be predicted to grow by less than 0.01 in. (0.25 mm) in 10 years [6]. Allowable flaws in NPS 24 (DN 600) Primary Loop Recirculation piping would be predicted to grow by no more than 0.025 in. (0.63 mm) in 10 years. This is a small amount of crack growth, and for this case the Acceptance Standards are applicable. If however, the flaw were to grow by IGSCC, a flaw in NPS 12 (DN 300) Primary Loop Recirculation piping of 10% to 15% of the wall thickness would grow to a through-wall, leaking flaw in approximately 40 months of operation. This period of time is significantly less than the 120 months in a 10-year inspection period. It was concluded that use of the Acceptance Standards for surface flaws in IGSCC susceptible materials is not justified.

27.4.2.2 Example Calculations of Stress Corrosion Cracking Growth of Initial Allowable Flaw Size for PWR Environment Example calculations of the amount of crack growth due to fatigue as compared with PWSCC over the service life of the component are provided in Ref. [6]. The PWSCC growth rate of Alloy 182 is higher than that of Alloy 600 or Alloy 82, and the example calculations were performed for Alloy 182. The Acceptance Standards in IWB-3514 of Section XI provide allowable flaw depths that are typically of the order of 10% of the pipe wall thickness. A flaw with a depth of 10% of the wall thickness of the reactor pressure vessel outlet nozzle to safe-end weld in the example calculations is 0.26 in. (6.6 mm). The projected future growth of this flaw was evaluated for both fatigue and PWSCC over the ten-year time period that is equal to the inspection frequency required by Section XI. If fatigue was the only mechanism of crack growth, the flaw would be predicted to grow less than 0.01 in. (0.25 mm) in 10 years, for either a circumferential or axial flaw. This is a very small amount of crack growth, and for this case the Acceptance Standards are applicable. If however, the flaw were to grow by PWSCC, a flaw in the outlet nozzle to safe-end weld of initially 10% of the wall thickness would grow to a through-wall, leaking flaw in 20 months for a circumferential flaw, and 56 months for an axial flaw. Both periods of time are significantly less than the 120 months in a ten-year inspection period. It was concluded that use of the Acceptance Standards for surface flaws in PWSCC susceptible materials is not justified.

27.4.2.3 Summary of Revisions to Restrictions for Stress Corrosion Cracking Susceptible Materials The revision to Section XI that prohibits use of the Acceptance Standards in IWB-3514 for planar surface-connected flaws that are detected in materials that are susceptible to stress corrosion cracking that are in reactor coolant environments was first published in the 2006 Addenda to Section XI. The restrictions apply to planar surface-connected flaws detected by either preservice or inservice examination in materials that are susceptible to stress corrosion cracking. There was a need to provide specific criteria of which particular Class 1 piping materials and environments lead to susceptibility to stress corrosion cracking. Based on understanding of the stress corrosion cracking mechanism, as well as industry experience, susceptible materials and environments were specified as Alloys 600, 82, and 182 in BWR or PWR reactor coolant environments, and austenitic stainless steels and associated welds in BWR reactor coolant environments.

As part of the 2009 Addenda, restrictions on use of the Acceptance Standards of IWB-3514 were refined and clarified. The revision in the 2009 Addenda specifies different restrictions and requirements for use of the Acceptance Standards for planar surface flaws that are in contact with reactor coolant environments during normal operation and are detected by either preservice or inservice examination of stress corrosion cracking susceptible material surfaces. The flaw Acceptance Standards are not applicable to planar surface flaws that are in contact with reactor coolant environments during normal operation and are detected by inservice examination in stress corrosion cracking susceptible materials. Since analytical evaluation is not permitted for planar surface flaws detected by preservice examination, there was a need to permit conditional use of the Acceptance Standards for planar surface flaws that are detected by preservice examination in materials susceptible to stress corrosion cracking. In this case, the condition is that the weld must be reexamined twice subsequent to preservice examination, and within 10 years. This requirement ensures that any potential flaw growth due to stress corrosion cracking is detected prior to the flaw reaching an unacceptable size. In addition, similar restrictions have been imposed on use of the Acceptance Standards for such planar surface flaws in Class 2 piping in IWC-3514 of Section XI.

For PWRs, the Acceptance Standards of IWB-3514 do not apply to planar surface flaws in reactor coolant environments in Alloy 600, Alloy 82 or Alloy 182 with a normal operating temperature greater than or equal to 275°C. For BWRs the Acceptance Standards do not apply to planar surface flaws in reactor coolant environments in Alloy 600, Alloy 182, or austenitic stainless steels, and welds, that are susceptible to stress corrosion cracking and are not mitigated. One example of mitigation is stress improvement. The requirements in the 2009 Addenda are less restrictive than in the 2006 Addenda to Section XI.

27.5 REVISED ACCEPTANCE CRITERIA FOR FLAWS IN PIPING TO MAINTAIN DESIGN INTENT MARGINS

For Class 1 piping, it was recognized that ASME Section XI structural factors on load for pipe flaw evaluation were not always consistent with the design intent of ASME Section III [7]. Issues were identified during a number of years that led to the conclusion that the acceptance criteria for pipe flaw evaluation in Section XI needed to be revised to be more consistent with the design intent of Section III [8,9,10,11]. For example, a ferritic pipe with no flaw with stress levels at the limits in NB-3650 of Section III would not meet the acceptance criteria that were in Section XI prior to the 2002 Addenda. As well, there was a need to simplify the flaw evaluation procedures. These and other issues were addressed by the revisions to the procedures and acceptance criteria for flaw evaluation in the 2002 Addenda to Section XI. The revised acceptance criteria for pipe flaw evaluation in the 2002 Addenda to Section XI were intended to reflect the design intent of ASME Section III. While the revised, separate structural factors for Service Level A, B, C and D Loadings for Section XI are not directly related to specific implicit design margins, they are more consistent with the design intent of Section III than the structural factors in the 2001 Edition of Section XI. Section XI contains requirements for inspection of Classes 2 and 3 piping. However, procedures and acceptance criteria for evaluation of flaws in Classes 2 and 3 piping were not provided in the 2001 Edition of Section XI. Procedures and acceptance criteria for evaluation of flaws in Classes 2 and 3 piping were implemented into the 2002 Addenda to Section XI. The detailed technical basis for the revisions to the acceptance criteria for circumferential flaws is given in Ref. [12], and is summarized below. The technical basis for axial flaws is similar, and is also given in Ref. [12].

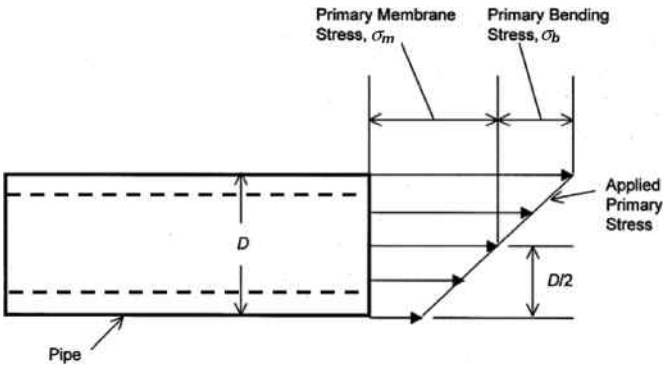


FIGURE 27.7 ILLUSTRATION OF APPLIED LONGITUDINAL PRIMARY MEMBRANE AND BENDING STRESSES (*Source*: Figure 3 of Ref. [49])

27.5.1 Plastic Collapse Equations for Circumferential Flaws and ASME Section III Primary Stress Limits

The longitudinal primary membrane stress, σ_m, and longitudinal primary bending stress, σ_b, are the gross nominal stresses acting over the entire cross-section of the pipe. The longitudinal primary membrane and bending stresses are illustrated for a pipe of outside diameter D in Figure 27.7. With reference to Figure 27.4, for circumferential flaws not penetrating the compressive region of the pipe such that $(\theta + \beta) \le \pi$, the longitudinal primary bending stress at limit load, with or without a primary membrane stress, σ_b^c, is given by

$$\sigma_b^c = \frac{2\sigma_f}{\pi}\left[2\sin\beta - \frac{a}{t}\sin\theta\right] \tag{27.1}$$

where

$$\beta = \frac{1}{2}\left[\pi - \frac{a}{t}\theta - \pi\frac{\sigma_m}{\sigma_f}\right] \tag{27.2}$$

The flow stress σ_f is a measure of the strength of the material in the pipe under large-scale, gross plastic deformation, and is between the values of the yield strength and ultimate tensile strength. For Class 1 austenitic piping, in ASME Section XI prior to the 2002 Addenda, the flow stress was set equal to $3S_m$, where S_m is the design stress intensity for the material at the service temperature for Class 1 from ASME Section II, Part D [13]. For Class 1 ferritic piping, in Section XI prior to the 2002 Addenda, the flow stress was set equal to either $2.4S_m$ or the average of the yield strength and ultimate tensile strength for the material. For longer circumferential flaws penetrating the compressive bending region of the pipe such that $(\theta + \beta) > \pi$, the limit load stress for plastic collapse is given by

$$\sigma_b^c = \frac{2\sigma_f}{\pi}\left[2 - \frac{a}{t}\right]\sin\beta \tag{27.3}$$

where

$$\beta = \frac{\pi}{2 - \dfrac{a}{t}}\left[1 - \frac{a}{t} - \frac{\sigma_m}{\sigma_f}\right] \tag{27.4}$$

These limit bending stresses are in the context of nominal bending stresses as calculated from applied bending moments assuming elastic behavior.

Equations (27.1) and (27.2) for longitudinal primary bending stress at limit load with a coincident longitudinal primary membrane stress can be used to predict the limit load bending stress of an unflawed pipe by setting $a/t = 0$ and $\theta/\pi = 0$. The flow stress σ_f is written in terms of the design stress intensity for Class 1, S_m, using [12]

$$\sigma_f = 2.6S_m \tag{27.5}$$

The normalized combined primary membrane plus bending stress at plastic collapse, $(\sigma_m + \sigma_b^c)/S_m$, for an unflawed austenitic pipe is plotted against the normalized primary membrane stress, σ_m/S_m, in the interaction diagram in Figure 27.8, where the stresses are normalized by the design stress intensity S_m. The collapse curve at $\sigma_m/S_m = 0$ corresponds to $\sigma_b^c = (4/\pi)\sigma_f$, which corresponds to $3.32S_m$, where $4/\pi$ is the shape factor for a thin-walled circular cross-section under pure bending. The end of the collapse curve at $\sigma_m/S_m = 2.6$ corresponds to attainment of limit load for pure membrane stress. Since the normalized primary membrane stress σ_m/S_m is on both the abscissa and ordinate of this Figure, the stress combinations cannot fall below the line given by $\sigma_b = 0$.

The limits on the normalized longitudinal primary stresses $(\sigma_m + \sigma_b)/S_m$ for Class 1 austenitic piping for Service Levels A, B, C and D in NB-3650 of ASME Section III are plotted as the horizontal lines in Figure 27.8 [12]. Since there are no separate limits

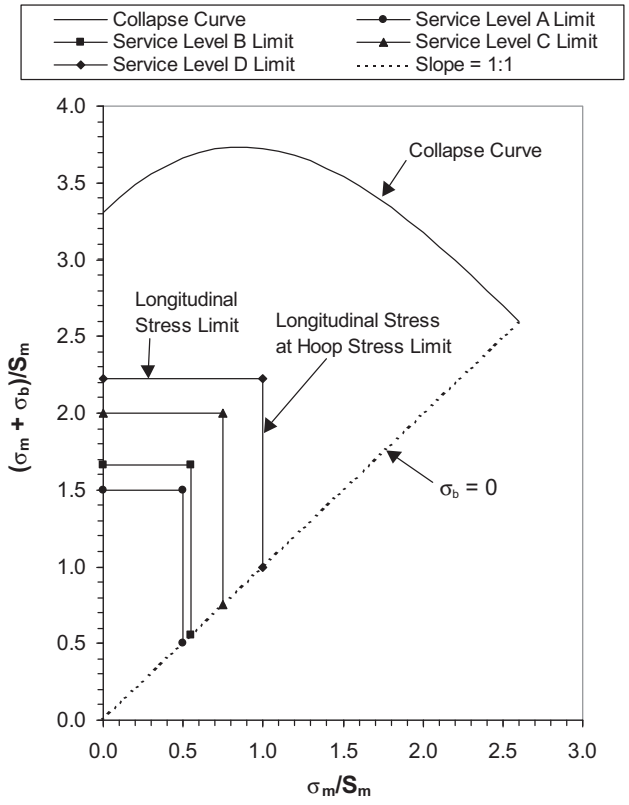


FIGURE 27.8 COMPARISON OF ASME SECTION III LONGITUDINAL PRIMARY STRESS LIMITS FOR CLASS 1 PIPING WITH PLASTIC COLLAPSE CURVE FOR AN UNFLAWED AUSTENITIC PIPE BASED ON FLOW STRESS EQUAL TO $2.6S_m$ (*Source*: Figure 4 of Ref. [12])

on the longitudinal primary membrane stress in NB-3650, the vertical lines at the right-hand side of each horizontal line in Figure 27.8 are at the value of σ_m/S_m corresponding to the limits on pressure as given by NB-3641.1 of Section III. The margin is determined from the ratio of the level of $(\sigma_m + \sigma_b^c)/S_m$, from the collapse curve divided by the Section III limit on longitudinal primary stresses $(\sigma_m + \sigma_b)/S_m$ at a given σ_m/S_m. The margin is variable and depends on the level of σ_m/S_m. The margin also depends on the flow stress for the material, as characterized by Eq. (27.5). Since the margins from the Section III design rules are variable for a given Service Level, and for practical reasons the structural factors in Section XI are fixed rather than variable, the margins in the Section XI acceptance criteria for flawed piping cannot be completely consistent with Section III. However, the Section XI acceptance criteria can be consistent with the overall design intent.

27.5.2 ASME Section XI Acceptance Criteria for Circumferential Flaws for Limit Load Prior to 2002 Addenda

Prior to the 2002 Addenda, the allowable primary bending stress, S_c, for limit load analysis was given by

$$S_c = \frac{\sigma_b^c}{(SF)} - \sigma_m \left[1 - \frac{1}{(SF)}\right] \qquad (27.6)$$

where

S_c = allowable longitudinal bending stress for a circumferentially flawed pipe
(SF) = Section XI structural factor on primary stress based on Service Level in 2001 Edition
σ_m = nominal (unintensified) longitudinal primary membrane stress

For austenitic piping, there was no requirement in terms of an allowable longitudinal primary membrane stress, σ_m. For ferritic piping the restriction that the value of σ_m used in the evaluation must not exceed σ_b was overly conservative for cases where the loading is predominately membrane.

The structural factors on load for evaluation of flaws in piping in the Section XI prior to the 2002 Addenda were developed to maintain some consistency with the design intent of Section III [14,15,16]. The structural factors were based on application of the concept of an implicit design margin, which is determined from the ratio of the failure stress in an unflawed pipe as calculated using Section XI equations for limit load, divided by the stress limit from Section III. The failure stress levels were based on analysis of pipe fracture experiments. These implicit design margins were used to provide guidance for selecting the structural factors in Section XI. For simplicity, the structural factors for Service Level A and B Loadings were based on implicit design margins for Service Level A. The structural factors for Service Level C and D Loadings were based on implicit design margins for Service Level D. For circumferential flaws, the structural factors were also selected to be based on averages of the implicit design margins for applied membrane and bending stresses. The Section XI structural factors prior to the 2002 Addenda for circumferential flaws were 2.77 for Service Level A and B Loadings, and 1.39 for Service Levels C and D. The Section XI structural factors prior to the 2002 Addenda for axial flaws were 3.0 for Service Level A and B Loadings, and 1.5 for Service Levels C and D.

27.5.3 Revised Structural Factors Specific to Each Service Level in 2002 Addenda to ASME Section XI

The structural factors first published in the 2002 Addenda to ASME Section XI were intended to reflect the design intent of ASME Section III in terms of the primary stress limits. While the separate structural factors for Service Level A, B, C and D Loadings are not directly related to specific implicit design margins, they are more consistent with the design intent of Section III than the structural factors in Section XI prior to the 2002 Addenda. As well, for circumferential flaws, separate limits on longitudinal membrane plus bending stresses, and on longitudinal membrane stress, were implemented to provide consistency with the method of application of primary stress limits in Section III. The piping design rules for primary stresses in Section III are based on limit analysis [17]. The development of the structural factors was also based on limit analysis.

The structural factors are based on the concept of a *Failure Load Factor*, which is defined as the ratio of the failure stress in an unflawed pipe as calculated using Section XI equations for limit load, divided by the stress limit from Section III.

$$\text{Failure Load Factor} = \frac{\text{Section XI Failure Stress}}{\text{Section III Stress Limit}} \qquad (27.7)$$

This results in different structural factors on primary loads for Service Levels A, B, C, and D, where the structural factors for Service Level A are the highest. The decrease in structural factor from Service Level A through to Service Level D is based on the lower probability of occurrence of the loading condition, and is consistent with the higher allowable stresses from Service Level A through to Service Level D in Section III. The structural factors were selected to be approximate averages of the *Failure Load Factors* for unflawed piping [12]. The Section XI failure stress levels were derived from pipe fracture experiments as described in Ref. [12]. The *Failure Load Factors* are based on limit load failure of straight pipe with no structural discontinuities. The same set of *Failure Load Factors* are considered to be applicable to other piping items and joint types without the use of other design factors such as primary stress indices. The effects of reduced load carrying capacity due to a different geometric configuration or structural discontinuity are already explicitly taken into account in the Section XI flaw evaluation procedures.

Although the structural factors were developed based on consideration of primary stresses and the limit load failure mode, the structural factors are considered to also be applicable to the ductile tearing (EPFM) and brittle fracture (LEFM) modes of failure. It was assumed that the piping item has been inspected, and that a detailed stress analysis of the piping item was performed at the flaw location. The *Failure Load Factors* for Class 1 piping, and for Classes 2 and 3 piping, were developed separately. The structural factors were then selected based on the entire set of *Failure Load Factors*.

The structural factors in the 2002 Addenda on primary membrane stress, SF_m, and on primary bending stress, SF_b, for circumferential flaws in Classes 1, 2, and 3 piping are compared with the structural factors in the 2001 Edition of Section XI in Table 27.1. The structural factors in the 2002 Addenda on primary membrane hoop stress, SF_m, for axial flaws in Classes 1, 2, and 3 piping are

TABLE 27.1 ASME SECTION XI STRUCTURAL FACTORS FOR CIRCUMFERENTIAL FLAWS IN CLASSES, 1, 2 AND 3 AUSTENITIC AND FERRITIC PIPING (*Source*: Table 9 of Ref. [12])

ASME SERVICE LEVEL	STRUCTURAL FACTOR ON MEMBRANE STRESS		STRUCTURAL FACTOR ON BENDING STRESS	
	2001 EDITION (SF)	2002 ADDENDA SF_m	2001 EDITION (SF)	2002 ADDENDA SF_b
A	2.77	2.7	2.77	2.3
B	2.77	2.4	2.77	2.0
C	1.39	1.8	1.39	1.6
D	1.39	1.3	1.39	1.4

TABLE 27.2 ASME SECTION XI STRUCTURAL FACTORS FOR AXIAL FLAWS IN CLASSES 1, 2, AND 3 AUSTENITIC AND FERRITIC PIPING (*Source*: Table 10 of Ref. [12])

ASME SERVICE LEVEL	2001 EDITION (SF)	2002 ADDENDA SF_m
A	3.0	2.7
B	3.0	2.4
C	1.5	1.8
D	1.5	1.3

compared with the structural factors in the 2001 Edition of Section XI in Table 27.2. The revised structural factors for Service Level A, B and D Loadings are less restrictive than, or essentially the same as, the 2001 Edition structural factors for Class 1 piping in Section XI. The revised structural factors for Service Level C Loadings are greater than the 2001 Edition structural factors for Service Level C in Section XI. The impact of the revised higher structural factors for Service Level C Loadings for Class 1 piping on existing evaluations of flaws at weld overlay repairs was assessed, and was found to be not significant [12].

27.5.4 Revised Acceptance Criteria for Circumferential Flaws in 2002 Addenda to ASME Section XI

For circumferential flaws, separate limits on longitudinal primary membrane plus bending stresses, $\sigma_m + \sigma_b$, and on longitudinal primary membrane stress, σ_m, were implemented into Appendix C of Section XI in the 2002 Addenda. The primary bending stress at limit load, σ_b^c, with or without a primary membrane stress, is first determined as given by Eqs. (27.1) through (27.4). The relation for flow stress is given by Eq. (27.5). The allowable primary bending stress, S_c, for limit load analysis is then given by

$$S_c = \frac{\sigma_b^c}{SF_b} \quad \sigma_m \left(1 - \frac{1}{SF_m}\right) \tag{27.8}$$

where

SF_b = Section XI structural factor on primary bending stress based on Service Level in the 2002 Addenda

SF_m = Section XI structural factor on primary membrane stress based on Service Level in the 2002 Addenda

The Section III design rules for piping do not require a separate limit on the longitudinal primary membrane stress due to internal pressure and piping thrust loads. In the design of piping, the internal pressure is limited by the equation for the permissible pressure based on the primary hoop stress in the pipe. However, when a pipe contains a relatively large circumferential flaw, failure of the pipe cross-section caused by the longitudinal membrane stress due to internal pressure alone may occur prior to reaching failure based on the hoop stress. For this reason, a separate criterion in terms of an allowable longitudinal primary membrane stress was developed for implementation into Section XI. This approach is the same as the general design rules for Class 1 components in NB-3200, and for Class 2 components in NC-3200, and which are used for design of pressure vessels. The longitudinal primary membrane stress at limit load under pure membrane loading, σ_m^c, is calculated by using

$$\sigma_m^c = \sigma_f \left(1 - \frac{a}{t}\right) \frac{2}{\pi} \tag{27.9}$$

where

$$\theta = \arcsin\left(\frac{1}{2}\frac{a}{t}\sin\theta\right) \tag{27.10}$$

The allowable primary membrane stress, S_t, is then given by

$$S_t = \frac{\sigma_m^c}{SF_m} \tag{27.11}$$

The normalized allowable combined longitudinal primary membrane plus bending stresses for an unflawed pipe from the Section XI acceptance criteria, in terms of $(\sigma_m + S_c)/\sigma_f$, were calculated from Eq. (27.8) where the structural factors are given in Table 27.1. The normalized allowable stresses $(\sigma_m + S_c)/\sigma_f$ for combined primary membrane plus bending stress for Classes 1, 2, and 3 austenitic and ferritic piping for Service Levels A, B, C and D are plotted in Figure 27.9. The separate normalized allowable

levels of longitudinal primary pure membrane stress for an unflawed pipe from the acceptance criteria, in terms of S_t/σ_f, were calculated from Eq. (27.11) for each Service Level, where the structural factors are also given in Table 27.1. The normalized allowable stresses S_t/σ_f for Classes 1, 2, and 3 austenitic and ferritic piping for Service Levels A, B, C, and D are plotted as the vertical lines in Figure 27.9. For a given Service Level, the combination of these two criteria produces an allowable stress envelope in Figure 27.9. The normalized allowable membrane stress levels S_t/σ_f in Figure 27.9 extend out further, i.e., closer to the end of the plastic collapse curve as compared with the vertical lines in Figure 27.8. For the case of an unflawed pipe, the allowable longitudinal membrane stress shown in Figure 27.9 will never be reached, since the longitudinal membrane stress is governed by the permissible pressure rules based on hoop stress in Section III. For example, for the case of a Class 1 austenitic pipe, and using a flow stress equal to $2.6S_m$, the Section III limit on hoop stress for Service Level A is S_m, or $0.38\sigma_f$. The corresponding value of longitudinal membrane stress is $0.19\sigma_f$, which is significantly less than the Service Level A allowable longitudinal membrane stress in Figure 27.9 of $0.37\sigma_f$.

The margin on membrane plus bending stress against failure from the Section XI acceptance criteria is determined from the ratio of the level of $(\sigma_m + \sigma_b^c)/\sigma_f$ from the collapse curve divided by the alloble by the allowable longitudinal primary stresses $(\sigma_m + S_c)/\sigma_f$ from the acceptance criteria at a given σ_m/σ_f. As in Figure 27.8, the margin is variable and depends on the level of σ_m/σ_f. Although the margins, based on the plastic collapse curve as a reference, for each Service Level in Figure 27.9 are not the same as the corresponding margins from Figure 27.8, there is some similarity in margins between the two Figures. For example, for Service Level A, the margins are similar for values of σ_m/σ_f in Figure 27.9 up to 0.19. The separate margin on pure membrane stress is determined from the ratio of the level of σ_m^c/σ_f at the end of the collapse curve, which is 1.0 for an unflawed pipe, divided by the allowable stress S_t/σ_f.

Equations (27.1) through (27.4) were also used to predict the normalized longitudinal bending stress at limit load, σ_b^c/σ_f, for a range of values of normalized longitudinal membrane stress, σ_m/σ_f, for a pipe with a circumferential flaw with $a/t = 0.50$ and $\theta/\pi = 0.75$. The normalized combined membrane plus bending stress at plastic collapse, $(\sigma_m + \sigma_b^c)/\sigma_f$, is plotted against σ_m/σ_f in the interaction diagram in Figure 27.10. The normalized allowable combined longitudinal primary membrane plus bending stress for Classes 1, 2, and 3 austenitic and ferritic piping for Service Levels A, B, C, and D from the Section XI acceptance criteria were calculated from Eq. (27.8) and are also plotted in Figure 27.10. The separate allowable levels of normalized longitudinal primary membrane stress for Classes 1, 2, and 3 austenitic and ferritic piping for Service Levels A, B, C, and D from the acceptance criteria were calculated from Eq. (27.11), and are plotted as the vertical lines in Figure 27.10. This plot illustrates the reduced lev-

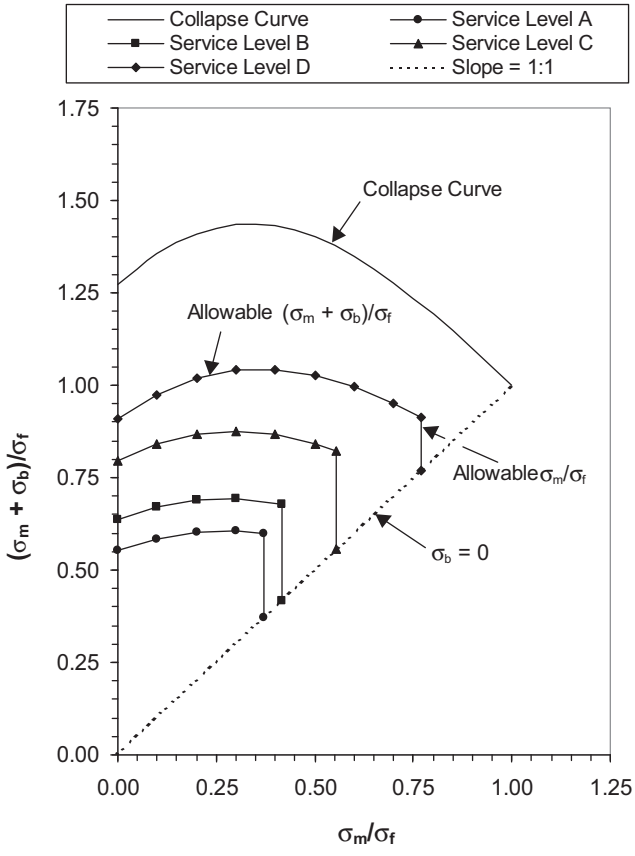


FIGURE 27.9 COMPARISON OF ALLOWABLE LONGITUDINAL STRESSES DETERMINED FROM ASME SECTION XI ACCEPTANCE CRITERIA WITH PLASTIC COLLAPSE CURVE FOR AN UNFLAWED PIPE (*Source*: Figure 5 of Ref. [12])

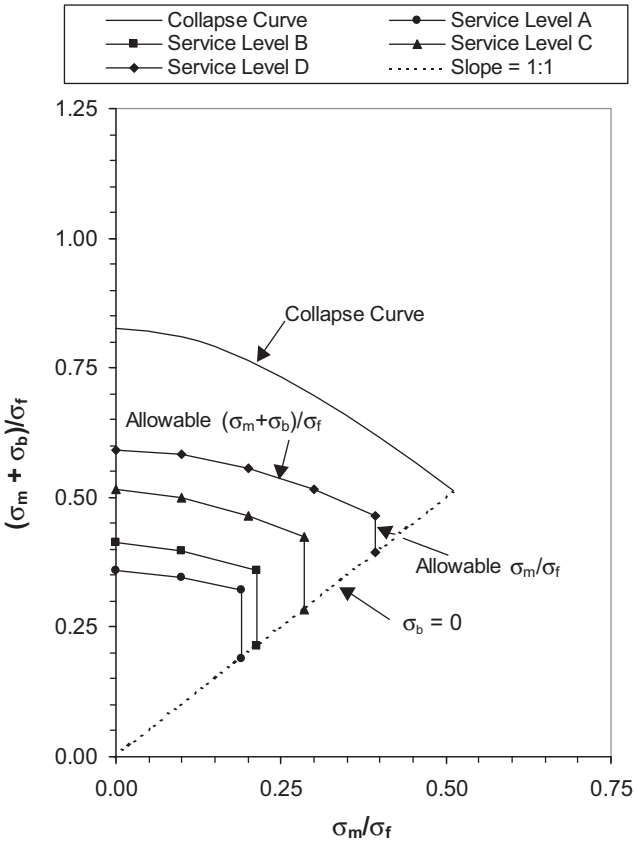


FIGURE 27.10 COMPARISON OF ALLOWABLE LONGITUDINAL STRESSES DETERMINED FROM ASME SECTION XI ACCEPTANCE CRITERIA WITH PLASTIC COLLAPSE CURVE FOR A FLAWED PIPE WITH *a/t* = 0.50 AND *θ/π* = 0.75 (*Source*: Figure 6 of Ref. [12])

els of the curves for plastic collapse and allowable primary stresses due to the presence of the circumferential flaw. The margins against failure in Figure 27.10 based on the Section XI acceptance criteria are similar to those of Figure 27.9.

Revised acceptance criteria for EPFM and LEFM analysis were also implemented into the 2002 Addenda, as described in Ref. [12].

27.6 RECENT DEVELOPMENTS TO ADDRESS STRESS CORROSION CRACKING IN PIPING ITEMS

27.6.1 Crack Growth Rates

The PWSCC crack growth rate for Alloy 600, as well as for Alloys 82, 182, and 132 weld metals, is a function of the material condition, temperature, environment, and the stress intensity factor due to sustained loading. A reference PWSCC crack growth rate model for Alloy 600, as well as for Alloys 82, 182, and 132 weld metals, in PWR environments was first published in Appendix C of ASME Section XI in the 2009 Addenda [18].

Reference stress corrosion cracking growth rate models for Alloy 600, as well as for Alloys 182 and 132 weld metal, in BWR coolant environments were first published in Appendix C of Section XI in the 2009 Addenda [18]. The dependence of the various environmental parameters, such as conductivity and Electrochemical Potential (ECP), as well as the stress intensity factor, on crack growth rate forms the basis for BWR environments. The crack growth rates are provided for two discrete conditions, namely, Normal Water Chemistry and Hydrogen Water Chemistry. The experimental crack growth rate data used to develop the models did not contain enough variability in conductivity and ECP to develop a crack growth rate model as a continuous function of these parameters. The benefit of Hydrogen Water Chemistry is taken into account with lower crack growth rates, similar to the effect for stainless steels.

Reference stress corrosion cracking growth rate models for IGSCC in stainless steels and associated welds in BWR coolant environments were first published in Appendix C of Section XI in the 2010 Edition [19]. The IGSCC crack growth rate depends on the water chemistry conductivity, ECP, temperature and stress intensity factor.

A fatigue crack growth evaluation is also required when crack growth is postulated. A reference fatigue crack growth rate model for Alloy 600 in either an air environment, or for PWR and BWR coolant environments, was first published in Appendix C of Section XI in the 2009 Addenda [18]. The amount of fatigue crack growth for a typical application is much smaller than that which occurs due to Primary Water Stress Corrosion Cracking (PWSCC).

Details on crack growth rate models are provided in Chapter 32 of Reference [2].

27.6.2 Weld Residual Stresses

Residual stresses in piping welds are a major driving force for stress corrosion cracking. The residual stresses from the welding process are a principal factor exacerbating PWSCC in Alloy 82/182 nickel-alloy weld materials used in dissimilar metal piping butt welds in PWRs. A representative dissimilar metal weld configuration in a PWR is shown in Figure 27.11.

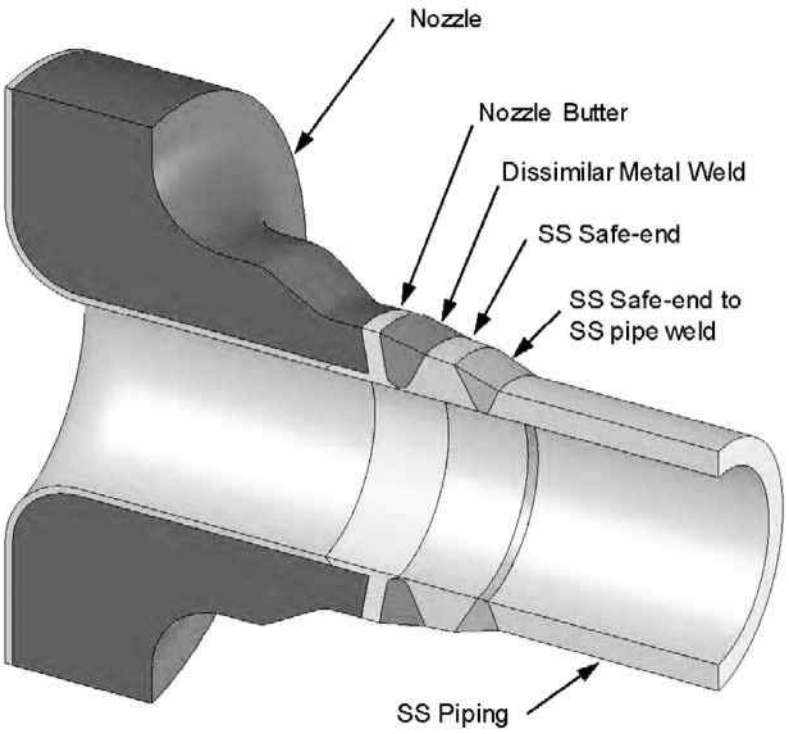


FIGURE 27.11 REPRESENTATIVE DISSIMILAR METAL WELD CONFIGURATION IN A PWR (*Source*: Figure 1-1 of Ref. [24])

27.6.2.1 Finite Element Calculations of Weld Residual Stresses Finite element analyses have been performed over a number of years to predict the residual stress distributions in dissimilar metal welds for the purpose of performing crack growth predictions or other evaluations [20,21]. The crack growth calculations, in turn, have demonstrated a high sensitivity to the weld residual stress distribution inputs. An EPRI/U.S. NRC project was performed to validate the analytical models used to perform weld residual stress analyses against measured residual stresses [22]. Weld residual stress modeling was performed by a number of organizations, and results were compared to develop best practices. Comparisons between the weld residual stresses calculated by different participating organizations showed significant differences in residual stress values but some agreement in trends. A weld residual stress validation report [23] and a modeler's handbook were produced [24]. Weld residual stress modeling guidelines have also been developed for the R6 document in the U.K. [25,26].

For example, a finite element simulation of weld residual stresses in a dissimilar metal weld with an optimized weld overlay in a 28 in. (710 mm) inside diameter reactor pressure vessel nozzle is provided in Ref. [27]. In the design of an optimized weld overlay, credit for a portion of the original weld metal is taken when calculating the required weld overlay thickness. The finite element analysis simulated a weld repair on inside surface for a postulated fabrication flaw within the original nozzle to safe-end dissimilar metal weld during plant construction. A mixed hardening model, which includes nonlinear isotropic and kinematic hardening models, was used to obtain most accurate results. The analysis also includes modeling the stainless steel safe-end to stainless steel pipe weld, as well as the subsequent optimized weld overlay. The weld residual hoop stresses are shown in Figure 27.12. From this figure, the weld repair results in very high weld residual hoop stresses on the inside surface, and these stresses are reduced to some extent after the stainless steel safe-end to stainless steel pipe weld. The optimized weld overlay results in weld residual hoop stresses on the inside surface that are slightly compressive.

27.6.2.2 Weld Residual Stress Improvement A weld overlay will result in a reduction in weld residual stresses on the inside surface [20]. Code Case N-504-4 [28] and Appendix Q of Section XI provide rules for weld overlays on austenitic stainless steel welds in Classes 1, 2, and 3 piping. Code Case N-740-2 [29] provides rules for full structural dissimilar metal weld overlays in Classes 1, 2, and 3 piping items. In the design of a full structural weld overlay, credit is not taken for the original weld metal when determining the required weld overlay thickness. Code Case N-754 [30] provides rules for an optimized dissimilar metal weld overlay for mitigation of PWR Class 1 Items. A mitigative weld overlay is applied over material with no inside surface connected flaws found during examination. A repair weld overlay is applied over material with an inside surface connected flaw or subsurface defect, or where a pre-weld overlay examination is not performed.

Another mitigation process to improve the weld residual stress distribution that is recognized by Section XI is a mechanical stress improvement process. In this process, the weld is plastically deformed by a mechanical clamping device such that residual compressive stresses are induced on the inside surface when the clamp is released.

27.6.2.3 Current Activities in ASME Section XI for Determining Weld Residual Stresses Weld residual stress distributions are currently not provided in Section XI. There is a need for providing either reference weld residual stress distributions for piping welds, or guidelines for calculating weld residual stress distributions, in Section XI. This is particularly important for dissimilar metal welds. Provision of reference weld residual stress distributions, or calculation guidelines, in Section XI would benefit the user by ensuring that the stress distributions reflect industry best practices. Another benefit would be reduced uncertainty of regulatory acceptance of the weld residual stress distribution used in a flaw growth evaluation.

An activity is underway in Section XI to provide a methodology for determining weld residual stress distributions in piping butt

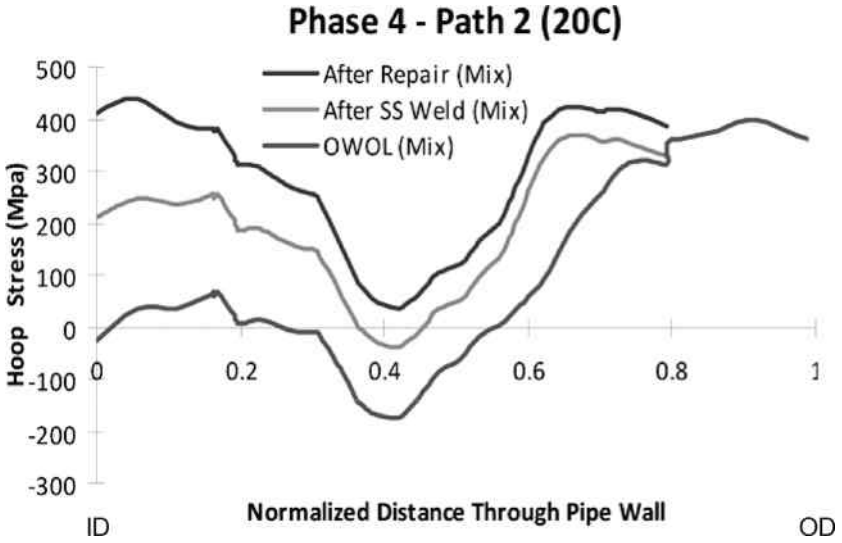


FIGURE 27.12 WELD RESIDUAL HOOP STRESS DEVELOPMENT AFTER REPAIR, STAINLESS SAFE-END WELD AND SUBSEQUENT WELD OVERLAY (*Source*: Figure 8 of Ref. [27])

welds that would be implemented into a nonmandatory Appendix to Section XI. The methodology will be based on industry best practices that have been developed to date. One approach that is under investigation is to develop a set of reference weld residual stress distributions that characterize the residual stresses in the various types of piping butt welds. Another approach that is under investigation is to provide a set of guidelines for calculation of weld residual stress distributions using the finite element method. Such guidelines would be based in industry best practices such as described in Ref. [20–26]. Calculation guidelines would need to provide a level of detail that would ensure that weld residual stresses calculated by different analysts would be reproducible, while at the same time be practical to implement into a nonmandatory Appendix.

27.6.3 Structural Integrity Evaluation of Dissimilar Metal Welds Based on EPFM

The structural integrity evaluation procedures in Appendix C of ASME Section XI have been revised to include methods that are applicable to EPFM evaluation of Alloy 82/182 dissimilar metal welds. For example, the Z-factor is defined as the ratio of the failure stress at limit load divided by the failure stress under the actual EPFM ductile tearing conditions.

$$Z = \frac{\text{Limit Load}}{\text{EPFM Failure Load}} \tag{27.12}$$

Equations for the Z-factor that reflect the relatively high fracture toughness of Alloy 600 and Alloys 82, 182, and 132 welds have been developed by performing J-integral ductile tearing instability analyses [31]. The Z-factor values were calculated using the stainless steel base metal strength and the fracture toughness of the Alloy 182 weld metal. Fits to the calculation results yielded the following relations.

$$Z = 6.5 \quad 10^{-4} D^3 \quad 0.01386 D^2 + 0.1034 D + 0.902 \quad \text{for } 2\,\text{in.} \quad D \quad 8\,\text{in.} \tag{27.13}$$

$$Z = 2.2 \quad 10^{-6} D^3 \quad 2.0 \quad 10^{-4} D^2 + 0.0064 D + 1.1355 \quad \text{for } 8\,\text{in.} < D \quad 40\,\text{in.} \tag{27.14}$$

where D is the pipe outside diameter (in.) Equations (27.13) for the Z-factor for Alloy 600, and Alloys 82, 182, and 132 welds, were incorporated into Appendix C of Section XI in the 2009 Addenda.

27.7 TRANSITION TEMPERATURES FOR ONSET OF UPPER SHELF BEHAVIOR IN FERRITIC PIPING

In the version of Appendix C of ASME Section XI prior to the 2011 Addenda, the temperature for onset of upper-shelf behavior of ferritic piping steels was 200°F (93°C) when heat-specific fracture toughness test data was not available. Results from a large number of ferritic pipe fracture tests over a wide range of pipe wall thickness and flaw sizes have been evaluated [32,33], and this evaluation has concluded that the temperature for onset of upper-shelf behavior of 200°F (93°C) is overly-conservative. Flaw evaluations performed using the temperature of 200°F (93°C) could provide an underestimate of the load carrying capacity of the pipe, which could result in unnecessary repair/replacement of the pipe. This is particularly the case for application of Code Case N-513-3 [34] to leaking flaws in Classes 2 and 3 moderate energy piping operating at lower temperatures.

Table C-8321-2 of Appendix C of Section XI was first published in the 2011 Addenda, and is given below as Table 27.3. This table provides more accurate representation of the temperature for onset of upper-shelf behavior than 200°F (93°C). Use of Table C-8321-2 will result in less restrictive evaluations of flaws

TABLE 27.3 TEMPERATURE FOR ONSET OF UPPER-SHELF BEHAVIOR FOR AXIAL AND CIRCUMFERENTIAL FLAWS IN FERRITIC STEEL BASE METALS AND WELDMENTS
(*Source*: Table C-8321-2 of Appendix C of Section XI of ASME B&PV Code)

Wall Thickness		Surface Flaws		Through-Wall Flaws	
		Temperature		Temperature	
in.	mm	°F	°C	°F	°C
≤ 1/4	≤ 6	-45	-43	6	-14
3/8	10	-4	-20	49	9
1/2	13	22	-6	73	23
5/8	16	35	2	86	30
3/4	19	43	6	94	35
1	25	52	11	104	40
5/4	32	58	15	110	43
3/2	38	63	17	114	46
7/4	44	66	19	118	48
2	51	70	21	121	50

in ferritic piping, and in particular for Classes 2 and 3 piping. This table provides temperatures for onset of upper-shelf behavior for both surface and subsurface flaws. The technical basis for the table involved the development of a series of transition temperature shifts from various fracture mechanics test specimens to either a surface crack in a pipe or a through-wall crack in a pipe [32,33]. The transition temperature shifts were determined empirically from thousands of laboratory tests, and hundreds of full-scale pipe tests. Applicability of the table to wrought carbon steel pipe fittings is limited to those fittings that have been hot-formed and subsequently normalized or annealed in accordance with the requirements for the material specification in Part A of ASME Section II.

27.8 EVALUATION PROCEDURES AND ACCEPTANCE CRITERIA FOR WALL THINNING IN PIPING

27.8.1 Overview of Code Case N-597-2

An example of flow-accelerated corrosion in a pipe is shown in Figure 27.13. Evaluation procedures and acceptance criteria for wall thinning, or nonplanar flaws, such as due to flow-accelerated corrosion and other corrosion mechanisms, in Classes 1, 2, and 3 piping are provided in Code Case N-597-2 of ASME Section XI [35,36]. The Code Case was developed in response to a need for ASME Code evaluation rules for piping system components degraded by the effects of flow-accelerated corrosion and other corrosion mechanisms that result in nonplanar flaws. The Code Case provides a basis for evaluation for continued service until such time as repair or replacement is necessary and achievable. Code Case N-597-2 supersedes the previous related Code Case N-480. Code Case N-597-2 is applicable to Classes 1, 2, and 3 carbon and low alloy steel piping systems, as well as piping systems fabricated from other materials when justified. The Code Case is applicable to evaluation of straight pipe, elbows, reducers, tees and branch connections. A detailed description of the Code Case procedures is provided in Chapter 30 of Reference [2].

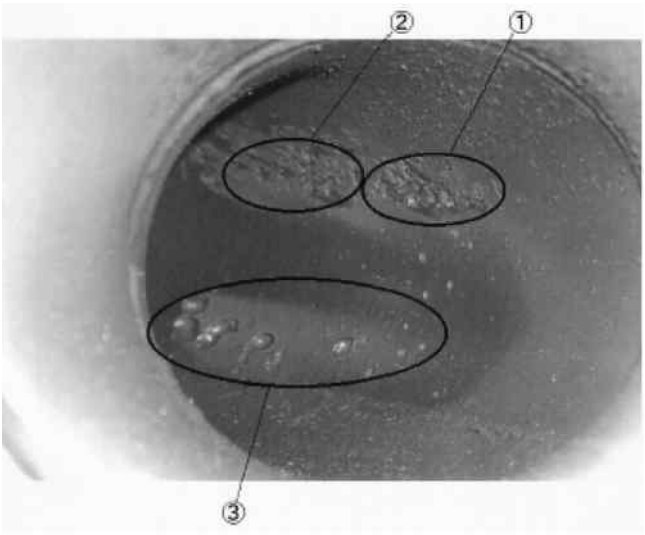


FIGURE 27.13 FLOW-ACCELERATED CORROSION IN A PIPE (*Source*: Figure 1 of Ref. [39])

27.8.2 NRC Conditions on Code Case N-597-2

Subsequent to publication of Code Case N-597-2, the U.S. NRC found the Code Case to be conditionally acceptable. The NRC conditions are given in Regulatory Guide 1.147 [37], and are summarized below.

(1) The Code Case must be supplemented by the provisions of EPRI Nuclear Safety Analysis Center Report 202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program" for developing the inspection requirements, the method of predicting the rate of wall thickness loss, and the value of the predicted remaining wall thickness. (The most recent version of this report is Ref. [38].)
(2) Components affected by flow-accelerated corrosion to which this Code Case are applied must be repaired or replaced prior to the value of t_p (predicted minimum remaining wall thickness at the end if the evaluation period) reaching the allowable minimum wall thickness, t_{min}. Alternatively, use of the Code Case is subject to NRC review and approval.
(3) For Class 1 piping, the use of analytical evaluation methods and criteria is subject to NRC review.
(4) The rate of wall thickness loss is to be used to determine a suitable inspection frequency so that repair or replacement occurs prior to reaching allowable minimum wall thickness, t_{min}.
(5) For corrosion phenomenon other than flow-accelerated corrosion, use of the Code Case is subject to NRC review and approval.

27.8.3 Activities to Address NRC Conditions on Code Case N-597-2

The conditions imposed on Code Case N-597-2 have been discussed with NRC staff as an activity under Section XI. As a result of these discussions, a number of tasks have been performed to address the conditions. A supplementary technical basis document for the Code Case that provides expanded explanations of the basis for the procedures for the evaluation of wall thickness less than the pressure-based minimum allowable wall thickness, t_{min}, was published [39]. Proposed revisions have been made to the Code Case that are currently under review in Section XI. These revisions include:

(a) The Code Case has been restructured and editorial changes have been made to improve clarity of the requirements.
(b) The proposed revised Code Case is no longer being applicable to Class 1 piping items.
(c) Provisions that permitted local through-wall leakage in Class 3 piping items whose maximum operating tempera-

ture does not exceed 200°F (93°C) and whose maximum operating pressure does not exceed 275 psi (1.9 MPa) have been deleted in the proposed revised Code Case.

(d) Requirements for predicting the rate of metal loss during the evaluation period have been added in the proposed revised Code Case. Factors to account for the uncertainties in the metal loss rate must be evaluated.

27.9 EVALUATION PROCEDURES AND ACCEPTANCE CRITERIA FOR TEMPORARY ACCEPTANCE OF FLAWS IN MODERATE ENERGY CLASSES 2 AND 3 PIPING

27.9.1 Overview of Code Case N-513-3 and Appendix U of ASME Section XI

Evaluation procedures and acceptance criteria for temporary acceptance of flaws, including through-wall flaws, in moderate energy Classes 2 and 3 piping are provided in Code Case N-513 [34,40,41] and Appendix U of ASME Section XI. Moderate energy piping is defined as those piping systems where the maximum operating pressure does not exceed 275 psi (1.9 MPa), and the maximum operating temperature does not exceed 200°F (93°C). The first version of Code Case N-513 was published in 2000. Since then, there have been three revisions to the Code Case, and the current version is N-513-3. The provisions are intended to prevent gross failure of the affected pipe for a temporary period, which is generally until the next outage. Inspection and monitoring of the degraded condition is part of the overall integrity assessment. A temporary condition of through-wall leakage is permitted provided that adequate structural integrity and system function will be maintained during operation, and the consequence of leakage is not significant. Code Case N-513-3 and Appendix U are applicable to planar flaws, as well as nonplanar flaws due to microbiologically induced corrosion, pitting and general corrosion. An example of a nonplanar flaw due to microbiologically induced corrosion is shown in Figure 27.14. A detailed description of the procedures is provided in Chapter 30 of Reference [2]. Examples of application of Code Case N-513-3 are provided in Ref. [42].

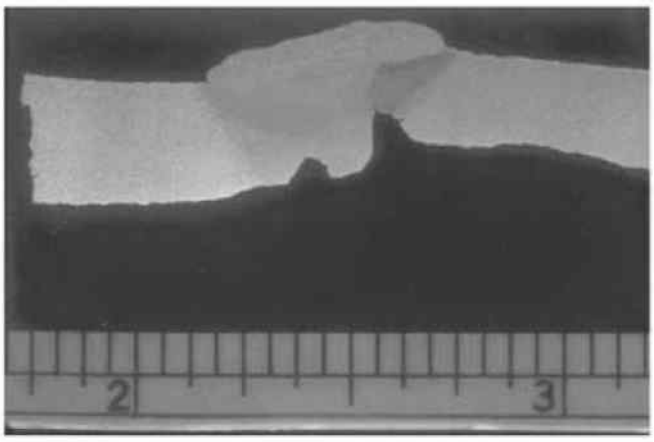


FIGURE 27.14 MICROBIOLOGICALLY INDUCED CORROSION IN A PIPE (*Source*: Figure 9 of Ref. [49])

27.9.2 Proposed Revisions to Code Case N-513-3

Based on service experience, there is a need for revisions to Code Case N-513-3 that include scope expansion. Code Case N-513-3 is currently applicable only to Classes 2 and 3 straight piping items in moderate energy systems. Through-wall corrosion pitting has been detected in elbows, and there is a need to extend the applicability of the Code Case to include fittings. There is also a need to extend applicability of the Code Case to detected leaking flaws in Classes 2 and 3 moderate energy heat exchanger tubes. It was also determined that the evaluations for longitudinal stresses should be consistent with other requirements in Section XI and the piping design Code of Record.

Based on the above and other considerations, a number of proposed revisions to Code Case N-513-3 are under currently review in Section XI as given below.

(a) The repair or replacement activity temporarily deferred under the provisions of the Code Case must be performed during the next scheduled outage. This proposed revision addresses the only NRC condition on Code Case N-513-3 in the U.S. NRC Regulatory Guide 1.147 [37].

(b) Based on user feedback, the requirement for the method of daily monitoring of a throughwall leaking flaw has been made less specific to provide more flexibility to the Utility while still ensuring the leaking flaw is monitored on a daily basis.

(c) The proposed scope of the Code Case has been expanded to cover through-flaws in elbows, bent pipe, reducers, expanders and branch tees. The flaw evaluation procedures for straight pipe are used, where the nominal stresses in a straight pipe are modified by the piping design Code of Record stress indices B_1 and B_2, and stress intensification factor, i. If the piping design Code of Record does not provide stress indices, the 2004 Edition of ASME Section III may be used to define B_1 and B_2.

(d) The proposed scope of the Code Case has been expanded to cover through-flaws in Classes 2 and 3 moderate energy heat exchanger tubes in cases where the flaw can be characterized.

(e) For evaluation of nonplanar flaws, the remaining pipe minimum wall thickness section is required to meet the longitudinal stress limits in the Code of Record for the piping for all service levels.

27.10 EVALUATION OF FLAWS IN BURIED METALLIC PIPE

Buried metallic pipe can be susceptible to corrosion mechanisms. This can occur when external coatings degrade or when catholic protection is no longer active. In addition, microbiologically induced corrosion can occur on the inside surface, as shown in Figure 27.14. External corrosion in a buried pipe is shown in Figure 27.15. Buried pipe integrity in the nuclear industry has

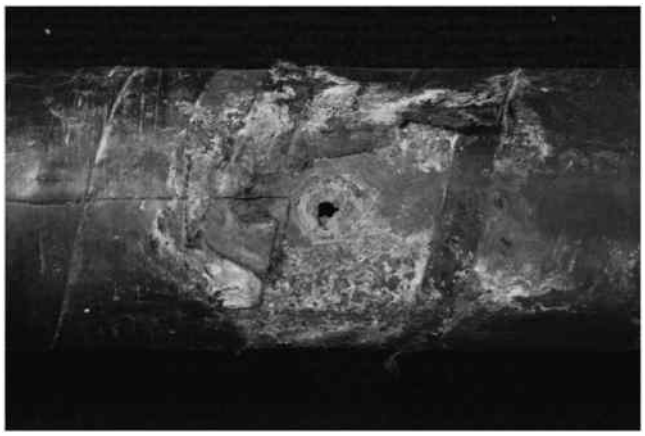


FIGURE 27.15 EXTERNAL CORROSION IN A BURIED PIPE (*Source*: G. Ogundele of Kinectrics, Inc.)

been of increasing interest in recent years. In addition to addressing emergent buried pipe issues, nuclear utilities are proactively evaluating the condition of their plant buried piping including ASME Code Class piping. Industry programmatic reports [43,44] have been developed to assist utilities with these efforts. There was a need for ASME Section XI to provide specific guidance for evaluation of buried pipe inspection results. Code Case N-806 [45,46] has been developed to provide evaluation procedures and acceptance criteria for Classes 2 and 3 metallic piping items (e.g. pipe and fittings) buried in a back-filled trench with metal loss on the internal and/or external surfaces.

The Code Case is applicable to ASME Section III, B31.1 and B31.7 metallic piping classified as Classes 2 or 3 and buried in a back-filled trench. The provisions of the Code Case do not apply to the following:

(1) cast iron piping items,
(2) leakage through a piping item or piping joint,
(3) a cracked piping item or piping joint.

The Code Case provides two levels of analysis. The *Level 1* evaluation is based on the piping meeting the design requirements assuming a conservative uniform wall thickness. The *Level 2* evaluation criteria are more involved hand calculations that are less conservative and allow for localized thinning below the minimum design wall thickness.

The evaluation criteria apply to lined, unlined, coated, and uncoated straight pipe, elbows, and bends, including welded joints. The *Level 2* evaluation criteria also apply to adjoining fittings and flanges to a distance of $(R_o t_{nom})^{1/2}$ from the weld centerline, where R_o is the outside radius of the piping item and t_{nom} is the nominal wall thickness of the piping item specified in the applicable industry standard.

27.10.1 Overview of Evaluation Procedure

The evaluation procedure is summarized below.

(a) The geometry of the metal loss region is characterized.
(b) The length of the evaluation period, τ_{ev}, during which the evaluation remains valid is established.
(c) The rate of metal loss during the evaluation period is determined considering the relevant mechanisms, such as general corrosion or wastage. The metal loss region is projected to the end of the evaluation period.
(d) If multiple metal loss regions are detected, the interaction and combined area of metal loss in a given pipe section is accounted for in the evaluation. Concurrent metal loss on both the inside and outside surfaces, as applicable, in a given pipe section is accounted for in the evaluation.
(e) The projected metal loss region at the end of the evaluation period must be evaluated using the acceptance standards of the Code Case. One of two levels of analytical evaluation of the metal loss region is used as follows.
  (i) *Level 1* evaluation requires that the piping item meets the design requirements.
  (ii) *Level 2* evaluation is based on use of engineering equations to demonstrate that requirements based on internal pressure loading, soil and surcharge loads, bending moments, axial forces, and transverse forces, are met.
(f) Subsequent examination of the metal loss region must be performed no later than the end of the evaluation period. If examinations reveal the metal loss does not meet the acceptance criteria, a repair/replacement activity must be performed.
(g) Examination or repair/replacement activity of the affected piping item must be performed no later than when the metal loss region is projected to no longer meet the acceptance criteria.

27.10.2 Characterization of Metal Loss

Current wall thickness of the metal loss region, t_c, is characterized by volumetric thickness measurement or by physical measurement. An evaluation must be performed to determine the cause of metal loss. The rate of metal loss during the evaluation period must be determined, and must include the relevant metal loss mechanisms determined in the cause evaluation. The rate of metal loss must account for concurrent internal and external corrosion, as applicable, at the affected location, based on the conditions on the internal and external surfaces. Rates of metal loss are not provided in Code Case N-806. Determination of predicted rates of metal loss and factors to account for uncertainties in predicted metal loss must be taken into consideration. Metal loss regions due to concurrent internal and external corrosion are illustrated in Figure 27.16.

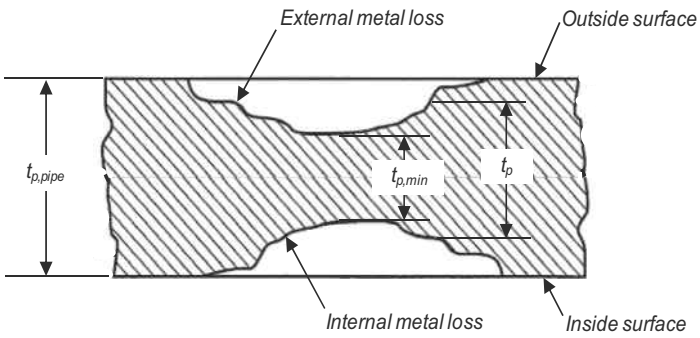


FIGURE 27.16 ILLUSTRATION OF METAL LOSS REGIONS DUE TO CONCURRENT INTERNAL AND EXTERNAL CORROSION IN A BURIED PIPE (*Source*: Figure 1 of Code Case N-806 [45])

The projected future metal loss during the evaluation period, Δt_{ml}, is calculated as follows.

$$t_{ml} = \left(F_{ml,ID} R_{ml,ID} + F_{ml,OD} R_{ml,OD}\right)\ _{ev} \tau \tag{27.15}$$

where

$F_{ml,ID}$ = factor to account for uncertainty in predicted rate of metal loss on the internal surface

$F_{ml,OD}$ = factor to account for uncertainty in predicted rate of metal loss on the external surface

$R_{ml,ID}$ = predicted rate of metal loss during the evaluation period on the internal surface

$R_{ml,OD}$ = predicted rate of metal loss during the evaluation period on the external surface

τ_{ev} = length of the evaluation period

The projected distribution of wall thickness of the metal loss region at the end of the evaluation period, t_p, must be determined. The projected wall thickness of the metal loss region may have a different value at any given location within the metal loss region.

$$t_p = t_c \quad t_{ml} \tag{27.16}$$

where

t_c = current wall thickness of the metal loss region

t_p = projected wall thickness of the metal loss region at the end of the evaluation period

The minimum value of t_p anywhere in the metal loss region is $t_{p,min}$. The projected wall thickness of the material surrounding the metal loss region at the end of the evaluation period, $t_{p,pipe}$, must be determined.

27.10.3 Acceptance Standards for Metal Loss

There are three requirements for acceptance of metal loss.

(a) Analytical evaluation of the metal loss region must be performed using either the *Level 1* or *Level 2* analytical method. In the *Level 1* method, the piping item must meet the design requirements of the Construction Code, assuming uniform wall thickness equal to $t_{p,min}$. Details of the *Level 2* method are provided below. The *Level 1* and *Level 2* methods ensure adequate structural integrity.

(b) The minimum value of projected wall thickness at the end of the evaluation period, $t_{p,min}$, must be at least 0.1 in. (2.5 mm). This requirement is to prevent leakage.

(c) For axial or circumferential extent of wall loss greater than the allowable diameter of an unreinforced opening in accordance with the Construction Code, the minimum value of projected wall thickness at the end of the evaluation period, $t_{p,min}$, must be at least 20% of the nominal wall thickness specified in the applicable industry standard for the piping item. This requirement is to ensure a margin on structural integrity considering potential aggressive corrosion mechanisms.

27.10.4 Level 2 Analytical Evaluation Method

The metal loss region must be evaluated for internal pressure, soil and surcharge loads, longitudinal stresses and shear stresses. The interaction and combined area of concurrent metal loss on both the inside and outside surfaces, as applicable, in a given pipe section must be accounted for in the evaluation.

27.10.4.1 Evaluation for Internal Pressure The minimum allowable wall thickness of a straight section of pipe, elbow, or bend, exclusive of tolerances and any allowances for corrosion, for internal pressure, t_{min}, is first calculated using

$$t_{min} = \frac{P_D D_o}{2(SE + 0.4P_D)} \tag{27.17}$$

where

D_o = nominal outside diameter of the piping item

E = longitudinal weld joint efficiency factor for Class 3 piping items, 1.0 for other piping items

P_D = Design Pressure

S = allowable stress for Classes 2 and 3 components at the Design Temperature

For internal pressure loading, an evaluation based on either general metal loss or a local metal loss region must be performed.

An evaluation of general metal loss, for any axial or circumferential extent, must be based on both an average, and a minimum, wall thickness of the metal loss region at the end of the evaluation period. The metal loss region must be at a distance that is greater than or equal to $(Rt_{min})^{1/2}$ from a structural discontinuity, such as a welded component, flange, branch connection or tee, where R is the mean radius of the piping item at the end of the evaluation period. An average current wall thickness of the metal loss region, $t_{c,avg}$, must be calculated. Procedures for calculation of average current wall thickness that are based on API 597/ASME FFS-1 [47] are provided in a nonmandatory Appendix A to the Code Case. An average wall thickness of the metal loss region at the end of the evaluation period is then determined based on rate of metal loss. The values of $t_{p,avg}$ and $t_{p,min}$ must satisfy the following.

$$t_{p,avg} \geq t_{min} \tag{27.18}$$

$$t_{p,min} \geq 0.5 t_{min} \tag{27.19}$$

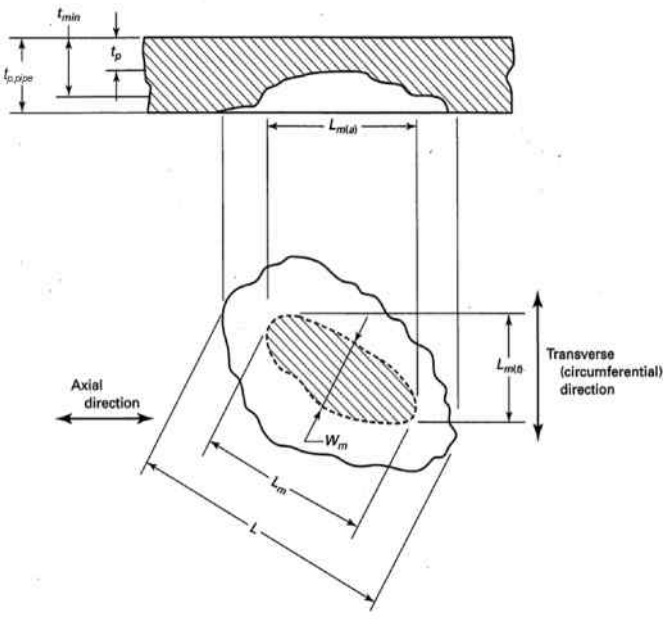


FIGURE 27.17 ILLUSTRATION OF LOCAL METAL LOSS REGION (*Source*: Figure 2 of Code Case N-806 [45])

A local metal loss region is illustrated in Figure 27.17. With the exception of t_{min}, the dimensions in Figure 27.17 correspond to the end of the evaluation period, and are defined as

L = maximum extent of local metal loss region with wall thickness less than $t_{p,pipe}$ at the end of the evaluation period
L_m = maximum extent of local metal loss region with wall thickness less than t_{min} at the end of the evaluation period
$L_{m(a)}$ = maximum axial extent of local metal loss region with wall thickness less than t_{min} at the end of the evaluation period
$L_{m(t)}$ = maximum circumferential extent of local metal loss region with wall thickness less than t_{min} at the end of the evaluation period
$t_{p,pipe}$ = wall thickness of the material surrounding the local metal loss region at the end of the evaluation period
t_p = projected wall thickness of the local metal loss region at the end of the evaluation period, and which may vary along the local metal loss region
W_m = width of local metal loss region

The minimum projected wall thickness of the metal loss region at the end of the evaluation period must satisfy where

$$t_{p,min} \geq t_{aloc} \tag{27.20}$$

t_{aloc} = pressure-based minimum allowable local wall thickness of the metal loss region

Procedures to determine the allowable local wall thickness, t_{aloc}, depend on the circumferential and axial extents of the local metal loss region, as well as the location of the local metal loss region in the case of metal loss in an elbow or bend. The classification of circumferential and axial extent is relative to the characteristic dimension $(R_{min}t_{min})^{1/2}$, where R_{min} is the mean radius of the piping item based on outside radius, R_o, and t_{min}.

$$R_{min} = R_o - \frac{t_{min}}{2} \tag{27.21}$$

(1) Local metal loss is classified as *Limited Circumferential Extent* when the circumferential extent, $L_{m(t)}$, of the local metal loss region projected to be less than t_{min} does not exceed $(R_{min}t_{min})^{1/2}$.
(2) Local metal loss is classified as *Limited Axial and Circumferential Extent* when the maximum extent, L_m, of local wall thickness projected to be less than t_{min} is less than or equal to $2.65(R_{min}t_{min})^{1/2}$ and $t_{p,pipe}$ is greater than $1.13t_{min}$.
(3) Local metal loss is classified as *Unlimited Circumferential Extent* when the circumferential extent, $L_{m(t)}$, of the local metal loss region projected to be less than t_{min} exceeds $(R_{min}t_{min})^{1/2}$.
(4) Local metal loss is classified as *Local Metal Loss Region on Outer Portion of Elbow or Bend* when the local metal loss region is on the outer portion of an elbow or bend and is farther than $(R_{min}t_{min})^{1/2}$ from an adjacent piping item.

The analysis methods to calculate t_{aloc} for each classification of local metal loss are essentially the same as in Code Case N-513-3 and Appendix U of Section XI, and are described in detail in Chapter 30 of Reference [2].

27.10.4.2 Evaluation for Soil and Surcharge Loads Evaluations of the metal loss region for soil and surcharge loads must be performed for the following:

(a) pipe ovality under soil and surcharge loads
(b) compression of buried pipe walls
  (1) circumferential through-wall ovality stress
  (2) crushing compressive stress in side walls
  (3) buckling due to external pressure
  (4) effects of negative internal pressure
(c) buoyancy and flotation

Procedures for evaluation of the metal loss region for soil and surcharge loads that are in general based on a uniform wall thickness in the pipe are provided in a nonmandatory Appendix B to the Code Case. An analysis method to take credit for non-uniform wall thickness, such as an area reinforcement approach, is current under investigation for possible incorporation into a revision of the Code Case. Appendix B currently does not provide soil properties such as soil modulus. Tables of soil properties are under preparation for incorporation into a revised version of the Code Case.

27.10.4.3 Evaluation of Longitudinal Stresses The longitudinal stresses in the piping item at the location of the metal loss region must be evaluated in accordance with the equations of the Construction Code used in the evaluation. Stresses due to axial forces must be added to the stresses due to internal pressure and bending moments in the equations of the Construction Code. The potential for shell buckling of the metal loss region due to compressive longitudinal stresses must be evaluated. The piping stress evaluation must be based on the projected wall thickness at each cross-section of the piping item that contains a metal loss region or is affected by a change in stress index or stress intensification factor. Alternatively, the evaluation may be based on the limiting cross-section. Changes in the piping item metal area, piping item inside area, section modulus, and stress indices or stress intensification factors, must be evaluated. For example, the minimum section modulus of the cross-section of the piping item containing the metal loss region, including consideration of the shift of the neutral axis of the cross-section containing the metal loss region, is calculated using

$$Z_{min} = \frac{I_{min}}{R_o} \tag{27.22}$$

where

I_{min} = projected minimum moment of inertia of the cross-section of the piping item containing the metal loss region about the neutral axis, considering all orientations of the cross-section of the neutral axis

Section properties for an idealization of the cross-section of the piping item are provided in a nonmandatory Appendix C to the Code Case. The evaluation procedures for longitudinal stresses are similar to those in Code Case N-597-2 [35], and these are described in detail in Chapter 30 of Reference [2].

27.10.4.4 Evaluation of Shear Stresses Shear loads and shear stresses in the piping item containing a metal loss region must be calculated using a pipe-soil interaction model to represent the confining effect of the soil, and the interaction between buried pipe

and its extension above the ground, if applicable. Shear loads that might be applicable to an evaluation include the following:

(1) differential seismic anchor motion
(2) frost heave
(3) non-seismic natural ground settlement and building settlement
(4) buoyancy and flotation

In the Code Case, the modeling method of the 2010 Edition of ASME B31.1, Appendix VII, *Procedures for the Design of Restrained Underground Piping* [48], may be used.

27.11 CONCLUSIONS

Committees under ASME Section XI update flaw Acceptance Standards and analytical flaw evaluation procedures on an ongoing basis in response to industry needs and lessons learned from inservice degradation of piping items as well as from user experience with Section XI. This chapter summarized developments in flaw Acceptance Standards and analytical evaluation procedures in Section XI for nuclear piping degraded by flaws and corrosion processes. Evaluations of both planar and nonplanar flaws are addressed by ASME Section XI. There has been a history of Intergranular Stress Corrosion Cracking (IGSCC) in Boiling Water Reactor (BWR) Class 1 austenitic piping, and Primary Water Stress Corrosion Cracking (PWSCC) in Alloy 82, 182 and 132 dissimilar metal welds in piping in Pressurized Water Reactors (PWRs). It was determined that procedures needed to be developed to evaluate flaws in piping systems susceptible to IGSCC and PWSCC, and a significant number of revisions have been made to the Section XI flaw Acceptance Standards and analytical evaluation procedures to address IGSCC and PWSCC. Such revisions are published on an ongoing basis. Recent developments and work in progress to address stress corrosion cracking in piping items include crack growth rates and weld residual stresses.

There has also been a history of wall thinning due to flow-accelerated corrosion, as well as wall loss due to other corrosion mechanisms, in nuclear piping systems. It was determined that procedures needed to be developed to evaluate wall thinning and wall loss due to these corrosion mechanisms. Improvements to evaluation procedures and acceptance criteria for wall thinning due to flow-accelerated corrosion, as well as for temporary acceptance of flaws including through-wall flaws in moderate energy Class 2 and 3 piping systems, are in progress. In addition, based on service experience with leakage from buried piping, evaluation procedures and acceptance criteria for evaluation of flaws in buried piping have recently been published. Changes to the pipe flaw evaluation procedures in Section XI are supported by technical basis documents, and a number of these documents are listed in the references for this chapter.

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CHAPTER

28

LESSONS LEARNED IN THE USE OF PRESSURE RELIEF DEVICES

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28.1 INTRODUCTION

This chapter focuses on the historical development of pressure relief, from its early days to present, as well as the application of pressure relieving requirements and pressure relieving devices (PRDs). Its purpose is not to re-cite ASME code rules, per se, as there are many books in circulation which cover that subject very well [1,2], but to provide designers and owners an insight on applying code rules more effectively for pressure equipment. While the focus is toward pressure vessels, other pressure equipment will be addressed such as boilers, piping, and tankage. Nuclear application is not discussed.

Code rules are established by a consensus agreement of industry experts that often will disagree on approved wording, and occasionally on philosophy. No attempt will be made to challenge the Code rules as-written but to offer ways to meet these rules in a cost effective manner while maintaining safety and reliability. In today's competitive market, decisions made by designers and front line supervisors can affect a company's profitability. Successful outage and sourcing options all start with a better understanding of code (and standards) requirements. The more informed these individuals are, the greater the chances of a company's sustained profitability. This chapter attempts to aid in this effort.

Generally, pressure relieving requirements are performance-based while PRDs are prescriptive based. For readers not familiar with these terms, performance-based requirements are focused on the end result while prescriptive requirements are step-by-step instructions on how to get there. Both functions are needed to ensure success. These two different approaches will be revisited throughout this chapter.

Finally, approved code cases and interpretations, mostly inaccessible to the reader, will be cited with narration. These documents are often overlooked by designers but can be very powerful when unusual situations arise. Code cases provide alternative rules, often requiring local jurisdiction approval, while interpretations add clarity to a code (or standard) and do not require jurisdictional approval. Direction on obtaining jurisdictional approval for code cases is provided.

28.2 TERMINOLOGY

The term pressure relief device (PRD) is being used more and more in codes and standards as well it should since there are many devices now used for overpressure protection. The physical and mechanical properties of springs, pins, and disks are all used in this field. To maintain clarity of the subject matter, the following terminology is presented, which is also consistent with the codes and standards cited in this chapter.

Safety Relief Valve — A spring-loaded pressure relief valve that may be used as either a safety or relief valve depending on the application [3]. The trim is designed to allow its use in either compressible or incompressible fluid service.

Pressure Relief Valve — A pressure relief device designed to open and relieve excess pressure and to reclose and prevent the further flow of fluid after normal conditions have been restored [3].

Safety Valve — A spring-loaded pressure relief valve actuated by the static pressure upstream of the valve and characterized by rapid opening or pop action. A safety valve is normally used with compressible fluids (steam, air, gases, vapors) [3].

Relief Valve — A spring-loaded pressure relief valve actuated by the static pressure upstream of the valve. The valve opens normally in proportion to the pressure increase over the opening pressure. A relief valve is used primarily with incompressible fluids (i.e. liquids) [3].

Non-Reclosing Device — A pressure relief device which remains open after operation. A manual resetting means may be provided [3]. This includes rupture disks, buckling pins, and breaking pins.

Pressure Relieving Device (PRD) — A device actuated by inlet static pressure and designed to open during emergency or abnormal conditions to prevent a rise of internal fluid pressure in excess of a specified design value. The device also may be designed to prevent excessive internal vacuum. The device may be a pressure relief valve, a non-reclosing pressure relief device, or a vacuum relief valve [3]. Note: A PRD encompassing all the above.

Accumulation — The pressure increase over the maximum allowable working pressure of the vessel, expressed in pressure units or as a percentage of maximum allowable working pressure (MAWP) or design pressure. Maximum allowable accumulations are established by applicable codes for emergency operating and fire contingencies [3].

Overpressure — The pressure increase over the set pressure of the relieving device. Overpressure is expressed in pressure units or as a percentage of set pressure. Overpressure is the same as accumulation only when the relieving device is set to open at the maximum allowable working pressure of the vessel [3].

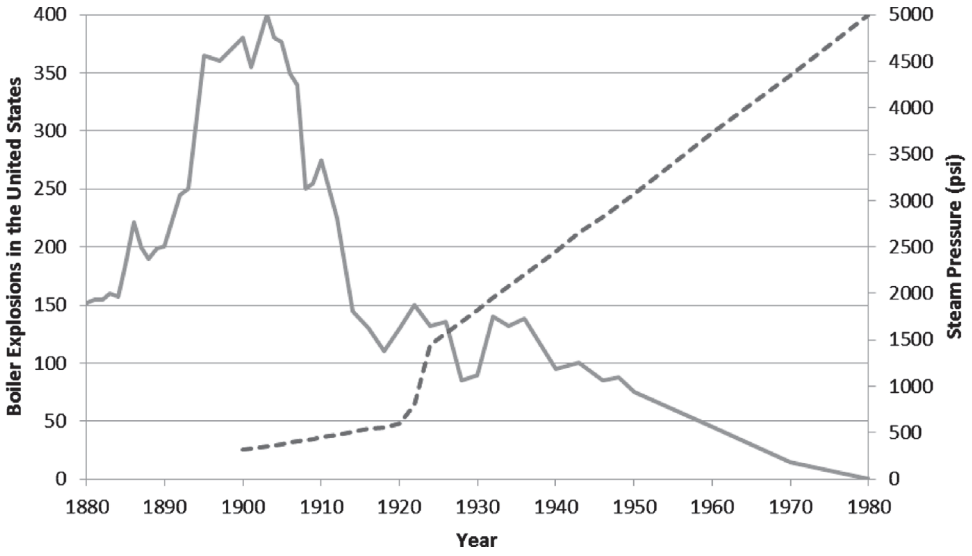


FIGURE 28.1 BOILER EXPLOSIONS VERSUS STEAM PRESSURE – 1880 THRU 1980 [4]

28.3 HISTORY OF PRESSURE RELIEF DEVICES

The need for pressure relief devices was recognized from the very beginning of the use of steam in industry and transportation. Boiler explosions and loss of life increased steadily from 1880 to 1900 as the demand for more powerful boilers steadily increased (Note: the step in boiler pressure is the transformation from riveted to welded boilers, which was a technology developed during WWI).

The need to improve boiler safety led to the formation of the ASME Code Committee in 1911 and the first issuance of the Boiler and Pressure Vessel Codes (1914 and 1924, respectively). These codes were influenced by the Massachusetts Boiler Law issued in 1911. The result proved beneficial as the number of boiler accidents showed an immediate decrease. Safety valves were still in early stages of development where weights and counter weights where often the norm.

As the codes for pressure equipment were developed, often in response to numerous and violent accidents, requirements for pressure relief devices were included. The original ASME Boiler Code published in 1914 included construction rules and methods of calculating capacity based upon boiler dimensions such as grate surface or heating area. These calculations were empirical in nature, and not based upon fluid flow theory or testing.

In the 1930s the National Board of Boiler and Pressure Vessel Inspectors sponsored testing of steam safety valves which was done at the Ohio State University Engineering laboratory. Large discrepancies between marked capacity and tested values were observed. From this work, the original requirements to perform certification testing were developed, and the basics of those requirements are still included in the Code today.

The first tests required were a set of tests done to establish the rating value that could then be used to calculate a nameplate capacity for any valve of that design. The tests were mandated first for steam and later for air and gas when ASME Code Section VIII for pressure vessels was developed. Tests have to be done at an ASME accepted test facility, and all test results submitted to the National Board for review and certification. These tests were essentially prototype valves, so a requirement to test randomly selected production valves was later added, to verify that the valves coming from a production environment would meet their rated capacities and performance requirements. This tested the design itself, capabilities of the manufacturer's test equipment and experience of their personnel. This certification must be repeated every six years to maintain the ability to apply the Code symbol stamp.

28.3.1 20% OP Valves

The needs of differing types of equipment have been recognized in the on-going development of the Code. Standard overpressure for a Section VIII pressure relief valve is 10% above set pressure. A special designation of "20% OP" (for 20% overpressure) was added for the protection of pressure vessels for non-refrigerated liquefied compressed gasses where there is no permanent supply connection. The most common examples are propane storage tanks and agricultural ammonia tanks. Although overpressure from a fire is a concern that requires overpressure protection, a more common problem is leakage from a pressure relief valve causing a fire hazard, or health concern. The 20% OP valves use a special set pressure tolerance of −0% to +10%, with rated capacity being determined at 20% above the nameplate set pressure. A slightly higher risk of the elevated overpressure is countered by reduced risk of discharges caused by a valve opening under the stamped set pressure or leaking during a minor pressure excursion caused by ambient temperature increases while the vessel is full.

28.3.2 Liquid Capacity Certification

One gap in the certification process was that liquid service valves were not covered. Liquid service designs had been traditionally rated at 25% overpressure, and capacity rating values had been estimated or determined from unaudited manufacturer's information. In 1984 capacity certification of valves for liquid service was added first to the nuclear standards and then into Section VIII. The same 10% overpressure as used for Section VIII steam or air/gas service was specified. The traditional 25% overpressure valves would not reliably meet the new requirement, and manufacturers responded by coming up with designs that were more like safety valves, which exhibited more of a popping action instead of the gradual relief opening of previous designs.

28.3.3 Rupture Disk Certification

In 1928, the inspiration of the rupture disk was born as a result of a tremendous explosion, ensuring fire, and loss of life at an oil storage facility. The concept of a disk was simple; design a "thin spot" in the vessel that would fail before the rest of the vessel/tank becomes dangerously stressed. After years of development, in 1931, the first rupture disk was patented for commercial use. Its usefulness took hold and in 1946, ASME Code Section VIII included rupture disks as an accepted method of providing overpressure protection, both as a sole relieving device, and in combination with a pressure relief valve. In 1965, the reverse buckling, knife blade disk was introduced as an improvement over the forward acting disk since the former was prone to fatigue issues. After years of service, knife blade technology showed some repeatability issues so precision scored disks were introduced in 1974 and remain the best available technology on the market today. When added in 1946, the Code included rules on production testing that manufacturers should follow, but little information was provided on how capacities of these devices would be determined. The same calculations as used for pressure relief valves were included and disks received a capacity value on the nameplate. However this method did not take into account the widely varying installation options when a disk is used. A disk could be installed close to the protected pressure vessel with a short straight discharge pipe, and the capacity estimate would be acceptably close, but it could also be installed in a pipe network with long lengths of pipe and numerous elbows and other fittings, and the nameplate capacity on the disk might significantly overestimate the capacity of the entire system. Flow resistance values (K_R factors) were included in some manufacturer's literature and estimated values were also included in some industry standards. Values of either 1.5 or 2.4 were commonly cited and used by design engineers.

Test methods to actually calculate rupture disk capacity were worked on for a number of years by members of the ASME Subcommittee on Safety Valves (which covers all non-nuclear pressure relief issues in the ASME Code). Initial attempts to rate disks using test procedures similar to valves were problematic because of the need to accurately understand the free area of a disk following actuation. Methods using projected area of the open disk were tried, but wide variations were seen in similar devices, and this did not seem to be a practical method. Disks were flow tested using the same installations as pressure relief valves, but these tests did not represent many common installations, and the results obtained were probably more indicative of the test nozzle geometry than the disk itself.

An inline method was developed and this work was presented in a paper to The American Institute of Chemical Engineers (AICHE) by J. E. Huff and K. R. Shaw [5]. This test method was then added to Performance Test Code PTC-25 and accepted as the test method to be used for rating disks in Section VIII.

Disks to be tested are installed into a specified test rig which reflects the use of the device in an in-line position instead of being placed on the end of a nozzle. The flow rate is measured, along with pressure drops across the rupture disk device being tested and two specified pipe lengths in the test rig. Using the flow rate and pressure drop across an upstream pipe section, the pipe friction factor is calculated. The pressure drop across the test section is then used to determine the flow resistance of that section. The flow resistance due to the pipe length included in the test section is calculated from the measured length and the fiction factor and that value is subtracted from the test section flow resistance. The remainder represents the flow resistance of the rupture disk and holder. A downstream pipe section is used as a check section to determine if the flow pattern of the rupture disk is affecting the pressure measurement immediately downstream of the disk.

The Code test procedure requires a set of nine disks to be tested and a K_R consistency requirement must be demonstrated. The average test K_R value plus three average deviations is then used as the certified flow resistance for the rupture disk device. This certified value then can be reliably used by design engineers to calculate the capacity of a relief system including a rupture disk device. Some of the certified values were close to the previously used estimated K_Rs but some disks were found to have higher values (resulting in a lower system capacity), which are sometimes a result of area reduction in the devices.

The first Code tests did not recognize the differences in disk performance that could result from being actuated in a compressible medium or an incompressible fluid. A test procedure to require disks for liquid service to be burst tested with water was added to the test procedure. The burst pattern of the disk is established on water, and the disk is then installed in the flow resistance test rig and the K_R value is measured with air. Many designs exhibited similar opening patterns on gas and liquid, but some were found to vary significantly which led to the need to designate a flow resistance specifically for liquid. The nameplate flow resistance marking rules were revised to add a subscript designator of "g" for gas, "l" for liquid, or "gl" for designs which had been shown to have equivalent performance on gas or liquid. Where a separate liquid K_{RL} value has been determined, it is almost always higher than the gas value because the lack of expansive energy when the disk opens on water does not permit it to open as fully as when actuated on gas.

The rules for rupture disk certification were added to the 1998 edition of Section VIII, and an implementing Code Case allowed an extra year to allow manufacturers to test their designs, and go through quality assurance reviews. The new ASME UD Code stamp was introduced for the rupture disk devices, and capacity was no longer marked on disk nameplates, with the certified K_R value being shown instead.

The addition of rupture disk certification rules addressed the situation where a pressure relief valve protecting an ASME Code pressure vessel was required to be a certified device bearing a Code stamp, but a rupture disk used in the same service was not Code stamped. The SC-SVR has since gradually adopted the concept that all pressure relief devices used to protect ASME Code pressure vessels should be treated equally. They should be built under an accepted quality program represented by the ASME Code symbol stamp, and a capacity rating value should be determined under specified tests which are independently certified.

28.3.4 Pin Type Devices

In the 1980s pin type devices were explored by a manufacturer as an actuating method for pressure relieving devices. This concept was used to develop several Code Cases for the use of buckling pin devices (2091 and 2267). These are non-reclosing devices where a valve disk is held closed by an axially loaded pin. The pin is designed as a slender column using Euler's law, and the buckling force can be accurately estimated from the pin dimensions and material modulus of elasticity. The valve opens when the pressure forces on the disk equal the pin strength, and the pin buckles allowing the disk to open. Another manufacturer then

requested a code case (published as Code Case 2487) for a breaking bar device where the device is actuated by the shearing of a bar which included a notch, similar to a Charpy impact test bar.

These Code Cases were eventually incorporated into the Code, but the committee recognized that manufacturer's would continue to come up with pressure relief devices that might include differing details on the actuation method. Rather than try to anticipate every possible variation, the Code Cases were incorporated in a more general fashion which puts all devices of this type into the general classification of "pin devices". Instead of addressing the specific actuation method, requirements are performance-based with one set pressure tolerance of ±5% applied to all devices in this class, and capacity testing permitted by either a coefficient method similar to a pressure relief valve, or a flow resistance method similar to a rupture disk, when the device would be used in an in-line application. The general rules for pin devices are included in paragraph UG-138 of Section VIII and attempt to treat each variation in an equal manner. No doubt in the future an ingenious manufacturer or inventor will come up with something not anticipated, and rules will be required to address that situation.

28.3.5 Service Issues

Valve Repair:

Although the ASME Code includes Sections VI and VII which address the in-service inspection of power boilers and heating boilers, the primary focus of most of the Code has always been new construction. (Note that Section XI of the Code addresses the in service inspection of nuclear power plants and is referenced from US Code of Federal regulations. The users of that document and the responsible committee are very active in the ongoing work addressing the needs of the operating nuclear power plants in the US and around the world.)

One widely used standard in the US which addresses in-service inspection of boilers and pressure vessels is the National Board Inspection Code (NBIC), and this standard is referenced [6] by many Jurisdictional Authorities. ASME Code rules for pressure relief valves again are mostly for new construction. The standard that becomes applicable to that equipment when it is installed and in use is the NBIC. It includes rules for the installation of pressure relief devices, policies and procedures for in-service inspection, and a program for certifying organizations that repair pressure relief valves. Adopted by many states and accepted by Canadian authorities as well, the National Board VR program was established in 1977 with the goal of assuring that repair work done on pressure relief valves would assure their continued performance to the same standards as new valves. The VR program scope is based upon valves which were originally built to ASME Code rules, and were certified for capacity to those rules (which establishes a known baseline).

The program started strictly addressing repairs to bring the valve back to its original condition. The program scope has expanded to recognize that valves may need to be modified in service to meet changing user needs. This includes set pressure changes, service fluid changes (steam to air, air to liquid etc.) and changes called "conversions" which allow modifications from one configuration to another. The repair organization cannot deviate from the original manufacturer's certified design, but they can make changes within the scope of the design. Common examples include revised lifting lever configurations, addition or deletion of a bellows; or a change from a metal seat to a soft seat variation. Since the valve model number is often affected, the VR program requires that the original information be marked through, and revised data applied to the repair nameplate.

28.3.6 Introduction of New Technology, and Implementation of New Code Rules

A common concern when new Code rules are implemented is the effect on current installations. As previously noted, the Code is designed as a new construction standard. Therefore existing installations should be exempt from any changes until the affected equipment is replaced. Most Jurisdictions will cover this concept in what is often called "grandfathering." One instance where this idea was tested was with the implementation of the rupture disk requirements in the 1998 Code, which mandated Codes stamping and type certification. The "grandfathering" concept was applied in three phases.

1. Rupture disk holders in service, and the spare disks purchased for those disk holders were considered to be existing equipment that could be used based upon the Code rules in effect when it was purchased.
2. When new disks were needed they should be purchased to the Code in affect at that time. This would imply that the disks would need to be Code stamped. They could be used in an existing holder, however, it should be noted that the disk and holder are considered as a matched set of components. Before Code certification rules were in effect, some disk manufacturers offered disks that would fit into another company's holder. Since these items are certified in combination, this practice would no longer be acceptable.
3. When a new disk holder was needed, it too should be purchase to the new Code rules, which mandates that the holder also be Code symbol stamped.

28.3.7 Updates to Code Markings

Since the beginning of the ASME Code, one principle was that products conforming to the Code would be marked in a specified manner to show compliance. This included various Code Symbol stamps which contained a specified letter inside a cloverleaf figure. The letter ("V" for boiler safety valves for example) designated the part of the Code to which the item was built. In 2011, a change was made to the marking. The individual Code stamps were replaced by one ASME Certification Mark containing the letters ASME diagonally inside the cloverleaf figure. Underneath the Code Certification mark is a "Designator", the letter that was previously inside the cloverleaf (the letter "V" would be used for a Section I pressure relief valve).

The pressure relief industry has been using this change as a chance to introduce more automated methods of applying the Certification mark, instead of using a steel stamp to apply the mark, computer controlled lasers or scribing methods are being implemented as a means to permanently apply the mark to a nameplate. Productivity gains have been demonstrated, the graphic images improved, and the risk of damaging a product by hitting it with a big hammer has been removed.

The Certification mark with designator retains its meaning to users and regulatory authorities, gives the public an easy way to know the product they are looking at is built to a standard that helps assure safety, and is the result of many years of work on the part of thousands of volunteers.

28.4 ASME CODES AND JURISDICTIONAL REQUIREMENTS

28.4.1 Jurisdictional Requirements

Before delving into ASME code requirements, it is important to discuss the role of the local jurisdiction. In the US and Canada, states, provinces, and a few large municipalities legislate requirements for the safe design and operation of boilers and pressure vessels. Typically, the person responsible for enforcing these laws for the jurisdiction is a Chief Boiler Inspector. In order to maintain some level of consistency between jurisdictions, the National Board of Boiler and Pressure Vessel Inspectors, located in Columbus, OH, was formed in 1919 with all the Chief Boiler Inspectors making up the governing body. While overpressure protection based on ASME code and API Standard requirements will be presented in this chapter, all the succeeding information may or may not be legislated by the jurisdiction in which the pressure equipment is operating. It's important to know the jurisdictional requirements, which maybe more or less restrictive, before designing for overpressure protection. The National Board Synopsis NB-370 [6] provides an overview of each state/province/city's jurisdictional requirements and contacts. www.bpvinspector.com provides a direct link to all the jurisdiction's statutes and regulations. It is often an explicit requirement of the code case to obtain jurisdictional approval for its use.

28.4.2 ASME Section I — Power Boilers

Pressure relieving requirements for power boilers are covered in para PG-67 thru PG-73. A power boiler is one that generates steam greater than 15 psig. The title of the Code can be misleading in that many boilers of this type do not provide steam to a steam turbine (to produce electricity) but are used for process heating and turbine-driven machinery (e.g., pumps, compressors). Much has been written on pressure relieving requirements for power boilers in other ASME Press publications [2] so no attempt will be made here to restate or reword all the basic requirements. However, a quick overview of safety valve application is warranted.

ASME Section I boilers are typically sold as units and pressure relief sizing is performed by the designer, often the original equipment manufacturer (OEM). Heating surface and firing rates are used to determine safety valve capacities. This information is stamped on the boiler's code plate depending on which basis is used and the year of construction. However, there are situations when the owner will have a more active role in determining Section I pressure relieving requirements. Often, ancillary equipment is added to the boiler by the owner, such as economizers, feedwater heaters, and superheaters, to increase the efficiency of the boiler system. If the add-ons are within the boiler boundary, Section I requirements apply and typically the OEM will provide overpressure protection. If the add-ons are outside the boiler boundary, either Section I or Section VIII requirements apply. While Section I OEMs are qualified to determine pressure relieving requirements (and provide the safety valve(s)), non-boiler OEMs providing Section VIII add-ons often are not. For economizers and feedwater heaters, the safety valve(s) should be sized for the vaporization of trapped liquid. Merely determine the heat input (btu/hr) and divide by 1000 (conservatively, the heat of vaporization of water, not the enthalpy). The result will be in lb/hr. For isolatable superheaters, the same energy balance method is used or the total heating surface multiplied by 6 (lbs/hr per ft^2). Section I valves will be V stamped and capacities stamped in lbs/hr. For add-ons outside the boiler boundary in which Section VIII applies, the methodology is the same, but the valves are stamped UV and capacities in lbs/hr.

TABLE 28.1 TABLE A-44 GUIDE FOR ESTIMATING STEAMING CAPACITY BASED ON HEATING SURFACE [7]

US Customary Units		
	Pounds of Steam/(hr ft^2)	
Type of Surface	**Firetube Boilers**	**Watertube Boilers**
Boiler Heating Surface		
Hand fired	5	6
Stoker fired	7	8
Oil, Gas, or pulverized fuel fired	8	10
Waterwall Heating Surface		
Hand fired	8	8
Stoker fired	10	12
Oil, Gas, or pulverized fuel fired	14	16
SI Units		
	Kilograms of Steam/(hr m^2)	
Type of Surface	**Firetube Boilers**	**Watertube Boilers**
Boiler Heating Surface		
Hand fired	24	29
Stoker fired	34	39
Oil, Gas, or pulverized fuel fired	39	49
Waterwall Heating Surface		
Hand fired	39	39
Stoker fired	49	59
Oil, Gas, or pulverized fuel fired	68	78

With the promulgation of new environmental regulations, owners have been required to replace old burners with low-NOx burners, changing the firing rate and hence, re-verification of the safety valve capacity. In absence of the OEM, local jurisdictions or your Authorized Inspection Agency (AIA) will assist to ensure safety of the boiler. A quick, conservative method for determining new pressure relieving requirements is found in Section I, Table A-44, which was in the mandatory part of the code prior to 1994. With the evolution of boiler technology, such as heat recovery steam generation (HRSG) boilers, fluidized and circulating bed boilers, and stoker boiler firing refuse, this one-size-fits-all approach became obsolete and the table was placed in Appendix A to be used as a guide.

28.4.3 ASME IV — Heating Boilers

ASME Section IV covers requirements for steam heating, hot water heating, and hot water supply boilers. These boilers can be fired by any fossil fuel but natural gas or electricity is typically used. These units are typically found in schools, hotels, hospitals, large commercial buildings, and industrial plants when large quantities of process steam is not required. Safety valve requirements in Section IV use similar rules as in Section I, in that the heat output of the burner is determined and divided by 1000, or the surface area of the unit is compared to a table. Pressure relieving requirements should be addressed back to the OEM, but in the absence of an OEM, your local jurisdiction or AIA can provide guidance.

28.4.4 ASME Section VIII, Division 1 – Pressure Vessels

Pressure vessels represent the largest and widest application of pressure relieving requirements. Many other code sections have established a portion of their rules based on Section VIII. The reader should clearly understand one fundamental requirement of the owner and that is to ensure adequate overpressure protection of their equipment. That is, the requirement is performance-based. Prescriptive-based requirements are provided mainly for the OEM and designer, but it's ultimately the owner/operator's responsibility to ensure the proper overpressure scenarios have been identified, pressure relieving device sized, installed and maintained. Appendix M and API standards are available to assist the owner/operator in this endeavor.

Pressure Relieving requirements can be found in UG-125 thru UG-140, Appendix 11 and Appendix M. A discussion on these requirements follows.

UG-125 thru UG-138 provides prescriptive rules for the designer and manufacturer of PRDs, while UG-140 is for the owner/operator. Much of these rules have been in existence for 50 years. However, in the last 10 years, PRDs using buckling and breaking pins have entered the market necessitating the addition of rules to cover these devices (e.g., UG-138). In the last 5 years, a few major changes were added which warrant discussion.

28.4.4.1 U-1(c)(2)(h)(1) — Vessels Not Exceeding the Design Pressure of 15 psig In the 2006 addenda, a subtle change was made to the internal/external pressure limit for an ASME code exemption. Prior to this addenda, vessels that did *not operate* over 15 psig were code exempt, but the language was changed in 2006 to vessels *not exceeding a design pressure* of 15 psig. The implication to pressure relieving is prior to 2006, while a vessel could operate under 15 psig and be ASME exempt, the accumulation during an overpressure event wasn't adequately addressed and left up to interpretation. During an overpressure event, can a non-code vessel exceed 15 psig? In 2006, the ASME Code clarified this by stating in order for a vessel to be exempt, it cannot exceed 15 psig. Hence, no overpressure allowance permitted. This is a grey area for most owners and jurisdictions which will still cause much constatation consternation in the future for pre-2006 equipment.

There are occasions when a vessel meeting one of the numerous U-1(c) exemptions is chosen to be ASME stamped by the owner or designer. For those vessels, the ASME Code Committee issued the following interpretation stating a certified PRD is required.

Interpretation: VIII-1-92-15R

Subject: Section VIII, Division 1 (1989 Edition, 1990 Addenda); U-1(c)

Date Issued: December 5, 1991

Question: A vessel which by the provisions of U-1(c) in Section VIII, Division 1 is exempted is nevertheless fabricated to the Code and Code Symbol stamped. Must a pressure relief device, as outlined by the requirements in UG-125 through UG-136 of the Code, be installed?

Reply: Yes

A paradox exists with the issuance of this interpretation for stamped vessels below 15 psig in that pressure relief valve manufacturers did not independently certify valves at these low pressures. This created a code requirement which no code pressure relief valve exists. Since most states exempt all vessels stamped below 15 psig, a non-stamped PRD would be acceptable. However, in code states, the owner/designer should contact the jurisdiction in which the vessel operates to determine the appropriate method for overpressure protection. In absence of a local jurisdiction, your Authorized Insurance Agency will provide guidance.

28.4.4.2 UG-127(d) — Open Vents While it seems intuitive to recognize open vents as a safe method of preventing overpressure of equipment, its use was not addressed in the Code until the addition of UG-127(d) in the 2008 Addenda. Open vents allow ASME vessels stamped at pressures above atmospheric to operate without a PRD, though a detailed pressure drop analysis is required and an additional 10% margin is added to the results.

28.4.4.3 UG-140 — Overpressure Protection by System Design Formerly Code Case 2211, this newest change to the ASME Code was added in the 2008 addenda allowing the omission of a PRD by system design, recognizing the highly hazardous fluids handled in the nuclear and chemical industries. Design of these highly hazardous systems minimizes potential leak sources (flanges, pump seals, valves etc.) and discharging of PRDs represented paradoxically a safety hazard. Through the advancement of instrumentation and hazardous analysis tools, overpressure events are no longer handled by venting but by the use of engineering design and controls. UG-140 subdivides overpressure protection scenarios into two categories and an overview is provided.

28.4.4.3.1 Self-Limiting (UG-140(a)) These are scenarios where the physics of the system *prevents* internal pressure from continually rising. Such is the case of a centrifugal (not positive displacement) pump or compressor. The maximum pressure developed is limited to the vessel's MAWP (10% accumulation is not allowed).

28.4.4.3.2 Non-Self-Limiting (UG-140(b)) These are scenarios where the physics of the system *does not limit* the rise of internal pressure. Examples would be runaway, decomposition reaction, deflagrations, (i.e. exothermic reactions), positive displacement pumps or compressors, etc. The maximum pressure developed is limited to 116% of the vessel's MAWP multiplied by the ratio of the allowable stress at relieving temperature to the allowable stress at design temperature. This computation is best performed by a pressure vessel engineer.

In both Self-Limiting and Non-Self-Limiting scenarios, the decision to omit the pressure relieving device is the owner's decision and a hazard analysis must be conducted by a multi-discipline team. The results shall be documented and signed by an individual of responsible charge of operating the vessel(s). For new vessels, the applicable sub-paragraph (UG-140(a) or UG-140(b)) shall be noted on the ASME Manufacturer's Data Report (U-1) and local jurisdiction approval will most often be required (State laws in many cases explicitly require a PRD so UG-140 needs jurisdictional approval).

28.4.5 Appendix 11 (Mandatory) — Capacity Conversion for Safety Valves

This appendix provides the designer a method for converting capacity requirements in fluid media other than saturated steam, water, and air to another fluid. It is necessary because manufacturer's certified capacities (including those stamped on the device's code plate) are required to be reported in steam, water or air. When fluids other than these three are the service fluid, adjustments are required. API 520 Part 1 provides additional equations for making adjustments for viscosity and for non-ideal fluids (i.e., two-phase flow).

28.4.6 Appendix M (Non-Mandatory) — Installation and Operation

This appendix provides general information on methods to safely install and operate systems with pressure relieving devices. It covers subjects such as 1) how to appropriately install isolation block valves, 2) when a single pressure relieving device can be used to protect a system of vessels, 3) considerations of operating margins (operating pressure/set pressure) which affect blowdown, 4) the use of soft seats to off-set leakage due to vibration and other external loads, and 5) the 3% and 10% rule. References are made to API 520, 521, and 2000 showing the inter-dependence of the two organizations.

28.4.7 Pressure Relief Valve Inlet Pressure Drop — the 3% Rule

Appendix M of ASME Section VIII, Division 1 states that "the nominal pipe size of all piping, valves and fittings, and vessel components between a pressure vessel and its safety, safety relief, or pilot operated pressure relief valves shall be at least as large as the nominal size of the device inlet, and the flow characteristics of the upstream system shall be such that the cumulative total of all non-recoverable inlet losses shall not exceed 3% of the valve set pressure. The inlet pressure losses will be based on the valve nameplate capacity corrected for the characteristics of the flowing fluid" [8]. This section of appendix M pertains to safety valves in compressible fluid service, but is also generally followed for incompressible fluids. The 3% inlet pressure drop, commonly referred to as the 3% rule, was adopted by ASME in the 1980's. It is believed that the 3% rule originated from research in the 1940's sponsored by the American Petroleum Institute (API) [9]. The 3% rule is used as a guideline to prevent valve instability and reduced flow capacity. Every pressure relief valve has a blowdown value. The blowdown value is "the difference between the set pressure and closing pressure of a pressure relief valve, expressed as a percentage of the set pressure or in pressure units" [3]. For a conventional safety valve in compressible fluid service, a typical blowdown could range from 7% to 10% [10]. This range will vary depending upon the pressure relief valve type, the pressure relief valve manufacturer, and whether the pressure relief valve has a fixed or adjustable blowdown design. Applying the 3% rule would therefore allow for a margin of safety. This rule has been used extensively when designing new systems.

For existing systems with pressure drops greater than 3%, designers are allowed to perform an "engineering analysis" to justify higher inlet losses [11]. The objective is to complete detailed calculations to demonstrate that the pressure drop is less than the blowdown of the pressure relief valve. Currently, however, there is no widely accepted procedure to complete this analysis. There is also concern in industry that pressure relief valve instability may not be a function of inlet pressure drop alone. Studies are underway to examine other potential interactions that may be sources of pressure relief valve instability, but for the foreseeable future, it is likely that the 3% criteria will remain the standard guideline.

28.4.8 Pressure Relief Valve Outlet Pressure Drop — the 10% Rule

API Standard 520, Part I defines backpressure as "the pressure that exists at the outlet of a pressure relief device as a result of the pressure in the discharge system." Backpressure is composed of "superimposed and built-up backpressures." Superimposed backpressure is "the static pressure that exists at the outlet of the pressure relief device at the time the device is required to operate" and can be a "constant or variable" pressure. Built-up backpressure is "the increase in pressure at the outlet of a pressure relief device that develops as a result of flow after the pressure relief device opens" [3].

Conventional (non-balanced) pressure relief valves can exhibit instability due to high backpressure at their discharge. Backpressure can add to the spring force on the valve's disk. This can reduce the flow capacity of the pressure relief valve and also result in instability. For Conventional (non-balanced) pressure relief valves, the "built-up backpressure should not exceed 10% of the set pressure at 10% allowable overpressure" [3]. Some pressure relief valves may have an open bonnet design (exposed spring) which may allow for a greater backpressure limit. In this case, the pressure relief valve manufacturer should be contacted to confirm the acceptable backpressure limits for the specific device. API 520, Part I further states that "a higher maximum allowable built-up backpressure may be used for allowable overpressures greater than 10% provided the built-up backpressure does not exceed the allowable overpressure" [3]. However, it is generally considered conservative to use the 10% limit (10% built-up backpressure at 10% overpressure) for Conventional pressure relief valve evaluations. Refer to Reference [12] for additional discussion on this topic. For systems where there is high backpressure, a balanced bellows direct spring pressure relief valve may be a suitable option. A bellows is positioned above the top of the pressure relief valve disk to help reduce the effects of variable superimposed backpressure. The bellows also allows the pressure relief valve to tolerate higher built-up backpressures. A typical balanced

bellows pressure relief valve may be exposed to 30% backpressure (at 10% overpressure) without derating the valve's capacity and higher backpressure may be allowed with or without a derating factor applied depending on the allowable overpressure [10].

28.4.9 Pressure Vessels with Internal Pressures of 15 psi and Less

As stated earlier in this chapter, pressure vessels that fall under the ASME Section VIII Code require a UV or UD code stamped pressure relief device, an open vent meeting the requirements of UG-127(d), or otherwise have overpressure protection by design per UG-140. However, some vessels are designed and constructed per ASME Section VIII Code with an internal pressure of 15 psi or less. By definition, these vessels are not within the scope of the Code. However, owners may still choose to have the U or UM stamp (depending on design) applied to these vessels. Although these vessels have a Code stamp, it is recognized in industry that a Code stamped pressure relief device (bearing the UV or UD symbol) may not always be available, as previously discussed in this chapter. The reason for this is that most vendors of pressure relief devices do not currently code certify all of their available devices below a set pressure (or burst pressure) of 15 psig. Most of these devices are still available with set pressures less than 15 psig, some as low as 3 psig; they just may not be Code stamped. Currently, though, all pressure relief valves with a set pressure below 15 psig will not have the UV Code stamp applied and their capacities are not certified by the National Board (NB). On the other hand, some rupture disk and pin devices are available with a UD Code stamp below 15 psig. For instance, some models of metal rupture disks can be Code stamped as low as 5 psig and some graphite disks can be Code stamped as low as 1/4 psig [13]. It is important to note that these low settings are not available for all rupture disk sizes within a given model and manufacturers would need to be consulted for specific details.

When a non-code pressure relief device is acceptable for overpressure protection for a non-code vessel or equipment there are several options available. Some of these non-code devices include conventional pressure relief valves, rupture disks, modulating relief valves, pilot operated, weight loaded, and spring loaded pressure vents, and pin devices. The choice of the device may depend on available connection sizes, required capacities, type of relief effluent, operating conditions, amount of overpressure required, design pressure of the pressure relief device, and the allowable accumulation of protected equipment. One point to emphasize is the importance of knowing the protected equipment's allowable accumulation. For a pressure vessel within the limits of the Code, the allowable accumulation is clearly defined depending on the vessel's design pressure or MAWP (maximum allowable working pressure), the type of overpressure event, and the number of pressure relief devices installed. For Code stamped pressure vessels with an internal design pressure or MAWP equal to or less than 15 psig, the accumulation limits from the Code will typically apply. The designer, however, should always verify that state jurisdictional requirements are met as well as the Owner's requirements. For a non-code stamped pressure vessel, the designer may not necessarily be able to apply code allowable accumulations. For example, a designer evaluating an existing vessel to ensure adequate overpressure protection exists will typically review the available information for the vessel including the detailed fabrication drawings. The drawings may note that the subject vessel was designed and constructed per the ASME Section VIII Pressure Vessel Code, but no code stamp was applied. Not having the code stamp applied to the vessel nameplate in this situation opens the possibility that the vessel manufacturer may not have actually met all the requirements of the Code. If, however, the vessel manufacturer indicates the vessel was designed, constructed, examined, and tested with the appropriate hydrotest pressure, the designer may feel inclined to allow an accumulation for the vessel. The designer may have to rely on available documentation (drawings, calculations, plant inspection/test reports, etc.) or possibly confirmation from the OEM when determining if an accumulation should be allowed. Consulting with an experienced pressure vessel engineer is another option. Evaluating an existing vessel using available program software may allow an engineer to determine if accumulation is acceptable. As stated before, the designer will also need to verify that state jurisdictional requirements are met as well as the Owner's requirements. In the absence of positive identification from all available resources, the conservative choice may be to assume 0% vessel accumulation.

28.4.10 ASME Section VIII, Divisions 2 and 3 — High Pressure Vessels

Division 2 and 3 pressure relieving requirements are similar to Div 1 except for the following:

When a pressure relieving device is omitted by system design (UG-140), Div 2 does not allow accumulation greater than MAWP.

Div 3 does not allow omission of pressure relieving devices (UG-140) unless the source of overpressure is external to the vessel.

28.4.11 ASME Section X — Fiber-Reinforced Plastic Pressure Vessels

ASME Section X covers the rules for fiber-Reinforced Plastic pressure vessels. These vessels are used when exotic metals are cost prohibitive. While Section X has its own set of pressure protection rules, much of the Section X rules are derived from Section VIII rules (i.e., allowed accumulation, set pressure tolerances, required blowdown).

28.4.12 National Board (NB-18) Pressure Relief Device Certification (The Redbook)

NB-18 provides a comprehensive list of all approved ASME pressure relieving devices, manufacturers, assemblers, and certified valve repair companies, for the various code books described above. This book contains a wealth of information for an owner or designer when changing a pressure relieving device from one service to another. The "Redbook" as it's called by its users, provides information as to the applicable code, allowable set pressure ranges (if any), certified flow coefficients, combination safety valve/rupture disk coefficients and other relevant information. Spring ranges, valves permitting restricted lift, and other valve characteristics are also provided. All PRD OEMs will be very familiar with the "Redbook" as it is an excellent resource.

28.4.13 ASME B31.1, Power Piping

The Power Piping Code has two defined areas of responsibility; boiler external piping, from the boiler proper out to the first or second stop valve (depending on the boiler configuration), and Non-Boiler external piping, feedwater, condensate, and steam distribution. The functional requirements for the safety valve are identical for both applications (see ASME B31.1, para 122.1.7). In summary, requirements for these safety valves are:

V Stamping
Open Bonnet design
6% accumulation
2–4% blowdown
Lifting Lever

M Bernstein and L Yoder [2] is a well written source discussing overpressure protection for boiler and boiler piping.

ASME B31.1, Appendix II (Rules for the Design of Safety Valve Installation) is a much cited source for safety valve installation. Here a designer will find information such as 1) how to calculate forces during relieving conditions and associated nozzle loads/moments, 2) installation details, 3) discharge piping analysis such as shear lugs and predicted stresses, and 4) the effect due to tapering the outlet of the discharge piping.

28.4.14 ASME B31.3, Process Piping

Overpressure protection requirements for process piping are found in the base code of ASME B31.3 in paragraphs 301.2.2 and 322.6. For Non-Metallic, Category M, High Pressure, and High Purity piping systems, slight modifications to these paragraphs, based on those specific fluid system needs, are found in Chapter VII thru X respectively. Only the ASME B31.3 base code requirements will be discussed here for the sake of brevity. The reader should refer to ASME B31.3 for Chapter VII thru X for the aforementioned services. Para 301.2.2 is written with the designer in mind and provides them with the option of 1) designing the system for the maximum expected pressure (e.g., containment or 2) providing a relief device (note that non-reclosing devices are not prohibited in ASME B31.3). Para 322.6 provides detailed requirements to the designer on how to meet para 301.2.2 but also provides requirements to the owner and manufacturer. Both options will be addressed.

The committee has received several inquiries over the years on designing a piping system for relief or containment. One of significance was received and addressed in 1983 and allows a wide latitude of options to the designer.

Interpretation: 2·29

Date Issued: December 20, 1983

Subject: Required Pressure Containment or Relief (para 301.2.1, re-numbered to 301.2.2 in later B31.3 editions)

Question: Does any device or system, such as pressure reducing valves or similar mechanical or electrical interlocks and/or control instruments, satisfy the requirements of ANSI/ASME B31.3, 301.2.1, to safely relieve any excess pressures?

Reply: The Code requires that provision be made to contain or safely relieve excessive pressure, but does not address acceptable types of pressure relieving devices.

This interpretation clearly does not prohibit the use of pressure regulating valves, instrumentation, interlocks, over-speed protection/overpressure protection inherent to rotating equipment, the list goes on. However, an overriding requirement which cannot be ignored is that the code is performance based in regard to overpressure protection. So while ASME B31.3 does not prohibit mechanical and electrical devices to be used to prevent overpressure, should overpressure occur, the design then fails to meet code requirements. Hence, any attempt to avoid installing a relief valve should be scrutinized for reliability/repeatability and treated as a critical safety device with independent review.

ASME B31.3, as with many of the ASME piping codes, contains PRD rules based on the experience of the ASME BPV Section VIII overprotection rules, but stops short of citing all Section VIII requirements. What's noticeably missing in ASME B31.3 is the requirement that relief devices require UV/UD stamping, (i.e., independent verification of manufacturing, assembling, and capacity). There has been some effort within ASME B31.3 recently to require UV stamping but this change has not been approved by the committee. The thinking behind not stamping ASME B31.3 relief devices is the volume in a piping system is not significant compared to pressure vessels; hence the stored energy is less. While most relief valve manufacturers provide UV stamped relief valves, there are some that do not. For these manufacturers, a certificate of conformance (COC) is required attesting their relief valve meets ASME B31.3 requirements.

Finally, ASME B31.3 has some unique overpressure protection rules that warrant explanation. One is, with the owner's approval, allowing a relief valve's set pressure to be higher than the design pressure. This allows the use of the occasional pressure/temperature variation clause in para 302.2.4, used often in the process industry, which states a piping system can be over-pressurized/overstressed occasionally, such as during de-coking, steam-out , catalyst regenerating, etc. A limitation of this rule is set pressure plus overpressure cannot exceed the occasional variation limits (see ASME B31.3 para 302.2.4(f)) and the system must have been pressure tested during construction to this higher pressure. The other unique rule is the 20% overpressure thermal expansion rule. What this allows (para 322.6.3(b)(2)) is thermal relief valves to be set at 120% of design pressure without owner's approval (note, ASME B31.3 leak testing rules have recently been changed to allow pneumatic testing up to 133% of design pressure to support these two rules).

28.5 AMERICAN PETROLEUM INSTITUTE PRESSURE RELIEF STANDARDS

The API Subcommittee on Pressure Relieving Systems meets twice annually (Spring and Fall), typically split between an east coast and west coast city to accommodate travel for members and visitors. The documents that this Subcommittee maintains are API 520, 521, 526, 527, and 2000. Since these documents are ANSI approved, all subcommittee meetings are open to the public and public comments must be addressed. Much confusion exists in industry as to where these documents fit with respect to strict adherence or guidance documents? Often full compliance to these standards is not met by many owners since in many cases the API requirements go beyond what is specified in the ASME codes (for instance the 3% inlet piping pressure drop rule is in a non-mandatory appendix in ASME). However, while these API documents are standards (not codes), and not legislated by state authorities, they are considered RAGAGEP (Recognized And Generally Accepted Good Engineering Practice) documents by OSHA [14], and are enforced as codes by federal authorities. Therefore, not adhering to API pressure relieve standards has led to citations and fines. Overview of the relevant pressure relieving system standards are provided below.

28.5.1 API 520, Part 1 — Sizing and Selection

This document provides sizing criteria and nozzle selection for pressure relieving devices. It does not give guidance on ASME code compliance nor system application. That guidance is deferred to the applicable ASME code book and API 521 respectively. Sizing equations are provided based on compressible, non-compressible, and two-phase flow through a nozzle. This document focuses on the physics of fluid flow, not the system application.

28.5.2 API 520, Part 2 — Installation

This document provides guidance for pressure relieving device installation. Inlet and outlet piping and pressure drop rules are discussed with examples. This document provides guidance on the 3% and 10% inlet/outlet pressure drop. See ASME Section VIII, Appendix M in this chapter on more discussion on the 3% and 10% rule.

28.5.3 API 521 — Pressure Relieving and Depressurizing Systems

This document provides the designer with overpressure scenarios to consider when sizing a pressure relief device. The list is not inclusive and API has verbiage throughout which allows the designer to use a more rigorous approach. For instance, in a fire sizing case of a jacketed vessel, API 521 does not explicitly discuss credit for the insulation effect a jacket has to its vessel, but it is permitted by rigorous calculation methods. Common overpressure scenarios the designer should consider are:

1. Blocked Outlets — Feed Continues
2. Blocked Outlets — Heat Source-On
3. Pump or Compressor Isolated
4. Thermal Expansion of Liquids or Gases
5. Cooling or Reflux Failure
6. Accumulation of non-condensable
7. Power Failure
8. Instrument Failure (Instrument Air, DCS)
9. Automatic Control Valve Failure
10. External Fire (pool fires and jet fires)
11. Entrance of a More Volatile Fluid
12. Chemical Reaction (Runaway or Decomposition)
13. Internal Explosions (excluding detonations)
14. Absorbent Flow Failure
15. Backflow from Downstream Equipment
16. Heat Exchanger Tube Failure
17. Startup/Shutdown
18. Human Error

An important philosophy of API 521 is that two independent failures acting simultaneously is not a credible basis for design and only the worst case need be considered, such as loss of power resulting in shutdown of cooling pumps and air-fan coolers. Credit is allowed in API 521 for fluids exiting the vessel through unaffected flow paths. For example, in a fractionating column, if the overhead condenser is lost due to a tripped pump, credit for liquid exiting through side streams is allowed. The designer should be diligent to review all the common failures (and credible uncommon failures) to determine the worst case scenarios. Often the worst case scenario is fire sizing and can result in cumbersome valves. API 521 does not consider fire sizing necessary for vessel liquid levels 25-ft above grade or if flammables are not present in the area. The term flammable is a term that will cause much consternation but if a fluid has a flash point, it's considered flammable. Check the NFPA diamond to see if the fluid has a flammable rating greater than zero in the red square (e.g., ratings 1 through 4 are flammables).



FIG. 28.2 NFPA DIAMOND

28.5.4 API 526 — Flanged Steel Pressure Relief Valves

This document provides dimensional requirements for pressure relief valves. Face-to-face dimensions are standardized so that valves manufactured by different manufacturers are interchangeable.

28.5.5 API 527 — Valve Seat Tightness

This document provides guidance on acceptable seat leakage of metal and soft seated safety relief valves. Service Centers that perform valve repairs/servicing under an NB VR stamp will follow this acceptance criteria unless the owner establishes more stringent criteria. This document is needed if an owner chooses to setup their own safety relief valve repair program. Check with local jurisdictional regulations to determine if a VR certification is required. Currently, 38 states require VR stamping of repaired/serviced safety valves [6].

28.5.6 API 2000 — Venting Atmospheric and Low Pressure Storage Tanks

This document provides guidance on sizing and selecting pressure and vacuum breather and emergency vents for API 620 and API 650 tanks. The smaller API 12 tanks (12B, 12D, 12F, etc.) also use API 2000 for emergency sizing criteria. However, it is not to be used to determine venting requirements for tanks built to Underwriters Laboratory UL 58 or 142 (Below and Above ground flammable liquid steel storage tanks), as requirements are contained in those standards.

28.5.7 API Std 2510 — Design and Construction of LPG Installations

This document provides guidance specific for LPG storage tanks and installations. LPG tanks are constructed to the ASME code (typically stamped at 250 psig) and there are OEMs that provide safety valves sized to meet this standard. This is one of the rare cases when the pressure vessel manufacturer may provide the required safety valve(s). If this is not the case, refer to API Std 2510 for PSV requirements and NB-18 for available valve OEMs. A 20% OP safety valve is used for LPG tanks.

28.5.8 API Documents – Updates, Interpretations, and Membership

API makes changes to these documents every five years. Proposed changes are voted on by the members and only 2/3rd consensus agreement is required. Between meetings, API receives interpretation requests from the public on subject matter in the publications. At every meeting, these interpretation requests are

discussed, consensus wording developed and voted on by the members. The inquirer receives a formal reply back from API and often the interpretation leads to action by the committee to improve the wording in the standard. Since the members are made up of owners, designers, manufacturers, and consultants, a member with the appropriate background is assigned the action. Membership into this group is by application. Anyone with the appropriate background (e.g., 5+ years of experience with PRDs), and the financial backing to attend meetings and actively participate is typically approved. However, there is a one member per company rule to prevent biased results.

28.6 SUMMARY

From the beginning of the industrial revolution, and the advent of boilers, the need for pressure safety has been recognized. Due to numerous boiler explosions and loss of life, the ASME Boiler Code Committee was created to formulate rules for the safe design and operation of boilers. Over the years pressure vessels and other pressure equipment were codified, each with their unique but similar overpressure rules. A historical perspective of overpressure protection has been presented, from counter-weighted devices up to the newly issued para UG-140 in ASME Section VIII, Div 1,

TABLE 28.2 PERMITTED PRDS BY ASME/API BOOK SECTION OR STANDARD

	ASME/API Book Section or Standard									
	I	IV	VIII	X	XII	B31.1	B31.3	RTP-1	API 620	API 650
Direct Spring Loaded Pressure-relief valve	●	●	●	●	●	●	●	●	●	●
Pilot Operated Pressure-Relief Valve	●		●	●		●	●		●	●
Power Actuated Pressure-Relief valve	●					●				
Rupture Disks	◊		●	●			●	●	□	□
Breaking Pin Device with Pressure Relief Valve			●				●		□	□
Spring Loaded Non-Reclosing Pressure-Relief device			●				●		□	□
Buckling Pin			●				●		□	□
Pallet Weighted								●	●	●
Manway Covers										□

● — permitted

◊ — in combination with pressure relief valve on organic fluid vaporizer only

□ — recommended for emergency venting only

which allow complete omission of PRDs with the appropriate engineering review and design. An overview of the various PRDs permitted in the codes and standards discussed in this chapter are tabulated below.

28.7 ACKNOWLEDGMENTS

I would like to acknowledge Joseph Ball for his invaluable contribution on the history of the PRD certification process and Mr. Terry Baker for his input on the API and non-code application. Special thanks goes to my wife, Cheri Eskridge, who spent many hours reviewing the document and providing helpful comments.

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CHAPTER

29

INSIGHTS FROM NUCLEAR UTILITY EXPERIENCE WITH PRA APPLICATIONS

Deepak Rao

29.1 SUMMARY AND BACKGROUND

This chapter provides a discussion of probabilistic risk assessment, its origin and evolution, and insights from its usage in the nuclear power industry. It provides a comprehensive set of references on various topics related to PRA basics and applications. These may be used by the reader for delving into the items discussed in greater detail.

29.1.1 History of Risk Analysis

What is Risk? Risk is defined by answering the following three questions, called the "risk triplet," for any scenario of interest:

- What can go wrong?
- How likely is it to go wrong?
- What are the consequences if it does go wrong?

The "risk triplet" refers to:

- Scenarios,
- consequences,
- and likelihoods.

In the nuclear power industry, risk is estimated using probabilistic risk assessment (PRA), also called probabilistic safety analysis (PSA), or quantitative risk assessment (QRA) techniques. The three terms are completely interchangeable. In comparison to traditional nuclear power plant engineering design disciplines, PRA is a relatively new area. This section provides a brief discussion of the history of risk analysis with special emphasis on nuclear power plant applications of PRA.

29.1.2 Evolution of the Understanding of Probability and Risk

The concept and manifestation of risk has evolved tremendously over the ages. Peter Bernstein provides an intriguing discussion of this evolution of the understanding of probability from prehistoric ages to today in his book "Against the Gods" [1] which is replete with narrations of many of the instances where the state of knowledge about probability and risk kept growing over thousands of years.

Below is a summary of some of the major advancements he describes to be critical in this evolution:

- The Hindu-Arabic numbering system invented in India around 500 AD (this reached the West about 700 to 800 years ago).
- The Renaissance (15th to 17th century A.D.) and its new approaches to scientific method.
- Solution to Paccioli's puzzle in the 1600s (the puzzle was how to divide the stakes of an unfinished game of chance between two players when one is ahead) – this made a huge advance into decision analysis and the discovery of the theory of probability.
- By the 1700s mathematicians were applying probability theory. Tables of life expectancies were created and helped the English government sell life annuities.
- The normal distribution (or bell curve) and standard deviation was discovered by Abraham de Moivre in the 1730s.
- Bernoulli's assertion that satisfaction resulting from any small increase in wealth will be inversely proportional to the quantity of goods previously owned. This has remained valid for several centuries.
- Thomas Bayes, in the origination of Bayes' Theorem, made a major advance in statistics relating to how to make better informed decisions by mathematically blending new information into old information. This theorem is being extensively used in nuclear plant PRAs to combine new or plant-specific failure data with generic or industry failure data.

Many of the above events took place roughly between 1650 and 1750 AD; arguably, this is the period of history which saw the maximum relative improvements in risk analysis theory.

In the 20th century, there was much advancement in the invention, design and commercial production of complex machines and systems. Some of these are:

- automobiles
- airplanes
- nuclear power plants
- electronic systems (due the invention of the transistor and semiconductors)
- rockets and space propulsion devices
- the personal computer
- the internet

Notice that the complexity of these newly invented systems increased the then state of the art by leaps and bounds; much of it

along the lines of Moore's Law [2], which in essence asserts that state of the art computing hardware power doubles about every couple of years.

With increasingly complex systems, reliability and risk analysis needed to be a much more rigorous and comprehensive discipline. No longer was it possible to estimate the likelihood of the failure of a complicated system by performing some simple testing. What was worrisome was that there could be rare events caused by the confluence of multiple failures. The performance of complicated systems cannot be easily deduced from those of simple components. Redundancy and diversity of components improve reliability to varying extents, and human interaction with the system, even an automated system is much harder to model and quantify. Humans can erroneously override safety features (e.g., during the accident at Three Mile Island in 1979 [3]). Risk results for complex systems are not intuitively obvious for these reasons and need a systematic quantification of the various probabilities of combinations of hardware as well as human errors.

29.1.3 A Brief History of Early Nuclear PRAs

During the licensing of the early US nuclear power plants, there was neither risk analysis nor PRAs. The technical specifications for nuclear plants developed during the licensing phase were constructed from deterministic analyses and engineering judgment as to what constitutes safe operation with sufficient margin. F. Reg Farmer of the UKAEA [4] and B. John Garrick [5] appear to be the first few to conceive of nuclear PRA concepts. They were among the first few persons who advanced the opinion that a wide spectrum of accidents needs to be considered for risk and not just the maximum credible single failure which was then the basis for design of nuclear power plants. The first full scale nuclear probabilistic risk assessment is the WASH-1400 report, also known as the Reactor Safety Study (RSS) or the Rasmussen Report [6]. This was a generic probabilistic risk assessment of 100 operating nuclear power plants—the work on this began in 1972 and the report was finally issued in 1975. A few years following this *magnum opus* in risk analysis, there was a key event that prompted much increased need for PRAs—the accident at Three Mile Island that occurred in March 1979 [3]. This accident led to a partial nuclear meltdown and even though it had minimal release of radiation or public health effects, it was the first severe accident involving a commercial nuclear power plant.

The accident at Three Mile Island prompted several detailed studies of nuclear severe accident phenomena. The nuclear industry sponsored the IDCOR studies [7] which concluded:

- Probabilities of severe nuclear accidents occurring are extremely low,
- Fission product source term releases during such accidents were much less than previously thought, and,
- Risks and consequences to the public of such accidents were lower than previously predicted.

Several comprehensive plant-specific PRAs generating public health risk profiles of nuclear power plants in the vicinity of population centers such as the Zion, Indian Point, and Oconee PRAs [8], [9] and [10] were also developed. These PRAs helped the licensees provide quantitative risk estimates for justification of continued operation of nuclear power plants located near major population centers to counter questions about safety from regulators, the public and vocal interveners.

29.1.4 What is PRA?

B. John Garrick et al in their book "Quantifying and Controlling Risks" [11] provide a rigorous definition and discussion of the PRA framework and process, also called Quantitative Risk Assessment or QRA. This book provides four case studies with detailed depiction of the PRA process used to delineate and quantify risk as applied to some general, non-nuclear-plant scenarios, namely:

- Catastrophic Hurricane Risk in New Orleans, LA
- Asteroids Impacting the Earth
- Terrorist Attack on the National Electric Grid
- Abrupt Climate Change.

Nuclear Plant PRAs use a process with events trees and fault trees that is very similar to that used in the above four case studies. This book is an invaluable resource for someone desiring to learn and apply the PRA process that may not be familiar with either nuclear plants or PRAs. Appendix A of this book is titled "Roots of Quantitative Risk Assessment" and is available in its entirety on the Garrick Foundation website [12]. Another resource that has many papers discussing the application of PRA or QRA to a wide variety of diverse fields (such as cancer research, environmental, health, energy policy, etc.) is reference [13].

29.1.5 PRA and Decision Analysis

PRA (or QRA), in essence, is another facet of decision analysis. Our world is fraught with uncertainties. Yet we are required to make decisions in the face of these uncertainties. PRA (or QRA) techniques are systematic, organized methods available to help make decisions where there is a multitude of phenomena or variables all of which interact with each other and have to be combined and considered. These variables may not be well known, and each can have varying uncertainties associated with them. Uncertainties can be characterized with probability distributions. Once probability distributions are developed, they have to be combined in a logical fashion to generate the answers to the risk triplet. The risk triplet thus becomes very useful in decision making.

Two excellent books on Decision Analysis are "Making Hard Decisions" by Robert T. Clemen [14] and "Decision Traps" by J. Edward Russo and Paul J. H. Schoemaker [15]. These books provide much insight into how decisions can and should be made, as well as avoiding the common flaws in making good decisions.

For those not currently involved in PRA or QRA but who would like to explore and apply probabilistic and analytical tools to their particular scenario or field of interest, Decision Pro Software (by Vanguard Software Corporation) [16] is an example of a commercially available decision analysis tool to formulate and quantitatively analyze decision problems with probabilistic distributions.

29.2 REGULATORY INTERFACE WITH NUCLEAR PLANT PRAs

The first nuclear power plant to generate electricity commercially was the Shippingport Atomic Power Plant in Pennsylvania. This plant's site license was approved by the Atomic Energy Commission (AEC) in 1955 and the plant started operations in 1957.

A comprehensive discussion of the history of regulatory approval of nuclear reactor sites in the US has been provided by David Okrent [17]. He has provided considerable details in how

decisions pertaining to risk and safety (such as in the approval of the Shippingport Plant's license) were made in those days. In addition, he has provided a very useful and interesting chronology of some important events in the history of Light Water Reactor (LWR) safety, a sample of which is provided below:

- 1950—WASH-3, "rule of thumb" nuclear plant siting criterion
- 1952—Evolution of the concept of containment
- 1957—WASH-740 concerning effects of large reactor accidents
- 1958—"Maximum credible accident" concept by Clifford Beck
- 1960—ACRS rejects proposed California nuclear plant sites due to seismic concerns
- 1966—Recognition of the "China Syndrome" problem and correlation of containment failure with core melt
- 1967—Proposal for probabilistic approach to safety evaluation by F. R. Farmer

29.2.1 Design Requirements for Nuclear Power Plants

Early regulators in the AEC originated the idea of a "maximum credible accident" in the late 1950s. From the construction of the Shippingport reactor in 1953 to the Dresden-2 reactor in 1965, per Okrent [17], there was no set of safety criteria that the plant design or site choice was required to meet, and AEC review of these designs was on an *ad hoc* basis.

Design criteria were evolving with each successive licensing application through 1965, when the General Design Criteria (GDC) for nuclear power plants was established.

29.2.2 General Design Criteria (GDC)

The General Design Criteria (GDC) [18] were established by the AEC in 1965 and delineate the necessary design, fabrication, construction, testing, and performance requirements for structures, systems, and components (SSCs) important to safety. These SSCs were designed to provide reasonable assurance that the nuclear power plant can be operated without undue risk to the health and safety of the public. There are a total of 64 criteria covering various design and protection features and barriers to fission product releases to the public.

In essence, the GDC emphasize the need to protect against the worst single failure of either an active or a passive component (e.g., pipe break). The thinking was that if a plant was designed to successfully withstand the worst single failure, its design would be adequate. The worst single failure was believed to be a large loss of coolant accident (LOCA). A LOCA was defined in the GDC as follows:

> *Loss of coolant accidents mean those postulated accidents that result from the loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system from breaks in the reactor coolant pressure boundary, up to and including a break equivalent in size to the double-ended rupture of the largest pipe of the reactor coolant system.*

Therefore, the licensing of nuclear power plants was tied to the ability of the plant design to successfully withstand the worst single failure that was possible. Notice that concurrent multiple failures need not be considered in design. This is where PRA departs from traditional design basis analysis. What PRAs have concluded goes somewhat against this early design basis thinking, e.g.,

- Risk from small LOCAs is typically larger than risk from large LOCAs (this is because of the larger lengths of piping that can cause a small LOCA)
- Concurrent failure of multiple features (e.g., in a station blackout (SBO) event where offsite power is lost concurrently with all divisions of onsite electric power) is typically more likely to occur (i.e., of higher risk) than the large LOCA

Therefore, PRAs provided an important insight that one must consider a spectrum of possible accidents with their likelihoods and not just the worst credible (single) accident.

29.2.3 Evolution in the Concept of Safety

As PRA technology advanced in the late 1970s and 1980s, several industry PRA studies were performed on both generic and plant-specific basis as described in the Section 29.1.3 above.

The accident at Three Mile Island [3] and these industry PRAs [8], [9] and [10] led to a much increased awareness of and desire for risk results from PRAs among the regulators. Regulators are entrusted by the stakeholders with overseeing the safe operation of these nuclear power plants, and they needed to be able to answer questions on nuclear plant safety. This led to the issuance of a Generic Letter 88–20 by the US NRC [19]. This letter requested all licensees to evaluate through plant-specific PRAs (or alternate methods) risk levels for each of their plants with the specific goal of identifying any particular vulnerabilities. This led to considerable PRA work done by the utilities in the next several years. The Generic Letter 88–20 was supplemented by a request [20] to evaluate vulnerabilities in the external events area (including fire, external floods, high wind, seismic and any other plant-specific events such as toxic chemical accidents for those plants located in the vicinity of major chemical facilities.

The Maintenance Rule was promulgated by the US NRC in the mid-1990s [21]. This was a big change in process for licensees as the rule introduced new requirements to monitor maintenance that were hitherto absent. The maintenance rule required considering risk importances when classifying the importance of structures, systems or components (SSCs). Maintenance Rule Expert Panels were convened at licensees and these Panels considered SSC risk importances from PRAs while making these classifications. This program helped focus maintenance and monitoring on risk significant SSCs and lessened the focus on unimportant SSCs.

29.2.4 NRC Policy Statement on PRA

The NRC issued their Policy Statement on PRA in 1995, soon after the IPE's were submitted in response to the Generic Letter 88–20. This policy [22] served to increase the use of PRA in nuclear plant regulation in the US. An excerpt from this policy is provided below:

> *The use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data, and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.*

Consistent with this Policy Statement, the NRC considerably staffed up their PRA branches and engineers in the succeeding years and made increased use of PRA in regulatory activities. There was an increased awareness of the need to inject PRA into their activities by many departments in the NRC. NRC PRA staff also began to be actively involved in the industry standards

activities and began developing Regulatory Guides delineating how PRAs should be used for application and requirements for their technical adequacy.

29.2.5 Reactor Oversight Process (ROP)

As part of the NRC's transition to risk informed regulation, the Reactor Oversight Process (details available in [23]) was introduced in 2000. The ROP called for a much wider use of PRA in regulation. The significance of any finding or performance deficiency by a licensee was to be assessed using PRA techniques. This risk evaluation was to be as realistic as possible. This necessitated the use of a plant-specific PRA model. The NRC developed considerable guidance and inspection manuals in this respect for their staff. The result of this change was that utility PRA staffs were asked to analyze potential findings for risk impact. Licensees desired to include as much realism in these evaluations as was practicable in order to demonstrate to the regulators that many of these proposed findings were in fact not risk significant. This has led to a reduction in the number of cited violations compared to the "pre-ROP" era.

29.2.6 Maintenance Rule a(4) and Configuration Risk Management

In another step toward risk informed regulation, also in the 2000 timeframe, clause a(4) was added to the maintenance rule described above [21]. This clause is as follows

> *Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to those structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.*

In essence, this requirement dictated that PRA risk monitors or prequantified results be used in day to day scheduling decisions made at nuclear power plants. This essentially necessitated that a quick-running version of the PRA be used by each site's Work Management staff in evaluating proposed equipment work schedules as well as by the Operations Departments who had to evaluate risk impact when a risk-important SSC had an unplanned failure.

The net operational result of introducing this process was the increased focus on risk while scheduling outages, shorter periods of SSC unavailability, more online maintenance and improved plant performance in the capacity factor arena.

29.2.7 Mitigating Systems Performance Index

Prior to 2006, the NRC used the safety system unavailability metrics to assess nuclear plant performance via their performance indicators. This measured the unavailability of key safety systems (such as high pressure injection, low pressure injection, EDGs, etc.). The Mitigating Systems Performance Index or MSPI [24] was introduced after an industry group including licensees and the NRC jointly came up with a new risk informed process to generate performance indicators. In essence, this process combines unavailability as well as unreliability in a manner that includes their impact on the plant's CDF risk. MSPI essentially measures a change in CDF from industry baseline performance based on plant-specific performance and risk importance values from the PRA model. One of the outputs of a PRA is the risk importance of each SSC using the Birnbaum risk metric.

MSPI uses the Birnbaum measure because of its simple relationship to CDF.

Generally, unreliability is a considerably more important contributor to the index than unavailability. MSPI considers only the internal events PRA initiators, and does not include internal flooding events or external events initiators.

29.3 PRA STANDARDS AND TECHNICAL ADEQUACY OF PRAs

29.3.1 Industry Standards

The ASME/ANS PRA Standard [25] was initially drafted in the 1990s. There were much discussions and deliberations among the PRA community on the requirements included in it for several years. It was not until 2002 that it was first issued. The Standard has undergone a few revisions in the last ten years. External Events and Fire have been added to this Standard in recent years.

The use of the ASME/ANS PRA Standard has enabled the PRA community to enhance documentation levels providing an enhanced basis and traceability for the PRA calculations and risk results and in general providing increased scrutability for the PRAs. The owners' groups of the nuclear power vendors have coordinated peer reviews of internal events PRAs as well as external events PRAs as they have been completed. The NFPA 805 application of PRA (to be discussed in Section 29.4.3) has caused the Fire and Internal Events PRAs used for transitioning plants to have to undergo peer reviews with respect to the meeting of the PRA Standard.

29.3.2 Regulatory Guides

The NRC has developed its own guidance for acceptability of PRAs for various applications with the issuance of Regulatory Guide 1.200 on technical adequacy of PRAs [26]. In general, this guidance follows the industry standards with some qualifications. This Regulatory Guide originally covered only internal events PRAs but has undergone revision now and includes external events models as well. The expectation of the regulator now is that for significant PRA applications (such as EDG AOT relaxation submittals) the supporting PRA will be fully compliant with this Regulatory Guide or detailed justification to show why the gaps do not affect that particular application will need to be included in the submittal even for meeting the acceptance criterion.

This has led to a somewhat of a lull in risk-informed submittals as most utilities do not have external events (including fire, seismic, high winds and other applicable events) PRA models meeting the Regulatory Guide requirements.

29.4 SIGNIFICANT PRA APPLICATIONS

Several regulatory interface types of applications were discussed in Section 29.2. Some other key PRA applications are discussed below:

29.4.1 Relief for Nuclear Plant Technical Specifications

Many plant technical specification changes have been requested by licensees of the NRC and have been approved in the last 10 to

15 years based on risk-informed submittals. A PRA analysis of the proposed Technical Specification change is developed by the utility using the methods stated in Regulatory Guide 1.177 [27]. The most useful of these have been the Emergency Diesel Generator (EDG) permanent AOT extensions, typically to a two week period from as low as 3 days. This relief has provided a vast amount of increased flexibility to operating nuclear units and has helped them to avoid what would have been numerous plant shutdowns due to extended repairs needed for key equipment such as EDGs. This relief has allowed considerable improvement in capacity utilization of nuclear power plants over the last couple of decades without substantially affecting public health risk.

In recent years, the NRC reviewers of risk informed technical specification change requests have asked the utility making the submittal to include in the license amendment request (LAR) detailed information about the technical adequacy of the PRA model that was used in the analysis. This includes:

- Conformance of the PRA to PRA Standard [18]/PRA Technical Adequacy Regulatory Guide 1.200 [20];
- Details of the Peer Reviews performed on the PRA model and documentation;
- Detailed status of the Facts and Observations (F&Os) from the PRA Peer Review(s); and if these issues are not closed, then details on why the licensee believes that they do not impact the submittal.

Because the RG 1.200 has now been revised to include a requirement for using external events PRAs for Technical Specification relief, and most of the industry plants do not have external events PRAs conforming to this regulatory guide, the earlier spate of Technical Specification Change LARs has now reduced to a trickle.

29.4.2 In-Service Inspection

A useful summary of risk-informed in-service inspection processes has been provided in [28]. [29], provides an ASME Code Case N-716 which was instrumental in reducing RI-ISI burden by using internal flooding PRA results in conjunction with the internal events PRA model. This Code Case does require an up-to-date internal flooding PRA model that has undergone a gap analysis with respect to the PRA Standard. Utilities that have adopted this approach report having saved sizable sums of money (several hundred thousand dollars) as well as reduced personnel exposure during each successive refueling outage.

29.4.3 Fire Protection Licensing Basis using NFPA 805

10CFR50.48(c) is an alternate risk informed performance based approach to fire protection which has been available to the industry for the past several years [30]. This new approach to fire protection endorses the NFPA 805 code [31].

Licensees who have had open issues or findings associated with their fire protection program have been allowed to transition to this new approach and have received relief in enforcement discretion as part of the transition. About half the industry licensees, primarily pressurized water reactors (PWRs), have opted for this approach and are working through the submittal and regulatory review process.

Difficulties with the transition have been faced because industry NFPA 805 pilot plants' schedules slipped many times leading to a delay of several years compared with initial schedules. Also, Fire PRA methods were evolving and regulators' concurrence of these methods took much additional time compared with initial schedule projections.

The NUREG/CR-6850 [32] Fire PRA method that is currently being used in the NFPA 805 transition has significant conservatisms in it. An NEI report [33] has provided a detailed discussion of these conservatisms and why they skew fire results. This report has identified 13 technical areas where further development and research is necessary to achieve improved realism and be consistent with internal events PRA modeling:

- Fire event data characterization
- Fire severity characterization
- Credit for incipient detection
- Credit for suppression & control
- Fire growth assumptions
- Peak heat release rates
- Damage assessment
- Fire propagation
- Fire modeling
- Treatment of hot shorts
- Human reliability
- Modeling of control room fires
- PRA model advancement

The conservatisms in each element above are compounded when combined and quantified in a Fire PRA and the risk results from the Fire PRA then become ultra-conservative.

In the early years of nuclear power plant operation, there was much less awareness of the importance of fire protection. There was a fire at the Browns Ferry nuclear power plant (BFN) in 1975 (information available in [34], [35] and [36]). Polyurethane foam was used to plug leaks in cable penetrations. A candle was used for leak detection and this ignited the foam to start a fire that spread rapidly to the cables. This fire caused much increased regulation in nuclear plant fire protection. Cables of the type used at BFN are no longer used. As a result of this event, fire protection in nuclear power plants has been considerably enhanced and there have been few fires that have occurred with a reduced the margin of safety, i.e., with impacts on safety systems.

The Fire PRA is designed to estimate the risk from fire. It is an extension of the Internal Events PRA where the initiating event is a fire inside the plant. Fires that do not cause the plant to need to shut down do not contribute to risk. Therefore, for the fire initiating event to be a risk contributor, the fire has to be big enough to cause a plant trip or shutdown.

Over approximately 4000 reactor-years of US nuclear power plant operating history in the last several decades, there have been only a handful of fire events that have caused a need for the plant to be shutdown along with significant impacts on safety related equipment. If one compares this operating experience information against the fire ignition frequencies being used in the Fire PRAs being developed in the industry using NUREG/CR-6850 methods, then one can conclude that the NUREG/CR-6850 method is overestimating fire ignition frequencies by at least an order of magnitude.

The NUREG/CR-6850 method also uses 98th percentile values of heat release rates form fire events in the data base in determining the typical fire, i.e., the fire events are skewed to overestimate risk.

Thus, the conservatism in each of the Fire PRA methodology elements is compounded when risk results are quantified.

Until the above realism issues are substantially resolved, quantitative analysis using Fire PRA risk results will be impeded by

gross conservatisms that will mask and skew risk importances. **Aggregation of risk results from Fire PRA and Internal Events PRA should not be performed because of the skewing and masking introduced by Fire PRA conservatisms**. It should be noted, however, that qualitative risk insights may be usable from the conservative fire risk models. The industry currently has a Roadmap Plan to close these Fire PRA methods gaps in a phased manner. This is expected to take about five years as many of these tasks are very resource intensive and industry budgets are limited.

29.4.4 License Renewal and Evaluation of Cost/Benefits in SAMA Analyses

A brief overview of the license renewal process is provided in [37]. Status of industry license renewal applications is available in [38]. For license renewal, PRA needs to be extensively used to evaluate the potential severe accident mitigation alternatives along with plant model using the MACCS code [39] and cost benefit evaluation.

29.4.5 Surveillance Frequency Control Programs

The industry and NRC have jointly worked on TSTF-425 [40]. This actually builds on earlier BWROG submittals to obtain relief in instrumentation surveillance frequencies back in the late 1980s [41] which used PRA techniques to demonstrate that there was little impact on plant risk if instrumentation surveillance frequencies were extended.

29.4.6 Risk Informed Treatment of Missed Surveillances

Sometimes a licensee can miss doing a surveillance that can be performed only when the plant is shut down. A RITS initiative [42] allows some leeway in this issue depending upon the estimated risk impact of missing this surveillance. Continued plant operation without shut down could be justifiable in some cases as long as there is confirmation that this has minimal safety impact.

29.4.7 Special Treatment Requirements (also known as Graded QA)

The industry and NRC have jointly come up with guidance to implement a new process for classifying equipment in nuclear power plants based on their risk importance as determined from PRA.

This process and rule were codified via 10CFR50.69. Guidance is available via an EPRI report [43]. The guidance is structured such that the more complete the PRA, the more the likelihood of being able to classify a particular SSC as low safety significance.

An industry pilot of this process was done at South Texas Project (STP). This pilot has shown that there are substantial benefits for the utility once the program is implemented in the below two areas:

- Lower costs in maintenance and procurement for low safety significance SSCs with no adverse equipment performance and
- Enhanced safety culture at the plant

The major hurdles for utilities in adopting this new process are as follows:

- Existence of a complete and robust PRA to support this process, and a larger PRA staff size
- Costs involving modified implementation procedures and training

This rule has not been taken advantage of in the industry because of the "hump" that has to be traversed in resources, even though substantial savings may be realized down the road.

29.4.8 Flexible AOT/Completion Times

TSTF-505 Rev 1 [44] announces the availability of this initiative which has been in the works for over a decade. Although the regulatory process now allows utilities to pursue this relief, the PRAs now have to conform to a much more extensive revision 2 of Regulatory Guide 1.200 [26] that now includes requirements for external events PRA models.

Therefore, utilities have not been able to pursue this to the extent that was earlier envisioned. Once compliance with RG 1.200 is achieved in toto, this as well as many more risk applications may be acceptable to regulators.

29.5 SUMMARY OF INSIGHTS FROM UTILITY APPLICATIONS

The following provides a partial list of insights obtained from working with PRAs for several decades:

29.5.1 Public Health Risk from US Nuclear Plants

Is very low and continues to trend downward. [45] provides some useful graphs of risk metrics (CDF) versus year. Improvement in capacity factor versus year for the US nuclear fleet has been provided in [45] and [46]. US nuclear plants' risk models indicate that their risk is very low, especially when considered in relation to the most of the alternate options of generating electricity.

29.5.2 The Accident at Fukushima

Has prompted much exploration of ways to improve US plants (see [47] and [48]) but, basically the design flaw such as was present there is not present in US plants. FLEX equipment currently being added to nuclear plants [49] to address Fukushima insights is expected to further reduce the public health risk from these plants.

29.5.3 US Nuclear Plant Regulation

While more risk informed than before, still poses significant cost and process barriers on licensees. Also, US natural gas prices have dropped significantly in the last several years. For both these reasons, a few of the US nuclear plants have recently been permanently shut down.

29.5.4 Risk Monitors

Are being widely used in the US nuclear industry – the use of risk results from the PRA in day to day scheduling decisions has evolved considerably in the past decade so that this usage is now very much ingrained in the culture. The industry is currently working on enhancing these risk models by including insights related to fire risk; the initial rollout of this change is scheduled for December 1, 2013 [50].

29.5.5 Fukushima has Emphasized the Need to Review Designs for Hidden Vulnerabilities

Particularly against external events risk even though the design flaw there may not be directly applicable to US plants. An NRC

webpage on this [48] provides the status of these efforts. The Near Term Task Force (NTTF) report is available in the public domain for review [47]. PRAs provide a natural and objective method to evaluate the comparative importance and cost benefits of potential plant modifications to address and prioritize these concerns.

29.5.6 Socialization of PRA

Though some inroads have been made in use of risk monitors, much of the nuclear power plant community, particularly design and systems engineers, are still quite apprehensive about PRA technology. Design engineers who are used to the deterministic, single failure concept in design have difficulty in fathoming risk results as it goes completely against their knowledge base.

In recent years EPRI has developed some training modules which are available for download for members from the EPRI website. These may be provided to executives and others who are not PRA practitioners.

29.5.7 PRA Training and Qualifications

Significant progress has been made in the last 5 to 7 years in training risk professionals in the US nuclear industry, thanks to the EPRI risk informed professionals 6 week-long training classes which has been attended by new PRA engineers in utilities. PRA vendors have also developed their own training modules to quickly train new engineers working in the PRA field. A new generation of nuclear PRA professionals is being groomed for the future and this should help the industry as older staff transition to retirement.

29.5.8 New Nuclear Plant Designs

Have even lower risk profiles than existing designs. Several of these designs have passive safety systems which contribute to a lower core damage frequency. Risk results should be a non-issue when these designs are undergoing regulatory reviews or approval; however, the PRAs have to meet the Standards as well as undergo peer reviews.

29.5.9 There is Potential for Greater PRA Usage

In improving decision-making in nuclear power plants. Some areas are:

29.5.9.1 Graded Quality Assurance—This involves applying quality assurance requirements in a graded manner depending upon the risk importance of components. Pilots have confirmed that this can be cost beneficial. However, regulatory and economic hurdles prevent the majority of licensees from pursuing these benefits as discussed earlier in this Chapter.

29.5.9.2 Risk Informed Technical Specifications—These are starting to get adopted by utilities; however, the PRA requirements are very burdensome and this is delaying the implementation of this initiative.

29.5.10 PRA Techniques Can Be Applied to Increase Plant Availability

However, a lot more of the BOP (balance of plant) components have to be modeled; current modeling of these SSCs in PRAs is unimportant because of their low impact on CDF risk.

29.5.11 Greater the Realism There is in PRAs, Better the Quality of the Applications

And better the quality of the insights. For simple applications, approximate PRAs are sufficient. The impact of open items on the model and non-modeled items has to be considered in the application.

29.5.12 Very Significant Conservatisms Exist in Current Fire PRA Methods

Industry experience with fire related accident precursor events do not match the risk results that are being obtained by current Fire PRAs, i.e., if the Fire PRA methods were realistic we should have seen many more fire related precursor events than we have actually seen. Aggregation of Fire PRA and Internal events CDF can distort and mask true results and risk importances so is highly inadvisable.

29.5.13 Seismic PRA is Getting More Attention as a Result of the Accident at Fukushima

Seismic hazard at some sites appears to have increased over the past several decades and the sites with higher hazard may have higher seismic risk than earlier estimates. More sophisticated finite element failure analysis techniques may help reduce uncertainties and reduce excessive conservatisms in older seismic modeling. Though seismic PRAs may identify certain design vulnerabilities, in general, they will likely be of little use in day to day scheduling decisions. This is because seismic events contributing to risk typically fail redundant trains of equipment.

29.5.14 PRA Standards have Considerably Raised the Bar on Documentation, Basis and Rigor in and of PRA Models

They have also helped achieve some standardization of technical approaches, due to peer reviews that have been held in the industry among the PRA community, under the auspices of the owners' groups. However, basic risk insights from Internal Events PRAs have not changed substantially when these new PRAs meeting industry standards are compared to the approximate PRAs pre-dating the standards. What this implies is that our initial approximate PRAs were generally technically sound and captured many of the major risk insights, and, that an approximate PRA can provide a good deal of insights. The Pareto Principle [51] applies to this concept in that 80% of the risk insights were available from using a PRA model that cost 20% as much.

29.5.15 Risk Metrics and Safety Goals for New Nuclear Plants Need to Match Those for Existing Plants

Else, the credibility of the risk analysis process will be much reduced in the eyes of the stakeholders, i.e., the public. This is because otherwise there will be a perception of arbitrariness in the setting of these criteria and in creating double standards for acceptance.

29.6 SUMMARY

PRA technology has vastly improved and evolved in the nuclear industry in the last couple of decades. Public health risk from US nuclear power plant operation is very low and is trending downward as is evident from fewer accident precursors in the operating experience. The actions being taken to address the accident at Fukushima are further helping improve risk profiles. Wider use of PRA has helped both licensees and regulators focus more efforts on those issues that really impact risk and safety.

There is more standardization of PRA technical approaches as well as higher quality documentation and basis of the internal

events PRA models due to the adaptation of industry standards. Fire PRA methods, however, are in dire need of further refinement to match reality in order to comport with actual industry precursor experience. Work on these improvements is ongoing in the industry and should be ready in the next several years. Updated seismic and high winds models are starting to be developed in response to the recent Fukushima accident; these will help the nuclear community and stakeholders have a better understanding of total risk from nuclear power plant operation.

PRA technology was developed for nuclear power plants because there was much fear about the safety of nuclear power plants. In reality, other technologies and industries have had similar or worse experience in the US in terms of public health impacts (e.g., natural gas pipeline explosions, chemical plant and petroleum refinery accidents, etc.). **Regulation of nuclear as well as these alternate technologies needs to be commensurate with the risks**. Therefore, PRA technology should be used in a much wider realm in decisions involving regulation, e.g., in the environmental (by EPA) or in the health (FDA) disciplines. Federal and state budgets allocated to regulation of various disciplines need to be proportional to risks involved in that discipline. **Either over-regulation or under-regulation of a field will not be in the interest of the public and will have an adverse impact on their quality of life**. The importance of the use of PRA or QRA in making societal decisions is eloquently described by B. John Garrick [47], one of the key founders of PRA techniques:

> *As much as we would like it to be so, we do not live in binary world where our choices are clearly yes or no, on or off, right or wrong, 1 or 0, black or white, etc. We often have to make decisions in the face of great uncertainties. Thus, we have to infer as much as we can from the evidence we have as to which is the best choice. The field of risk analysis has provided us with tools to clinically and objectively extract the maximum amount of information we have about the outcome of events in order to make the best possible decision, even in the case of very limited information. Therefore, when it comes to safety, environmental impact, security, or our general welfare, the risk sciences have a major role to play in the sustainability of our lifestyle and our planet.*

Wider use of PRAs can help provide much better basis for decisions that are made by governments and regulators for societies.

29.7 ACRONYMS

AEC	Atomic Energy Commission
ANS	American Nuclear Society
AOT	Allowed Outage Time
ASME	The American Society of Mechanical Engineers
BFN	Browns Ferry Nuclear Plant
BOP	Balance of Plant
BWROG	Boiling Water Reactor Owners' Group
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedures
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F&O	Fact and Observation
FDA	Food and Drug Administration
FLEX	Post Fukushima Flexible Requirement
GDC	General Design Criteria
IDCOR	Industry Degraded Core Rulemaking
IPE	Individual Plant Examination
LAR	License Amendment Request
LOCA	Loss of Coolant Accident
MACCS	MELCOR Accident Consequence Code System
MSPI	Mitigating Systems Performance Indicator
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NTTF	Near Term Task Force
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Analysis
PWR	Pressurized Water Reactor
QA	Quality Assurance
QRA	Quantitative Risk Assessment
RG	Regulatory Guide
RI-ISI	Risk Informed In Service Inspection
RITS	Risk Informed Technical Specifications
ROP	Reactor Oversight Process
SAMA	Severe Accident Management Analysis
SSC	Structure, System or Component
STP	South Texas Project
TSTF	Technical Specification Task Force
UKAEA	United Kingdom Atomic Energy Authority

29.8 NOTE

The opinions presented in this Chapter are those of the author and do not necessarily reflect those of Energy Corporation or any of its subsidiaries.

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CHAPTER

30

LESSONS LEARNED: NRC EXPERIENCE

Chakrapani Basavaraju

30.1 INTRODUCTION

The objective of this chapter is to provide some highlights on the recent issues and lessons learned by the Nuclear Regulatory Commission (NRC) for the safety related and safety significant nuclear power plant components, which utilize the ASME Boiler and Pressure Vessel Codes, Sections III and XI. These include issues related to 2011 Japan Earthquake that directly impacted the Fukushima Nuclear Plant, and also led the regulatory bodies worldwide to take a closer look at the emergency systems for any needed changes for beyond the design basis events. This chapter also provides some information on environmental assisted fatigue of nuclear components exposed to Light Water Reactor (LWR) environments, buried piping leakage and contamination issues, the issues related to High density polyethylene (HDPE) as an alternate piping material for the replacement of buried steel piping, the issues and lessons learned related to BWR steam dryers subjected to flow induced vibration loading associated with extended power uprate (EPU) conditions, the current conclusions related to quasi-laminar indications in reactor pressure vessel ring forgings, steam generator tube leaks and fluid elastic instability, and lessons learned from Operating plants experience for consideration in new nuclear power plant (NPP) construction.

30.2 FUKUSHIMA LESSONS LEARNED

Lesson Learned: Protection measures are needed for NPP for beyond the design basis events.

Following the Fukushima nuclear accident, which was caused by the March 11, 2011, Tohoku earthquake-triggered tsunami waves, the NRC directed a Near-Term Task Force (NTTF) to conduct a systematic review of the NRC's regulatory processes and to make recommendations to the Commission for its policy direction. After its review, the NTTF concluded that continued operation of Nuclear Power Plants (NPPs) do not pose an imminent risk to the public health and safety. The NTTF made a set of recommendations to enhance the safety of US NPPs against natural hazards. The Commission accepted the NTTF's recommendations (Ref. 1) and the NRC staff further prioritized the NTTF's recommendations. On March 12, 2012, the NRC issued various Orders and a Title 10 of the Code of Federal Regulations (10 CFR) 50.54(f) letter to nuclear power plant licensees.

The Task Force recognized that an accident involving core damage and uncontrolled release of radioactivity to the environment, even one without significant health consequences, is inherently unacceptable. Thus, the Task Force developed a comprehensive set of 12 recommendations – many with both short and long term elements – to increase safety and redefine what level of protection of public health is regarded as adequate. NRC's Japan Task Force recommends changes to defense in depth measures at nuclear plants; addressing four areas for improvement: station blackout, seismic, flooding, and spent fuel pools The Task Force made 12 overarching recommendations.

Recognizing that rulemaking and subsequent implementation typically take several years to accomplish, the Task Force recommends interim actions to enhance protection, mitigation, and preparedness while the rulemaking activities are conducted. The focus is on what should be done to address events that create conditions beyond the design basis, such as those created by the Great East Japan Earthquake and Tsunami, where the design basis for multiple nuclear units was inadequate to accommodate the tsunami.

These recommendations are based on the best available information regarding the Fukushima Dai-ichi accident and a review of relevant NRC requirements and programs. The Task Force concludes that these are a reasonable set of actions to enhance U.S. reactor safety in the 21st century.

On March 12, 2012, the NRC issued the first regulatory requirements for the nation's 104 operating reactors based on the lessons-learned at Fukushima Daiichi. The NRC issued three orders requiring safety enhancements of operating reactors, construction permit holders, and combined license holders. These orders require nuclear power plants to implement safety enhancements related to (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, (2) ensuring reliable hardened containment vents, and (3) enhancing spent fuel pool instrumentation. The plants are required to promptly begin implementation of the safety enhancements and complete implementation within two refueling outages or by December 31, 2016, whichever comes first. In addition, the NRC issued a request for information, requesting each reactor licensee reevaluate the seismic and flooding hazards at their site using present-day methods and information, conduct walkdowns of their facilities to ensure protection against the hazards in their current design basis, and reevaluate their emergency communications systems and staffing levels.

The NRC Commission approved issuance of the orders on March 9, 2012. (see SRM SECY-12-0025) (Ref. 2).

(1) Clarifying the Regulatory Framework (Recommendation 1)
Recommendation 1: The Task Force recommends establishing a logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations.
(1.1) Draft a Commission policy statement that articulates a risk-informed defense-in-depth framework that includes extended design-basis requirements in the NRC's regulations as essential elements for ensuring adequate protection.
(1.2) Initiate rulemaking to implement a risk-informed, defense-in-depth framework consistent with the above recommended Commission policy statement.
(1.3) Modify the Regulatory Analysis Guidelines to more effectively implement the defense-in-depth philosophy in balance with the current emphasis on risk-based guidelines.

The Task Force believes that the Regulatory Analysis Guidelines could be modified by implementing some of the concepts presented in the technology-neutral framework (NUREG-1860) to better integrate safety goals and defense-in-depth.

(1.4) Evaluate the insights from the IPE and IPEEE efforts as summarized in NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," issued December 1997, and NUREG-1742, "Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program," issued April 2002, to identify potential generic regulations or plant-specific regulatory requirements.

Ensuring Protection (Recommendations 2 and 3)

(2) Recommendation 2: The Task Force recommends that the NRC require licensees to reevaluate and upgrade as necessary the design-basis seismic and flooding protection of structures, systems, and components for each operating reactor.

The Task Force recommends that the Commission direct the following actions to ensure adequate protection from natural phenomena, consistent with the current state of knowledge and analytical methods. These should be undertaken to prevent fuel damage and to ensure containment and spent fuel pool integrity:

(2.1) Order licensees to reevaluate the seismic and flooding hazards at their sites against current NRC requirements and guidance, and if necessary, update the design basis and SSCs important to safety to protect against the updated hazards.
(2.2) Initiate rulemaking to require licensees to confirm seismic hazards and flooding hazards every 10 years and address any new and significant information. If necessary, update the design basis for SSCs important to safety to protect against the updated hazards.
(2.3) Order licensees to perform seismic and flood protection walkdowns to identify and address plant-specific vulnerabilities and verify the adequacy of monitoring and maintenance for protection features such as watertight barriers and seals in the interim.

(3) Recommendation 3: The Task Force recommends, as part of the longer term review, that the NRC evaluate potential enhancements to the capability to prevent or mitigate seismically induced fires and floods.

The Task Force evaluation of insights from Fukushima to provide recommendations for enhancing the mitigation capability of U.S. reactors with regard to prolonged loss of ac power, containment overpressure protection, combustible gas control, spent fuel pool safety, and onsite emergency actions. The following mitigation capabilities were addressed:

(3.1) for pressurized water reactors (PWRs):
- additional sources of coolant water for the reactor and steam generators
- methods to reduce pressure in and feed cooling water to the steam generators
- methods to cool the reactor core and minimize releases of radioactive materials from containment

(3.2) for BWRs:
- additional sources of coolant water for the reactor
- methods to reduce reactor pressure and feed cooling water to the reactor
- methods to cool the reactor core and reduce releases of radioactive materials from containment

(3.3) for spent fuel pools:
- additional sources of coolant water for and methods to inject or spray to the spent fuel pools
- methods to control leakage from damage to the spent fuel pools
- methods to reduce releases of radioactive materials from the spent fuel pools

Enhancing Mitigation (Recommendations 4 through 8)

(4) Recommendation 4: The Task Force recommends that the NRC strengthen station blackout mitigation capability at all operating and new reactors for design-basis and beyond-design-basis external events.

SBO Rulemaking – In the SRM for COMSECY-13-0002 dated March 4, 2013, the Commission approved the staff's recommendation to consolidate the rulemaking activities stemming from NTTF Recommendation 4 – to strengthen station blackout mitigation capability at all operating and new reactors for design-basis and beyond-design-basis external events – and NTTF Recommendation 7 – to enhance spent fuel pool makeup capability and instrumentation for the spent fuel pool – into one rulemaking, the "Station Blackout Mitigation Strategies Rulemaking."

(4.1) Initiate rulemaking to revise 10 CFR 50.63 to require each operating and new reactor licensee to (1) establish a minimum coping time of 8 hours for a loss of all ac power, (2) establish the equipment, procedures, and training necessary to implement an "extended loss of all ac" coping time of 72 hours for core and spent fuel pool cooling and for reactor coolant system and primary containment integrity as needed, and (3) preplan and prestage offsite resources to support uninterrupted core and spent fuel pool cooling, and reactor coolant system and containment integrity as needed, including the ability to deliver the equipment to the site in the time period allowed for extended coping, under conditions involving significant degradation of offsite transportation infrastructure associated with significant natural disasters.
(4.2) Order licensees to provide reasonable protection for equipment currently provided pursuant to 10 CFR

50.54(hh)(2) from the effects of design-basis external events and to add equipment as needed to address multiunit events while other requirements are being revised and implemented.

(4.2.2) Containment Overpressure Protection

The risk of containment failure during severe accidents was higher at BWRs with Mark I containments because the containment volume of Mark I containment designs was significantly less than that of the other containment designs, approximately one-sixth the volume of large dry PWR containments. All BWR facilities with Mark I containment designs voluntarily installed a hardened vent. In BWRs with a Mark II containment design, the containment volume could be approximately 25 percent larger than the volume of Mark I containments. Eight BWR units in the United States have Mark II containment designs. Three of these units have installed hardened vents, and the remaining five units at three sites have not installed hardened vents.

(5) Recommendation 5: The Task Force recommends requiring reliable hardened vent designs in boiling water reactor facilities with Mark I and Mark II containments.

The Task Force recommends that the Commission direct the staff to take the following actions to ensure the effectiveness of hardened vents:

(5.1) Order licensees to include a reliable hardened vent in BWR Mark I and Mark II containments.

- This order should include performance objectives for the design of hardened vents to ensure reliable operation and ease of use (both opening and closing) during a prolonged SBO.

(5.2) Reevaluate the need for hardened vents for other containment designs, considering the insights from the Fukushima accident. Depending on the outcome of the reevaluation, appropriate regulatory action should be taken for any containment designs requiring hardened vents.

(6) Recommendation 6: The Task Force recommends, as part of the longer term review, that the NRC identify insights about hydrogen control and mitigation inside containment or in other buildings as additional information is revealed through further study of the Fukushima Dai-ichi accident.

(7) Recommendation 7: The Task Force recommends enhancing spent fuel pool makeup capability and instrumentation for the spent fuel pool. The Task Force recommends that the Commission direct the staff to do the following:

(7.1) Order licensees to provide sufficient safety-related instrumentation, able to withstand design-basis natural phenomena, to monitor key spent fuel pool parameters (i.e., water level, temperature, and area radiation levels) from the control room.

(7.2) Order licensees to provide safety-related ac electrical power for the spent fuel pool makeup system.

(7.3) Order licensees to revise their technical specifications to address requirements to have one train of onsite emergency electrical power operable for spent fuel pool makeup and spent fuel pool instrumentation when there is irradiated fuel in the spent fuel pool, regardless of the operational mode of the reactor.

(7.4) Order licensees to have an installed seismically qualified means to spray water into the spent fuel pools, including an easily accessible connection to supply the water (e.g., using a portable pump or pumper truck) at grade outside the building.

(7.5) Initiate rulemaking or licensing activities or both to require the actions related to the spent fuel pool described in detailed recommendations 7.1–7.4.

(8) Recommendation 8: The Task Force recommends strengthening and integrating onsite emergency response capabilities such as emergency operating procedures (EOPs), severe accident management guidelines (SAMGs), and extensive damage mitigation guidelines (EDMGs).

The Task Force recommends that the Commission direct the staff to further enhance the current capabilities for onsite emergency actions in the following ways:

(8.1) Order licensees to modify the EOP technical guidelines (required by Supplement 1, "Requirements for Emergency Response Capability," to NUREG-0737, issued January 1983 (GL 82-33), to (1) include EOPs, SAMGs, and EDMGs in an integrated manner, (2) specify clear command and control strategies for their implementation, and (3) stipulate appropriate qualification and training for those who make decisions during emergencies.

- The Task Force strongly advises that the NRC encourage plant owners groups to undertake this activity rather than have each licensee develop its own approach. In addition, the Task Force encourages the use of the established NRC practice of publishing RG (rather than NUREGs, supplements to NUREGs, or GLs) for endorsing any acceptable approaches submitted by the industry.

(8.2) Modify Section 5.0, "Administrative Controls," of the Standard Technical Specifications for each operating reactor design to reference the approved EOP technical guidelines for that plant design.

(8.3) Order licensees to modify each plant's technical specifications to conform to the above changes.

(8.4) Initiate rulemaking to require more realistic, hands-on training and exercises on SAMGs and EDMGs for all staff expected to implement the strategies and those licensee staff expected to make decisions during emergencies, including emergency coordinators and emergency directors.

Strengthening Emergency Preparedness (Recommendations 9 through 11)

(9) Recommendation 9: The Task Force recommends that the NRC require that facility emergency plans address prolonged station blackout and multiunit events. The Task Force recommends that the Commission direct the staff to do the following:

(9.1) Initiate rulemaking to require Emergency Preparedness (EP) enhancements for multiunit events in the following areas:

- personnel and staffing
- dose assessment capability
- training and exercises
- equipment and facilities

(9.2) Initiate rulemaking to require EP enhancements for prolonged Station Black Out (SB) in the following areas:

- communications capability
- Emergency Response Data System (ERDS) Emergency Response Data System (ERDS) capability

- training and exercises
- equipment and facilities

(9.3) Order licensees to do the following until rulemaking is complete:

- Determine and implement the required staff to fill all necessary positions for responding to a multiunit event.
- Add guidance to the emergency plan that documents how to perform a multiunit dose assessment (including releases from spent fuel pools) using the licensee's site-specific dose assessment software and approach.
- Conduct periodic training and exercises for multiunit and prolonged SBO scenarios. Practice (simulate) the identification and acquisition of offsite resources, to the extent possible.
- Ensure that EP equipment and facilities are sufficient for dealing with multiunit and prolonged SBO scenarios.
- Provide a means to power communications equipment needed to communicate onsite (e.g., radios for response teams and between facilities) and offsite (e.g., cellular telephones, satellite telephones) during a prolonged SBO.
- Maintain ERDS capability throughout the accident.

(9.4) Order licensees to complete the ERDS modernization initiative by June 2012 to ensure multiunit site monitoring capability.

(10) Recommendation 10: The Task Force recommends, as part of the longer term review, that the NRC pursue additional emergency preparedness topics related to multiunit events and prolonged station blackout. The Task Force recommends that the Commission direct the staff to do the following:

(10.1) Analyze current protective equipment requirements for emergency responders and guidance based upon insights from the accident at Fukushima.

(10.2) Evaluate the command and control structure and the qualifications of decision makers to ensure that the proper level of authority and oversight exists in the correct facility for a long-term SBO or multiunit accident or both.

- Concepts such as whether decision making authority is in the correct location (i.e., at the facility), whether currently licensed operators need to be integral to the on-shift emergency response organization (ERO) ERO outside of the control room (i.e., in the plant's Technical Support Center (TSC)), and whether licensee emergency directors should have a formal "license" qualification for severe accident management.

(10.3) Evaluate ERDS to do the following:

- Determine an alternate method (e.g., via satellite) to transmit ERDS data that does not rely on hardwired infrastructure that could be unavailable during a severe natural disaster.
- Determine whether the data set currently being received from each site is sufficient for modern assessment needs.
- Determine whether ERDS should be required to transmit continuously so that no operator action is needed during an emergency.

(11) Recommendation 11: The Task Force recommends, as part of the longer term review, that the NRC should pursue emergency preparedness topics related to decision making, radiation monitoring, and public education. The Task Force recommends that the Commission direct the staff to do the following:

(11.1) Study whether enhanced onsite emergency response resources are necessary to support the effective implementation of the licensees' emergency plans, including the ability to deliver the equipment to the site under conditions involving significant natural events where degradation of offsite infrastructure or competing priorities for response resources could delay or prevent the arrival of offsite aid.

(11.2) Work with FEMA, States, and other external stakeholders to evaluate insights from the implementation of EP at Fukushima to identify potential enhancements to the U.S. decision making framework, including the concepts of recovery and reentry.

(11.3) Study the efficacy of real-time radiation monitoring onsite and within the EPZs (including consideration of ac independence and real-time availability on the Internet).

(11.4) Conduct training, in coordination with the appropriate Federal partners, on radiation, radiation safety, and the appropriate use of KI in the local community around each nuclear power plant.

Improving the Efficiency of NRC Programs (Recommendation 12)

(12) Recommendation 12: The Task Force recommends that the NRC strengthen regulatory oversight of licensee safety performance (i.e., the Reactor Oversight Process) by focusing more attention on defense-in-depth requirements consistent with the recommended defense-in-depth framework. The Task Force recommends the Commission direct the staff to strengthen the Reactor Oversight Process (ROP) by doing the following:

(12.1) Expand the scope of the annual ROP self assessment and biennial ROP realignment to more fully include defense-in-depth considerations.

(12.2) Enhance NRC staff training on severe accidents, including training resident inspectors on SAMGs.

The Task Force proposes an integrated strategy for implementing its recommendations in a coherent manner. (1) rule making activities, (2) orders, (3) staff actions, and (4) actions for long-term evaluation.

Recommended Rulemaking Activities

The Task Force recommends that the Commission direct the staff to initiate these important rulemaking activities, including concurrent development of associated guidance, and complete them as a soon as possible.

- Initiate rulemaking to implement a risk-informed, defense-in-depth framework consistent with the above recommended Commission policy statement. (Section 3—detailed recommendation 1.2)
- Initiate rulemaking to require licensees to confirm seismic hazards and flooding hazards every 10 years and address any new and significant information. If necessary, update the design basis for SSCs important to safety to protect against the updated hazards. (Section 4.1.1—detailed recommendation 2.2)
- Initiate rulemaking to revise 10 CFR 50.63 to require each operating and new reactor licensee to (1) establish a minimum coping time of 8 hours for a loss of all ac power, (2) establish the equipment, procedures, and training necessary to implement an "extended loss of all ac" coping time of 72 hours for core and spent fuel pool cooling and for reactor coolant system and primary containment integrity as needed, and (3) preplan and prestage offsite resources to support uninterrupted

core and spent fuel pool cooling, and reactor coolant system and containment integrity as needed, including the ability to deliver the equipment to the site in the time period allowed for extended coping, under conditions involving significant degradation of offsite transportation infrastructure associated with significant natural disasters. (Section 4.2.1—detailed recommendation 4.1)
- Initiate rulemaking or licensing activities or both to require the actions related to the spent fuel pool described in detailed recommendations 7.1–7.4. (Section 4.2.5—detailed recommendation 7.5)
- Initiate rulemaking to require more realistic, hands-on training and exercises on SAMGs and EDMGs for all staff expected to implement the strategies and those licensee staff expected to make decisions during emergencies, including emergency coordinators and emergency directors. (Section 4.2.6—detailed recommendation 8.4)
- Initiate rulemaking to require EP enhancements for multiunit events in the following areas: personnel and staffing, dose assessment capability, training and exercises, and equipment and facilities. (Section 4.3.1—detailed recommendation 9.1)
- Initiate rulemaking to require EP enhancements for prolonged SBO in the following areas: communications capability, ERDS capability, training and exercises, and equipment and facilities. (Section 4.3.1—detailed recommendation 9.2)

The recommendations of the NTTF are subdivided into three tiers. The Tier 1 recommendations are to be started without delay and are the recommendations discussed herein. The following two Tier 1 recommendations focus on seismic re-assessment of US nuclear power plants:

- Recommendation 2.1 - Seismic and flood hazard reevaluations.
- Recommendation 2.3 - Seismic and flood walkdowns. Recommendation 2.3 was implemented first. The guidelines for implementation of 2.3 were developed by industry as Seismic Walkdown Guidance: For Resolution of Fukushima NTTF recommendation 2.3: the guidance was published as EPRI report 1025286 in June 2012, and approved by the NRC. Implementation of this recommendation 2.3 was completed in late 2012.
- The recommendation 2.3 reports have been submitted by each plant to the NRC for review.

Longer Term Recommendation 2.1 – Recommendation 2.1 is an exhaustive re-evaluation of the seismic hazard of each plant and an identification of plant-specific vulnerabilities. The implementation guide for this Recommendation 2.1 is contained in a document referred to as the Guidance for Screening and Prioritization Implementation Details (SPID).

The SPID contains a flowchart to help plants determine the level of re-evaluation required. For most plants, the following process will address recommendation 2.1:

- Development of site-specific Probabilistic Seismic Hazard Assessments (PSHA), using state-of-the-art techniques for defining the seismic source terms, attenuation models, and site amplification factors.
- Development of site-specific seismic Ground Motions Response Spectra (GMRS).
- Comparison of the design basis Safe Shutdown Earthquake (SSE) to the new GMRS to determine the extent and method of re-evaluation.
- In many cases a Seismic Probabilistic Risk Analysis (SPRA) will be necessary,
  - Development of the systems risk analysis, in the form of event trees and fault trees for the seismic event, as it challenges the reactor and the spent fuel pool (ASME/NS SA-2009, and NRC RG 1.200)
    - Calculation of margins and fragilities for structures, systems and components (SSCs)
  - Convolve the PSHA (the probability of earthquakes of different magnitudes), the system risk analysis, and the fragilities analysis to obtain a core damage frequency and a probability of large early release (i.e., a release before mitigative actions are implemented)
- For CEUS plants, the complete effort is requested to be completed by 2016 or 2018 depending on priority.

The NRC issued the following letter and orders.

1. **50.54 (f) Letter**: The 10 CFR 50.54(f) letter related to Near Term Task Force (NTTF) Recommendations 2.1 and 2.3 requests that Nuclear Power Plant (NPP) licensees reevaluate the seismic and flooding hazards at their sites against current NRC requirements and guidance and, if necessary, to perform a risk evaluation (NTTF Recommendation 2.1). The NRC staff will determine if additional regulatory actions are necessary, including updating the design basis for SSCs important to safety. The letter also requests the licensees to perform seismic and flooding protection walkdowns to identify and address plant-specific vulnerabilities and verify the adequacy of monitoring and maintenance for protection features such as watertight barriers and seals in the interim periods until longer term actions are completed (NTTF Recommendation 2.3).
2. **Order EA-12-049**: Issuance of Order to Modify Licenses with Regard to requirements for Mitigation Strategies for Beyond-Design-Basis External Events.
3. **Order EA-12-051**: Issuance of Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation– NRC Staff Interim Staff Guidance for implementing Commission Order EA-12-051 was originally issued August 31, 2012.
4. **Order EA-13-109** issued June 6, 2013 requiring installation of reliable hardened containment vents for BWR plants with Mark I and Mark II containment designs. Order EA-13-109 rescinds the order EA-12-050 (issued March 12, 2012).

The Task Force proposes an integrated strategy for implementing its recommendations in a coherent manner. (1) rulemaking activities, (2) orders, (3) staff actions, and (4) actions for long-term evaluation.

Recommended Rulemaking Activities

The Task Force recommends that the Commission direct the staff to initiate these important rulemaking activities, including concurrent development of associated guidance, and complete them as a soon as possible.

- Initiate rulemaking to implement a risk-informed, defense-in-depth framework consistent with the above recommended Commission policy statement. (Section 3—detailed recommendation 1.2)
- Initiate rulemaking to require licensees to confirm seismic hazards and flooding hazards every 10 years and address any new and significant information. If necessary, update the design

basis for SSCs important to safety to protect against the updated hazards. (Section 4.1.1—detailed recommendation 2.2)
- Initiate rulemaking to revise 10 CFR 50.63 to require each operating and new reactor licensee to (1) establish a minimum coping time of 8 hours for a loss of all ac power, (2) establish the equipment, procedures, and training necessary to implement an "extended loss of all ac" coping time of 72 hours for core and spent fuel pool cooling and for reactor coolant system and primary containment integrity as needed, and (3) preplan and prestage offsite resources to support uninterrupted core and spent fuel pool cooling, and reactor coolant system and containment integrity as needed, including the ability to deliver the equipment to the site in the time period allowed for extended coping, under conditions involving significant degradation of offsite transportation infrastructure associated with significant natural disasters. (Section 4.2.1—detailed recommendation 4.1)
- Initiate rulemaking or licensing activities or both to require the actions related to the spent fuel pool described in detailed recommendations 7.1–7.4. (Section 4.2.5—detailed recommendation 7.5)
- Initiate rulemaking to require more realistic, hands-on training and exercises on SAMGs and EDMGs for all staff expected to implement the strategies and those licensee staff expected to make decisions during emergencies, including emergency coordinators and emergency directors. (Section 4.2.6—detailed recommendation 8.4)
- Initiate rulemaking to require EP enhancements for multiunit events in the following areas: personnel and staffing, dose assessment capability, training and exercises, and equipment and facilities. (Section 4.3.1—detailed recommendation 9.1)
- Initiate rulemaking to require EP enhancements for prolonged SBO in the following areas: communications capability, ERDS capability, training and exercises, and equipment and facilities. (Section 4.3.1—detailed recommendation 9.2)

Recommended Orders

The Task Force recommends that the Commission use orders to ensure that licensees take the near-term actions described below. In some cases, these are interim actions to be taken until requirements associated with future rulemakings can be implemented.

- Order licensees to reevaluate the seismic and flooding hazards at their sites against current NRC requirements and guidance, and, if necessary, update the design basis and SSCs important to safety to protect against the updated hazards. (Section 4.1.1—detailed recommendation 2.1)
- Order licensees to perform seismic and flood protection walkdowns to identify and address plant-specific vulnerabilities and verify the adequacy of monitoring and maintenance for protection features such as watertight barriers and seals in the interim period until longer term actions are completed to update the design basis for external events. (Section 4.1.1—detailed recommendation 2.3)
- Order licensees to provide reasonable protection for equipment currently provided pursuant to 10 CFR 50.54(hh)(2) from the effects of design-basis external events and to add equipment as needed to address multiunit events while other requirements are being revised and implemented. (Section 4.2.1—detailed recommendation 4.2)
- Order licensees to include a reliable hardened vent in boiling-water reactor (BWR) Mark I and Mark II containments. (Section 4.2.3—detailed recommendation 5.1)
- Order licensees to provide sufficient safety-related instrumentation, able to withstand design-basis natural phenomena, to monitor key spent fuel pool parameters (i.e., water level, temperature, and area radiation levels) from the control room. (Section 4.2.5—detailed recommendation 7.1)
- Order licensees to provide safety-related ac electrical power for the spent fuel pool makeup system. (Section 4.2.5—detailed recommendation 7.2)
- Order licensees to revise their technical specifications to address requirements to have one train of onsite emergency electrical power operable for spent fuel pool makeup and spent fuel pool instrumentation when there is irradiated fuel in the spent fuel pool, regardless of the operational mode of the reactor. (Section 4.2.5—detailed recommendation 7.3)
- Order licensees to have an installed, seismically qualified means to spray water into the spent fuel pools, including an easily accessible connection to supply the water (e.g., using a portable pump or pumper truck) at grade outside the building. (Section 4.2.5—detailed recommendation 7.4)
- Order licensees to modify the EOP technical guidelines (required by Supplement 1, "Requirements for Emergency Response Capability," to NUREG-0737, issued January 1983 (GL 82-33), to (1) include EOPs, SAMGs, and EDMGs in an integrated manner, (2) specify clear command and control strategies for their implementation, and (3) stipulate appropriate qualification and training for those who make decisions during emergencies. (Section 4.2.6—detailed recommendation 8.1)
- Order licensees to modify each plant's technical specifications to conform with detailed recommendation 8.2. (Section 4.2.6—detailed recommendation 8.3)
- Order licensees to do the following until rulemaking is complete: determine and implement the required staff to fill all necessary positions for responding to a multiunit event, conduct periodic training and exercises for multiunit and prolonged SBO scenarios, ensure that EP equipment and facilities are sufficient for dealing with multiunit and prolonged SBO scenarios, provide a means to power communications equipment needed to communicate onsite and offsite during a prolonged SBO, and maintain ERDS capability throughout the accident. (Section 4.3.1—detailed recommendation 9.3)
- Order licensees to complete the ERDS modernization initiative by June 2012 to ensure multiunit site monitoring capability. (Section 4.3.1—detailed recommendation 9.4)

The NRC issued the following orders.

Order EA-12-049: Issuance of Order to Modify Licenses with Regard to requirements for Mitigation Strategies for Beyond-Design-Basis External Events.

Order EA-12-051: Issuance of Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation–NRC Staff Interim Staff Guidance for implementing Commission Order EA-12-051 was originally issued August 31, 2012.

50.54 (f) Letter: Request for Information Pursuant to title 10 of the code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident.

Order EA-13-109 issued June 6, 2013 requiring installation of reliable hardened containment vents for BWR plants with Mark I and Mark II containment designs. Order EA-13-109 rescinds the order EA-12-050 (issued March 12, 2012).

Induced Fires and Floods; (Section 4.1.2—detailed recommendation 3)

- Reevaluate the need for hardened vents for other containment designs, considering the insights from the Fukushima accident. Depending on the outcome of the reevaluation, appropriate regulatory action should be taken for any containment designs requiring hardened vents. (Section 4.1.3—detailed recommendation 5.2)
- Identify insights about hydrogen control and mitigation inside containment or in other buildings as additional information is revealed through further study of the Fukushima Dai-ichi event. (Section 4.1.4—detailed recommendation 6)
- Analyze current protective equipment requirements for emergency responders and guidance based upon insights from the accident at Fukushima. (Section 4.3.1—detailed recommendation 10.1)
- Evaluate the command and control structure and the qualifications of decision makers to ensure that the proper level of authority and oversight exists in the correct facility for a long-term SBO or multiunit accident or both. (Section 4.3.1—detailed recommendation 10.2)
- Evaluate ERDS to do the following: determine an alternate method (e.g., via satellite) to transmit ERDS data that does not rely on hardwired infrastructure that could be unavailable during a severe natural disaster, determine whether the data set currently being received from each site is sufficient for modern assessment needs, and determine whether ERDS should be required to transmit continuously so that no operator action is needed during an emergency. (Section 4.3.1—detailed recommendation 10.3)
- Study whether enhanced onsite emergency response resources are necessary to support the effective implementation of the licensees' emergency plans, including the ability to deliver the equipment to the site under conditions involving significant natural events where degradation of offsite infrastructure or competing priorities for response resources could delay or prevent the arrival of offsite aid. (Section 4.3.2—detailed recommendation 11.1)
- Work with FEMA, States, and other external stakeholders to evaluate insights from the implementation of EP at Fukushima to identify potential enhancements to the U.S. decision making framework, including the concepts of recovery and reentry. (Section 4.3.2—detailed recommendation 11.2)
- Study the efficacy of real-time radiation monitoring onsite and within the EPZs (including consideration of ac independence and real-time availability on the Internet). (Section 4.3.2—detailed recommendation 11.3)
- Conduct training, in coordination with the appropriate Federal partners, on radiation, radiation safety, and the appropriate use of KI in the local community around each nuclear power plant. (Section 4.3.2—detailed recommendation 11.4)

Summary

In summary, the events of the March 2011 Earthquake and Tsunami in Japan continue to significantly affect the nuclear industry worldwide. Regulators are reviewing the status of their plants, particularly concerning their vulnerability to beyond design-basis events such as the magnitude 9 earthquake and the resulting tsunami. There are many lessons-learned activities, most notable of which are seismic and flooding hazards reevaluations and corresponding walkdowns at operating plants. Broader lessons learned go beyond earthquake and tsunami response, and they are related to focusing on mitigation after extended station blackout with coping strategies for broad aspects of an accident occurrence, regardless of cause.

30.2.1 References

1. Recommendations for Enhancing Reactor safety in the 21st Century, The Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident, NRC NTTF Report, July 12, 2011.
2. NRC Commission SRM SECY-12-0025.

30.3 EFFECT OF LWR ENVIRONMENT ON FATIGUE LIFE OF NUCLEAR PLANT COMPONENTS

Lesson Learned: Data from worldwide fatigue tests shows that the effects of water environments on the fatigue resistance of materials used in operating pressurized water reactor (PWR) and boiling water reactor (BWR) plants, whose components were designed in accordance with the ASME Code Section III fatigue curves generated in air environment, may not adequately address long-term environmental effects on fatigue.

30.3.1 Introduction

The NRC as well as the nuclear industry worldwide recognized the effect of LWR environment on the fatigue life of components since 1990s. The NRC did extensive work related to the environmental fatigue and prepared NUREG-6909 Rev. 0 in 2007, and updated in 2013 as Revision 1 [1] to include recent additional data from Japan and other available sources. NREG-6909 summarizes, reviews, and quantifies the effects of the light-water reactor (LWR) environments on the fatigue lives of reactor materials, including carbon steels, low-alloy steels, nickel-chromium-iron (Ni-Cr-Fe) alloys, and austenitic stainless steels. The primary purpose of this NREG-6909 is to provide the background and technical bases to support Regulatory Guide 1.207, "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of the Light-Water Reactor Environment for New Reactors." [2]

The initial revision of NUREG-6909 included a review of the fatigue strain vs cycles (ε-N) data available at that time for carbon steels, low-alloy steels, Ni-Cr-Fe alloys, and austenitic stainless steels to define the potential effects of key material, loading, and environmental parameters on the fatigue lives of the steels. By drawing upon a larger database than was used in earlier published reports, the U.S. Nuclear Regulatory Commission (NRC) updated the Argonne National Laboratory (ANL) fatigue life models used to estimate the fatigue curves as a function of those parameters, and presented a procedure for incorporating environmental effects into fatigue evaluations. In this revision, additional fatigue ε-N data available since the original publication of NUREG-6909, most particularly from Japan, was incorporated into the database and the fatigue life models were updated. In addition, feedback from interested stakeholders obtained since the original publication of this NUREG-6909 were evaluated and incorporated, where appropriate.

Cyclic loadings on a reactor pressure boundary component occur because of changes in mechanical and thermal loadings as the system goes from one load set (e.g., pressure, temperature, moment, and force loading) to another. The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section III, Subsection NB contains rules for the design of Class 1 components of nuclear power plants and recognizes fatigue as a possible mode of failure in pressure vessel steels and piping materials. ASME Code Section III fatigue analysis procedures consider all fatigue cycles based on the anticipated number of thermal and pressure transients, and for each load-cycle or load set pair, an

individual fatigue usage factor is determined by the ratio of the number of cycles anticipated during the design lifetime of the component, as specified by the Owner, to the number of allowable cycles. Figures I–9.1 through I–9.6 of Mandatory Appendix I to Section III of the ASME Code specify fatigue design curves that define the allowable number of cycles as a function of applied stress amplitude. Those fatigue design curves have evolved significantly since the initial publication of Section III in 1963. However, Paragraph NB-3121 of the 2011 Addenda to Section III of the Code continues to state that the effects of coolant environments on the fatigue resistance of materials were not addressed in the fatigue design curves. Therefore, the effects of water environments on the fatigue resistance of materials used in operating pressurized water reactor (PWR) and boiling water reactor (BWR) plants, whose components were designed in accordance with the ASME Code Section III, may not adequately address long-term environmental effects on fatigue based on the data available at the time the fatigue design curves were derived.

The current Section III design fatigue curves in air contained in Section III of the ASME Code were based primarily on strain–controlled fatigue tests of small polished specimens at room temperature in laboratory air environments. Best–fit curves to the experimental test data were first adjusted to account for the effects of mean stress and then lowered by a factor of 2 on stress and 20 on cycles (whichever was more conservative) to obtain the design fatigue air curves. These factors were not intended as "safety margins," but rather they were intended as "adjustment factors" that were applied to the experimental laboratory data to obtain estimates of the fatigue lives of actual reactor components. Recent fatigue–strain–vs.–life (ε-N) data obtained primarily in the U.S. and Japan demonstrate that light water reactor (LWR) environments have potentially significant effects on the fatigue resistance of materials. Specimen lives obtained from laboratory tests in simulated LWR environments were much shorter than those obtained from corresponding tests in an air environment.

In the original versi.on of NUREG/CR-6909, the existing fatigue ε-N data for carbon and low–alloy steels, wrought and cast austenitic stainless steels (SSs), and nickel-chromium-iron (Ni-Cr-Fe) alloys in air and LWR environments were evaluated to identify the various material, environmental, and loading parameters that influence fatigue crack initiation. The results of those evaluations were used to establish the effects of key parameters on the fatigue lives of steels. The fatigue lives of materials were decreased in LWR environments; the magnitude of the reduction depended on the temperature, strain rate, dissolved oxygen (DO) level in the water, and, for carbon and low–alloy steels, the sulfur (S) content of the steels. For all steels, environmental effects on fatigue lives were significant only when critical parameters (temperature, strain rate, DO level, and strain amplitude) met certain threshold values. Environmental effects were moderate, e.g., less than a factor of 2 decrease in fatigue lives, when any one of the threshold conditions was not satisfied. The threshold values of the critical parameters and the effects of other parameters (such as water conductivity, water flow rate, and material heat treatment) on the fatigue lives of the steels were also discussed.

In Revision 1 of NUREG-6909, the comprehensive review of the fatigue ε-N data for nuclear power plant piping and pressure vessel steels presented in the original version of NUREG/CR-6909 was reevaluated using a much larger database. The results were updated to include this reevaluation, as well as to address concerns from interested stakeholders regarding the F_{en} methodology for incorporating environmental effects into ASME Code Section III fatigue cumulative usage factor (CUF) evaluations.

The results indicated that the ASME Code Section III mean air curve for low–alloy steels is in good agreement with the available experimental data, and the ASME Code Section III mean air curve for carbon steels is conservative. In addition, the best-fit mean air data used to develop the fatigue design air curve for austenitic SSs in ASME Code Section III editions prior to 2009b Addenda are is not consistent with the experimental data at strain amplitudes less than 0.5%; fatigue lives predicted by the ASME Code Section III mean air curve were longer than those obtained from experiments.

30.3.2 Fatigue Considerations for LWR Environments

In the initial version of NUREG/CR-6909, new fatigue design air curves were developed for carbon and low-alloy steels and austenitic SSs that were based on the ANL fatigue life models and were consistent with the fatigue ε-N data available at that time.

The air design curves were extended up to 10^{11} cycles using available high-cycle fatigue data. In 2009, the ANL design air curve for austenitic SSs was adopted into Mandatory Appendix I of Section III of the ASME Code. The reevaluation of the fatigue ε-N behavior of austenitic SS materials using a much larger database indicated that the air fatigue design curves previously developed by ANL are consistent with the available fatigue data, and do not warrant any modifications. However, in revision 1 of NUREG-6909, the extension of the air fatigue design curves for carbon and low-alloy steels up to 10^{11} cycles was modified to be consistent with the extension of the current ASME Code Section III fatigue design curve beyond 10^6 cycles.

The reevaluation results also indicated that the fatigue data for Ni-Cr-Fe alloys were not consistent with the current ASME Code mean air curve for austenitic SSs. The rather limited fatigue ε-N data for Ni-Cr-Fe alloys, such as Alloys 600, 690, and 800 and their welds, were consistent with the best-fit mean air curve for austenitic SSs at fatigue lives less than 10^4 cycles, and showed longer fatigue lives than the predicted values for fatigue lives greater than 10^4 cycles. However, a separate air fatigue design curve was not developed for Ni-Cr-Fe alloys, and the current ASME Code fatigue air design curve for austenitic SSs, which is based on the ANL model, was used to represent the fatigue, ε-N behavior of Ni-Cr-Fe alloys and associated weld metals. The data also indicated that the fatigue resistance of Inconel 718 is superior to that of the other Ni-Cr-Fe alloys. The slope of the Inconel 718 fatigue ε-N curve is flatter and the fatigue limit is higher than those for austenitic SSs.

The fatigue lives of carbon and low–alloy steels, austenitic SSs, and Ni-Cr-Fe alloys were decreased in LWR environments. The reduction depended on some key material, loading, and environmental parameters. The fatigue ε-N data were consistent with the much larger database on enhancement of crack growth rates in these materials in LWR environments. The key parameters that influenced fatigue lives in these environments, e.g., temperature, DO level in the water, strain rate, strain (or stress) amplitude, and, for carbon and low–alloy steels, S content of the steel, were identified. In addition, the functional form of the dependence of fatigue lives on these parameters and the range of the values of these parameters within which environmental effects were significant was defined. If these critical loading and environmental conditions exist during reactor operation, then environmental effects may be

significant and should be included in any relevant ASME Code Section III fatigue evaluations.

In the initial version of NUREG/CR-6909 (published in 2007), fatigue life models were developed to predict the fatigue lives of small smooth specimens of carbon and low–alloy steels, wrought and cast austenitic SSs, and Ni-Cr-Fe alloys as a function of material, loading, and environmental parameters using the existing fatigue ε-N database. The functional form and bounding values of these parameters were based on experimental observations and data trends. An approach was presented that incorporated the effects of LWR coolant environments into the ASME Code Section III fatigue evaluations based on the environmental fatigue correction factor, F_{en}. The fatigue usage for a specific stress cycle or load set pair derived using the ASME Code Section III fatigue design air curves was multiplied by the F_{en} to account for environmental effects.

In revision 1 of NUREG-6909, the F_{en} expressions were updated using a much larger fatigue ε-N database, primarily derived from extensive additional data provided from Japan. The updated expressions also address comments provided by interested stakeholders related to: (a) the constants in the F_{en} expressions that results in a F_{en} value of approximately 2 even when the strain rate is very high or temperature is very low, (b) the temperature dependence of F_{en} for carbon and low-alloy steels, and (c) the dependence of F_{en} on water chemistry for austenitic SSs.

NUREG-6909 also presents a critical review of the ASME Code Section III fatigue design margins of 2 on stress and 20 on life and assesses the possible conservatism in the choice of design margins. Although these factors were intended to be conservative, they were not considered safety margins in the work presented in this report. Instead, these factors cover the effects of variables that influence fatigue lives but were not investigated in the experiments that were used to obtain the air fatigue design curves. Data available in the literature were reviewed to evaluate the margins on cycles that are needed to account for such differences and uncertainties. Monte Carlo simulations were performed to determine the margin on cycles needed to obtain a fatigue design curve in air that provided a conservative estimate of the number of cycles required to initiate a fatigue crack in reactor components. The results presented in the initial version of NUREG/CR-6909 indicated that, for carbon and low-alloy steels and austenitic SSs, the current ASME Code Section III requirements for a factor of 20 on cycles to account for the effects of material variability and data scatter, as well as size, surface finish, and loading history, may be decreased by at least a factor of 1.7. Thus, to reduce conservatism, fatigue design curves were developed based on the ANL fatigue life models and those curve were then adjusted for mean stress effects and by a factor of 2 on stress and 12 on cycles. These adjustments were made to account for the effects of four parameters – material variability and data scatter, size, surface finish, and loading sequence. The results indicated that for carbon and low-alloy steels and austenitic SSs, a factor of 2 on stress and 10 on cycles are adequate to develop air fatigue design curves from the best-fit mean air curves. However, until these results are further validated with applicable fatigue data ε-N data, the air fatigue design curves presented in NUREG-6909 are based on factors of 2 on stress and 12 on life.

The F_{en} methodology was also validated by comparing the results of several experimental data sets obtained from fatigue tests that simulated actual plant conditions with estimated fatigue usage using the updated F_{en} expressions. The data sets represented fatigue tests with changing strain rate and/or temperature, complex loading that simulated a PWR safety injection transient, spectrum loading (i.e., random strain amplitudes), and pipe U-bend tests. In all cases, the results indicated that the predicted fatigue lives were in good agreement with the experimental values; the differences between the experimental and predicted fatigue lives were within a factor of two, which is within the experimental data scatter.

30.3.3 Fatigue Strain vs. Life (ε–N) Behavior in Air

In nearly all tests, fatigue life is defined as the number of cycles, N25, necessary for the tensile stress to drop 25% from its peak or steady–state value. As discussed earlier in Section 1.1, for the specimen size used in these studies, e.g., 5.1–9.5 mm (0.2–0.375 in.) diameter cylindrical specimens, this corresponds to an approximately 3–mm–deep crack. Some of the earlier tests in air were carried out to complete failure of the specimen, and in some other tests life was defined as the number of cycles for peak tensile stress to decrease by 10 or 50%. Fatigue lives defined by a criterion other than a 25% load drop were therefore converted toa consistent N_{25} value according to the following formula:

$$N_{25} = N_X/(0.947 + 0.00212X), \tag{30.1}$$

where X is the failure criterion (e.g., 10, 50 or 100% decrease in peak tensile stress). The fatigue life, N, of carbon steels is represented by

$$\ln(N) = 6.614 - 0.00124\,T - 1.975\,\ln(\varepsilon_a - 0.113), \tag{30.2}$$

and that of low–alloy steels by

$$\ln(N) = 6.480 - 0.00124\,T - 1.808\,\ln(\varepsilon_a - 0.151), \tag{30.3}$$

where ε_a is applied strain amplitude (%), and T is the test temperature (°C). Thus, in room-temperature (25°C) air, the fatigue life of carbon steels is expressed as

$$\ln(N) = 6.583 - 1.975\,\ln(\varepsilon_a - 0.113), \tag{30.4}$$

and that of low–alloy steels by

$$\ln(N) = 6.449 - 1.808\,\ln(\varepsilon_a - 0.151). \tag{30.5}$$

In air at temperatures up to 400°C, the fatigue data for Types 304, 304L, 316, 316L, and 316NG SSs were represented by the expression:

$$\ln(N) = 6.891 - 1.920\,\ln(\varepsilon_a - 0.112) \tag{30.6}$$

where ε_a is applied strain amplitude (%).

Overall, the results indicated that the best-fit mean air curve for austenitic SSs represented slightly conservative estimates of the fatigue lives of Ni-Cr-Fe alloys in the high-cycle regime (fatigue lives greater than 5×10^4 cycles), particularly for Ni-Cr-Fe alloy weld metals.

30.3.4 LWR Environment

The fatigue ε-N data in LWR environments were fitted to a modified version of Eq. expressed as

$$\ln(N) = A - B\,\ln(\varepsilon_a - C) - D\;\; S^*\,T^*\,O^*\,\dot{\varepsilon}^*, \tag{30.7}$$

where S*, T*, O*, and $\dot{\varepsilon}^*$ are transformed sulfur content, temperature, DO level, and strain rate, respectively, defined below, and D is a constant.

The effects of reactor coolant environments on the fatigue lives of structural materials are expressed in terms of a nominal environmental fatigue correction factor, $F_{en,nom}$, which is defined as the ratio of fatigue life in air at room temperature ($N_{air,RT}$) to that in water at the service temperature (N_{water}):

$$F_{en,nom} = N_{air,RT}/N_{water} \quad (30.8)$$

30.3.4.1 F_{en} For Both Carbon and Low-Alloy Steels

$$F_{en,nom} = \exp((0.003 - 0.031\ \varepsilon^*)\ S^*T^*O^*), \quad (30.9)$$

where S*, T*, O*, and ε* are transformed S content, temperature, DO level, and strain rate, respectively, defined as:

$$S^* = 2.0 + 98\ S \qquad (S \leq 0.015\ \text{wt.\%}) \quad (30.10a)$$

$$S^* = 3.47 \qquad (S > 0.015\ \text{wt.\%}) \quad (30.10b)$$

$$T^* = 0.395 \qquad (T \leq 150°C) \quad (30.11)$$

$$T^* = (T - 75)/190 \qquad (150 < T \leq 325°C) \quad (30.12)$$

$$O^* = 1.49 \qquad (DO < 0.04\ \text{ppm}) \quad (30.13)$$

$$O^* = \ln(DO/0.009) \qquad (0.04\ \text{ppm} \leq DO \leq 0.5\ \text{ppm}) \quad (30.14)$$

$$O^* = 4.02 \qquad (DO > 0.5\ \text{ppm}) \quad (30.15)$$

$$\dot{\varepsilon}^* = 0 \qquad (\dot{\varepsilon}^* > 2.2\%/\text{s}) \quad (30.16)$$

$$\dot{\varepsilon}^* = \ln(\dot{\varepsilon}^*/2.2) \qquad (0.0004 \leq \dot{\varepsilon}^* \leq 2.2\%/\text{s}) \quad (30.17)$$

$$\dot{\varepsilon}^* = \ln(0.0004/2.2) \qquad (\dot{\varepsilon}^* < 0.0004\%/\text{s}). \quad (30.18)$$

For both carbon and low-alloy steels, a threshold value of 0.07% for strain amplitude (one-half the strain range for the cycle) is defined, below which environmental effects on the fatigue lives of these steels do not occur. Thus,

$$F_{en,nom} = 1 \qquad (\varepsilon_a \leq 0.07\%). \quad (30.19)$$

30.3.5 Fatigue Lives of Austenitic SSs in LWR Environments

Fatigue lives of austenitic SSs in LWR environments were best represented by the following expression

$$\ln(N) = A - 1.920\ \ln(\dot{\varepsilon}_a - 0.112) + T'\dot{\varepsilon}'\ O', \quad (30.20)$$

where constant A was determined to be 6.157 and the transformed temperature, T', the transformed strain rate, ε, and the transformed DO content, O', were defined by Eqs. 30.22 through 30.30 as shown in 30.3.5.1.

30.3.5.1 F_{en} for Austenitic SSs in LWR Environments.

Fen is given by

$$F_{en,nom} = \exp(-\ T'\ O'\ \varepsilon'\ ), \quad (30.21)$$

where T', ε', and O' are transformed temperature, strain rate, and DO level, respectively, defined as:

$$T' = 0 \qquad (T \leq 100°C) \quad (30.22)$$

$$T' = (T - 100)/250 \qquad (100 < T < 325°C) \quad (30.23)$$

$$\dot{\varepsilon}' = 0 \qquad (\dot{\varepsilon}' > 10\%/\text{s}) \quad (30.24)$$

$$\dot{\varepsilon}' = \ln(\dot{\varepsilon}'/10) \qquad (0.0004 \leq \dot{\varepsilon}' \leq 10\%/\text{s}) \quad (30.25)$$

$$\dot{\varepsilon}' = \ln(0.0004/10) \qquad (\dot{\varepsilon}' < 0.0004\%/\text{s}) \quad (30.26)$$

For DO less than 0.1 ppm (i.e. for Pressurized Water Reactor (PWR) Hydrogen water Chemistry (HWC) water):

$$O' = 0.29 \quad \text{(all wrought and cast SSs and heat treatments and SS weld metals)} \quad (30.27)$$

For DO equal to or greater than 0.1 ppm (i.e. for Boiling Water Reactor (BWR) Normal water Chemistry (NWC) water).

$$O' = 0.29 \quad \text{(sensitized high-carbon wrought and cast SSs)} \quad (30.28)$$

$$O' = 0.14 \quad \text{(all wrought SSs except sensitized high-carbon SSs).} \quad (30.29)$$

For wrought and cast austenitic stainless steels, a threshold value of 0.10% for strain amplitude (one-half the strain range for the cycle) is defined, below which environmental effects on the fatigue lives of these steels do not occur. Thus,

$$F_{en,nom} = 1 \qquad (\varepsilon_a \leq 0.10\%). \quad (30.30)$$

30.3.6 F_{en} for Ni-Cr-Fe Alloys

The available fatigue data were very limited to develop a fatigue life model for Ni-Cr-Fe alloys in LWR environments. F_{en} relationship for Ni-Cr-Fe alloys is expressed as

For Ni-Cr-Fe alloys,

$$F_{en,nom} = \exp(-\ T'\dot{\varepsilon}'\ O'), \quad (30.31)$$

where T', ε', and O' are transformed temperature, strain rate, and DO, respectively, defined as:

$$T' = 0 \qquad (T < 50°C) \quad (30.32)$$

$$T' = (T - 100)/275 \qquad (50 < T < 325°C) \quad (30.33)$$

$$\dot{\varepsilon}' = 0 \qquad (\dot{\varepsilon}' > 5.0\%/\text{s}) \quad (30.34)$$

$$\dot{\varepsilon}' = \ln(\varepsilon/5.0) \qquad (0.0004 \leq \dot{\varepsilon}' \leq 5.0\%/\text{s}) \quad (30.35)$$

$$\dot{\varepsilon}' = \ln(0.0004/5.0) \qquad (\dot{\varepsilon}' < 0.0004\%/\text{s}) \quad (30.36)$$

$$O' = 0.06 \qquad (\text{NWC BWR water}) \quad (30.37)$$

$$O' = 0.14 \qquad (\text{PWR or HWC BWR water}). \quad (30.38)$$

For Ni-Cr-Fe alloys, a threshold value of 0.10% for strain amplitude (one-half the strain range for the cycle) is defined, below which environmental effects on the fatigue lives of these alloys do not occur. Thus,

$$F_{en,nom} = 1 \qquad (\varepsilon_a \leq 0.10\%). \quad (30.39)$$

The environmental fatigue evaluation method uses as its input the partial fatigue usage factors U_1, U_2, U_3, …U_n, determined in fatigue evaluations. To incorporate environmental effects into the fatigue evaluation, the partial fatigue usage factor for a specific stress cycle or load set pair, based on the fatigue design curves, is multiplied by the environmental fatigue correction factor:

$$U_{en.1} = U_1 \cdot F_{en,1}. \quad (30.40)$$

In the ASME Code Section III design–by–analysis methods, the partial fatigue usage factors are calculated for each type of stress cycle in Paragraph NB-3222.4(e)(5). For piping products designed using NB–3600 methods, Paragraph NB-3653 provides the procedure for the calculation of partial fatigue usage factors for each of the load set pairs.

The readers are directed to refer to NUREG-6909 for further details on environmental fatigue.

30.3.7 Summary

The environmental fatigue correction factor (F_{en}) methodology is considered acceptable for incorporating the effects of reactor coolant environments in fatigue usage factor evaluations of metal components. The methodology for performing fatigue evaluations for the four major categories of structural materials, e.g., carbon steels, low-alloy steels, wrought and cast austenitic stainless steels, and Ni-Cr-Fe alloys, is described.

30.3.8 References

1. Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, NUREG/CR–6909 Rev 1 (ANL–12/60), 2013.
2. "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of the Light-Water Reactor Environment for New Reactors." NRC Regulatory Guide 1.207.

30.4 BURIED PIPE-LEAKAGE ISSUES

Lesson Learned: Leakage from buried and underground pipes at NPP caused by corrosion has resulted in recent ground water contamination incidents, and protective measures are needed.

30.4.1 Introduction

Leakage from buried and underground pipes caused by corrosion has resulted in recent ground water contamination incidents. Some of these leaks resulted in groundwater contamination incidents with associated heightened NRC and public interest. The NRC conducted inspections using TI 2515/173, "Review of the Implementation of the Industry Groundwater Protection Voluntary Initiative" to assess licensee response to these incidents and determine the extent of the industry's voluntary groundwater protection initiative. Subsequently, the industry communicated its plan to address buried piping integrity in its November 2009 letter "Industry Initiative on Buried Piping Integrity" [1] The scope of the first underground piping initiative only addressed piping that is directly buried in soil. However, because operating experience which revealed that leakage of tritiated water from underground piping in vaults or chases (but not in contact with soil) could also lead to groundwater contamination, the industry expanded the scope of its first initiative to include Issue Date: 11/17/11 2 2515/182. Tritium is a radioactive form of hydrogen (H-3) found in air and occurs naturally due to cosmic ray interactions with the atmosphere and falls to the earth as rain. It is also produced by nuclear weapons testing. It is also a by-product of nuclear reactor operation.

30.4.2 Protection Measures

As a result of ground water contamination incidents, each nuclear power site developed a site-specific/company ground water protection program in accordance with NEI document, NEI 07-07, "Industry Ground Water Protection Initiative Final Guidance Document, to control degradation of underground piping and tanks and ensure structural and leakage integrity of buried piping and underground piping and tanks. underground piping not in direct contact with the soil and selected underground tanks. Its September 2010 letter "Industry Initiative on Underground Piping and Tanks Integrity" [2] describes its revised commitments. This second initiative contains all of the requirements and objectives from the first initiative but adds underground piping and tanks that are outside of a building and below the surface of the ground (whether or not they are in direct contact with the soil) if they are safety-related or contain licensed material or are known to be contaminated with licensed material. Also, an owner's piping located outside the owner controlled area is considered to be within the scope of the underground piping and tanks integrity initiative if it is safety-related or contains licensed material. The industry issued a guidance document, Nuclear Energy Institute (NEI) 09-14, "Guideline for the Management of Buried Piping Integrity" to describe a licensee's goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. NEI later issued NEI 09-14, Revision 1 [3] NPP sites drilled onsite groundwater monitoring wells to monitor tritium.

30.4.3 References

1. "Industry Initiative on Underground Piping and Tanks Integrity", 2009
2. "Industry Initiative on Buried Piping Integrity", 2010
3. "Guideline for the Management of Underground Piping and Tank Integrity", NEI 09-14, Revision 1

30.5 HDPE FOR REPLACEMENT OF CARBON STEEL PIPING IN SAFETY RELATED CLASS 3 BURIED PIPING

Lesson Learned: The service water piping systems in operating nuclear power plants are plagued by flow degradation, and leakage due to corrosion, microbiologically induced corrosion, and fouling. A better alternate replacement material that is not susceptible to fouling, corrosion, and MIC for raw water applications is needed.

30.5.1 Introduction

Due to its recognized resistance against galvanic corrosion, microbiological induced corrosion (MIC), and fouling compared to carbon steel, high density polyethylene (HDPE) piping material has recently been proposed for replacement of carbon steel piping in nuclear safety related class 3 service water buried piping applications. However, there are some unique challenges requiring special design considerations due to HDPE's visco-elastic nature, need for relatively thicker pipe walls, and very low material allowable stress. A paper by Basavaraju [1] examines special design considerations such as design factor, minimum required wall thickness for pressure, thermal gradient effects, and cumulative effect from loads of different duration. Useful guidelines from design and analysis perspective are provided.

The material commonly used for the service water piping systems is A106 Gr. B carbon steel or equivalent. The service water piping systems in operating nuclear power plants are plagued by flow degradation, resulting in piping leakage due to corrosion, microbiologically induced corrosion, and fouling. Industry operating experience has shown that carbon steel piping is susceptible to fouling, corrosion, and MIC for raw water applications.

Both corrosion and fouling problems have occurred in raw water piping systems in nuclear power plants. The raw water systems were originally designed using carbon steel material with no internal coating or lining. Coated or lined steel piping also pose problems because breaks in the coating or lining result in piping degradation. Experience has also shown that portions of piping in raw water systems replaced with corrosion resistant steel also had problems due to accelerated microbiological attack and pinhole leaks during service. Installed metallic service water piping in nuclear power plants has experienced severe fouling and significant internal and external corrosion. Thus, carbon steel piping with and without internal coating or lining as well as corrosion resistant steel piping exhibited corrosion, MIC, and fouling problems during service in raw water applications.

When the degradation reaches a severe stage, the industry has no choice but to replace the affected portions of the piping. Currently, the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code [2] sections II, and III do not permit non-metallic piping materials such as HDPE material in nuclear safety related piping applications. Therefore the industry recently developed a nuclear code case N-755 [3] to allow the use of polyethylene material. This code case is not yet endorsed by the U.S. Nuclear Regulatory Commission. ASME B31.1 piping code [4] first introduced a non-metallic piping appendix III in 1986 as an addendum to the 1986 edition. Some operating nuclear plants have utilized polyethylene piping material in the replacement of non-safety related portions of service water piping due to its inherent resistance to corrosion and MIC considerations.

Polyethylene piping offers advantages in corrosion protection over a design where corrosion protection of the system is provided by an internal coating or a liner used with steel piping. Polyethylene piping is not adversely affected by imperfections or minor damage. In contrast, coated or lined piping where breaks in the coating or lining result in piping degradation. The performance over the past ten years, of several hundred feet of replaced non-safety related steel piping with polyethylene above ground piping as well as buried service water piping of diameters up to 36 inches in B31.1 code applications at some nuclear power plants, points to excellent service history.

The primary advantage in using polyethylene piping compared to other carbon steel piping materials is its resistance to fouling, corrosion, and MIC. The resistance of polyethylene piping to corrosion and fouling due to tubercle formation and MIC ensures long term reliability from a structural integrity and flow standpoint. Polyethylene piping was found not to be susceptible to fouling or corrosion, and is also not susceptible to galvanic attack, since polyethylene is an electrical insulating material. In contrast, installed metallic service water piping at nuclear power plants is plagued by severe fouling and significant internal and external corrosion. Polyethylene piping also is not susceptible to localized degradation from microbiological attack, which has occurred frequently with some corrosion resistant steel alloys.

With demonstrated service experience in non-safety related ASME B31.1 type applications in nuclear plants, the licensees are strongly interested in extending polyethylene material piping application to nuclear safety related service water piping systems in nuclear plants. It is expected that new generation nuclear plant applicants would also be interested in the use of PE piping in service water systems. A limited amount of polyethylene piping was installed in above-ground, safety related, ASME Section III nuclear safety related Class 3 service water piping at British Energy's Sizewell B Plant in 2005 and information thus far indicates that it has been performing well in service.

TABLE 30.1 TYPICAL VALUES OF PROPERTIES FOR CARBON STEEL AND POLYETHYLENE MATERIAL [1]

Material	Carbon Steel (Isotropic linear elastic)	Polyethylene (HDPE) (Visco-elastic)
Internal Design Pressure (psig)	≈170	≈170
Temperature (°F)	175	175
Typical Pipe Diameters	≤30"	≤36"
Typical wall thickness	0.375"	≤4.0"
Mean diameter/thickness ratio	≈80 (Thin wall >20)	8.5 (Thick wall <20)
Density (lb/in^3)	0.283	0.035
Modulus of Elasticity (E)	27.9×10^6	2.8×10^4
Poisson's Ratio (v)	0.3	0.4 to 0.45
Coefficient of Thermal Expansion (α) in/in/°F	6.5×10^{-6}	6×10^{-5}
Thermal Conductivity (K) BTU/hr-ft-°F	26	≈0.25
Allowable Stress (psi)	15000	≈350

As piping with polyethylene material does not rust, rot, pit, corrode, tuberculate or support biological growth, the use of polyethylene piping in raw water applications with special design considerations ensures long term reliability from a structural integrity and flow standpoint. The NRC reviewed and granted two relief requests from two different licensees to replace their class 3 carbon steel buried piping with HDPE piping with some stipulations. There is an ASME code case N-755 and the NRC has not endorsed this code case and identified some issues for resolution, which are provided here. (Design related, NDE related).

30.5.2 Lessons Learned and Special Design Considerations

Due to its visco-elastic behavior, a need for relatively thick walls associated with polyethylene piping, and substantial differences in physical and mechanical properties compared to steel piping, some very special design considerations are appropriate when polyethylene piping is used in safety related applications. Typical values of properties for carbon steel and polyethylene material utilized in raw water, and service water applications are listed in Table 30.1 for comparison purposes to identify the significant differences. One main lesson learned is that HDPE pipe needs much thicker wall (nearly ten times thicker) compared to carbon steel pipe it replaces. It can only be used for relatively lower pressure and temperature applications (<170 psig, and 175°F). The failure mode to be guarded against for HDPE is SCG.

With higher grade and improved (bimodal) HDPE materials, such as PE4710, the nuclear industry is considering the use of HDPE for internal pressures up to (170 psig), and higher temperatures (175°F).

30.5.3 Thermal Gradient Stress

As compared with steel, polyethylene material is almost like an insulating material due to its very poor thermal conductivity. Additionally polyethylene pipes require thick wall pipes due to low

allowable stress. Thermal gradients develop due to the temperature difference between the inside and outside walls of the polyethylene piping. Therefore, the effect of thermal gradient stresses becomes an important consideration for polyethylene piping, which is negligible in thin wall steel piping of service water systems. In addition, the coefficient of thermal expansion (α) for polyethylene material is significantly higher than for steel.

Denoting the uniform temperature of the inside wall of the pipe as Ti and the uniform temperature of the outer wall of the buried pipe as T_o, the temperature difference is: $\Delta T_1 = (T_i - T_o)$. The fluid temperature may be used for T_i and the surrounding soil temperature may be used for T_o. A range of ΔT_1 from load cases can be used. From Timoshenko [5], and Young [6], the thermal gradient stresses (σ_{tg}) in thin wall and thick wall cylinders in longitudinal and circumferential directions are given by the following formulae which are tensile at the outer surface and compressive at the inner surface when $T_i > T_o$. In the following equations, E is Modulus of Elasticity, α is coefficient of thermal expansion, ν is Poisson's ratio, and ln denotes for natural logarithm.

In thin wall cylinders:

$$\sigma_{tg} = E\,\alpha\,(T_i - T_o)/[2(1-\nu)] \tag{30.41}$$

In thick wall cylinders:

At outer surface,

$$\sigma_{tg} = \{E\alpha(T_i - T_o)/[2(1-\nu)\ln(a/b)]\}\{1-[2a^2\ln(a/b)/(a^2-b^2)]\} \tag{30.42}$$

At inner surface,

$$\sigma_{tg} = \{E\alpha(T_i - T_o)/[2(1-\nu)\ln(a/b)]\}\{1-[2b^2\ln(a/b)/(a^2-b^2)]\} \tag{30.43}$$

The thermal gradient stress term for consideration in class 3 buried piping applications should be based on the above formulae corresponding to thick wall cylinders.

30.5.4 List of Issues Identified by NRC Related to Code Case N-755: (Buried Polyethylene Piping)

(A) Structural Related Issues

1. Use of a design factor (DF) greater than 0.5 (or factor of safety of less than 2) is not acceptable for ASME Section III, Class 3, nuclear safety related applications for the following reasons:

   In nuclear safety related applications of HDPE piping, a value for design factor or factor of safety to ensure reasonable assurance for providing adequate safety margin is important. In light of ongoing testing programs, and unique challenges with polyethylene piping in nuclear safety related service water applications, it is recommended that the design factor value be limited to no greater than 0.5 to provide a reasonable assurance of the safe operation of the important systems critical to support the safe shutdown of a nuclear power plant.

   Traditionally, the use of polyethylene (PE) piping material has not been employed in safety related applications. The Plastic Pipe Institute's technical report TR-9 recommends a DF of 0.5 for polyethylene water piping (with pressures, temperatures and loadings much less severe than those in the Code Case N-755. The use of design factor value of 0.5 for PE piping in potable water applications in North America has proved to be successful for over 40 years for diverse installation and use conditions. The design factor of 0.5 takes into consideration a broad spectrum of uncertainties. These include resin variation, extrusion and processing variables in the production of PE piping, handling during storage, shipping and installation, application temperatures of up to 80°F, joining and bending methods, various soil conditions, typical installation methods, dynamic loading, surges and water hammer, and other unknown factors. Now, with the introduction of HDPE piping in ASME nuclear safety related Class 3 service water applications, there are new challenges.

   The safety related applications are associated with higher temperatures (up to 175°F) and higher pressures (up to 170 psig), with a need for large diameter and heavy wall thickness piping, compared with traditional non-safety related cold water applications. The seismic and other loadings are considered because of safety related implications. New or improved grades or cell classifications are emerging, and conventional testing methods to determine properties such as slow crack growth (SCG) resistance are inadequate. New methodologies for testing are still evolving. Furthermore, one cannot ignore unique challenges associated with manufacturing large diameter piping and components, development of testing methods, lack of operating experience in nuclear safety related applications, effect of elevated temperature on rapid crack propagation (RCG), and methods to determine minimum detectable flaw size and maximum allowable flaw size. Non-destructive examination (NDE) methods to establish the integrity of the fusion welded joints are still evolving. To address the issues and challenges confronting the polyethylene piping industry, institutions across the world have embarked on research programs. The Electric Power Research Institute (EPRI) initiated an extensive testing program which includes tensile testing, fatigue testing of HDPE piping and components, assessment of the effect of aging on material properties, and development of slow crack growth data. The fatigue testing program of mitered elbows, reducers, electro-fusion couplings, tees, branch saddles, and Y-fittings is still on-going. Studies on the notch acuity for defects in wall thickness in large diameter piping from slow crack growth perspective are being pursued.

   In the temperature range of 32°F to 175°F, the allowable stress for HDPE piping materials is low and decreases very significantly ($\approx$800 psig to 340 psig) compared to that of carbon steel for which the allowable stress is higher ($\approx$15000 psi) and does not change significantly.
2. Resistance of butt joint to slow crack growth (SCG) relative to parent pipe material needs to be established as in its current form, the CC does not address this item. The results of some recent tests on a limited scale suggest that the SCG resistance of butt fusion joint is an order of magnitude lower than that of the parent material.
3. Extreme caution should be exercised during installation introducing surface flaws, scratches, and surface damage, etc. which can become the sources for brittle fracture at operating conditions.
4. The wall thickness for HDPE piping is much thicker than carbon steel piping. For HDPE piping, the D/t ratio is <<20. The use of more accurate (thick wall) pressure vessel formulas is more appropriate than thin wall vessel formulas.

5. HDPE material properties are substantially different from those for carbon steel. Such a substantial difference can lead to significant thermal gradient stress, based on thin or thick wall formulas. However for PE piping, thick wall formulas are more appropriate; thickness (2" to 4" for HDPE vs. 0.375" for steel pipe), alpha (1E-4 for HDPE vs. 6.5E-6 per degree F for steel), and thermal conductivity (0.5 for HDPE vs. 30 BTU/hr-ft-F for steel). Due to relatively higher wall thickness, high thermal expansion coefficient, and poor thermal conductivity of HDPE material, heat transfer in the radial direction will be relatively slow resulting in thermal gradients in the thick wall of HDPE piping. Therefore, the thermal gradient stresses could be significant in the thick wall of HDPE piping and should be accounted for.
6. The Code Case should address evaluations for the cumulative effect of load applications when loads of different durations are encountered. Either a conservative evaluation or an equivalent Miner's Rule type evaluation is required when loads of different duration are applied.
7. It appears that the modulus of elasticity for PE materials is dependent not only on temperature, and time but also on the stress level. There is a need to establish the effect of stress on the value of Apparent Modulus and determine if the CC-N755 Rev 1a Modulus values are conservative lower bound values.
8. There is a need for creep data (strain vs. time) and modulus for PE 4710 materials at stresses and temperatures of interest as the PE materials exhibit creep at much lower temperatures compared to metallic materials. Long term creep data is required to establish the safe allowable stress.
9. Models used for service life prediction for PE parent and fusion joint materials at elevated (and varying) temperatures, sustained stress, and with an allowable flaw need modifications, based on the use of accelerated testing data.
10. Concern related to the resistance of PE4710 to thermal aging. Euro standards have lower allowable temperature limits for 50 years of service due to thermal aging. Basis to provide evidence that PE4710 is resistant to thermal aging at the service conditions in N-755 needs to be developed.
11. Backfill: The code case should specify the requirements for backfill for buried HDPE Pipe. In accordance with NUREG-1801, Rev. 2, Backfill is consistent with National Association of Corrosion Engineers (NACE) standard SP0169-2007 Section 5.2.3. The staff considers backfill that is located within 6 inches of the pipe that meets ASTM D 448-08 size number 10 to meet the objectives of SP0169-2007. The staff also considers the use of controlled low strength materials (flowable backfill) to meet the objectives of SP0169-2007. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections. Backfill not meeting this standard, in either the initial or subsequent inspections, is acceptable if the inspections conducted do not reveal evidence of mechanical damage to pipe coatings due to the backfill.

(B) Material, Fabrication, and Examination Related Issues:

1. Essential Variables:

   The Code Case currently has only two essential variables for the fusion procedure performance demonstrations and an incomplete list of essential variables for the pre-qualified fusion procedure. The Code has several definitions for the term essential variables. In simple terms, any change that affects the integrity of the fused joint is an essential variable. Examples of missing essential variables are equipment, pipe wall, and pipe diameter. Some essential variables are open to subjective measurements such as fusion bead size and cool down temperature under fusion pressure. Changes to equipment control settings, equipment interchangeability, internal thermal conductivity of HDPE (type of material or time), external environment temperature, external process temperature, wall thickness and diameter (cross section temperature-pressure gradient), fusion cycle pressures, fusion cycle times, and fusion process are obvious variables. The Code Case should incorporate the missing essential variables, and replace subjective measurement with actual measurement or explain the omission of items/variables that have an influence on joint integrity and explain the use of subjective measurements for essential variables referenced in the Code Case.

   The Code Case currently has only two essential variables for the fusion procedure performance demonstrations and an incomplete list of essential variables for the pre-qualified fusion procedure. The Code has several definitions for the term essential variables. In simple terms, any change that affects the integrity of the fused joint is an essential variable. Examples of missing essential variables are equipment, pipe wall, and pipe diameter. Some essential variables are open to subjective measurements such as fusion bead size and cool down temperature under fusion pressure. Changes to equipment control settings, equipment interchangeability, internal thermal conductivity of HDPE (type of material or time), external environment temperature, external process temperature, wall thickness and diameter (cross section temperature-pressure gradient), fusion cycle pressures, fusion cycle times, and fusion process are obvious variables. The Code Case should incorporate the missing essential variables, and replace subjective measurement with actual measurement or explain the omission of items/variables that have an influence on joint integrity and explain the use of subjective measurements for essential variables referenced in the Code Case.

   The Code Case places a low temperature design limit of minus 50ºF on HDPE pipe. The low temperature design limit may not be applicable for a low temperature fusion limit; however, in the absence of a stated low temperature fusion limit, the low temperature design limit may inadvertently be used as a low temperature fusion limit. The low temperature fusion limit is an essential variable which the Code Case needs to consider in the performance-based demonstrations or the reason for excluding it should be explained.
2. Performance Demonstration Qualifications:

   Performance demonstrations are necessary to validate capability, and repetitions are necessary to statistically establish reliability. Section XI, Appendix VIII and Section V, Article 14, intermediate rigor are examples of the performance demonstration concept for ultrasonic examination procedure, equipment, and personnel qualifications. Performance demonstrations for the fusion procedure and associated equipment and nondestructive examination qualifications are necessary. Performance demonstration qualifications apply to joining pipe-to-pipe, pipe-to-fitting, and fitting-to-fitting.
3. Fusion Procedure and Equipment Qualifications:

   The qualification must be performance-based with the essential variables being demonstrated at their range extremes. The demonstrations must contain representative configurations,

pipe and fitting sizes, environment conditions, fabrication process, and equipment, and material. The qualification testing records must be accessible and readily retrievable. Qualification of the fusion procedure and equipment for all the essential variable range extremes is required.

4. Visual and Ultrasonic Testing Qualifications:

   The qualification must be performance-based with the essential variables being demonstrated at their range extremes. The demonstrations must contain representative configuration, pipe and fitting sizes, environment conditions, fabrication process and material. The demonstrations should have a statistically significant number of areas without (acceptable) flaws and areas with unacceptable flaws. The qualification testing records must be accessible and readily retrievable. Records should contain sufficient detail to evaluate flaw type and distribution, to evaluate representativeness of test specimens, and to evaluate testing effectiveness. The Code Case should qualify the NDE procedure, equipment, and personnel using performance demonstrations.

5. Examinations:

   In-service joint failures are usually attributed to volumetric flaws in the vicinity of the failure.

   To validate joint integrity and minimize in-service joint failures, visual/surface and volumetric nondestructive examinations (NDE) following fabrication should be performed on the joint and adjacent base material. Combinations of different NDE methods should be considered for configurations not easily examined with a particular method. When necessary, access should be provided for examinations performed from the inside surface to achieve inspection coverage. Surface conditions should be stipulated for the different NDE methods. Appropriate and detailed examination records (raw data) should be maintained for future references. The visual examination may be insufficient to detect the variety of flaws that have an influence on joint integrity.

30.5.5 References

1. Special Design Considerations for Buried HDPE Piping in Nuclear Safety Related Applications, Chakrapani Basavaraju, and Kamal A. Manoly, PVP2009-77747, Proceedings of PVP2009, ASME PVP 2009 Conference, July 26–30, 2009, Prague, Czech Republic.
2. ASME Boiler and Pressure Vessel Code, Section III: Rules for Construction of Nuclear Facility Components, Section II: Materials, ASME 2007.
3. Use of Polyethylene (PE) Plastic Pipe, Sections II, Division I and XI, Code Case N-755, ASME, NC-Supp. 1, 2007.
4. ASME Code for Pressure Piping, Power Piping, Appendix III, Nonmandatory Rules for Non-metallic Piping, ANSI/ASME B31.1-1986 Edition, A86.
5. Timoshenko, S.P., and Goodier, J.N., *Theory of Elasticity*, McGraw-Hill, Third Edition, N.Y., 1970.
6. Young, W.C., and Budynas, R.G., *Roark's Formulas for Stress and Strain*, Seventh Edition, McGraw-Hill, N.Y., 2002.

30.6 LESSONS LEARNED – BWR STEAM DRYERS FOR EPU OPERATION

Steam dryers in Boiling Water Reactors, located in the upper steam dome of the reactor pressure vessel, are not pressure retaining components and are not designed and constructed to the provisions of Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. As such, these components do not correspond to any specific safety class referenced in the Code. Although the steam dryers in BWRs perform no safety function, they must maintain the structural integrity in order to avoid the generation of loose parts that may adversely impact the capability of other plant equipment to perform their safety functions. Therefore guidance from Section III of the ASME Code is utilized in the design and fabrication of replacement dryers as well as for design modifications of the existing dryers for extended power uprates. Located above the core and steam separator within the reactor pressure vessel, the steam dryer is a crucial component that removes excess moisture from steam produced in the plant's reactor before it is delivered into the turbine-generator units to produce electricity. Steam quality is very important for efficient operation of the steam turbine as well as to prevent damage to the steam turbine blades. The majority of licensees of operating nuclear plants are applying for EPU, which generally increases the thermal power output to 20% above the original licensed thermal power. Nuclear power plant components such as steam dryers can be subjected to strong fluctuating loads and can experience unexpected high cycle fatigue due to adverse flow effects while operating at EPU conditions. However, there are some unique challenges related to steam dryer operation at EPU conditions requiring special considerations to prevent fatigue damage from the effects of flow induced vibration. The issues and lessons learned related to FIV considerations during EPU reviews of BWR steam dryers are summarized below based on information from papers by Basavaraju et al. [1,2].

The issue of fatigue cracking became very significant while the Quad Cities Unit 2 (QC2) plant was ascending to EPU power for the first time. The issue persisted even after the steam dryer replacement. After EPU implementation in 2002, steam path component vibration induced problems began to escalate in Quad Cities. Finally, the issue was resolved only when acoustic mitigation devices were installed.

To ensure structural integrity of the steam dryer for EPU conditions, a majority of BWR plants have made significant steam dryer modifications, installed acoustic mitigation devices, or replaced the steam dryers.

30.6.1 Acoustic Resonance

Consideration for acoustic resonance in BWR steam dryer evaluations in EPUs came into prominence after QC steam dryer experience. The SRVs are attached to short standpipes branching off the MSLs. The SRVs are normally closed and therefore the connected standpipes contain a stagnant column of steam that is exposed to turbulent steam in the MSL flowing past the standpipe opening. Flow past a valve entrance cavity such as those for SRVs in MSLs can excite a standing wave resulting in vibration and noise. As flow passes over stagnant SRV standpipes, vortices develop causing pressure pulsations. As reported by Baldwin et al. [3], and Hambric et al. [4], these pulsations and vibrations can be greatly amplified if acoustic or structural resonance occurs. Ziada et al. [5] indicated that the pulsation amplitudes generated by acoustic resonance can be several times higher than the dynamic head in the main process pipe. This means that it is much higher than the velocity square effect. Acoustic resonance occurs when the acoustic standing wave frequencies in the MSL SRV branch pipe coincide with fluid shear wave vortex shedding frequencies. As described by Rockwell et al. [6], flow excited acoustic resonance is a fluid resonant mechanism and is generally

due to unstable separated flows such as shear layers. On the other hand, a fluid dynamic mechanism generates self sustained oscillations of impinging shear flows in the absence of resonance effects.

For the acoustic standing wave, the normally closed end of the standpipe where the SRV is connected is a node, and the mouth or the end of the standpipe connected to the MSL is an antinode. Therefore the length (L) of the standpipe corresponds to the quarter of the wavelength ($\lambda/4$) for the fundamental mode of the acoustic standing wave. Similarly for the second acoustic mode, (L) corresponds to three quarters of the wave length; for the third acoustic mode, (L) corresponds to five quarters of the wave length and so on.

Thus for the nth mode, $\lambda = 4L/(2n - 1)$ where n is an integer. The acoustic wave speed (c), frequency (f_a), and the wavelength are related by the well known equation:

$$c = f_a (\lambda) \tag{30.44}$$

For the first, or fundamental mode, of the standing acoustic wave, which is the important mode for steam dryer evaluations, the frequency of acoustic standing wave is: $f_a = c/\lambda = c/(4L)$. In typical BWR steamlines, the steam pressure, temperature, steam quality, and sonic velocity are approximately 1050 psia, 550°F, 99.5%, and 1600 ft/sec, respectively.

As described by Ziada [7], Ziada et al. [5], and Hambric et al. [4], the steam flowing in the MSLs separates at the leading edge of the branch pipe, such as SRV standpipe opening, and a shear layer forms. The steam flow passing over the standpipe opening creates vortices that produce pressure pulsations. While many other plant-specific conditions have influence, flow instability occurs over a specific range of Strouhal numbers $\{S = f_1(d + r)/v\}$ when the wavelengths of the vortices coincide with the branch or standpipe opening diameter (d). In this expression, r is the corner fillet radius for the branch opening. When the shear layer vortex shedding frequency (f_1) coincides with the acoustic standing wave frequency (f_a), that is when $c/(4L) = S*v/(d + r)$ acoustic resonance occurs.

30.6.1.1 Single and Double Vortex Acoustic Resonances Hourigan et al. [8] and Stoneman et al. [9] characterized acoustically-coupled shear layer oscillations in terms of the number of vortices formed in the shear layer during a typical oscillation cycle. From their studies, Erickson et al. [10] concluded that high velocity flow in a pipe with a side branch causes substantial tone generation by virtue of the interaction of the shear 1ayer with the resonant cavity. The frequency of the oscillation is determined by the fundamental mode (quarter wavelength) of the cavity. The amplitude is determined by the speed of flow in the pipe. Apparently, the feedback mechanism is such that for lower velocities a double vortex structure exists on the shear layer which drives the cavity flow at its resonant frequency. The coupling is such that strong reinforcement of the shear layer mode occurs. At higher velocities it is evident that strong feedback from the resonant cavity occurs such that a single vortex structure exists on the shear layer. This is the lower shear layer mode and typically results in the strongest coupling. Based on flow visualization studies, Ziada [24] determined that the first mode, which constitutes a quarter wave-length along the branch, is excited over two different ranges of Strouhal numbers. The main resonance is initiated at S = 0.5, and it is excited by the first mode of the shear layer instability, which develops a single vortex between the separation and impingement location. The weaker resonance is excited at S = 0.85 by the second mode of the shear layer instability with two vortices forming along the branch mouth.

There are in-vessel sources (typically low frequency hydrodynamic flow over the steam dryer) as well as external sources (main steam line safety relief valve stand pipe resonances-high frequency loading, MSL closed branches, MSL deadlegs, vibratory loads from recirculation pump vane passing frequencies, etc.) that load the steam dryer.

30.6.2 Acoustic Mitigation Device

The effect of vortex shedding in the vicinity of SRV stand pipes in MSLs could potentially trigger acoustic resonance. The severity of fluctuating pressure pulsations due to acoustic resonance propagating in the steam path has the potential to damage the steam dryer and steam path components. Approaches to mitigate this acoustic resonance, as reported by DeBoo et al. [12], include changing the standpipe diameter, reducing the standpipe effective diameter by placement of inserts, shortening of SRV standpipe lengths, and installation of acoustically tuned ASBs in the standpipes. The ASB increases the effective length of the relief valve branch line resulting in a shift or decrease of the acoustic standing wave frequency. This in turn causes the acoustic excitation from the SRV branch pipe opening shear layer instability to occur at lower MSL velocities corresponding to lower thermal power levels. The ASBs are filled with fine screen material to absorb the acoustic pressure waves from relief valve disk seats. Thus the ASBs provide a damping effect to the acoustic energy input into the system. The performance of the ASBs depends on the effective length of the acoustic chamber and the fine screen material. In the long term there is a possibility that debris might accumulate and block the ASB. In summary, it should be noted that the installation of ASBs (a) increases the effective length (L) of the ERV/SRV standpipes, decreasing the acoustic standing wave frequency (f_a), (b) does not alter the vortex shedding frequency at a given power level, but the acoustic and vortex shedding frequencies are no longer coupled, so that resonance does not occur, and (c) causes the acoustic signal or vortex shedding exciting the acoustic standing wave to occur at a lower plant power level (that is at a lower MSL steam flow velocity). It is emphasized that the proper design, tuning and performance effectiveness of the ASBs need to be established by testing for the plant specific requirements and application.

30.6.3 Steam Dryer Margin

The BWR steam dryers are subject to transient dynamic pressure loading under EPU conditions. These loads have the potential to cause high-cycle fatigue failure and generate loose parts, challenging the functionality of the safety components, such as safety relief valves. The pressures acting on the steam dryer are currently estimated from the real-time measurements of acoustic pressures from the main steam line strain gages. The computer codes using an acoustic model transform the measured acoustic pressures from the main steam lines into the pressures acting on the steam dryer. This method of estimating the steam dryer pressures using the MSL strain gage data is not only a remote sensing method but also an indirect method and introduces several uncertainties and bias errors in the magnitude of estimated loads acting on the steam dryer and, therefore, in the assessment of the structural integrity of the steam dryer.

Therefore, the NRC staff has implemented the following two recommendations: (1) The use of the acoustic codes should be consistent with the procedures used in the previous benchmark

plant data. (2) At the projected EPU conditions, a minimum of 100% margin at the location of maximum fatigue stress of the steam dryer from FIV loading should be maintained to address the unknown uncertainties and bias errors when relying on remote and indirectly obtained (from plant specific MSL strain gages) data for steam dryer qualification.

30.6.4 Issues and Lessons Learned

During review of recent license amendment requests for EPU operation of BWR steam dryers and operating experience from the plants that have implemented EPU, several issues came to light and the lessons learned from those issues related to steam dryer evaluations are outlined here for use in future dryer evaluations. The lessons learned fall in to areas such as bias errors & uncertainties, instrumentation, fabrication, installation, quality control, and analytical methods used to determine FIV loads, monitoring, and other areas.

30.6.4.1 Bias Errors and Uncertainties Related

- The applicability of bias errors and uncertainties based on benchmarking of the General Electric Hitachi parallel vane bank dryer design to other dryer designs, such as Nordic dryer designs with panels arranged in a concentric polygon shape has to be established prior to their use.
- Bias errors & uncertainties for the acoustic codes used for dryer load prediction should be based on consistent approaches (such as filtering of plant noise, electrical noise) used between benchmark plants and the plant to which these bias errors and uncertainties are applied. The dryer designs for the benchmark plant and the plant under evaluation must be similar.
- Bias errors and uncertainties; from all known sources such as (1) frequency range dependent bias errors and uncertainties for acoustic codes (2) pressure measurement (strain gages) uncertainty; (3) pressure sensor location uncertainty; (4) pressure sensor measurement on dryer (for benchmark plant); (5) FEA mesh discretization bias error; (6) Discrete frequency error; (7) FEM modeling simplification uncertainty.

30.6.4.2 MSL & Dryer Instrumentation Related

- In order to preclude any electromagnetic interference, the drywell penetrations used for routing cables from on-dryer instrumentation and main steam line strain gages to data acquisition systems should not be in close proximity to the penetrations through which electrical cables for other equipment such as recirculation pumps drywell cooling fans are routed. The cables must be properly rated for their application and the environment.
- MSL mounted strain gages seem to under-predict the pressure loading and the under-prediction factor based on in-plant static pressure tests needs to be considered.
- Direct measurement of internal pressure fluctuations inside MSL pipes is by pressure transducers which require cutting into the pressure boundary of the MSLs. Indirect measurement of internal pressure fluctuations inside MSL pipes is by external mounting of strain gages on MSLs. Instrumenting the steam dryer with pressure transducers, strain gages, and accelerometers at reasonable locations provides direct measurement of dryer pressure loading, dryer strains, and accelerations, but is impractical for existing dryers in operating plants due to radiation doses.
- At least two axial locations on each MSL are recommended for strain gage installation.

  The selected locations should be such that they do not coincide with nodes (zero pressure amplitude location) for an acoustic mode.
- In order to eliminate the effect from pipe bending modes, which do not contribute to acoustic pressure fluctuations from breathing modes, at least four circumferentially mounted strain gages at 90 degrees apart are required for each location on MSLs. To improve the signal to noise ratio, the optimal location for strain gages is an odd multiple of quarter wave length.
- Careful consideration should be given to the potential for instrumentation failures and need for redundancy. Due to plant vibrations and environment and improper or loose mounting, the MSL mounted strain gages can fail, and therefore eight circumferentially mounted strain gages at 45 degrees apart are recommended for each location on MSLs. Data from on-dryer instruments should be obtained at the earliest opportunity.

30.6.4.3 Analytical Methodology Related

- The loading on the dryer consists of in-vessel sources, external sources, and non-acoustic sources. Low frequency hydrodynamic pressure loading on the dryer surface due to shedding of the vortices of steam flow passing over the outer hoods of the dryer toward the MSL inlet nozzles is an in-vessel source. External sources may include acoustic sources from SRV standpipe resonances, MSL dead-legs, blind spare standpipes in MSLs, other stagnant sections of pipes such as RCIC lines under off normal situations. Other sources of dryer loading may include vibratory loads due to recirculation pump vane passing frequencies.
- Off-normal loading conditions associated with the operational lineup of the RCIC system. With RCIC isolation valve closed, this can introduce a tone at a specific frequency not seen in normal lineup.
- The steam dryer structural evaluation should consider structural response up to 250 Hz frequency since in-plant measurements (i.e., QC2) using on-dryer instrumentation have shown no structurally significant pressure load content above 250 Hz.
- Due to many uncertainties in the predictive analysis, a margin of 100% is recommended for maximum alternating dryer stress from FIV at the projected EPU conditions when relying on remote or indirect (MSL SG) measurements.
- The structural FEM should be properly verified for (i) dimensions against fabrication drawings, and (ii) for nodal and elemental connectivity and (iii) element mesh size.
- When detailed submodels are used to capture the effects of the localized details, they should be validated for acceptability and verified for the appropriate loads and boundary conditions imported from the global structural finite element analysis.
- Solid-to-Shell transition modeling using overlay or painted shell elements should be justified and properly validated against currently available techniques for modeling of transition regions.
- CLTP to EPU projection scaling factor of not less than MSL steam flow velocity ratio square (if no acoustic resonances), and much higher factor if acoustic resonances are present, established from SMT or MSIV closure tests, or data collected from operating plants with similar resonances.
- Plants considering EPU must assess the steam dryers for first shear layer mode driven acoustic resonance (Strouhal number

range between 0.3 and 0.6) and second shear layer mode driven acoustic resonance (Strouhal number range between 0.8 and 1.0) at SRV stand pipes. These are plant-specific and are dependent on power level, MSL steam flow velocity, sonic speed, and SRV standpipe dimensions.

- The reactor dome pressure (pressure regulator setting) and core flow also affect dryer pressure loading and dryer stresses. As such, their variations during various plant power levels must be considered.
- Appropriate weld factors for stress concentration effects should be applied to the stresses from structural FEA of steam dryer accounting for all types of welds (full penetration, partial penetration, and fillet welds) and their locations based on fabrication drawing of the dryer. In addition, any applicable under size weld factor must also be considered for under size fillet and partial penetration weld locations.
- Acoustic FEM should be verified for geometrical accuracy comparing with as-built drawings. The industry guidance on mesh size in acoustic finite element models of at least six elements per wavelength should be followed.
- The reactor recirculation pump VPF can cause equipment vibration. The contribution from vibratory loads caused by recirculation pump VPF to dryer stresses is plant specific. The measurements made on an operating plant attributed the cracking of an inner bank hood panel on a steam dryer to VPF loads. Therefore, consideration of VPF effects is important and filtering of VPF signals is questionable. The separate paths (direct and indirect) for transmission of VPF loads to a dryer are presented in Table 1. VPFs are affected by recirculating pump flow control methods (constant versus variable speed). Variable speed pumps are more likely to generate VPF vibration due to the presence of many exciting VPFs.

30.6.4.4 Fabrication, Installation, & Quality Control

- Tri-junction welds where components of significant thickness difference, such as the support ring, skirt, and seismic block, in close proximity of welds with overlapping heat affected zones should be avoided as the stress concentration at such junctions is difficult to quantify and result in high stress location leading to high cycle fatigue cracking.
- Stitch welds are not to be used for structural connections. There is a potential for non-structural attachments with stitch welds becoming loose parts.
- During fabrication and on-site final assembly welding of the dryers, proper quality control measures must be implemented to prevent introducing cold work and residual stresses into the dryer material. Adequate procedures must be in place and followed during installation of dryers to ensure proper fit-up avoiding any cold work and residual stresses.
- Not following proper procedures related to shop inspection, field inspection, welder training, quality control during manufacturing, and guidance from BWRVIP-84 on smooth polishing after grinding and cold work could lead to dryer cracking.

30.6.4.5 Monitoring

- The development of Limit Curves for use during power ascension should be based on maximum alternating stress from predictive analysis of the steam dryer included in the EPU request using measured data at CLTP to reach 13,600 psi for level 1 during power ascension for each MSL strain gage location or on-dryer instrument location. For level 2, the stress limit is 80% of 13,600 = 10,800 psi. Limit curves need to be updated during power ascension using actual strain gage data at the previous power level for use at the next power level.
- In addition to dryer performance monitoring through plant parameters such as moisture carryover, valuable information can be gleaned from flow imbalances in the MSLs, monitoring of the plant piping vibrations and SRV vibrations through SRV body mounted and actuator mounted accelerometers.

30.6.4.6 Others

- Hammer tests on steam dryers provide information to validate the dynamic behavior such as frequencies and mode shapes of dryer components obtained from structural FEA. Shaker tests on steam dryers provide information to obtain B&Us due to FEM simplifications.
- SS fatigue curves A & B (in high cycle range) were eliminated in the 2010 Edition of the ASME Code. Only one curve was retained (Curve C in the prior editions of the Code) because it is difficult to quantify the mean stress (equal to the fabrication stress) in base material, and the mean stress (which is the residual stress of as much as yield stress) in the weld. If code versions prior to 2010 edition are utilized in steam dryer FIV evaluation, the curve C based fatigue limit of 13,600 psi for stainless steel at 1011 cycles should be utilized.
- Any existing Flaws in steam dryer should either be repaired or evaluated for acceptability for operation at EPU.

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30.7 RPV INDICATIONS IN DOEL & TIHANGE NPP

Current understanding – Some 8000 quasi-laminar indications found in Reactor Pressure Vessel (RPV) ring forgings found in Doel-3 NPP and some 2000 quasi-laminar indications found in Tihange-2 NPP are of a size, shape and nature that are structurally insignificant (oriented nearly parallel to direction of applied stress) and considered acceptable according to the ASME Code, Section III. Most of these indications are in upper and lower core shell with a few in vessel head flange, vessel flange, nozzle shell, and transition ring [1].

- Flaws in the core shells observed up to a depth of 100 mm from the ID; however, most of the flaws are located between 20?70 mm (first half of shell thickness)
- Flaws are circular discs with a typical diameter of 10 mm
- Flaws are laminar but not clustered

30.7.1 Hydrogen Flaking

- Belgian Regulator Federal Agency for Nuclear Control (FANC) and the NPP owner determined that the most likely origin of the indications is hydrogen flaking.
- Hydrogen flaking caused failures of forgings such as turbine shafts which are very thick components compared RPV shells.
- Hydrogen flakes are flat discontinuous internal fissures caused by stresses and decreased solubility of hydrogen during cooling.
- Generally numerous and found in bands near the center of a forging, not close to surfaces.

Factors Influencing Steel's Sensitivity to Flaking

- High strength steels – Reactor vessel steels not in this category
- Thick parts – Turbine rotor shafts are much thicker than reactor vessel shells
- Cleaner steels with lower sulfur, oxygen content create fewer inclusions, causing each inclusion to have a greater H concentration

High H content in ingot or forging may be due to

- Inadequate degassing
- For non-degassed steels, lack of de-hydrogenation heat treatment
- Tolerable H concentration depends on flaking sensitivity of the steel
- Cooling too fast after forging

Countermeasures for flaking

- Special heat treatments to reduce hydrogen
- Controlled cooling practices for forgings
- Vacuum degassing

30.7.2 Reference

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30.8 STEAM GENERATOR TUBE LEAKS

Lesson Learned: Steam Generator tubes need to be evaluated for as-built conditions for susceptibility to flow induced vibration. A minor change in gaps or clearances can have a significant impact.

30.8.1 Steam Generator Tube Leak

It was determined that the two replacement steam generators installed in San Onofre Unit 3 contained a minor manufacturing feature that resulted in a "perfect pitch" harmonic. At just the wrong condition – 100% steam flow – a combination of relatively dry steam, precisely manufactured anti-vibration bars (AVB), and densely packed u-tubes resulted in a few hundred (out of nearly 10,000) tubes vibrating with a large enough amplitude to make contact. The unexpected vibration and contact resulted in accelerated wear and caused one tube to fail while the steam generator was operating. Surprisingly enough, the reason that the condition does not exist in Unit 2 is that the anti-vibration bars (AVB) in Unit 2 were made less precisely preventing the perfect pitch situation. Instead of being virtually perfectly round holes through which the steam generator tubes could penetrate with tight tolerance but no contact, the AVB's in unit 2 had enough manufacturing variation that they made contact with the penetrating tubes with an average force that was twice as high as the minor, incidental contact achieved in Unit 3.

All of the tubes with tube-to-tube-wear (TTW) are located in the region of highest average void fraction, where velocities are highest and damping is lowest. Both Unit 2 and Unit 3 have the same thermal hydraulic conditions. The tube-to-AVB contact forces in the Unit 3 RSGs are smaller by a factor of two than those of the Unit 2 RSGs. Almost all of the TTW tubes were found in the Unit 3 replacement steam generators (RSGs). The difference in the contact forces explains this large difference between the two units.

30.8.2 Root cause Analysis

The root cause analysis team used a systematic approach to identify the mechanistic cause of the tube-to-tube wear including Failure Modes Analysis and Barrier Analysis. The team identified a list of possible causes and then using supporting and refuting facts identified areas warranting more detailed analysis, including primary flow induced vibration, divider plate weld failure, fluid elastic instability (FEI), fabrication/manufacture, shipping, and thermal-hydraulic conditions.

The mechanistic cause of the tube-to-tube wear was identified as FEI, involving the combination of localized high steam/water velocity (tube vibration excitation forces), high steam void fraction (loss of ability to dampen vibration), and insufficient tube to AVB contact forces to overcome the excitation forces.

30.8.3 Conclusions

That extra contact force, which was considered to be undesirable by the designers at the time they designed and manufactured the tubes, provided enough unplanned disruption to the tube bundle that the harmonic vibration could not get started and could not reach enough of an amplitude to cause tube to tube wear (TTW).

It is instructive to learn that the tighter tolerances in unit 3 were purposely chosen because the supplier was seeking continuous process improvement. MHI engineers had determined that a small change in the manufacturing process could improve the repeatability of the AVB holes. The design team agreed that the tighter

tolerances resulted in a design that was "significantly more conservative than previous designs in addressing U-bend tube vibration and wear.

Because the computer models used for the design process were not perfect fidelity reproductions of the complete environment of the steam generator, simulation runs did not reveal the potentially detrimental effect of the tighter tolerances.

Thus the likely cause of the slight simulation infidelity condition was a limited data set. The San Onofre steam generators are different from any other steam generator that the company has produced; the only ones that are remotely similar are those at Fort Calhoun. Even those generators have major differences, including substantially different sizes. MHI has manufactured dozens of nuclear power plant steam generators that are reliably operating around the world, but they use a design that could not meet the requirements for installation into the San Onofre units.

30.8.4 Reference

1. Root Cause Analysis Report for tube wear identified in the Unit 2 and Unit 3 Steam Generators of San Onofre Nuclear Generating Station, Mitsubishi Heavy Industries, UES-20120254, Rev. 0, Redacted Public version. 2012.

30.9 ISSUES FOR NEW CONSTRUCTION

Lessons Learned from Operating plants experience for consideration in new construction are summarized here.

Based on experience with Primary Water Stress Corrosion Cracking (PWSCC), fabrication steps are very important relative to weld residual stress (WRS). Welds that were back chipped and with last pass ID welded have high tensile WRS at the ID region, making them more susceptible to SCC. Welds with oversized lands that are drilled out prior to welding the piping product to the safe end, have much lower WRS in the ID region.

Documentation of weld repairs (weld repair records) made during construction is important and are required for flaw growth analysis performed for mitigations such as weld overlays and mechanical stress improvements.

Enhanced PWSCC susceptibility in the base material adjacent to welds in thick walled Ni-Cr-Fe Alloy 690 is due to micro-structural changes and the introduction of high residual stresses.

PWSCC susceptibility of Alloys 52/152 with weld fabrication defects. The Ni based alloy dissimilar metal welds (DMW) are typically made using Alloy 182 and Alloy 82 with alloy 52 recently introduced in new construction as well as in repair welding. The base material alloy is 690 with Ni-base alloy filler metals (Alloy 82, 182, 52, and 152) for welds.

Design for Accessibility: All components and piping should be able to have 100% accessibility during construction and subsequent In-Service inspections (ISI). The NRC will not entertain relief requests related to accessibility issues during new construction.

Potential relationship of construction repairs to degradation during operation.

Emerging issues:

1. Small Modular reactors (SMR)−Codes and regulatory information needs to be developed.
2. Socket welds have been a continuing problem, and have relatively high failure rates. There have been 111 Licensee Event reports (LERs) since 1980, 31 caused plant shutdown. Increasing leg length to 2-1 on pipe size reduces stresses and fatigue.
3. Emerging issues and operating experience, such as the SONGS steam generator tube rupture issues and the DOEL vessel flaw issues.

Weld residual stress mitigation

- Efforts to reduce weld mitigating residual stresses should not be limited to just weld bead sequencing. There is no Code guidance on residual stress and mitigation after the weld. Efforts may be related to the weld residual stress analysis MRP-316, MRP-317.

Issues for new plants, related to inspectability:

- There is an EPRI report ("Nondestructive Evaluation: Guideline for Inspectability for New Plant Components" 1015139) that provides some guidance on inspectability.

Lessons Learned:

- Fabrication processes, such as forming, machining, grinding and polishing, can induce high levels of cold work (CW) in critical reactor components if not properly controlled.
- Improper cold work (CW) controls can significantly reduce the SCC resistance of austenitic materials in the reactor circuit.
- In some cases welding best practices may not be adequate to keep residual stresses to an acceptably low level and residual stress (RS) mitigation is needed to maintain high SCC resistance.

CHAPTER

31

POWER AND PROCESS PIPING LESSONS LEARNED

Jimmy E. Meyer

31.1 INTRODUCTION

Over the past 40 years piping designed to either the ASME B31.1 Power Piping Code or the ASME B31.3 Process Piping Code has proved it will perform well. That being said, why are there still failures in the industry? This chapter will attempt to review some significant failures or more common types of failures and provide some guidance on how they can be avoided. The design rules have proved adequate and have significant margin for safety if all of the design requirements have been identified. This is proving to be no small task and involves the original design as well as operations and maintenance activities.

31.2 SEAM WELDED PIPE IN THE CREEP RANGE

31.2.1 Seam Welded Pipe in the Creep Range

This is the worst example of where the Code Rules did not adequately protect or warn the user of the potential failure. Two failures occurred around 1985 and the Code rules have since been modified to correctly identify the issue. Both the ASME B31.1 Power Piping Code and ASME B31.3 Process Piping Code have added a weld strength reduction factor "W" to the wall thickness calculation equations for piping which is operating in the creep range. For ASME B31.1, this is paragraph 104.1.4 and Table 102.4.7. [1], For ASME B31.3 the requirements are found in paragraphs 304.1, 304.2 and Table 302.3.5 [2].

The basic problem was welded piping operating in the creep range where the weld properties accelerated the creep damage along the weld line/heat- affected zone leading to premature failure which could occur without warning in a catastrophic manor. The Creep Rate can be significantly affected by minor changes in operating temperature, so both design and operations must be aware of the risks and take appropriate precautions for systems operated in the Creep Range. More on this subject can be learned from the following references.

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16. J.F. Henry, F.V. Ellis, and C.D. Lundin, "The Influence of Flux Composition on the Elevated Temperature Properties of CR-MO Submerged Arc Weldments", Welding Research Council Bulletin 354, June 1990

17. Gregory V. Thorwald, and Ted L. Anderson, "Studies of Local Differences in Material Creep Properties on Weldments, Part 1, Finite Element Case Study of Local Stress Effects in Long Seam Welded Piping", Welding Research Council Bulletin 475, September 2002

18. Carl D. Lundin, and Peng Liu, "Studies of Local Differences in Material Creep Properties on Weldments, Part 2, Determination of Creep Behavior of Singular HAZ Regions to Model the Behavior of the Entire HAZ of CR-MO Steels (ASME T/P11, T/P91, T/P92, T/P122) in Elevated Temperature Service", Welding Research Council Bulletin 475, September 2002

19. J.R. Foulds and R. Viswanathan, "Graphitization of Steels in Elevated Temperature Service", Microstructures and Mechanical Properties of Aging Materials, The Minerals, Metals, and Materials Society, 1993, p. 61–69

31.3 EXPANSION JOINTS

31.3.1 Expansion Joints

Expansion joints are used as one method to increase the flexibility of a piping system. There are a number of different types of joints, and the Codes warn of some potential pitfalls. Table 31.1 lists a number of different types of expansion joints along with advantages and disadvantages with each type.

Despite the warnings, a misunderstanding of the issues with expansion joints and more specifically the pressure thrust from them resulted in one of the major industrial accidents of our time which is described in more detail below. All of the major expansion joint manufactures provide information on how to calculate and control the pressure; thrust, from their products; however, the author still finds this subject is not well understood by many in the industry. Many expansion joints are provided with control hardware to handle the pressure thrust, however installing and maintenance personnel do not fully understand the magnitude of this thrust and how the hardware must be maintained or adjusted. Figure 31.9 is included later in this chapter to provide an example of how large diameter piping can fail under vacuum, but it also provides an excellent view of how large the tie-rods (control devises) are for even relatively low pressure systems. Note the figure is a pressure-balanced bellows where an additional bellows is added out of the main process stream to

TABLE 31.1 ADVANTAGES AND DISADVANTAGES OF DIFFERENT TYPES OF EXPANSION JOINTS

Types of Expansion Joints	Advantages	Disadvantages/Limits
Bellows	No Packing Leaks Inexpensive Custom Fabrications Quickly	Pressure Thrust Cannot Take Torsion Limited Pressure to generally below 300 psig
EJMA Standards — (Expansion Joint Manufacturers Association)	High Temperatures Many Control Options	
Slip or Packed	High Pressure Allow Torsion Limited Stop on Movement Slightly Less Pressure Thrust	Expensive Alignment is critical Packing Can Leak
Ball	High Pressure No Pressure Thrust Allow Torsion	No Axial Movement No Lateral Movement Expensive Packing Can Leak
Fabric	Flexible Inexpensive Square or Round Large Sizes	Low Pressure < 1 psig Temperature Limits Not Applicable to Pressure Piping (15 psig) Very Stiff
Flanged and Flued (usually limited to Heat Exchangers)	High Pressure	
Rubber	Abrasion Resistance Vibration Isolation	Temperature Limits Some Code Limits for Non-Metals like Flammable Fluids
Teflon	Flexible Vibration Isolation	Temperature Limits Some Code Limits for Non-Metals like Flammable Fluids
Victaulic Couplings	Inexpensive Easy to Assemble	Seals Can Leak Limited Movement Limited Temperature

balance the pressure thrust from the other bellows and still permit axial movement.

The major industrial accident noted above was a Caprolactam plant in Flixborough, UK which exploded in 1974 and killed approximately 28 plant workers, injuring many more. The explosion was caused by a temporary 20 inch by-pass line installed with expansion joints on both sides to replace one of the six reactors in the series. The force from the pressure thrust was about 60,000 lbs on the temporary pipe spool which was only supported by scaffolding. Figure 31.1 below shows three of the reactors in the series after the accident and fire. The reactor which was removed is not shown in the photo.



FIG. 31.1 EXPANSION JOINTS INSTALLED BETWEEN EACH REACTOR (Photo from Reference 5)

31.3.2 References:

1. ASME B31.3 Process Piping Code, 2012 Edition Base Code, Appendix F, Para. F304.7.4, and Appendix X
2. EJMA, Expansion Joint Manufacturers Association, 25 North Broadway, Tarrytown, New York 10591
3. Piping Handbook, McGraw Hill, 7th Edition Edited by Mohinder Nayyar, 2000
4. Health and Safety Executive, 'The Flixborough Disaster: Report of the Court of Inquiry', HMSO, ISBN 0113610750
5. Flixborough (Nypro UK) Explosion 1st June 1974COMAH Regulations

31.4 WATER HAMMER/STEAM HAMMER

31.4.1 Water Hammer/Steam Hammer

These are common terms used to identify a number of different flow transients which can cause severe pressure waves or surges in a piping system. As a minimum these can lead to loud noises or banging and worst cases piping failures. Some of the more common types of fluid transients associated with Steam or Water hammer.

* Long pipelines with fast closing valves are one cause, the reader is warned that this phenomenon is not limited to water, it will occur in any non-compressible fluid. A pressure wave is created by the change in momentum of the large column of liquid coming to a sudden stop.
* Mixed flow such as condensate flashing to steam causing slug flow. See reference 4 below.
* Steam condensing suddenly to create a void collapse.
* Void collapse as the result of momentum change where a vacuum/void is created due to flow transient or localized vacuum condition. Once the transient is over, the void collapses and creates the pressure wave.

31.4.2

A recent example of a large scale accident with major loss of life was the 2009 Russian Dam Accident with 76 people killed. See reference 3 below.

31.4.3 References:

1. ASME B31.3 Process Piping Code, 2012 Edition Base Code, Appendix F F301.5
2. Piping Handbook, McGraw Hill, 7th Edition Edited by Mohinder Nayyar, 2000
3. Popular Mechanics Feb. 2, 2010, 'Investigating Russia's Biggest Dam Explosion: What Went Wrong' By Joe P. Hasler
4. New York Times, Published: April 4, 1995, Con Edison Penalized $217,800 for Violating Work Safety Rules in '92 Blast By Matthew L. Wald

31.5 GAS BLOWS

31.5.1 Gas Blows

This is the practice of blowing large quantity of gas through a pipe line to remove dirt and debris from the line prior to putting the line into service. While this practice has been in place a long time, there are a number of inherent risks.

Most recently, there have been a number of major accidents and fatalities associated with this practice when the appropriate precautions have not been taken. Process/Start-up procedures like this are not in the scope of the Pressure Piping Codes; however ASME B31.1 did have some warnings about the temporary piping which might be required for a procedure like Gas Blows [4].

As a result of a request from the Chemical Safety Board, ASME B31.1 Chapter II Part 6 Para 122.10 Temporary Piping Systems and Chapter VIII Para. 138 were revised to clarify the Code does not address flushing or cleaning operations. Since the accidents, NFPA has drafted and published "NFPA 56 (PS): Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems [2].

31.5.2 Recent Incidents

Two of the recent incidents were at a Kleen Energy Combined Cycle Plant in Middletown Connecticut (6 fatalities and 50 injured) and ConAgra Foods meat processing facility in Garner, North Carolina (4 fatalities and 67 injured. Significant information is available on both of these accidents if the reader is interested in the details [3].

31.5.3 References:

1. NFPA 54, National Fuel Gas Code, 2012.
2. NFPA 56 (PS): Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems, 2012.
3. U.S. Chemical Safety and Hazard Investigation Board, 2175 K Street, NW, Suite 650, Washington, DC 20037.
4. ASME B31.1 Power Piping Code, 2012 Edition, Para 122.10, and 138.

31.6 MATERIAL IDENTIFICATION/ VERIFICATION

31.6.1 Material Identification/Verification

When the wrong material gets installed in a piping system, it can lead to major problems and failures. While a slightly lower grade of the same basic material might go by unnoticed for the life of a plant, other type of material substitutions result in sudden failures of piping systems. Examples include carbon steels where the operating temperatures are over 800°F or corrosive services where the incorrect material will corrode away very quickly.

Appendix J of ASME B31.1 provides Quality Control Requirements for Boiler External Piping (BEP). While the requirements for BEP are mandatory, similar requirements apply to Non-Boiler External piping to prove it meets the requirements of ASME B31.1 [1], or the piping is designed and installed to ASME B31.3. ASME B31.3 [2]. Process Piping Code, 2012 In all cases, if a specific material is required in a system, there must be some kind of quality control process to make sure the material is manufactured to the correct specification and the correct material is actually installed in the piping system. These quality control procedures have generally worked well, but there have been problems. For ASME B31.3, additional quality control requirements can be found in Appendix Q – Quality System Program. Both of these programs rely on the Material Test Reports from the Mill where the material was made. They then document the journey of this material through manufacturing, distribution, fabrication, shipping, site storage and finally installation. In critical services, many companies have added the requirement for positive material identification over top of the quality control requirements in the Codes. Examples of problems or material considerations can be found in B31.3 (Reference 2) Appendix F Para. 323 and FA323.4 for non-metals.

In critical services where material selection is critical and the possibility of an error cannot be tolerated, Positive Material Identification (PMI) is a very effective method to verify the correct material has been installed. Many vendors are able to provide this service, or equipment for positive material identification. One example of hand held analyzers to perform this verification is X-ray fluorescence (XRF). This is the emission of characteristic "secondary" (or fluorescent) X-rays from a material which has been excited by high energy X-rays or gamma rays. The phneomenom is widely used for elemental analsysis and chemical analysis, particularly in the investigation of metals. PMI can be added as a final verification after piping has been installed, or it can be used as part of the quality program requirements at any stage of the manufacture, fabrication or distribution.

31.6.2 References:

1. ASME B31.1, Power Piping Code, 2012
2. ASME B31.3, Process Piping Code, 2012
3. Beckhoff, B., Kanngießer, B., Langhoff, N., Wedell, R., Wolff, H., *Handbook of Practical X-ray Fluorescence Analysis*, Springer, 2006, ISBN 3-540-28603-9
4. Bertin, E.P., *Principles and Practice of X-ray Spectrometric Analysis*, Kluwer Academic/Plenum Publishers, ISBN 0-306-30809-6
5. Buhrke, V.E., Jenkins, R., Smith, D.K., *A Practical Guide for the Preparation of Specimens for XRF and XRD Analysis*, Wiley, 1998, ISBN 0-471-19458-1
6. Jenkins, R., *X-ray Fluorescence Spectrometry*, Wiley, ISBN 0-471-29942-1
7. Jenkins, R., De Vries, J.L., *Practical X-ray Spectrometry*, Springer-Verlag, 1973, ISBN 0-387-91029-8

31.7 FLOW ASSISTED CORROSION (FAC)

31.7.1 Flow Assisted Corrosion (FAC)

This is otherwise known as Erosion/Corrosion and resulted in fatalities at the Surry Power Station in 1986. Since then it has been the focus of a lot of research as well as plant inspections. Erosion/corrosion in single-phase piping systems was not clearly recognized as a potential safety issue before this pipe rupture incident. While the incedent was first observed in the feedwater piping for a Nuclear Power Plant, it has since been located in a number of piping systems in both power plants and Chemical and Refinery Piping and susceptable piping should be monitored by the operations and maintenance programs.

ASME B31.3, Appendix F, Precautionary Considerations Para. F323, notes selection of materials to resist deterioration in service is not within the scope of the Code. The reason for this is only the owner of a process can really have the knowledge of all of the materials which they are handling.

ASME B31.1, Nonmandatory Appendix IV, Corrosion Control for ASME B31.1 Power Piping Systems provides a number of different warnings and factors which might affect the errosion/corrosion of a piping system. This appendix also identifies systems and components susceptible to Erosion/Corrosion and recommends monitoring.

ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines [4] and API 579-1/ASME FFS-1 [5], 2007 provide methods for evaluation of piping systems which have reduced wall thicknesses caused by Erosion/Corrosion or other mechanisms.

31.7.2 References:

1. NUREG—1344, "Erosion/Corrosion-lnduced Pipe Wall Thinning in U.S. Nuclear Power Plants," 1989
2. EPRI Report NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," April 1985
3. Piping Handbook, McGraw Hill, 7th Edition Edited by Mohinder Nayyar, 2000
4. ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines
5. API 579-1/ASME FFS-1, 2007

31.8 VIBRATION

There are a number of different vibration problems similar to the Water/Steam Hammer issues. Some of these issues which the designer should be aware of are identified below.

31.8.1 Low-Frequency Vibration

Low-Frequency Vibration (typically less than 10 cycles per second) is primarily associated with long runs of piping with very little support friction. This can occur in vertical lines without adequate guides, or horizontal lines where long hanger rods do not offer any friction or resistance to lateral motions. These lines can develop very large lateral displacements; however, the stresses associated with these displacements are generally low, and this type of vibration will take a much longer time (if ever) to lead to a pressure boundary failure. However, piping with large lateral movements does not make plant personnel comfortable with the safety of their environment and should usually be corrected. This type of vibration has not lead to any failures the author is aware of.

31.8.2 High-Frequency Vibration

High-Frequency Vibration (typically well over 30 cycles per second) is much more likely to be associated with piping failures. Very frequently, this will occur on a small vent or drain valve and some kind of rotating equipment which drives the vibration. This vibration may not be visible to the eye, but the stress associated with it is still there. While the stress may be the same magnitude as the low-frequency vibration, failure results much more quickly because the number of cycles might exceed a million in just 24 hours. As a result, the fatigue limit of the material is reached much more quickly. Also, small vents and drains are commonly attached with fillet welds, or threaded. Both of these act as stress risers for cyclic stresses. The author has seen this lead to piping failures a number of times. Fortunately, these were in steam and water systems where failures tend to leak before they break causing significant damage.

31.8.3 References:

1. ASME B31.1 Power Piping Code, 2012 Edition Para. 101.5.4
2. ASME B31.3 Process Piping Code, 2012 Edition Para. 301.5.4
3. Piping Handbook, McGraw Hill, 7th Edition Edited by Mohinder Nayyar, 2000

31.9 PIPE FITTINGS

31.9.1 Pipe Fittings

The piping Codes discussed here rely on other standards for pressure ratings. One example is ASME B16.9 Factory-Made Wrought Butt welding Fittings. The fittings made to this standard are rated by Burst testing the fitting design against a seamless pipe of the same wall thickness. Tees have been encountered in service which do not appear thick enough to have passed this burst test. In some cases, the tees failed because they were exposed to extreme pressure cycling associated with a descaling operation in a steel mill. The system was exposed to pressures near the limits of the seamless piping. The tees failed after about a month in service. Inspection of the fittings after failure indicated there was very little extra metal to reinforce the crotch area of the tee. The Codes do not provide specific thickness requirements, however they do require a burst test to verify the fittings are at least as strong as the pipe. In this case, it appears these fittings could not have passed a burst test required by ASME B16.9 Para 9.0 Design Proof Test (Figure 31.2).

This 4 in schedule 80 tee had a calculated burst pressure of 10,814 psig and actually failed at 11,900 psig.

Similar to the above, recent testing sponsored by ASME (Reference [4] ST-LLC 07-02) also found some ASME B16.9 tees which did not seem to have enough reinforcing to have passed a burst test.

31.9.2 Stress Intensification Factors (SIF) and Flexibility Factors

ASME B31.1 and ASME B31.3 provide SIF's and Flexibility Factors in Appendix D of both Codes. These factors were developed from research in the 1950s and before [3]. For the most part, they are still used today; however a lot of research has found there are area's where these factors are not conservative. Whether conservative or not, both Codes permit the use of better SIF and Flexibility Factors if they are available. The use of non-conservative SIF's has not produced a lot of failures, or failures which have been catastrophic from a standpoint of loss of life or significant injuries. There appears to be a number of reasons for this as outlined below.

The basis for fatigue analysis in the code is 7000 cycles which equates to approximately one cycle per day over 20 years. Most systems cycle significantly less.

Usually where the SIF is non-conservative, the Flexibility Factor is conservative, or helps reduce the calculated moment creating the stress. This is not always true, but as a general rule, this seems to be one of the factors which are providing some extra margin where the Code provided SIF's are not as conservative as the author would hope.

A recent ASME sponsored study [4] should significantly improve the available SIF's and Flexibility Factors for piping analysis when it is published and incorporated into the ASME Pressure Piping Codes.

31.9.3 References:

1. ASME B31.1 Power Piping Code, 2012 Edition, Appendix D
2. ASME B31.3 Process Piping Code, 2012 Edition, Appendix D
3. Markl, A., "Fatigue Tests of Piping Components," *Pressure Vessel and Piping Design, Collected Papers, 1927–1959*, The American Society of Mechanical Engineers, pp. 402–418, 1960
4. ASME (Reference ST-LLC 07-02)

31.10 VACUUM CONDITIONS

31.10.1 Vacuum Conditions

The Code has clear guidance for external pressure rules when the conditions are known in B31.1, Ref. 1 Para 104.1.3 and B31.3, Ref. 2 Para 304.1.3. However, many times, the designer does not consider the possibility of flow transients or maintenance practices which can also cause a vacuum in a piping system. For many piping systems with normal diameter to thickness ratios, the piping is already capable of withstanding full vacuum or an external pressure of 15 psig. As the diameter to thickness ratio starts to go up as in larger diameter lines designed to relatively low internal pressures, the effect of a vacuum can be significant. See Figure 31.3 for an example of a piping failure under vacuum. Both B31.1, ref. 1 and B31.3, ref. 2 refer to ASME B&PV Code

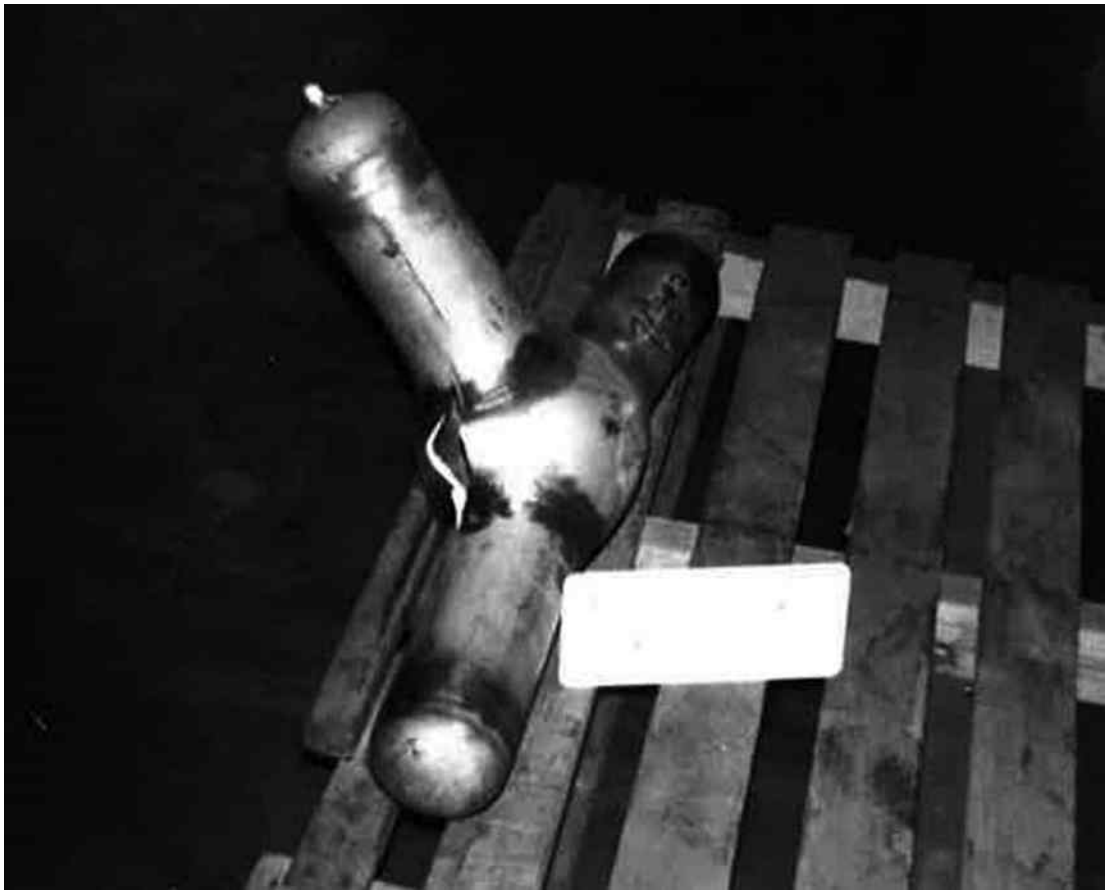


FIG. 31.2 EXAMPLE OF A PROOF TEST COURTESY OF FLOWLINE DIVISION

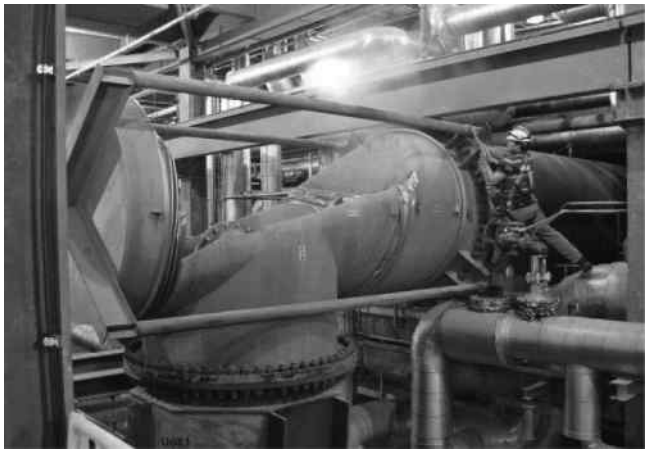


FIG. 31.3 FAILURE OF LARGE DIAMETER PIPING/ EXPANSION JOINT UNDER VACUUM
(*Source:* The picture is from a power plant in Texas)

Sections II and VIII References 3 and 4 to design for vacuum conditions.

ASME B31.3 Para. 301.2.1 and 301.4.1, provide some warnings of potential vacuum conditions, however the system engineer as well as the designer should always be aware of other potential conditions which might subject the piping system or part of it to a vacuum conditions. A few examples are provided below.

ASME B31.3 Para. 301.2.1 and 301.4.1, provide some warnings of potential vacuum conditions, however the system engineer as well as the designer should always be aware of other potential conditions which might subject the piping system or part of it to a vacuum conditions. A few examples are provided below.

Many process lines which would never see a vacuum condition as the result of their operating conditions are required to be Steamed Out to any maintenance activities. If during this process, the line is accidentally isolated, the steam will condense and cause a vacuum to be created in the line.

Valve Closures and Liquid Columns can also create short term vacuum conditions which might not have been identified by the process engineers who were concentrating on the pressure required for the normal process and not the layout, or transient conditions during a shut down.

31.10.2 References:

1. ASME B31.1 Power Piping Code, 2012 Edition, Para. 104.1.3
2. ASME B31.3 Process Piping Code, 2012 Edition, Para. 304.1.3
3. ASME B&PV Code Section VIII, Division 1, UG-28 through UG-30
4. ASME B&PV Code Section II, Part D, Table Y-1

CHAPTER

32

PART A: A SCALABLE APPROACH TO COMMERCIAL NUCLEAR POWER: NUSCALE POWER'S NEW APPROACH TO SAFETY AND DEPLOYMENT OF NUCLEAR PLANTS

José N. Reyes and Daniel Ingersoll

PART B: NEW DELIBERATIONS IN NUCLEAR MODULAR CONSTRUCTION—WESTINGHOUSE SMALL MODULAR REACTOR

Alexander W. Harkness

PART A

32A INTRODUCTION, SEE FIG. 32A

NuScale Power's unique, scalable approach to the deployment of commercial nuclear plants provides the financial, schedule, supply chain, and workforce advantages that will broaden the market for commercial nuclear power. NuScale Power also offers a new level of safety that may simplify siting and increase public acceptance of nuclear power. Although novel in its deployment approach, the factory-fabricated NuScale Power Module (NPM) relies on well-known light-water reactor technology, significantly reducing technological and regulatory risks. Most importantly, the NuScale design has achieved the "Triple Crown of Nuclear Safety." That is, a NuScale reactor can safely shutdown and self-cool for an indefinite period of time with no operator action, no AC power or DC power, and no additional water. The design also eliminates the possibility of many accidents from occurring and adds greater defense in depth to protect against even the most severe events such as occurred at the Fukushima Daiich plant in Japan. These remarkable advances in safety are achieved while offering all the financial benefits that come with small modular infrastructure.



FIG. 32A WORLD'S FIRST SMR CONTROL ROOM SIMULATOR LOCATED AT NUSCALE POWER

32A.1 NOVEL APPROACH TO SMALL MODULAR REACTOR DEPLOYMENT

The NuScale design originated as a result of integral system testing conducted at Oregon State University. The design leverages more than 50 years of light-water reactor research and operations experience. A detailed report of the early efforts leading to this design titled *Multi-Application Small Light Water Reactor (MASLWR)* was issued by the DOE in 2003 [1]. The design has advanced significantly because of focused design efforts by more than 200 NuScale engineers and contractors, nearly 10 years of additional testing, and a major investment by NuScale's strategic partner, Fluor, NuScale is proposing a novel approach to the deployment of nuclear power plants, which creates a new industry for fabrication of SMR components. It begins with the manufacturing of complete NuScale Power Modules (NPM) in a factory. Each NPM includes an integrated reactor vessel and the containment vessel (CV). This is a significant departure from traditional "stick-built" nuclear power plants. Approximately 80% of each NuScale plant will consist of factory built equipment that can be shipped to the site as prefabricated packages ready for installation. As shown in Figure 32A.1, key modules unique to a NuScale plant include the NPMs and the skid-mounted turbine generator sets. The NPM can be shipped by rail, truck, or barge from the factory and installed into a reactor building sized to match the long-term power needs of the owner.

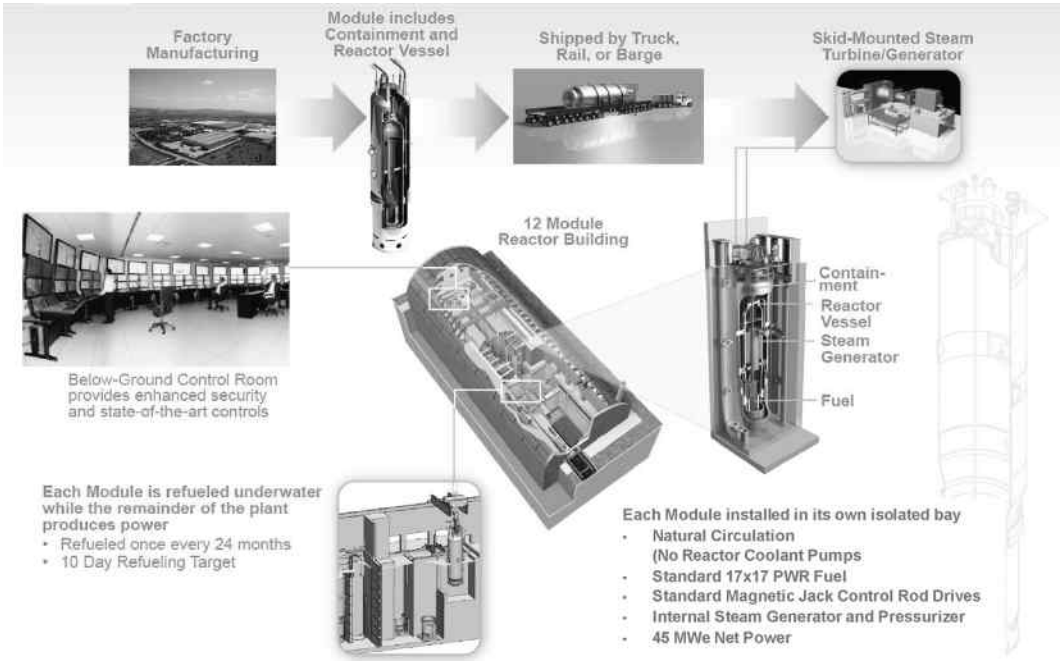


FIG. 32A.1 NUSCALE OFFERS AN INNOVATIVE APPROACH FOR THE DEPLOYMENT OF NUCLEAR POWER PLANTS

32A.2 PLANT DESIGN OVERVIEW

The NPM is composed of a reactor core, a pressurizer, and two steam generators integrated within the reactor pressure vessel and housed in a compact steel CV. The NPM is sized to allow full factory fabrication of the entire module, including all internal components, and can be transported in three sections to the plant site for fuel loading and assembly. The module is connected to an independent turbine-generator power conversion unit, which is skid-mounted for easy installation and maintenance. A simple schematic of the power production train for each module is shown in Fig. 32A.2.

The NPM is designed to operate efficiently at full power conditions using gravity-driven natural circulation as the means of providing core coolant flow, eliminating the need for reactor coolant pumps. As shown in Figure 32A.3, the reactor core is located inside a shroud connected to the hot leg riser. The reactor core heats the primary coolant causing the coolant to flow upward through the riser. When the heated coolant exits the riser, it flows radially outward and then downward over the tubes of the helical coil steam generator, which acts as a heat sink. As the primary coolant passes through the steam generator, it cools, increases in density, and naturally circulates downward through the annular down-comer. The coolant then is directed inward to the lower end of the reactor core, where the cycle begins again.

The core configuration for the NPM, also shown in Figure 32A.3, consists of 37 fuel assemblies and 16 control rod assemblies. The fuel assembly design is modeled from a standard 17 $\times$ 17 pressurized-water reactor fuel assembly with 24 guide tube locations for control rod fingers and a central instrument tube. The assembly is nominally half the height of standard plant fuel. The U-235 enrichment is below the current U.S. manufacturer limit of 4.95 percent enrichment.

The reactor pressure vessel consists of a steel cylinder with an inside diameter of ~9 ft. an overall height of 65 ft. and is designed for an operating pressure of approximately 1850 psig. The upper and lower heads are elliptical, and the lower portion of the vessel has flanges to provide access for refueling. The pressurizer is internal to the reactor vessel and provides the primary means for controlling reactor coolant system pressure. It is designed to maintain a constant pressure during operation. Reactor coolant pressure is increased by applying power to a system of heaters in the reactor pressure vessel head and is reduced by using sprays provided by the chemical and volume control system (CVCS).

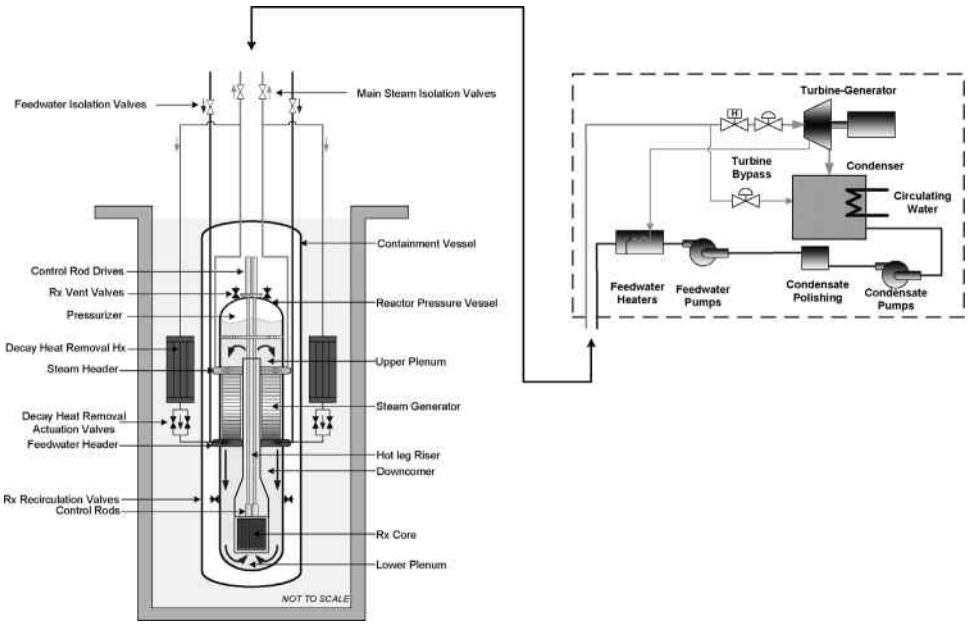


FIG. 32A.2 SCHEMATIC OF SINGLE NUSCALE POWER MODULE AND DEDICATED POWER CONVERSION UNIT

The reactor vessel is surrounded by a CV, which consists of a steel cylinder with an outside diameter of approximately 15 ft. and an overall height of approximately 80 ft. The containment is designed to withstand an internal pressure of 600psia, although it operates at a vacuum during normal operation. The CV represents a significant innovation in the NuScale design and is an important contributor to the high level of safety and robustness achieved by the design. This critical innovation is discussed more thoroughly in Section 32A.3.

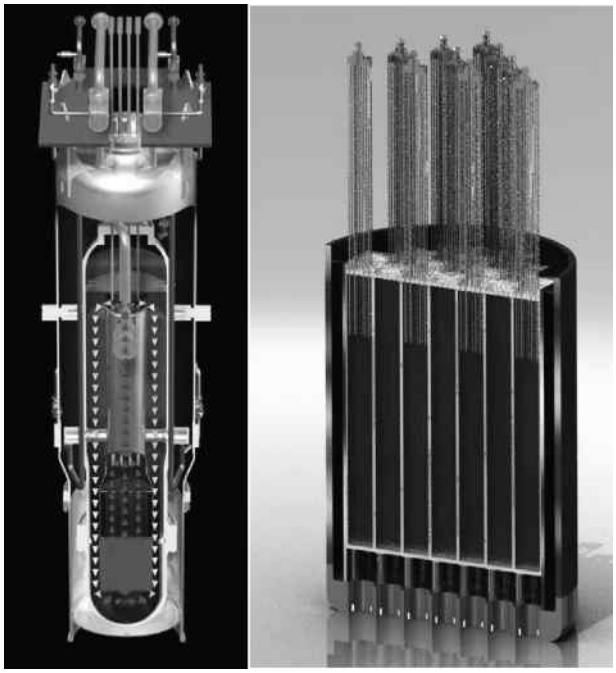


FIG. 32A.3 NATURAL CIRCULATION FLOW OF PRIMARY COOLANT (LEFT) AND REACTOR CORE (RIGHT)

Power modules are protected by passive safety systems. Each NPM has a dedicated CVCS, emergency core cooling system (ECCS), and decay heat removal system (DHRS), and is submerged in a separate bay within a large reactor pool shared by all modules. Each reactor bay is approximately 20 ft. wide and physically isolates each NPM from adjacent modules. The entire pool is lined with stainless steel for leakage control. Each bay has a concrete cover that serves as a biological shield. The cover also serves to prevent deposition of foreign materials onto the pool. The reactor pool is located in a Seismic Category I building designed to withstand postulated adverse natural conditions and aircraft impact for the plant location. The shared reactor pool, which is depicted in Figure 32A.4, is another key innovation in the NuScale design.

On the secondary side, preheated feedwater is pumped into the tube side of the steam generator where it boils. As the steam continues to flow upwards in the tubes, it continues to be heated to produce superheated steam before leaving the steam generator. The superheated steam is directed to a dedicated steam turbine. A generator, driven by the turbine, creates electric power that is delivered to the utility grid through a step-up transformer. Steam is extracted from turbine stages to preheat the feedwater and increase the efficiency of the power plant. Exhaust steam from the turbine is directed to the condenser, where a circulating water loop removes heat and condenses the steam. Heat from the circulating water loop is rejected to atmosphere by an evaporative mechanical-draft cooling tower.

The reactor building, as depicted in Figure 32A.4, houses the NPMs, shared pool, spent fuel storage pool and all nuclear safety functions. The reactor building is a Seismic Category I reinforced concrete structure designed to withstand the effects of aircraft impact, environmental conditions, natural phenomena, postulated design basis accidents, and design basis threats. The NPMs, reactor pool, and the spent fuel pool are located at or below nominal plant grade level, while the hoisting and handling equipment is located above grade. Also located below grade are

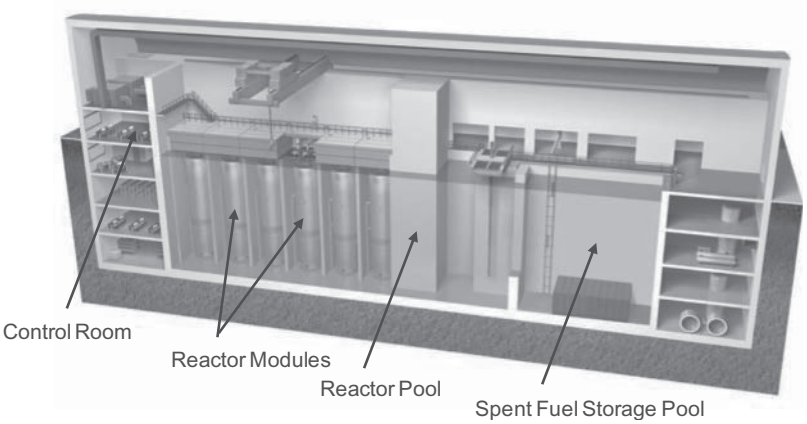


FIG. 32A.4 CUTAWAY OF A 12 MODULE REACTOR BUILDING SHOWING SHARED REACTOR POOL

the safety-related batteries, main control room, most primary systems, and some radioactive waste management equipment.

Figure 32A.5 provides a diagram of the site layout for a 12-unit plant. A wide range of configurations including single units, 2-packs, and 4-packs are possible. The configuration shown in Figure 32A.5 offers significant economic advantages. First, it eliminates single shaft risk. That is, the temporary shutdown of a single unit does not require shutdown of the entire plant. Second, the layout permits refueling to be completed on a single module while the other modules continue to generate power.

The refueling process begins after the reactor is brought to cold shutdown conditions. The feedwater lines and the steam-lines are disconnected from the module. The module is then connected to an overhead crane and transported from its bay into the central pool. From the central pool, the module is transported through a set of gates into the refueling area. Once in the refueling area, the module is remotely disassembled and refueled. The module is then reassembled and transported back through the gates to a bay. The feedwater and steam lines are connected and the startup process initiated. Economics may support the idea of having a spare module ready in advance. This staggered refueling of individual modules, that is "in-line refueling," can be done by a small, well-trained, permanent team rather than employing a large temporary workforce. Refueling operations could be conducted

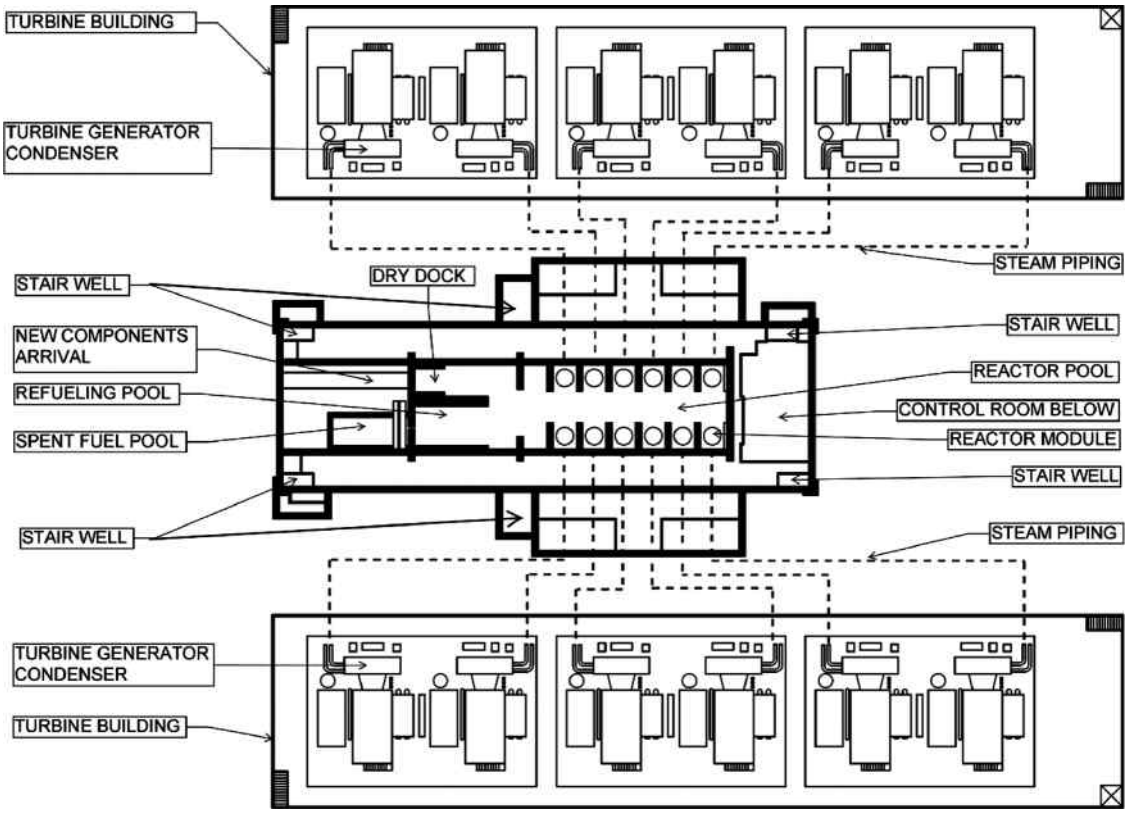


FIG. 32A.5 LAYOUT OF A 12-UNIT POWER PLANT SHOWING REACTOR AND TURBINE-GENERATOR BUILDINGS

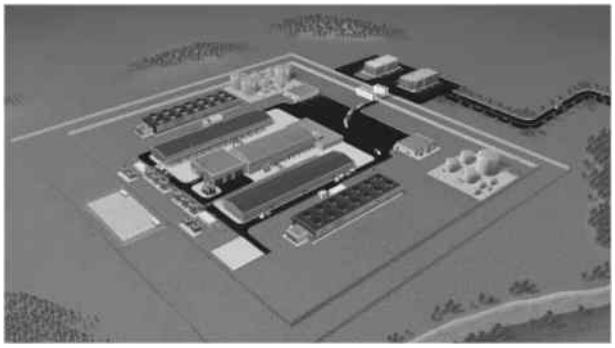


FIG. 32A.6 CONCEPT FOR 12-UNIT NUSCALE PLANT

throughout the year while keeping the remaining modules online. In addition, skid-mounted turbine-generator sets and ample lay down areas in the turbine building permit ease of maintenance and turbine replacement to reduce single unit down-times. The NPMs are refueled on a staggered 24-month cycle resulting in a high plant capacity factor. During refueling, the module is disconnected from its operating bay and moved to a common refueling area, at which time the module is disassembled, refueled and inspected, and reassembled. The other 11 modules continue to operate during the module refueling, which is estimated to require ten days.

An artistic rendition of the full 12-unit site is shown in Figure 32A.6. The majority of the site buildings, including an area for dry storage of a 60-year compliment of discharged fuel, are located within the protected area, which is surrounded by a double fence and intrusion-detection equipment. The switchgear area is located outside the protected area but within the restricted owner controlled area surrounded by an additional single fence. Only the administration building and the warehouse are located outside of the restricted area. The entire footprint of the site is nominally 40 acres. Table 32A.1 summarizes the overall characteristics of the NuScale plant.

32A.3 SAFETY, SECURITY, AND ASSET PROTECTION

NuScale recently announced a major technology breakthrough as described in the Wall Street Journal [2]. The NuScale plant is designed to provide an unparalleled level of safety, security, and asset protection. It is the only LWR SMR capable of providing an *unlimited period* of cooling for the nuclear fuel and containment without the need for operator action, AC *or DC power*, or the addition of water. Its unique engineered safety features (ESFs) provide stable long-term nuclear core cooling and plant recovery under all design basis accident conditions. It also provides severe accident mitigation for low probability beyond design basis accidents. The ESFs include a high pressure CV, a passive decay heat removal system (DHRS), a passive emergency core cooling system (ECCS), and CV retention for severe accident mitigation. These safety systems are briefly described in the sections that follow.

32A.3.1 High Pressure Containment

The CV has several features that distinguish it from existing containment designs. It has been designed to a rated pressure of 800 psia; approximately 12 times that of traditional containments. As a result, it can withstand all small break loss-of-coolant accident (SBLOCA) events that can occur inside containment. However, because of its relatively small diameter, it does not require a large wall thickness to achieve this capability. During normal power operation, the containment atmosphere is evacuated

TABLE 32A.1 CHARACTERISTICS OF A 12-UNIT NUSCALE POWER PLANT

Overall Plant	
Net nominal power rating	540 MWe
Thermal efficiency (gross)	>30%
Number of power units	12
Nominal plant capacity factor	>95%
NuScale Power Module	
Number of reactors	One
Electrical capacity (net)	>45 MWe
Steam generators	Two, independent tube bundles
Steam generator type	Vertical helical tube
Steam cycle	Rankine — subcritical regenerative with superheat
Turbine type	3600 rpm, condensing, with extraction
Thermal power rating	160 MWt
Operating pressure	1850 psig
Height/Diameter	80 ft/15 ft
Reactor Core	
Fuel	UO_2 (<4.95% enrichment)
Fuel assemblies	37
Control rods	16
Core height	6 ft
Refueling interval	24 months

to provide an insulating vacuum that significantly reduces heat loss from the reactor vessel. As a result, the reactor vessel does not require surface insulation. This eliminates the potential for sump screen blockage, which has been an issue for many large LWRs (NRC GSI-191 [3]). Furthermore, the deep vacuum improves steam condensation rates during any sequence where safety valves vent steam into this space. In addition, by eliminating containment air, it prevents the creation of a combustible hydrogen-air mixture in the unlikely event of a severe accident (i.e., little or no oxygen), and eliminates corrosion and humidity problems inside containment.

32A.3.2 Passive Safety Systems – Elimination of the LOCA

With all nuclear plants, a primary safety issue is the need to provide assurance that decay heat can always be removed following a reactor shutdown. For traditional light-water reactors, the limiting safety condition has been the need to provide cooling for accidents where supplies of cooling water are lost by some form of breach, usually a break in the largest cooling pipe. An ECCS is provided to ensure the availability of cooling water for such accidents. In the first generation of nuclear plants, this was accomplished using "active" systems that required emergency pumps to operate and thus imposed requirements for adequate supplies of emergency electricity generation. Newer plants being built today have enhanced safety by moving to "passive" emergency cooling systems, i.e., supplying back-up sources of cooling water using natural circulation systems that do not require pumps.

NuScale enhances safety several steps further. First, large break loss-of-coolant accidents (LBLOCAs) have been completely eliminated by design. There are no large diameter pipes inside containment that can generate LBLOCA phenomena. In addition, because of the passive safety systems, there are no design basis SBLOCAs that can cause the fuel to uncover of liquid. Second, as shown in Figure 32A.6, the entire NPM is immersed in a pool of water capable of absorbing all decay heat generated following a reactor shutdown; eliminating the piping and pumps needed to transport water from an external storage tank. The water is contained in a stainless-steel-lined concrete structure that is entirely below ground. Finally, each NPM includes two redundant and independent passive safety systems to provide pathways for decay heat to reach the containment pool: the DHRS and the ECCS. These systems do not require AC or DC power for actuation in the event of a complete station blackout.

32A.3.3 Decay Heat Removal System

The DHRS provides secondary side reactor cooling for non-LOCA events when normal feedwater is not available. The system, as shown in Figure 32A.7, is a closed-loop, two-phase natural circulation cooling system. Two trains of decay heat removal equipment are provided, one attached to each steam generator loop. Each train is capable of removing 100 percent of the decay heat load and cooling the reactor coolant system. Each train has a passive condenser submerged in the reactor pool. The condensers are maintained with sufficient water inventory for stable operation.

Upon receipt of an actuation signal or a complete station blackout, the DHRS valves open. This allows water from the decay heat removal condensers to travel to the steam generators and cool the reactor coolant as it is turned to steam. The steam then travels through the steam generator back to the decay heat removal condenser where it is condensed by the reactor pool water, and the cycle is repeated. Heat is removed via the steam generators, thus preserving natural circulation within the reactor coolant system.

Because the CV is directly immersed in the ultimate heat sink, i.e., the reactor pool, the NuScale DHRS is remarkably simple and mounted directly to the external surface of the CV. This eliminates additional tankage, piping, and valves associated with comparable systems in other reactor designs.

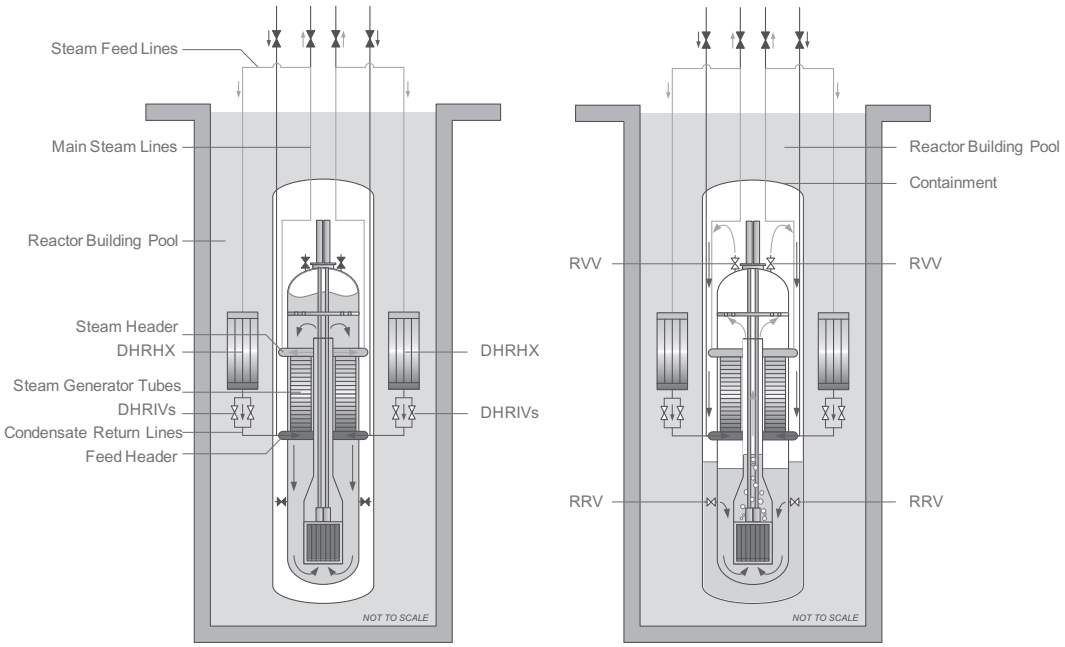


FIG. 32A.7 DELAY HEAT REMOVAL SYSTEM (LEFT) AND EMERGENCY CORE COOLING SYSTEM (RIGHT)

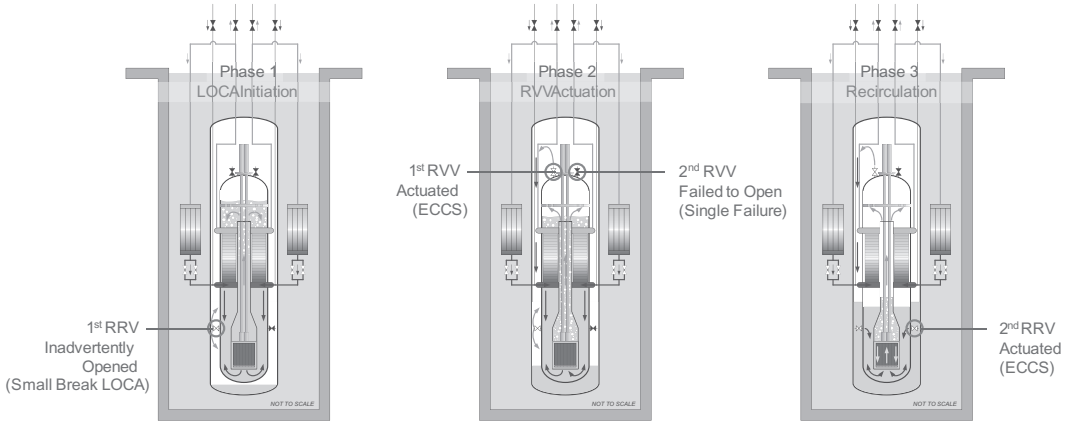


FIG. 32A.8 OPERATION OF EMERGENCY CORE COOLING SYSTEM IN RESPONSE TO INADVERTENT OPENING OF A REACTOR RECIRCULATION VALVE

32A.3.4 Emergency Core Cooling System

As with the DHRS, the unique design of the NuScale CV and its immersion in the ultimate heat sink allows the ECCS to be simplified considerably compared to other reactor designs. Also shown in Figure 32A.7, the ECCS consists of two independent reactor vent valves (RVV) and two independent reactor recirculation valves (RRVs). The ECCS provides a means of long-term decay heat removal in the event of a LOCA or loss of the main feedwater flow in conjunction with the loss of both trains of the DHRS.

The ECCS removes heat and limits containment pressure by steam condensation on the inside surface of the CV. It also allows heat conduction through the steam condensate to the CV walls and heat conduction and convection to the water in the reactor pool. Long-term cooling of the reactor core is established via recirculation of reactor coolant to the reactor pressure vessel via the reactor recirculation valves (RRV), which when opened; provide a return flow of cooled water to the reactor.

The ECCS is initiated by opening the two fail-safe RVVs located at the top of the reactor pressure vessel (the pressurizer region) and the two fail-safe RRV located on the reactor pressure vessel in the downcomer region at a height above the core. Opening the valves allows a natural circulation path to be established. Water that is vaporized in the core leaves as steam through the RVVs, is condensed and collected in the CV, and is then returned to the downcomer region inside the reactor vessel through the RRVs.

Following a LOCA or other condition resulting in an actuation of the ECCS, heat removal through the CV rapidly reduces the containment pressure and temperature and maintains them at acceptably low levels for extended periods of time. Steam is condensed on the inside surface of the CV, which is passively cooled by conduction and convection of heat to the reactor pool water. Since the CV is evacuated to a low absolute pressure during normal operation, only a small amount of noncondensable gas will be present inside the CV. For example, Figure 32A.8 depicts the three main phases of a small-break LOCA; in this case, an inadvertent opening of the reactor recirculation valve (RRV). In Phase 1, the RRV is unexpectedly opened and water begins to drain from the reactor vessel into the CV. In response to the event, the reactor vent valves (RVV) are opened in Phase 2, which causes steam to be released into the CV and condense on the vessel's inside surface. The pressures of the reactor vessel and CV quickly come into equilibrium (see Figure 32A.9) and water accumulates at the bottom of the CV due to the open RRV and steam condensation. In Phase 3, after the water level reaches the elevation of the RRV, the second RRV is also opened and water is circulated back through both RRVs into the reactor vessel to cool the core.

32A.4 RESPONSE TO EXTREME EVENTS

The destruction of the four nuclear power units at Fukushima Daiichi, in Japan, on March 11, 2011 was a vivid reminder that extreme natural disasters can happen and that nuclear facilities must be prepared to survive the event without placing the public at risk. The NuScale plant is being designed to ensure protection of the public and additionally, protection of the owner's substantial investment in the plant.

The plant's resilience to extreme events is provided by the robust design features highlighted in the previous section, including the elimination of several design vulnerabilities, a small core and source term, high-pressure compact CV, natural circulation heat removal systems, and ensured ultimate heat sink. Multiple phenomena identification and ranking table (PIRT) panels were assembled to identify design vulnerabilities and postulate potential accidents, including design basis and beyond design basis accidents. The results of the PIRT assessments were used to guide scoping analyses of the identified phenomena, followed by deterministic analyses of potential severe accidents. Results of these analyses were then used to inform and update the design. To validate the resilience of the design, a Probabilistic Risk

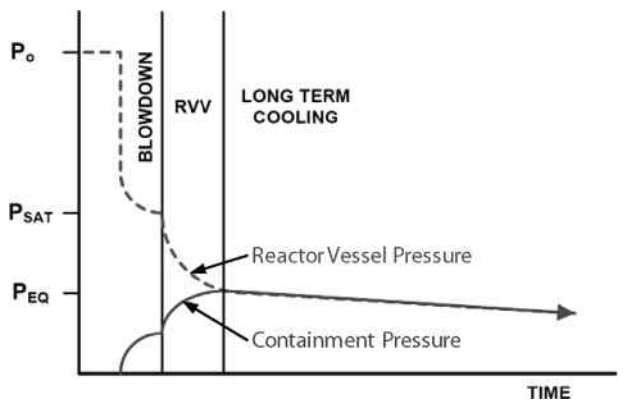
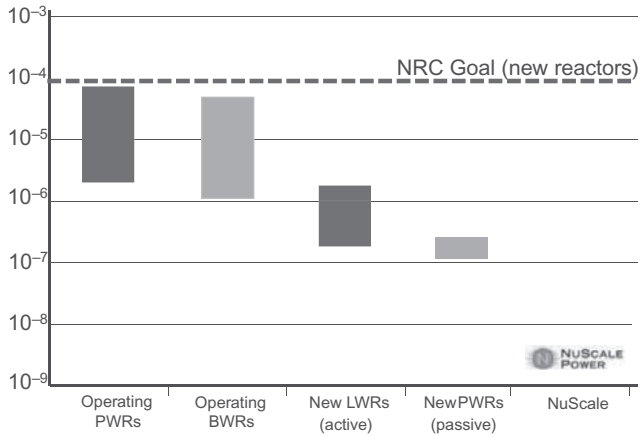


FIG. 32A.9 REACTOR VESSEL AND CONTAINMENT VESSEL PRESSURE RESPONSE TO SMALL BREAK LOCA



Source: NRC White Paper, D. Dube; basis for discussion at 2/18/09 public meeting on implementation of risk matrices for new nuclear reactors

FIG. 32A.10 INTERNAL EVENTS PROBABILISTIC RISK ASSESSMENT COMPARISON SHOWS THE NUSCALE MODULE HAS A CORE DAMAGE FREQUENCY ON THE ORDER OF 10^{-9}

Assessment (PRA) model was developed very early in the design development. This "living" PRA is used to regularly inform its design. As shown in Figure 32A.10, the level 1 PRA for internal events shows a significantly reduced core damage frequency (CDF), on the order of 10^{-9} per reactor per year, for the NuScale design. This CDF coupled with a reduced source term and additional fission product barriers indicates a reduced overall risk to the public and offers significant advantages for emergency planning and response.

32A.4.1 Complete Station Blackout

NuScale has developed an alternate 1E Power System that eliminates the need for DC power for all Engineered Safety Feature Actuation Systems (ESFAS) such that all safety valves align in their safest configuration on loss of all plant power. Details of the patent pending Alternate 1E Power System Fail-safe concept were presented to the NRC in December 2012. The success of the 1E alternate power system and the plant's resilience to extreme events could only be accomplished because of the simplicity and robustness of the safety features highlighted in the previous section.

In the event of a complete station blackout, as experienced at the Fukushima plants, heat would be removed from the reactor modules by allowing the reactor building pool to heat up and boil. Water inventory in the reactor pool is large enough to cool all of the reactors and prevent fuel damage for at least 30 days without adding water. After 30 days, water boil-off and passive air cooling of the NPMs provide adequate cooling for an indefinite period of decay heat removal. The stages of passive removal of the reactor decay heat for a long-term cool-down of the reactor module is depicted in Figure 32A.11. The key to ensuring the transition from water cooling to air cooling is the very small decay heat and the large containment surface area. As shown in Figure 32A.11, one second after reactor shutdown, the power has decayed to 10 MWt and after one day, the power has decayed down to 1.1 MWt. By 30 days, the decay heat being generated per module is less than 400 kW.

This extremely robust safety feature is a direct consequence of providing an ensured supply of long-term cooling (the reactor pool) and the relatively low power output of each module. Table 32A.2 summarizes the NuScale plant features that prevent or mitigate consequences of major upset events.

32A.5 TEST PROGRAMS

NuScale has a comprehensive test program designed to validate its safety analysis and design computer codes and to assess the performance of its safety systems. A unique feature of the NuScale design process is that an integrated system test facility was built early in the concept development phase and has been

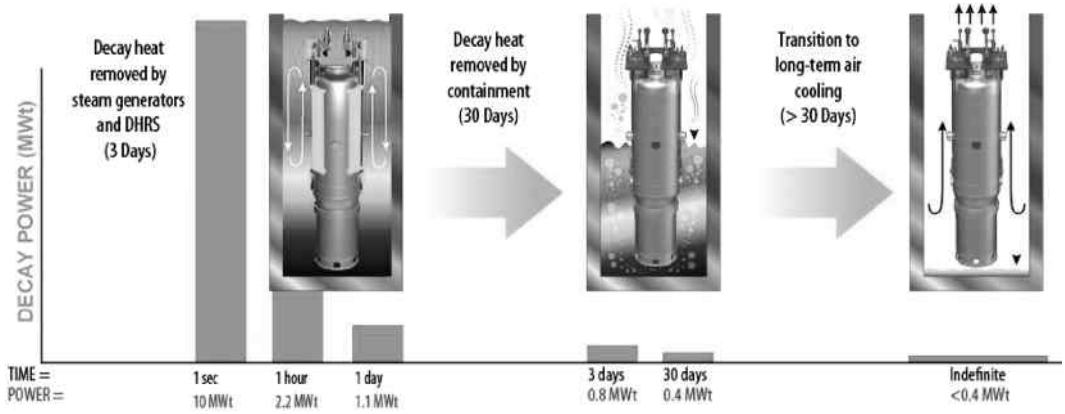


FIG. 32A.11 NUSCALE POWER MODULE HEAT REMOVAL DURING A PROLONGED STATION BLACKOUT EVENT

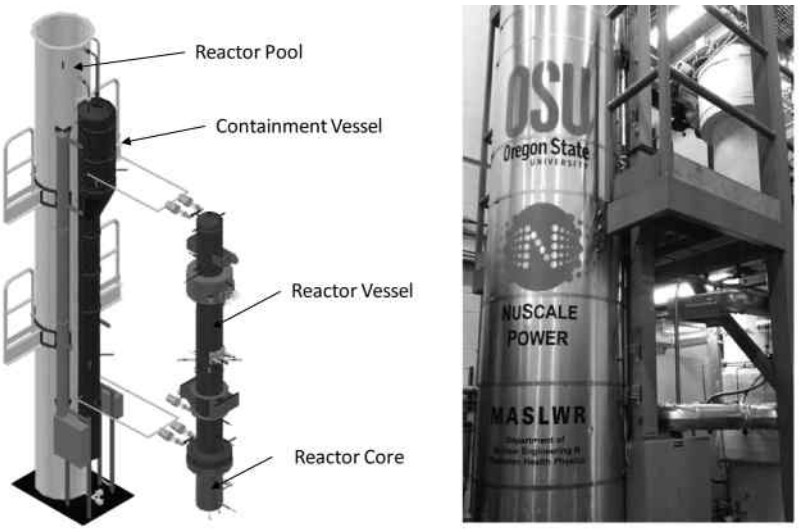


FIG. 32A.12 SCHEMATIC (LEFT) AND A PHOTOGRAPH (RIGHT) OF THE NUSCALE INTEGRAL SYSTEM TEST FACILITY

used throughout the design process to inform design choices. The NuScale Integral System Test (NIST) facility is located at Oregon State University. It is a full pressure, full temperature, 1/3rd height scale model of the NuScale reactor vessel, containment and reactor building cooling pool. It models the reactor core (electrically heated rod bundle), the pressurizer, the helical coil steam generator, the passive safety systems and the safety logic. The facility provides integral system data for steady-state operating conditions and transient conditions such as SBLOCA. The data is used for system characterization, safety code validation, informing operational procedures, and safety methodology development. The test facility is required to meet NQA-1 quality assurance and is being used to support NuScale design certification by the NRC. Figure 32A.12 shows a schematic and a photograph of the NIST.

A.12 and Figure 32A.13 present the data for a SBLOCA stuck-open reactor vent valve test conducted in the test facility. The initiating event for this test was essentially identical to that for the accident at Three Mile Island. However, as can be seen from the measured data, the results were significantly different and the accident completely mitigated without requiring external power or operator actions.

A.12 shows reactor pressure and containment pressure reaching equilibrium followed by long-term cooling and continued containment and core cooling. Complete cooling was achieved using the ECCS alone. The DHRS was not implemented in this test. As expected, water accumulated in the space between the pressure vessel and the containment and was not lost to the system. This is verified in Figure 32A.14, which shows that the collapsed liquid level remained well above the top of the core throughout the entire transient. The core was never close to becoming uncovered. It is also observed that the NRELAP5-3D code provided excellent predictions of the test data.

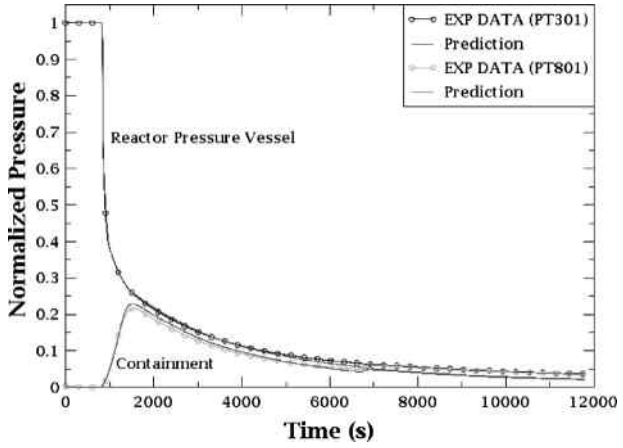


FIG. 32A.13 NRELAP5-3D CODE PREDICTIONS ARE IN EXCELLENT AGREEMENT WITH PRESSURIZER AND CONTAINMENT PRESSURES MEASURED DURING THE NUSCALE SBLOCA-2 TEST

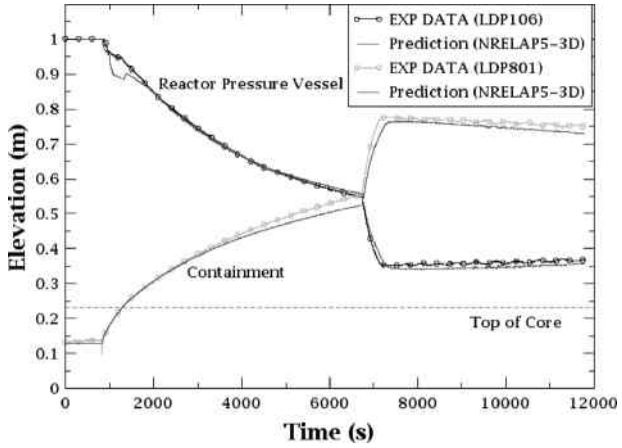


FIG. 32A.14 NRELAP5-3D CODE PREDICTIONS ARE IN EXCELLENT AGREEMENT WITH PRESSURIZER AND CONTAINMENT COLLAPSED LIQUID LEVELS MEASURED DURING THE NUSCALE SBLOCA-2 TEST



FIG. 32A.15 CONTROL ROOM SIMULATION LABORATORY

32A.5.1 NuScale Control Room Simulator

In 2012, NuScale constructed a main control room simulator laboratory, shown in Figure 32A.15. The simulator is being used to support NuScale's NRC design certification effort. The control room laboratory includes 12 individual module stations, each capable of modeling the neutronic and thermal-hydraulic behavior of each module using state-of-the-art computer codes. The entire balance of plant is modeled and coupled to all 12 modules. This unique facility is being used to perform the human factors engineering studies and the human-system interface studies needed to ensure that a multi-module NuScale plant can be operated safely from a single, all digital, state-of-the-art control room. In January 2013, NRC human factors staff conducted a 3 day visit of the NuScale control room simulator.

32A.6 CAPTURING THE ECONOMIES OF SMALL

The nuclear industry has been built on the belief, backed by experience, that larger plants are necessary to capture the economies of nuclear power. Although *economies of scale* have been achieved, this approach has posed difficulties in maximizing the ability of nuclear power to achieve its full potential. First, many markets do not need large plants. This is true not just in developing countries where grid size, system capacity, and financial reserves are less able to support large plants, it is also the case in domestic markets. Second, as plant size grows to the point of stretching global manufacturing capabilities, they begin to encounter some "diseconomies of scale," as described by Li [4] and Dahlgren et al. [5]. The most obvious diseconomies are the significant financial commitment and associated financial risk that they carry. Other potential factors include limited component availability, increased plant complexity leading to increased maintenance requirements, and greater construction risks. NuScale presents a different deployment model based on capturing the *economies of small*.

NuScale's *economies of small* are built on four principles as summarized in Figure 32A.16: 1) design simplicity, 2) nuclear steam supply system (NSSS) factory assembly and mass production, 3) simplified parallel construction, and 4) innovative operations. The application of all four principles has resulted in a NuScale plant design that has lower capital investment, shorter construction times, and competitive pricing on a $/MW(e) basis.

32A.6.1 Design Simplicity – Size Reduction and Simplification

It is readily recognized that scaling down a large nuclear plant with all of its inherent complexity to a smaller size will not yield an economic advantage in terms of cost/MW(e). The key is to design the plant from the bottom-up in a manner that exploits every economic, safety, and security advantage afforded by going small. This requires invoking extreme simplicity in a manner that promotes a robust domestic supply chain, employs standardized components with ensured manufacturability, and guarantees ease of transport. This was the approach implemented by NuScale. The passive, natural circulation based NuScale systems eliminate nearly all of the expensive and redundant NSSS active systems commonly found in large plants while offering an enhanced level of safety and security. The smaller diameter vessels provide high

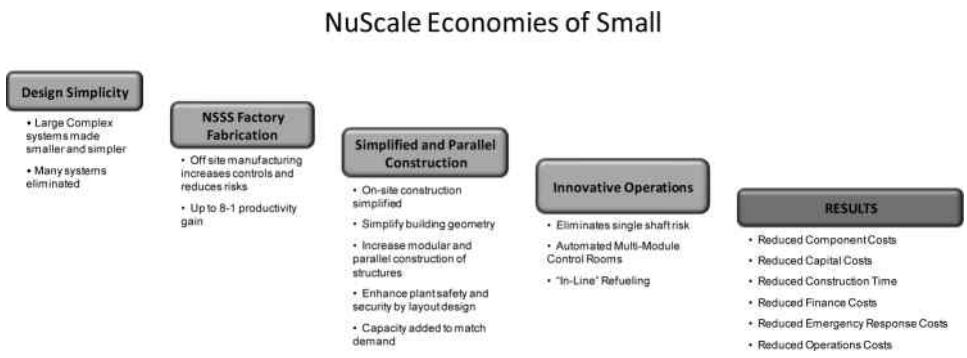


FIG. 32A.16 THE *ECONOMIES OF SMALL* FOR THE NUSCALE PLANT

TABLE 32A.2 NUSCALE PLANT FEATURES TO PREVENT OR MITIGATE CONSEQUENCES OF MAJOR UPSET EVENTS

Events and Threats	NuScale Plant Design Features and Benefits
Earthquakes, Floods, Tornados, and Aircraft Impacts	• 0.5g acceleration design baseline and deeply embedded reactor building provide enhanced seismic protection • Robust reactor building design protects against external hazards including aircraft impact • Below-grade placement of the self-contained ultimate heat sink provides ensured heat removal even from extreme external events • Plant does not rely on off-site power to maintain core cooling, thereby limiting external event consequences • Ability of the plant to establish fuel cooling indefinitely means that a NuScale plant can remain safe during extreme external events that might preclude outside emergency support
Complete Station Blackout or Loss of Off-site Power	• Passively safe nuclear fuel and containment cooling systems do not require power for safety functions • Fuel and cladding can be cooled indefinitely without AC power • No operator actions required to maintain cooling; operators provide monitoring function only
LOCAs	• Small piping diameters eliminate large-break LOCAs • Design basis small-break LOCAs cannot uncover the core; fuel cladding temperatures never rise above normal operating temperature • No operator action or AC electrical power required
Excessive Steam Demand or Heat Removal	• No operator action or AC electrical power required • Large water-to-power ratio in the reactor pressure vessel significantly slows transient behavior • Small steam generator inventory limits event consequences
Loss of Load or Heat Removal	• No operator action or AC electrical power required • Large water-to-power ratio in the reactor pressure vessel significantly slows transient behavior • 100% turbine bypass capability
Loss of Primary Flow	• No operator action or AC electrical power required • All flow is natural circulation; there is no sudden loss-of-flow accident • Loss of flow evaluated as part of loss of load
Containment Integrity	• Vacuum in containment reduces non-condensable gases, which improves steam condensation rates and limits pressure rise during design basis LOCAs • Vacuum reduces corrosion and humidity issues inside containment • Absence of mechanical insulation eliminates containment-sump blockage issues • High-pressure steel containment is shielded from external challenges
Spent Fuel Pool Integrity and Cooling	• Housed in underground protected structure • Approximately four times more water volume than conventional spent fuel pools per MWt for increased cooling capacity • Accessible supplies of backup water if needed for extended cooling

internal pressure capabilities using reduced vessel wall thickness. Smaller diameter vessels also offer a much greater ratio of surface area to internal volume; which, for the case of passive containment cooling, translates into a significant enhancement in decay heat removal per metric ton of vessel metal mass. Reduced metal mass directly corresponds to reduced plant component costs.

32A.6.2 Nuclear Steam Supply System Factory Assembly and Mass Production

Going small and simple enables the NuScale NSSS and containment to be fabricated entirely in a factory. A factory assembly line using smaller, less expensive standardized systems and components is expected to yield lower cost, high quality power modules. Experience has shown as much as an 8-1 productivity advantage in assembly-line manufacturing over onsite fabrication. Furthermore, assembly line production with a reasonable throughput offers a short learning curve with the potential for significant manufacturing optimization.

32A.6.3 Simplified Parallel Construction

Factory fabrication of the NuScale NSSS and containment greatly simplifies on-site construction. A three-year construction time for the 12-module plant is readily achievable using modern construction methods combined with parallel fabrication of the NuScale modules. The on-site construction is greatly simplified, because the nuclear components are not installed until after the on-site civil construction is essentially completed. This approach significantly reduces on-site workforce requirements by a factor

of 2–3 less than that expected for a conventional nuclear plant of comparable power. This combination of reduced workforce requirements, a simpler build, and a shorter construction schedule results in lower capital costs with a commensurate reduction in financial risk.

32A.6.4 Innovative Operations

Designing from the bottom-up offers an opportunity to introduce some innovation into operations that are unique to a NuScale plant. First, the NuScale "in-line" refueling approach eliminates the need for a large contractor workforce to perform refueling and maintenance during outages. This eliminates costly contractor training and security screening and labor associated with the set-up and take-down of refueling and monitoring equipment. Second, the NuScale Power Modules offer simpler, more automated, operations with less financial consequences for a module trip. That is, only 45 MW(e) are lost to the grid with a single module trip while the remainder of the plant continues to produce power. Similarly, the passive nature of the safety systems and the underground placement of the modules, control room, and spent fuel pool result in numerous enhancements to plant security.

32A.7 READY FOR MARKET

The NuScale design is a near-term deployment technology that includes the ongoing development of a robust supply chain and regular interactions with the regulator and customers.

32A.7.1 Supply Chain

NuScale is actively working with Fluor and top U.S. manufacturers to create a supply chain that is robust, competitive, and aligned for mass production. Many of the companies are already actively engaged with NuScale and providing design support for key plant components and systems. Because NuScale Power Modules and skid-mounted systems are relatively small, new opportunities are being created for high quality mid-size manufacturers of forgings, flanges, pressure vessels, and small steam turbine generator sets. The supply chain includes suppliers of valves, controls, instrumentation, and piping. It also includes services for heavy load rigging and transport.

32A.7.2 Regulator

NuScale has completed 4 years of active pre-application meetings with the NRC to discuss unique features of a multi-module plant. As a result, the NRC is developing a Design Specific Review Plan (DSRP) that will enable both a comprehensive and efficient review of the NuScale design certification application. Most of the DSRP falls within the existing regulatory framework for light-water reactors. More importantly, by the time that the Design Certification Application is submitted to the NRC, expected to be in 2015, they will already be intimately familiar with NuScale's innovative design features and supporting analyses and tests. The result is expected to be a streamlined and expedited review and approval.

32A.7.3 Customer Advisory Board

The NuScale Customer Advisory Board (CAB) was created in 2008 and currently includes 22 U.S. utilities. The CAB meets twice per year and has been a valuable resource for developing the NuScale Plant Owners Requirements Document, which serves to inform the design. Active engagement of the CAB, including participation in the design phase review process, will help ensure that the NuScale plant design will be marketable and attractive to customers.

32A.8 SUMMARY

The NuScale design combines proven LWR-based technology and innovative engineering to provide a new nuclear plant option with a high level of safety and affordability. The design was built from the ground up with safety as the fundamental goal and continues to support that goal through a design process that is both risk-informed and test-informed. The many innovations within the NuScale plant, including design-specific innovations, operational innovations, and economic innovations, create a new paradigm in nuclear power deployment. The innovations are appropriately balanced by active engagement with the regulator and utility customers to help ensure that the design is convincingly safe and will satisfy the desired market needs.

32A.9 REFERENCES

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PART B

The material in this chapter had been published in part previously by ASME, An Overview of the Westinghouse Small Modular Reactor, by Fetterman, Harkness, Smith, Taylor, Paper Number SMR2011-6597.

32B.1 INTRODUCTION

The Westinghouse Small Modular Reactor (SMR) incorporates an integral pressurized water reactor (iPWR) design in which all components associated with the nuclear steam supply system (NSSS) are housed within one pressure vessel, shown below in Figure 32B.1.

The Westinghouse SMR design also utilizes many of the key features developed for the **AP1000®** plant, including passive safety systems. The Westinghouse SMR will be fueled by a derivative of the successful 17 × 17 Robust Fuel Assembly (RFA) product. An 89 assembly core with an active height of 8 feet will provide a 24 month operating cycle with a power output of 800 MWt. Derived from the **AP1000** plant and adapted to operate inside the reactor pressure vessel, 37 control rod drive mechanisms provide reactor shutdown and reactivity control capabilities. Eight seal less pumps provide a nominal reactor coolant flow of 100,000 gallons per minute. An innovative evolution of a straight tube steam generator produces a saturated mixture that is delivered to a steam separating drum located outside of the containment vessel. The steam generator along with the integral pressurizer is attached to the reactor vessel with a single closure flange located near the center of gravity of the reactor assembly and is designed to be removed during refueling operations. Like the AP1000 plant, the Westinghouse SMR relies on the natural forces of gravity and natural circulation to provide core and containment cooling, during accident conditions. The passive cooling systems provide sufficient heat removal for seven days without the need for offsite AC power sources. The Westinghouse SMR also includes traditional active components such as diesel generators and pumps; however these components are not required for the safe shutdown of the plant. At a diameter of 32 feet, approximately 25 of the Westinghouse SMR containment vessels can fit within the envelope of the **AP1000** plant containment building (Illustrated in Figure 32B.2).

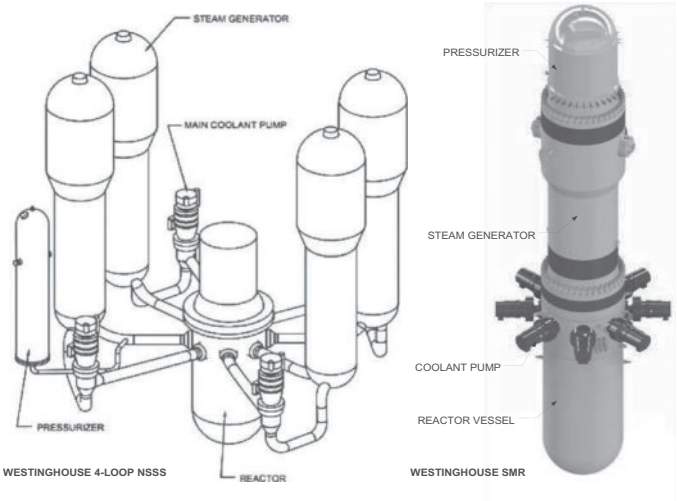


FIG. 32B.1 COMPARISON BETWEEN WESTINGHOUSE TRADITIONAL NSSS AND THE WESTINGHOUSE iPWR

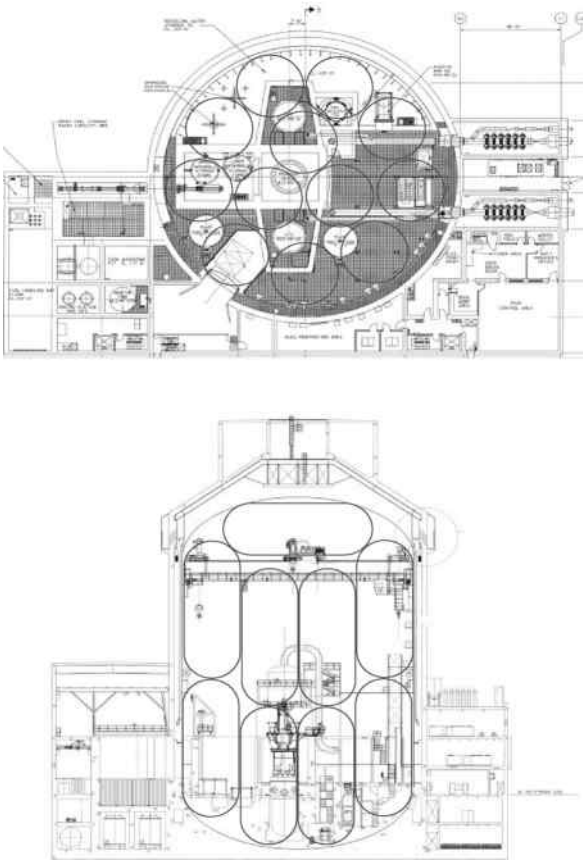


FIG. 32B.2 SIZE COMPARISON BETWEEN SMR AND AP1000 PLANT CONTAINMENT VESSELS (RED OUTLINE DEPICTS SMR CV)

This compact containment will be completely submerged in water during power operation providing a heat sink for postulated accidents. For protection against external threats, the containment vessel and plant safety systems are located below ground level. At approximately one fifth the net electrical output of the **AP1000** plant, the Westinghouse SMR is designed to address infrastructure challenges associated with replacing America's aging fossil fuel plants by providing a safe, clean and reliable energy source. The challenges associated with economies of scale are offset with a compact and simplified plant design, rail shippable components and modular construction.

32B.1.1 Market

The Westinghouse Small Modular Reactor (SMR) will provide a practical non-greenhouse gas producing replacement option for America's aging fossil fueled generating capacity. Economic studies show that our 225 MWe reactor is sized to provide maximum flexibility in its application without ignoring the industry recognized challenges associated with economies of scale. Some market observations that contributed:

- Slow and steady load growth in the U.S. of 2% or less per year [1]
- Incremental base load additions typically range from 200 to 300 MWe – based on coal and combined cycle natural gas units [2]

- Greenhouse gas emissions reductions such as coal requirements average 150 to 250 MWe - based on actual shutdowns and recent public announcements [1]
- Less than one quarter of U.S. utilities may have enough capital to fund 1000 MWe or greater projects costing $8B to $10B. Whereas, most U.S. utilities could fund projects costing $1B to $2B – based on Market Capitalization of entities [2]

32B.1.2 Objectives

The reactor's size will also allow for the use of the infrastructure associated with existing non-nuclear generating stations, providing a nuclear option for non-nuclear utilities. The small capacity also provides an option for small markets such as national laboratories and military installations. The Westinghouse SMR will require significantly less capital investment compared to traditional nuclear plants that are typically greater than 1000 MWe allowing for a wider range of potential investors. Compressed construction schedules also shorten the time between investment and the start of cash flow from plant operation.

The size of the larger components, such as the reactor vessel, containment vessel, steam generator, and turbine generator set has been limited during design to allow unrestricted rail shipment of components from the fabrication facilities to the construction site (see Figure 32B.3). The reduction in the size of these large components also allows for associated forgings to be fabricated in the United States. Beyond the size of the forgings, the Westinghouse SMR is designed to be manufactured and assembled in the United States, creating new jobs.

To be competitive, a new model for construction must be developed. In this model, small reactors will be assembled not constructed at the site. Fabrication and assembly of the majority of the plant must be done in a factory environment and construction reduced to assembly at the installation site providing an opportunity to significantly compress construction schedules. To achieve this objective, the Westinghouse SMR will be highly modularized in its design. The benefits of modularization are currently being realized with the **AP1000** builds in China and the United States. Westinghouse will leverage its experience with **AP1000** plant modular design and combine it with the reduced plant size of the SMR to further take advantage of the significant cost savings associated with a factory built plant. The smaller size of the SMR also allows for many systems to be designed using off-the-shelf components further reducing cost.



FIG. 32B.3 LARGE COMPONENT RAIL SHIPMENT

Safety and security of the Westinghouse SMR are inherent by design. Using passive safety systems driven by the forces of nature, pioneered by Westinghouse with the development of **AP1000** plant, the SMR can achieve a safe shutdown condition and maintain cooling without the aid of offsite resources for more than seven days. Passive safety systems allow active defense in-depth systems to be classified as non-safety, significantly reducing the cost of active system components. By locating safety related systems and components below grade, the Westinghouse SMR provides the ultimate protection from external threats. Recognizing the need for this level of security but also wanting to control capital costs, the size, configuration and number of the systems and components critical to safety are optimized to reduce the size of the plant.

It is recognized that SMRs are inherently more robust to mitigate beyond design basis events like those experienced by Japan in 2011. The Westinghouse SMR design team continues to build safety into the design paying careful attention to recommendations resulting from the Fukushima events. The Westinghouse SMR design already includes a significant increase in the number of physical barriers between the environment and the fuel, separation of safety systems, passive safety systems, and increased design margins. Using a probabilistic approach, risks associated with each design decision are analyzed to produce the safest integrated design.

32B.2 PLANT DESIGN

The Westinghouse SMR is a boron moderated light water reactor that uses control rods for load follow and plant shutdown. The integral reactor, protected by redundant passive safety systems is housed within a compact containment vessel that is located completely below grade.

32B.2.1 Site

The reactor building is centrally located on a 15 acre site. Adjacent are the annex, radwaste and turbine building (shown in Figure 32B.4).

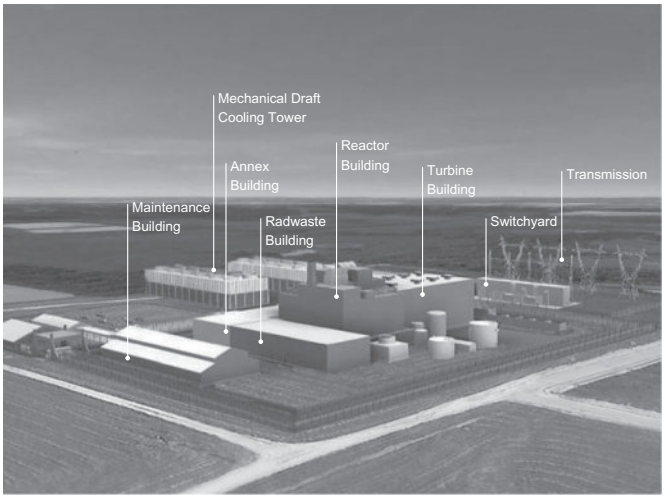


FIG. 32B.4 WESTINGHOUSE SMR SITE LAYOUT

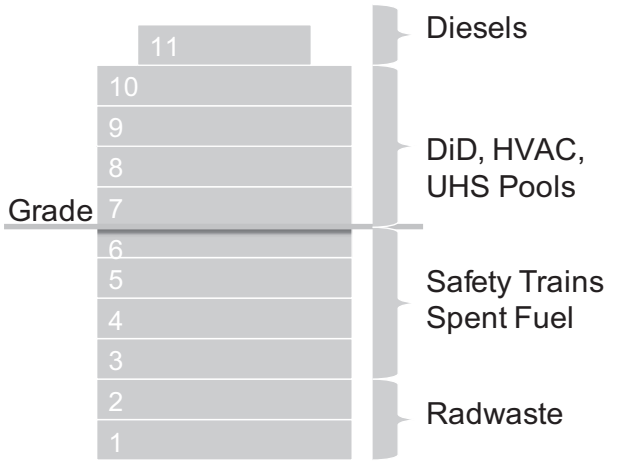


FIG. 32B.5 REACTOR BUILDING ELEVATION SCHEMATIC

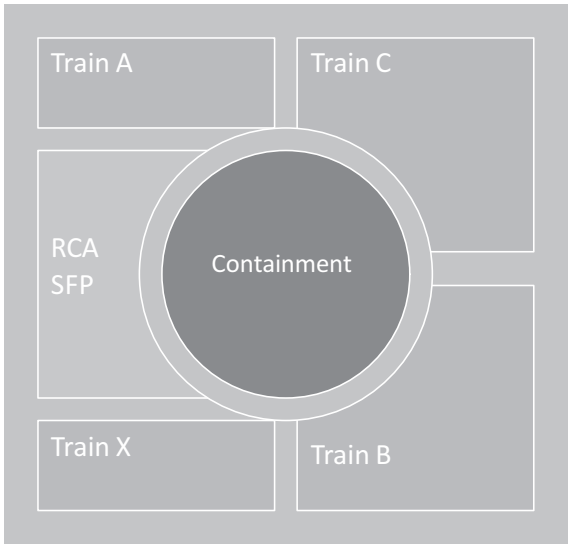


FIG. 32B.6 REACTOR BUILDING PLAN SCHEMATIC

32B.2.2 Nuclear Island

The Westinghouse SMR nuclear island contains all systems that are critical to safety. Systems required to bring the plant into safe shutdown condition are located below grade (Figure 32B.5). Physical separation between redundant safety related divisions is incorporated into the design (Figure 32B.6). Above grade floors will house equipment that is not subject to radionuclide releases. The spent fuel pool is located below grade (Figure 32B.4) to protect against external threats.

32B.2.2.1 Integral Reactor Utilizing an integral pressurized water reactor (iPWR), the Westinghouse SMR eliminates a complete class of potential accidents typically associated with traditional nuclear steam supply systems which use large bore piping to connect the system components (Figure 32B.8). All of the components associated with the reactor coolant system are contained within a single pressure vessel. The maximum diameter of

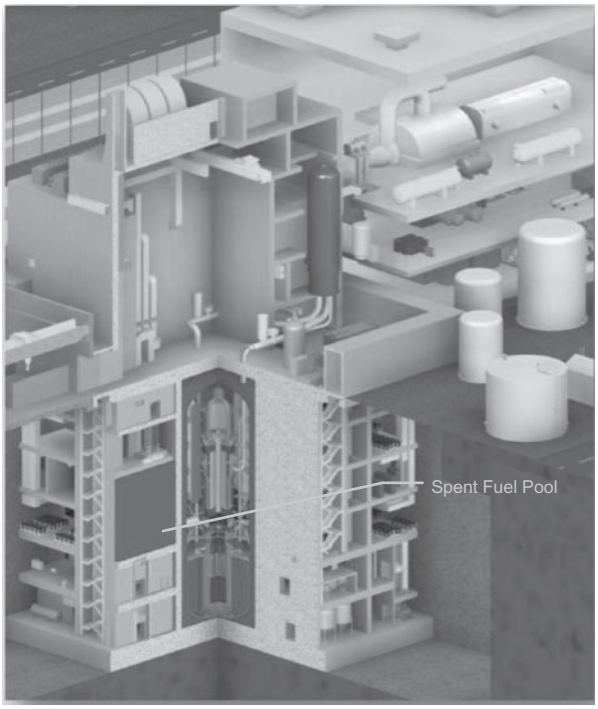


FIG. 32B.7 SECTIONED ISOMETRIC VIEW OF THE NUCLEAR AND TURBINE ISLAND

the reactor is held to 12 feet to ensure that it can be shipped via standard rail. The reactor is an ASME Division 1, Section III, Subsection NB pressure vessel with a design pressure and temperature of 2500 psig and 650°F.

To achieve a thermal power of 800 MWt, the core is made up of 89 17 × 17 RFA fuel assemblies with an active length of 8 ft. The core sits near the bottom of the reactor vessel while the steam generator with an integral pressurizer is located above the reactor vessel flange. A bolted flange near the center of the integral reactor assembly allows for the steam generatorpressurizer assembly to be removed allowing access to the fuel during a refueling outage (Figure 32B.8).

32B.2.2.1.1 Pressurizer Water level in the reactor is controlled within the pressurizer as it is in all Westinghouse PWRs, using sprays and heaters. The fluid volume in the pressurizer is separated from the reactor coolant system by a system of plates that are designed to perform the same function as a surge line in traditional PWRs. This system of plates allows fluid to pass from the pressurizer to the reactor coolant system while significantly reducing the amount of heat lost from the pressurizer to the reactor coolant system. The heaters which are the electrical resistance type are mounted horizontally just above the isolation plate system.

32B.2.2.1.2 Steam Generator The steam generator is a straight tube configuration with the primary reactor coolant passing through the inside of the tubes and the secondary coolant on the outside (see Section 32B.2.2.2 for complete a description of the steam generator design).

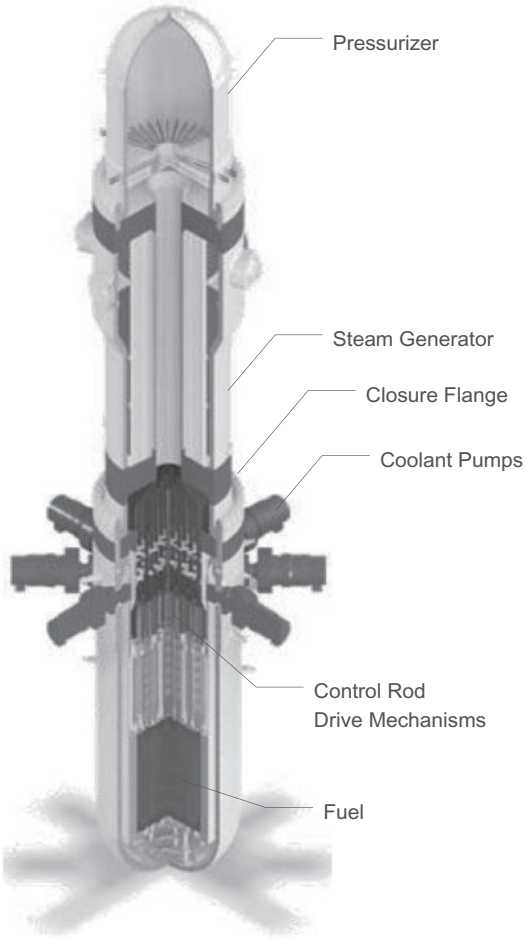


FIG. 32B.8 ISOMETRIC SECTION VIEW OF SMR REACTOR

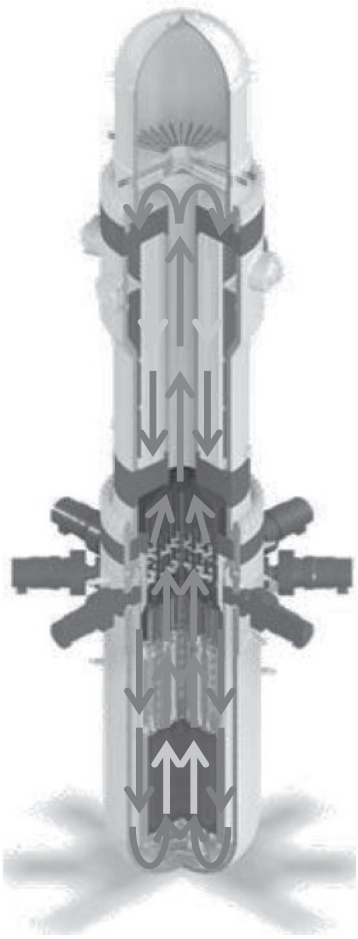


FIG. 32B.9 INTEGRAL REACTOR – COOLANT FLOW

32B.2.2.1.3 Coolant Pumps Eight axial flow seal less pumps mounted to the shell of the reactor vessel just below the closure flange provide the reactor coolant flow through the fuel assemblies necessary to operate the plant. These pumps, derived from commercially available pumps, have been designed to provide sufficient coast down flow to prevent departure from nucleate boiling (DNB) without the use of an integral flywheel, significantly simplifying the pumps design.

The speed of the pumps will be controlled during start-up, shutdown and operation with variable frequency drives (VFD). Using VFDs to control the RCPs simplifies start-up and shutdown operations.

The reactor coolant flow path is illustrated in Figure 32B.9.

32B.2.2.1.4 Reactor Internals The lower internals used in the SMR are derived from the 3XL, 4XL and **AP1000** plant design. The components used are essentially that same however the dimensions have been scaled appropriately for the smaller core.

The upper internals of the reactor support 37 control rod drive mechanisms (CRDMs) used to control reactivity (Figure 32B.8). A combination of shutdown and control CRDMs are used in the design of the SMR.

An integral part of the upper internals is a penetration flange. The penetration flange is sandwiched between the lower flange of the steam generation and the reactor vessel flange. All of the reactors internal instrumentation, CRDM power and position indication are supplied through the penetrations in this flange.

32B.2.2.1.5 Control Rod Drive Mechanisms The CRDMs are a high temperature and pressure version of the recently developed **AP1000** plant CRDM. A high temperature lifting coil winding and stainless steel housing allow the **AP1000** plant CRDM, which has already been tested to 8 million steps, to be used within the pressure boundary of the SMR integral reactor (Figure 32B.10 shows the **AP1000** plant CRDMs in the Westinghouse Newington, NH test facility). Elimination of control rod penetrations through the reactor pressure boundary has resulted in reduced cost of manufacture and the elimination of the normally postulated rod ejection event.

32B.2.2.2 Steam Generator/Drum Design For compactness, Westinghouse has chosen to employ an innovative evolution of a straight tube steam generator with a steam separating drum located outside of the containment vessel as shown in Figure 32B.11. In this design, primary reactor coolant flow is directed vertically downward through the inside of the tubes where heat is transferred to the secondary fluid. Secondary flow enters the steam generator shell as a subcooled liquid and exits as a saturated steam mixture where it is directed to the steam drum for moisture separation. The moisture separation equipment in the drum was selected and sized to produce



FIG. 32B.10 AP1000 PLANT CRDM TEST FACILITY

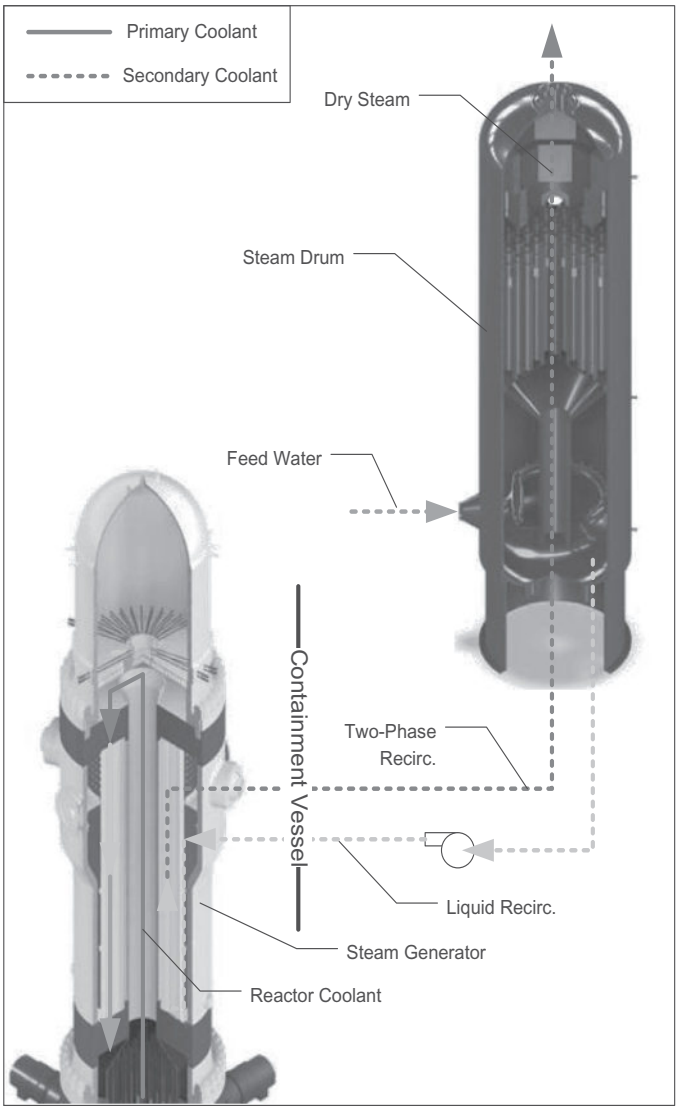


FIG. 32B.11 STEAM GENERATOR/STEAM DRUM CYCLE

dry steam conditions, ≥ 99.9% quality, for input to the turbine for power generation. Operating conditions were selected by design to operate predominantly within the efficient nucleate boiling heat transfer regime. For example, the steam drum provides a mixing volume where recirculating liquid preheats the feedwater reducing the sensible heat addition required for onset of nucleate boiling (ONB) resulting in a more compact design. During normal full power conditions, a secondary recirculation pump is used for head addition to offset piping losses; during low power conditions, the recirculation pump can be bypassed and steam drum elevation head is adequate to ensure natural circulation.

Key features of the Westinghouse SMR steam generator and steam drum design include:

- Alloy 690 tubes with an outer diameter of 0.625 inch (1.5875 cm) on triangular pitch
- 25 foot active heated tube length
- Tube supports to reduce tube flow induced vibration
- Flow baffles for secondary flow distribution
- Large secondary liquid volume for decay heat removal in most accident scenarios
- Proven best in class moisture separation equipment
- Secondary blowdown provisions for chemistry control
- Secondary loose parts trap

32B.2.2.3 Containment Vessel The Westinghouse SMR containment is a compact steel vessel (Figure 32B.12). Only 32 feet in diameter and 90 feet tall, approximately 25 of these containment vessels will fit within the containment vessel of **AP1000** plant (Figure 32B.2). The compact design significantly reduces the cost of the vessel, nuclear island structure, building excavation, facilitates modular construction and significantly increases the allowable

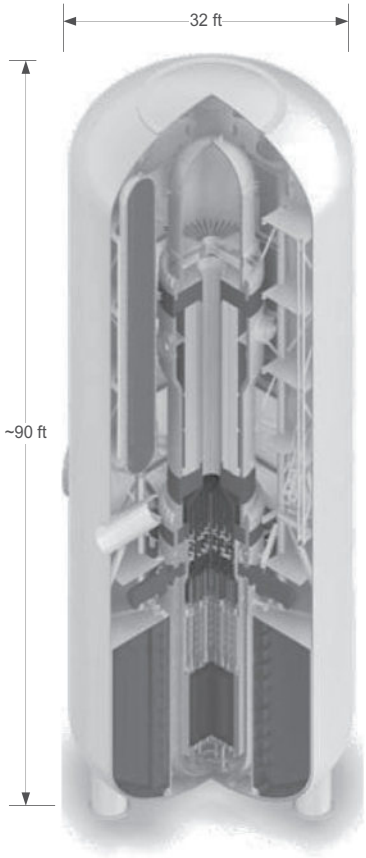


FIG. 32B.12 ISOMETRIC SECTION VIEW OF SMR CONTAINMENT VESSEL

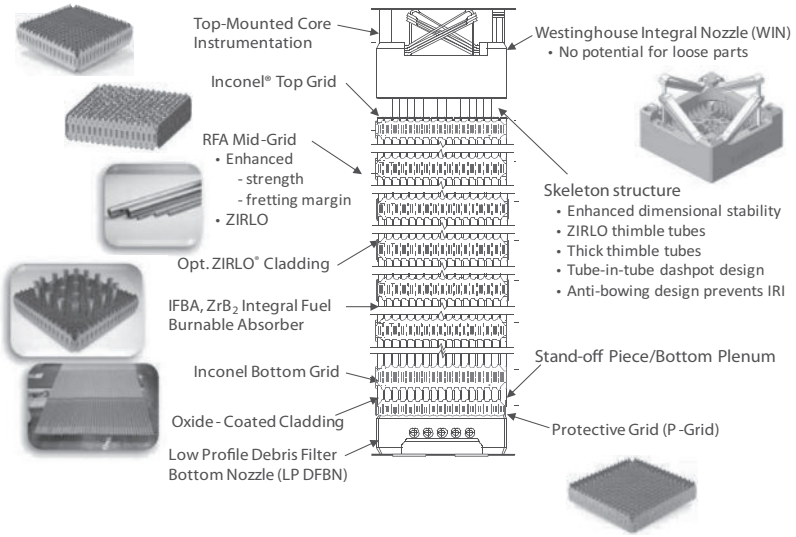


FIG. 32B.13 17 × 17 RFA FUEL ASSEMBLY COMPONENTS

design pressure. Designed to be submerged in water during normal operation, the containment also withstands relatively high external pressure loadings as well high internal loadings. The containment vessel is design to meet the requirements of ASME Division I, Section III, Subsection NE MC Vessel.

32B.2.2.4 Fuel and Core Design For simplification of design and ease of licensing, Westinghouse has chosen to fuel its SMR with a derivative of the successful 17 × 17 Robust Fuel Assembly (RFA) design. This fuel assembly design consists of a square lattice of 264 fuel rods with an outer diameter of 0.374 inch, 24 guide thimble tubes and a central instrument tube. This design was chosen as the basis for the SMR fuel assembly due to it significant operating experience and excellent performance. Over 14,000 assemblies have operated in 252 fuel cycles at 50 plants worldwide since 1997. Fuel assemblies have operated with lead rod burnup closely approaching the USNRC licensed lead rod burnup limit of 62 GWD/MTU and lead test assemblies have operated to approximately 70 GWD/MTU. This operating experience has been beneficial in the development of the **AP1000** PWR fuel assembly as well as in the SMR fuel assembly design. Key features of the Westinghouse SMR fuel assembly design include (see Figure 32B.13):

- 8 foot active core length
- Optimized **ZIRLO®** fuel rod cladding
- Alloy 718 top and bottom grids
- Optimized top grid spring designs to reduce rod bow
- Thick walled **ZIRLO** thimble tubes with tube-in-tube dashpots for enhanced dimensional stability and improved resistance to assembly bow
- Removable top nozzles
- Debris filter bottom nozzles, protective grids and oxide coated cladding for resistance to debris related failures

The size of the reactor core is an important design consideration in the Westinghouse SMR. The diameter of the core is directly related to the radial size of the reactor pressure vessel, which itself is limited by the requirement to ship the vessel by rail car. The height of the core directly influences the length of the control rods and their drives and the reactor internals; each foot of core height adds three feet of height to the reactor pressure vessel.

Another important consideration in the size of the reactor core is the customer expectations for 24 month operating cycles. A total of 89 fuel assemblies can fit within the SMR pressure vessel, with room remaining for a heavy radial reflector. Given this maximum core radial size, the active core height was then selected as 8 feet for total core uranium loading of approximately 27 MTU. This core size supports the 24 month cycle energy requirement with a reasonable number of feed assemblies each cycle, while also maintaining a relatively modest core height. A sample 3-region core configuration is shown in Figure 32B.14, which also indicates the locations of the 37 control rod drive mechanisms. The loading pattern in Figure 32B.14 feeds 36 fuel assemblies

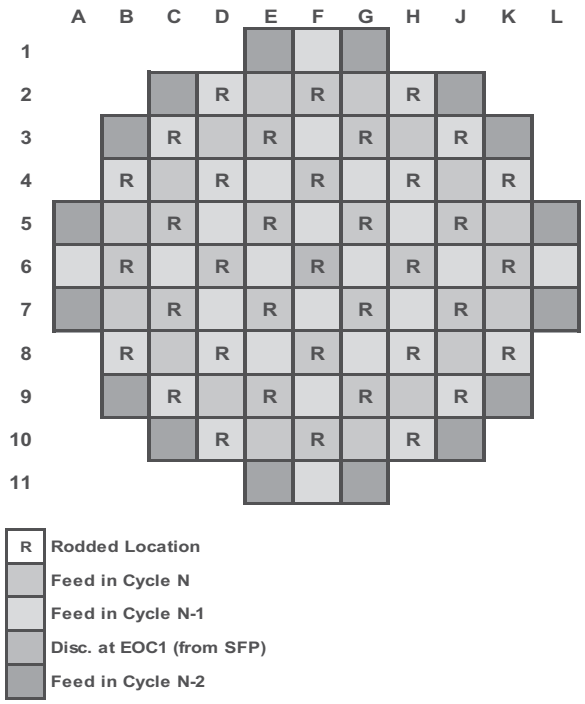


FIG. 32B.14 SAMPLE 3-REGION SMR CORE CONFIGURATION

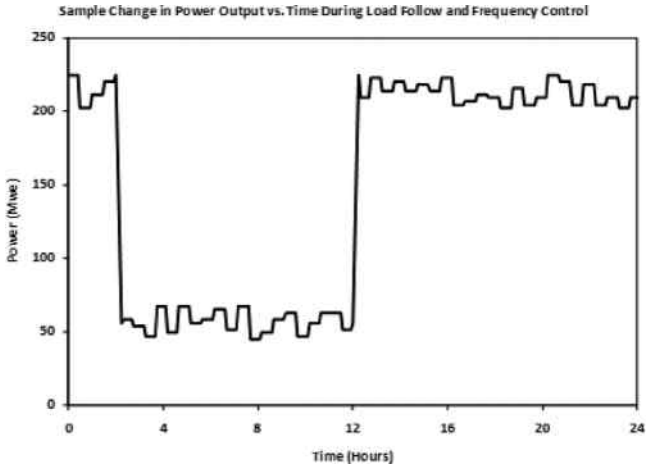


FIG. 32B.15 LOAD FOLLOW EXAMPLE

each cycle at 4.95 w/o U235, providing a cycle energy output of 700 effective full power days at 800 MWt.

Using grey rods in the core allows for significant power level control without borating. This method, developed for **AP1000** plant and known as mechanical shim (**MSHIM**) reactivity control will allow the Westinghouse SMR to load follow. Greater flexibility in operation is becoming more desirable with the introduction of additional wind and solar power sources to the grid. Figure 32B.15 shows an example of load follow.

32B.2.3 Turbine Island

Balance of plant systems such as the turbine-generator set, condenser and feedwater heaters are located on the turbine island. No safety related systems or components are housed within the turbine island.

32B.2.3.1 Balance of Plant Design The turbine and generator emphasize values of simplicity and cost-informed design. The turbine consists of a full speed, single flow high pressure section which passes its steam through a moisture separator and into a twin flow low pressure section with last stage blades of 40 inches in length.

A moisture separator is used in lieu of a moisture separator reheater (MSR) between the high and lower pressure stages. It was determined that in this power range, the additional cost of an MSR was not recovered over the life of the plant. The operational simplicity is also greatly improved with this design.

From the low-pressure turbine, steam then passes to a condenser with integral deaerator. The use of an integral deaerator also significantly saves on complexity and building space while only requiring a small penalty in efficiency.

Five, closed feedwater heaters and electric feedwater pumps, which are simpler to maintain and operate in a plant this size, are also used in the design.

The generator is a 320 MVA class, air-cooled unit with solid state excitation. Air-cooling the generator, once again, reflects simplicity and a cost-informed design. Hydrogen-cooled generators require multiple additional systems, higher maintenance, frequent site deliveries of flammable gas, additional monitoring, and represent both a fire/explosion hazard and a reliability risk.

32B.2.4 Annex Building

The annex building provides a location for administrative functions such as security and access control. The annex building houses no safety related equipment.

32B.2.5 Radio Building

The radwaste building is designed to handle and store radioactive materials produced by the plant. The building is also used to store contaminated materials and equipment used to refuel the plant. New fuel and spent fuel assemblies are also handled in the radwaste building. Spent fuel which has already been placed in dry cask storage containers is loaded for transport to the dry cask storage facility. The radwaste building houses no safety related equipment.

32B.3 SAFETY

The design of the Westinghouse SMR enables inherently safe power operation while also allowing for a safe transition from normal operating conditions to a passive shutdown condition. The design includes the three main barriers of protection of traditional PWRs (fuel cladding, reactor coolant system (RCS) pressure boundary and the containment vessel) with the added benefit of an external pool of water to filter out radionuclides that might escape from the containment's pressure vessel. Additionally, the plant's underground placement reduces the likelihood of external events affecting the safety of the plant.

The integral design of the RCS contains no large bore piping, which significantly reduces the flow area of postulated loss of coolant accidents. The use of CRDMs internal to the pressure boundary eliminates the possibility that the ejection of a control rod will occur. The pump-driven RCS flow during power operation results in a large thermal margin of safety that is predictable to a high level of confidence. The vertical arrangement of the plant allows for a safe transition to natural circulation in the event of a disruption to the forced reactor coolant flow. Also, the vertical arrangement of the plant inherently places the majority of the RCS water directly above the core for use in cooling of the reactor during an event.

During an event, the Westinghouse SMR relies on the natural forces of gravity and convection to shutdown and maintains the plant in a safe condition. The protection system of the Westinghouse SMR will diagnose that reactor protection is necessary and send a signal to unlatch the control rods. The control rods will fall by gravity to shut down the nuclear reaction, just like in the **AP1000** plant. In the unlikely event that the control rods do not fall into the core or an event occurs while at a shutdown condition, diverse shutdown will be performed through the gravity-fed injection of highly borated water from the core makeup tanks (CMT).

The RCS pressure boundary of the Westinghouse SMR will be maintained through the use of self-actuating, spring loaded pressurizer safety valves that will automatically open to limit any RCS pressure increase.

The large water inventory of the steam drum is automatically available for decay heat removal during most accident scenarios; however feedwater flow can also be isolated from the steam generator tubes and containment if a break occurs on the secondary side of the steam generator. If available, natural circulation from the steam drum to the steam generator tubes and back again to the steam drum provides residual heat removal via steam dump. The capability to add additional inventory to the steam drum and the capability to pump flow to the steam generator tubes are also available, however, neither are required to demonstrate that a safe shutdown condition is achieved for all design basis scenarios. An additional benefit to the large water inventory in the steam drum is improved water level control and extended response time to level transients.

If steam generator heat removal is unavailable or inadequate, four passive residual heat removal heat exchangers are automatically actuated by the protection system. Through the automatic opening of a single valve associated with each heat exchanger,

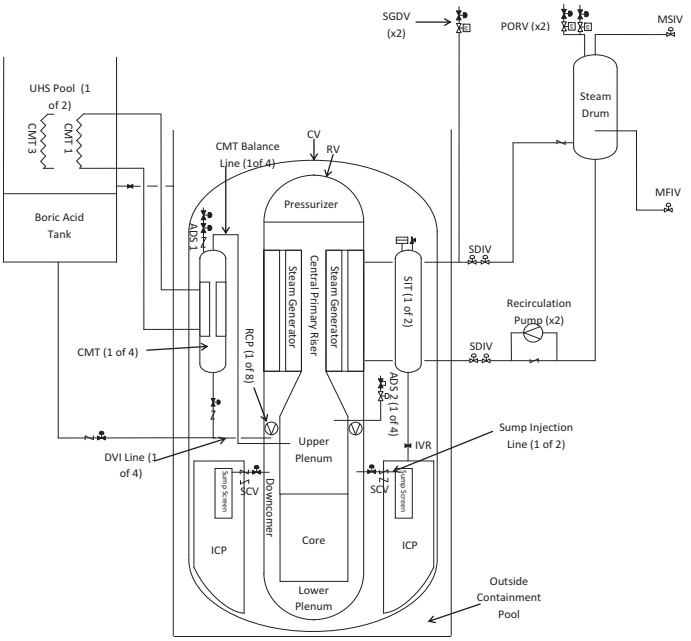


FIG. 32B.16 SAFETY SYSTEM SCHEMATIC

natural circulation of RCS water through the heat exchanger is established to provide residual heat removal. The inlet flow of the cooling side of the heat exchanger is cooled via natural circulation by the plant's ultimate heat sink tanks. The configuration and heat transfer capacity of the heat exchangers addresses design basis accident considerations related to the availability of the equipment. A schematic of the SMR safety systems is shown in Figure 32B.16.

An additional layer of residual heat removal capability is available through the containment wall to the external pool of water surrounding the containment vessel. Filling of the external pool of water is accomplished automatically via a connection to the ultimate heat sink tanks. In total, there is sufficient water inventory available to remove residual heat for a minimum of seven days without the need for offsite AC power sources. Connections are available to add additional water to indefinitely cool the plant.

The proportionally large RCS water volume to the thermal power level provides an increased energy sink during anticipated operating occurrences and postulated events. Should additional inventory be required during a postulated loss of coolant accident, multiple tanks of water will automatically inject additional inventory. In the unlikely scenario that additional inventory is required and the RCS is at an elevated pressure relative to containment; the RCS will be automatically depressurized to equalize the pressures. Once equalized, flow from the in-containment pool will automatically inject into the RCS to provide additional inventory.

Since the outside of the containment wall is cooled with water, the steam from the break will condense along the inside of the containment wall and collect in the containment sump. A path from the containment sump to the in-containment pool and into the RCS can be automatically opened to allow water collecting in the sump to re-enter the RCS. This establishes an internal natural convection and recirculation loop to provide liquid inventory to the RCS that will continue as long as the outside wall of containment continues to be cooled.

In an unlikely postulated severe accident such as core melt, the reactor vessel wall will be cooled by the water in the shield tank which can be manually actuated to cool the outside of the reactor vessel. The cooling of the reactor vessel wall is sufficient to prevent molten core debris in the lower head from melting the steel vessel wall and spilling into the containment.

32B.4 MODULARIZATION AND CONSTRUCTION

In order to compensate for economy of scale, and subsequently be competitive with large scale nuclear power projects, the Westinghouse SMR construction schedule must be compressed significantly. In order to do this, the Westinghouse SMR uses, to a much greater extent, the modular construction techniques pioneered by Westinghouse during the implementation of the **AP1000** plant. The cost of systems, components and structures can be greatly reduced by manufacturing them in factories in lieu of constructing them at the site. A commonly accepted rule is that; if something cost $1 to produce in a factory it will cost $3 if fabricated at the site and if this item was to be constructed "in-situ," or commonly known as "in-the-hole," the item would cost $8. The modular design of the Westinghouse SMR significantly increases the number of systems, components and structures that are manufactured in factories.

To reduce construction time, the SMR is almost entirely made from structural composite concrete panels. Eliminating virtually all use of traditional reinforced concrete. In this method of construction, again pioneered by Westinghouse in the deployment of **AP1000** plant, the steel walls that serve as forms for the concrete are left in place. As a result, even the structure of the building entirely modular.

To further compress the schedule for construction, or assembly rather, the Westinghouse SMR nuclear island is constructed from 12 very large modules that are already outfitted with systems and components in an assembly area before being joined together in the hole. These modules are illustrated in Figure 32B.17.

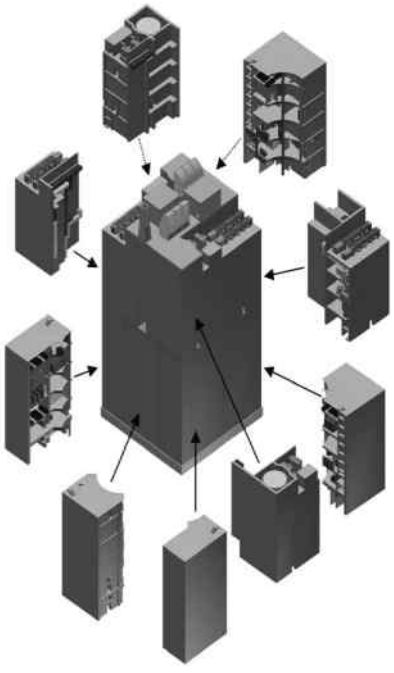


FIG. 32B.17 LARGE MODULES ILLUSTRATED

32B.5 OPERATION AND MAINTENANCE

As with the **AP1000**, the Westinghouse SMR has been designed with a focus on operability and maintainability. Plants

using passive safety systems require fewer components than plants with multiple active safety trains. Fewer components results less maintenance, testing, surveillance and inspection for the plant operators. Additionally fewer active components means fewer potential forced plant outages.

The speed of the eight seal less reactor coolant pumps (RCPs) is controlled using variable frequency drives (VFDs) simplifying plant start-up and shutdown operations. Using VFDs also allows for the pumps that are mounted directly to the reactor vessel to much small and subsequently allow the SMR plant to use a smaller containment vessel.

The Westinghouse SMR uses our licensed digital instrumentation and control (I&C) system simplifying surveillance testing, troubleshooting, repair and post-maintenance testing.

Further challenged by the small footprint of the plant and specifically the tight confines of nuclear island (NI), practical considerations such as inspection, maintenance and ALARA remain a key focus in the design of the plant.

32B.6 CONSTRUCTION CODE

The Westinghouse SMR is being designed the structural codes that are currently endorsed by the United States Nuclear Regulatory Commission (USNRC). It is anticipated that the latest edition approved ASME B&PV Code at the time of design certification application (DCA) will be the 2007 Edition through 2008 Addenda.

32B.7 LICENSING

To achieve near term operation of an SMR, the Westinghouse philosophy of design is to use many of the components realized in the industry leading **AP1000** plant reactor design. In doing this, the licensing of the Westinghouse SMR will be streamlined, yet maintain the highest level of safety. Specifically, the Westinghouse SMR builds upon the following technology achieved in the **AP1000** plant reactor design:

- Passive Safety Systems
- Forced Flow for Normal Operation
- Instrumentation and Control
- Control Rod Drive Mechanisms
- 17 × 17 RFA Fuel

Designed as a standard plant, the Westinghouse SMR will be licensed under the 10CFR Part 52 that allows owners to obtain a combined operating license (COL).

32B.8 REFERENCES

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CHAPTER

33

NEW DELIBERATIONS-FUSION REACTORS PART A: THEORETICAL BASES AND SCIENTIFIC FOUNDATIONS

James A. Mahaffey

PART B: ITER

Brad Nelson

PART C: NUCLEAR FUSION

Irving Zatz

PART 33A THEORETICAL BASES AND SCIENTIFIC FOUNDATIONS

33A.1 INTRODUCTION

The fundamental principles of hydrogen fusion make this process seem inevitable as a method of commercial power production. It is a clean power process, producing no harmful by-product, using an inexhaustible supply of fuel, and hydrogen fusion is the source of all energy release in the larger universe, illumining countless galaxies with starlight. On a terrestrial, non-universal scale, hydrogen fusion can be accomplished on a tabletop using a number of elementary procedures.

On closer examination, fusion principles are not quite as simple nor as inevitable as once believed. The problems of scaling a process of solar size down into an industrial building and causing fusion that will result in a net energy product have proven challenging over the past 60 years of investigation and experimentation. If, however, the basic modes of fusion are examined, the most productive path of this pursuit becomes clear, and power-production experiments are currently in development.

33A.2 THE FUSION OF LIGHT ELEMENTS

The most common material in the universe is simple hydrogen, or hydrogen-1, consisting of a single, positively charged nucleon, the proton, surrounded by a negatively charged electron. This assembly is electrically neutral, and a single unit weighs only 1.67×10^{-27} kg. There are two heavier examples of hydrogen. The isotope deuterium (hydrogen-2) consists of two nucleons, a proton plus a neutral particle, the neutron, forming a nucleus at the center of the unit. The neutron particle weighs about the same as a proton, so deuterium weighs approximately twice as much as hydrogen-1. Tritium (hydrogen-3) has two neutrons in its nucleus, weighing as much as three hydrogen-1s. All three species of hydrogen are chemically identical.

From a purely statistical standpoint, everything in the cosmos is hydrogen-1, with some isolated exceptions, and the hydrogen atom is primarily empty space. If the outer reaches of the electron orbital were the size of a football field, then the nucleus at the center would be the size of a strawberry seed.

Nucleosynthesis occurs when two nuclei fuse together to form a new element that is approximately as heavy as the sum of its components. On the scale of elements by nuclear weight, the next

heaviest element after hydrogen is helium, and its common isotope is helium-4, consisting of two protons and two neutrons and weighing almost four times as much as hydrogen-1. When the synthesized nucleus is lighter than iron-56, the combining process sheds excess energy, and the event is named *fusion*. When four hydrogen-1 nuclei fuse to form one helium-4 nucleus, the weight of the assembled unit does not quite add up to that of the four component pieces. This hydrogen fusion event occurs 9.2×10^{37} times per second in the Sun, and that minor weight discrepancy per fusion, the mass deficit, warms the Earth.

Albert Einstein (1879–1955), a German theoretical physicist, presented a logical proof that mass and energy are equivalent as a brief addendum to his paper *Theory of Special Relativity* in 1905 [33A.1]. If mass is lost in a transaction such as the assembly of helium-4 from hydrogen-1 nuclei, then, by the principle of conservation, it must show up as a conversion into energy. The total amount of mass plus energy in the universe is conserved, and there can be no net loss of mass or its equivalent energy in any process. This phenomenon is stated simply in his equation,

$$E = mc^2 \tag{33A.1}$$

E is energy, m is mass, and c^2 is the conversion factor, the speed of light, or *celeritas*, squared. The conversion factor is quite large, about 9×10^{16} in SI units, indicating that very little mass converts to a great deal of energy.

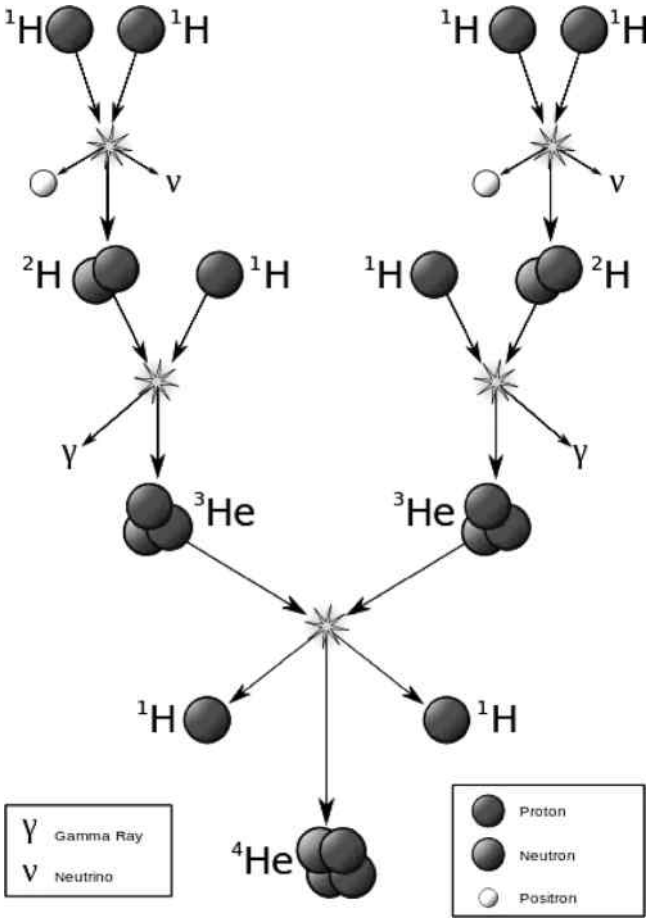


FIG. 33A.1 TWO PROTON–PROTON FUSIONS RESULTING IN HELIUM-4 [33A.3]

Energy escape from the fusion of hydrogen into helium is the major source of power in stars the size of the Sun or smaller. The proton–proton reaction, or PPI, is a multi-stage chain reaction, requiring special conditions of pressure and temperature. It is diagrammed in Fig. 33A.1. To fuse, the nuclei of two atoms must be brought closely together, practically touching, or to within 1 to 3×10^{15} m for the strong nuclear binding force to overcome the Coulombic repulsion of the proton electrical charges. Hydrogen-1 at the center of the Sun is heated to 15,700,000 K, and at this temperature the electron clouds have been stripped away from the single-proton nuclei, leaving the hydrogen in the plasma state.

This problem of bringing two nuclei that electrically repel each other close together is the main technical difficulty of making terrestrial fusion power, but in a structure the size of a star it is inevitable. The gaseous plasma at or near the center of the Sun is pressed to a density of 150 g/cc, or 150 times the density of water. The high temperature causes particles to travel in random directions at extremely high speed, and collisions are highly likely [33A.2].

33A.3 TERRESTRIAL-SCALE FUSION

A terrestrial fusion power plant does not actually achieve the fusion conditions at the center of the Sun. The Sun produces power at the level of 3.85×10^{26} watts, but as an average sized star the Sun weighs 1.99×10^{30} kg and is 109 times as wide as the Earth. Fusion at the core occurs slowly, giving a power-production density of about 277 watts per cubic meter, which approximately describes the metabolism of a reptile. An adult box turtle, awake and occupying 500 cc of space, therefore generates as much heat as a similar volume of plasma at the center of the Sun. An active compost heap the size of the Sun would glow white from the heat build-up and illumine the Earth. The problem of achieving power production by fusion in an Earth-based reactor is therefore not to emulate the Sun; rather it is to create fusion under conditions that are orders of magnitude greater than occur in the Sun, which has a volume 1,300,000 times that of Earth. To do so requires greater core temperature and greater pressure in a structure that can occupy a realistically sized building.

Another way of visualizing the size of the Sun is to consider the time it takes for a photon to travel from its release in a PPI fusion at the center and travel to the surface. The photon travel time, in a random path at the speed of light, reflecting innumerable times off matter in the Sun, is no shorter than 10,000 years, nor longer than 170,000 years. Each photon starts traveling as a high-energy gamma ray, but by the time it reaches the surface of the Sun and enters the vacuum of space, its energy has been downgraded to yellow light from the multiple reflections.

The PPI reaction begins with a collision, producing a highly unstable configuration of a proton stuck to a proton by nuclear binding force. One of the protons immediately decays into a neutron, and the combination becomes a hydrogen-2 (deuterium) nucleus. The proton decay ejects a positron, or anti-electron, plus a neutrino and a modest 0.42 MeV of kinetic energy. The anti-electron immediately finds an electron in the plasma soup, and the two annihilate one another. The energy of the matter destruction is carried off as two gamma rays, totaling 1.02 MeV of energy.

The deuterium then collides with another proton (hydrogen-1 nucleus) and produces a light isotope of helium (helium-3). The energy of this fusion is carried away as a single gamma ray, having an energy of 5.49 MeV. The total energy released from this sequence of events is 6.93 MeV.

From this point there are three possible ways to make the final product, which is a common helium-4 nucleus, by fusing two deuterium nuclei. The simplest reaction and thus the most likely to occur is the PPI, in which two helium-3 nuclei, left over from two examples of the first reaction, collide and result in one helium-4 plus two freed protons, ejected with a kinetic energy of 12.86 MeV. The total energy released by the PPI chain reaction is 26.72 MeV, and 86 percent of the proton–proton fusions occur in this mode. To put this in perspective, a single fission of a uranium-235 nucleus releases 210 MeV of energy (200 MeV recoverable). Burning a single molecule of coal releases less than 0.000001 MeV of energy.

The first experimental confirmation of fusion theory was performed by Mark Oliphant (1901–2000), an Australian physicist at the Cavendish Laboratory, University of Cambridge, England, in 1932 [33A.4]. He discovered the light isotopes helium-3 and hydrogen-3 (tritium). Oliphant used a 500-KV linear accelerator to accelerate deuterons (deuterium nuclei) into stationary tritium, creation helium-4 by fusion. This reaction is diagrammed in Fig. 33A.2. Terrestrial, small-scale fusion giving an energy release of 17.6 MeV per reaction was therefore established.

The difference between the solar PPI fusion, requiring a reactor the size of a star, and the deuterium–tritium fusion accomplished in a small laboratory in England was the relative probability of fusion. As with all nuclear reactions, the probability of success is expressed as an effective cross section in square centimeters. A cross section of 10^{-24} cm^2 is one barn, due to the discovery of the fission cross-section of uranium-235, which was found to be "as big as a barn." Of all possible light-element fusions for power production, the deuterium–tritium reaction has the highest measured cross section, 5.0 barns. In contrast, the beginning reaction for the PPI fusion, proton–proton making deuterium, has a theoretical cross section of only 3.6×10^{-26} barns [33A.6]. The probability of reaction, and thus the power density in a fusion reactor, can be increased to practical levels by heating the reactive plasma to high temperatures and increasing the density of the plasma by compression. The high temperature increases the collision speed, and the pressure ensures that there will be something with which to collide.

The deuterium–tritium reaction, while having an attractive cross-section, is not the only fusion mode that is possible for terrestrial power production. Table 33A.1 shows several possible fusion reactions with reasonable fusion cross-sections [33A.7]. Using a deuterium–deuterium fusion could, for example, eliminate the need for tritium fuel. Tritium does not occur naturally, and must be manufactured by exposing lithium-6 to free neutrons, or using a deuterium–deuterium fusion. All fusion cross-sections are temperature dependent, and the maximum cross section plus the temperature (center-of-mass kinetic energy) at which it occurs is shown in the table. The deuterium–tritium fusion has maximum probability at a billion degrees Kelvin, which is 64 times hotter than the center of the Sun.

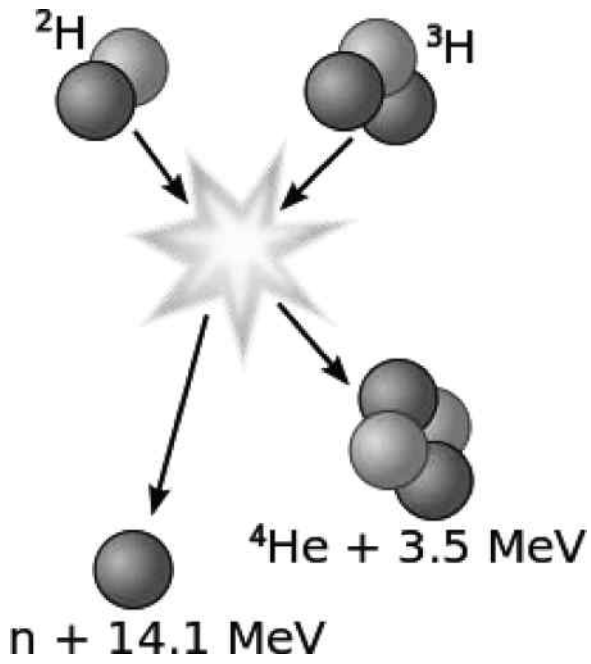


FIG. 33A.2 THE DEUTERIUM–TRITIUM FUSION REACTION [33A.5]

TABLE 33A.1 CHARACTERISTICS OF LIGHT ELEMENT FUSIONS [33A.7]

Reactions	Max Cross-Section (barns)	Kinetic Energy (KeV)	Temperature (°K)
$D + T \rightarrow {}^4He + n$	5.0	64	1.00×10^9
$D + D \rightarrow T + {}^1H$	0.096	1250	1.45×10^{10}
$D + D \rightarrow {}^3He + n$	0.11	1750	2.03×10^{10}
$T + T \rightarrow {}^4He + 2n$	0.16	1000	1.16×10^{10}
$D + {}^3He \rightarrow {}^4He + {}^1H$	0.9	250	2.90×10^9
${}^1H + {}^6Li \rightarrow {}^4He + {}^3He$	0.22	1500	1.74×10^{10}
${}^1H + {}^{11}B \rightarrow 3{}^4He$	1.2	550	6.38×10^9

Aside from the effort of producing tritium, there was a problem to be overcome with producing clean power from deuterium-tritium reactions: More power was required to run Oliphant's accelerator at 500 KV than was recoverable from the fusions [33A.8]. Even with an enormous cross-section of the deuterium-tritium reaction, the fusion was still improbable. Efforts to achieve sufficient temperature and pressure conditions to make net power from this reaction remain in progress.

33A.4 TERRESTRIAL POWER PRODUCTION THEORIES

The first successful creation of net energy from deuterium-tritium fusion was on November 1, 1952, on Eugelab Island in the Pacific Ocean. An energy pulse of 5×10^{16} joules was made by compressing a two-story tall Dewar flask filled with a deuterium-tritium mixture held in liquid form at –253°C using a plutonium-powered atomic bomb [33A.9]. Energy yield of the experiment was the equivalent of exploding 12 million tons of TNT, and Eugelab Island ceased to exist.

Success of this experiment was impressive, and it proved that net power could be made using terrestrial-scale fusion, but the task of reducing this mono-pulse mode down to a continuous or semi-continuous power source has required several decades of international research. There are currently two modes of power-level fusion under development: inertial confinement and magnetic confinement.

Inertial confinement compresses and heats a small ball of deuterium-tritium ice into an extremely small ball of deuterium-tritium plasma using a collapsing, spherical wave-front of coherent light. The wave-front is provided by multiple, synchronized, high-power lasers, optically aimed into the ice-ball. While countable fusions have been produced by this method, the goal is to produce self-sustaining fusions. In this mode, the heat and pressure necessary to fuse a practical percentage of the hydrogen isotope mixture is produced by the initial fusions triggered by the sudden compression of the ice-ball. A power plant running on this principle will operate in a pulsed mode, making steam to turn a turbine with several mini-thermo-nuclear explosions per second. At this writing, a self-sustained inertial fusion event has yet to occur [33A.10].

Magnetic confinement exploits the electrical qualities of hydrogen isotope plasma by confining and compressing volumes of plasma using carefully shaped, powerful magnetic fields. This mode of operation isolates the plasma from physical influences, causing it to levitate in mid-space and avoid contact while being compressed by nothing but magnetic forces. Additional triggering heat is injected from outside the plasma using a variety of energy projection methods, including microwaves and particle beams. This method shows great promise, with remaining challenges in magnetic-field stability and unpredictable plasma behavior [33A.11].

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33A.6 NOMENCLATURE

D	deuterium
K	kelvin
KeV	thousand electron volts (1.16×10^7 °K)
KV	kilovolts
MeV	million electron volts (1.602×10^{-13} joules)
n	neutron
PPI	proton–proton fusion reaction, type I
SI	Le Système International d'unités (the metric system)
T	tritium
TNT	tri-nitro-toluene

PART 33B ITER

This chapter is a compilation of content from www.ITER.org and is attributable to the ITER team [33B.1].

33B.1 ITER BACKGROUND

ITER (Latin for "the way") is a major international research project with the goal of demonstrating the scientific and technological feasibility of fusion energy. ITER is designed to be the world's first fusion device large enough to produce a self-heated or "burning" plasma [33B.2].

The project is being designed and built by seven partners: the European Union, India, Japan, the People's Republic of China, the Republic of Korea, the Russian Federation, and the United States. The site for the device is near St.-Paul-lez-Durance in southeastern France, with the European Union as the host party. Each partner will contribute hardware components, personnel, cash for the central ITER organization, and contingency during the construction phase of the project.

33B.2 ITER DESIGN DESCRIPTION

ITER will use the magnetic confinement approach to fusion, where ionized fuel, plasma, is confined with a high magnetic field and heated to fusion temperatures. The ITER configuration is a long-pulse tokamak (toroidal shaped plasma with internal current) designed to operate with a fuel mixture of deuterium and tritium. The ITER tokamak design emphasizes high plasma confinement with a vertically elongated plasma and single-null poloidal divertor. The device is illustrated in Fig. 33B.1 [33B.1] and the main parameters are listed in Table 33B.1. The nominal inductive operation will produce fusion power of 500 MW for a burn duration of 300 to 500 seconds, with 50 MW of injected auxiliary heating power. Extended operation would aim at steady state performance with a 1000 second or longer pulse length. ITER's 500 MW of fusion power, with only 50 MW of auxiliary heating, will yield an energy gain, or Q, of 10, producing 10 times more power than required to keep the plasma hot.

ITER is situated on a level graded platform of approximately 103 acres and features 39 buildings and technical areas that will house the plant systems necessary for the operation of the tokamak, as illustrated in Fig. 33B.2 and Fig. 33B.3. The Tokamak Building will be the core of ITER. The reinforced, six-story concrete structure will be 73 meters high (13 meters below grade and 60 meters above). Pre-assembly of tokamak components will take place in the adjacent Assembly Hall. Other auxiliary buildings in the vicinity of the Tokamak Building will include cooling towers, electrical installations, a control room, facilities for the management of waste, and the cryogenics plant that will provide liquid helium to cool the ITER magnets.

The major ITER systems include the

- Superconducting magnet system that provides the magnetic field to confine, shape, and control the plasma;
- Vacuum vessel and internal components that surround the plasma;
- Cryostat and thermal shield that provide the insulating vacuum for the superconducting magnets;
- Major ancillary systems that heat and diagnose the plasma;
- Balance of plant systems that support the plasma fuel cycle and provide water cooling, cryogenic cooling, and electrical power; and
- Systems to support assembly and maintenance of the tokamak.

33B.2.1 Magnet System

The superconducting magnet system provides the magnetic field to confine, shape, and control the plasma, and consists of the set of toroidal field (TF) coils, the central solenoid (CS), the external poloidal field (PF) coils, and correction coils [33B.3]. The coils are designed to the ITER Magnet Structural Design Criteria, an internal ITER document using design rules similar to the ASME code but modified to account for behavior of materials at low temperature.

33B.2.1.1 Toroidal Field Coils The set of 18 toroidal field (TF) coils produce a magnetic field around the torus, whose primary function is to confine the plasma particles. The TF coils will have

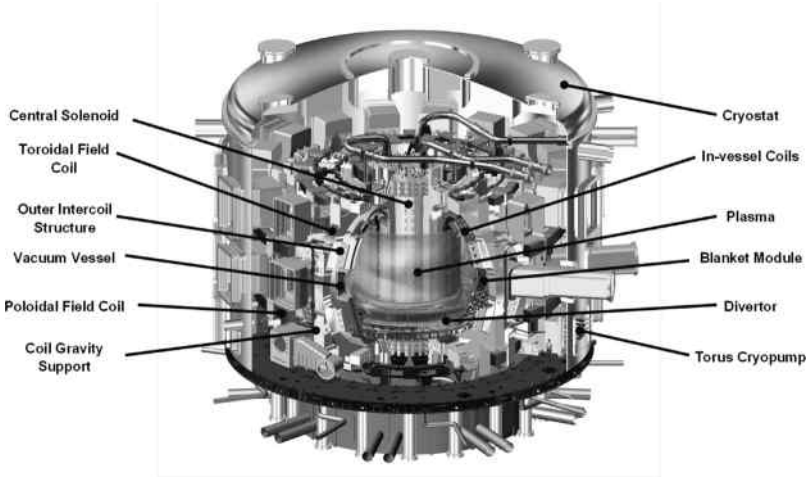


FIG. 33B.1 THE ITER TOKAMAK (*Source*: US ITER [33B.1])

TABLE 33B.1 MAIN PARAMETERS OF ITER

Total Fusion Power	500 MW (700 MW)[1]
Fusion Power Gain, Q	≥ 10 (inductively driven burn)
(Q = fusion power/auxiliary heating power)	≥ 5 (steady state objective)
Plasma inductive burn time	300–500 s
Plasma major radius (R_0)	6.2 m
Plasma minor radius (a)	2.0 m
Plasma current (I_p)	15 MA (17 MA)[a]
Vertical elongation @ 95% flux surface/separatrix (κ_{95})	1.70/1.85
Triangularity @ 95% flux surface/separatrix (δ_{95})	0.33/0.49
Toroidal field @ 6.2 m radius (B_T)	5.3 T
Plasma volume	830 m^3
Plasma surface area	680 m^2
Installed auxiliary heating/current drive power	73 MW (110)[b]

[a]Increase possible with limitations on burn duration.

[b]A total plasma heating power up to 110 MW may be installed in subsequent operation phases.

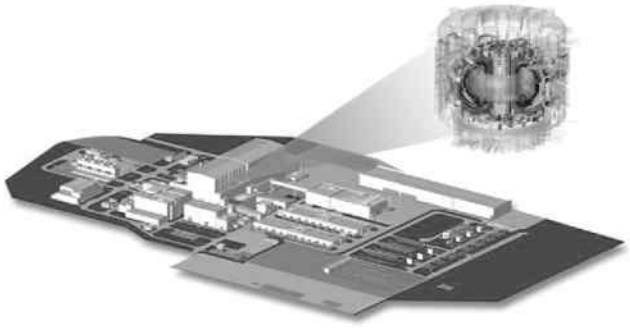


FIG. 33B.2 ITER SITE, WITH LOCATION OF TOKAMAK NOTED (*Source*: ITER Organization and US ITER [33b.1]).

a total magnetic energy of 41 gigajoules and produce a maximum magnetic field of 11.8 tesla. The 18 coils and their structure will weigh 6,540 tons. A TF coil is illustrated in Fig. 33B.4.

The coils will be wound from cable-in-conduit superconductor, in which a bundle of niobium-tin (Nb_3Sn) superconducting strands is cabled together and compacted within a structural stainless steel jacket. The ITER TF coil superconducting strands have a total length of 80,000 kilometers. During operation the conductor is cooled by a flow of supercritical helium through the strands.

The TF coil windings are enclosed in strong cases. The centering force of ~40,000 tons acting on each of the D-shaped TF coils is mutually reacted by these coils wedging into a vault structure formed by their inner most straight sections. The coils are also connected together on the outboard side with an intercoil structure.

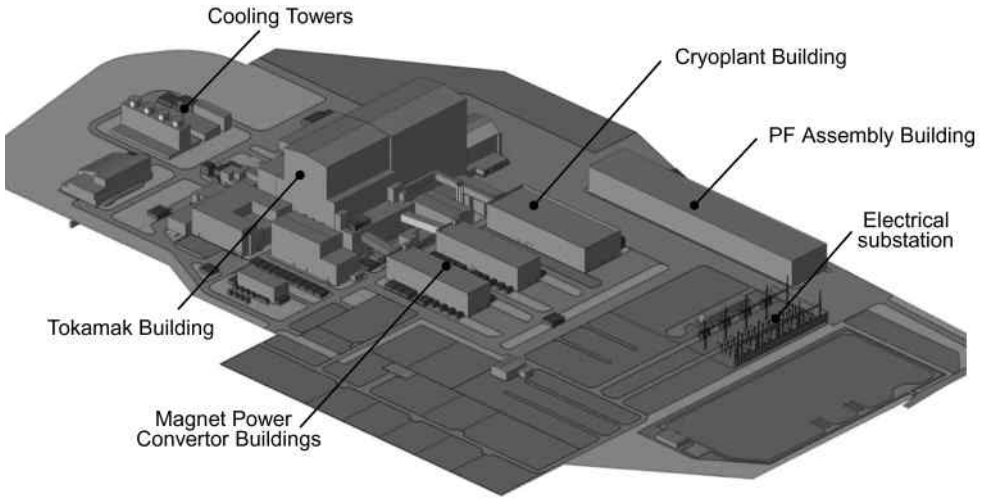


FIG. 33B.3 ITER SITE ILLUSTRATION WITH BUILDINGS NOTED (*Source*: ITER Organization and US ITER [33B.1])

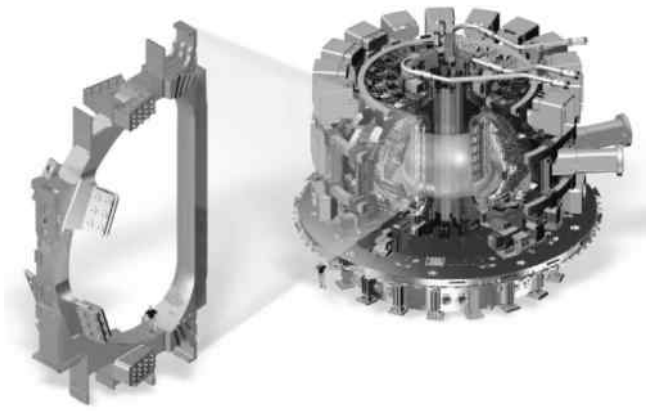


FIG. 33B.4 TOROIDAL FIELD COIL (*Source*: US ITER [33B.1])

The TF structural assembly also serves to support the central solenoid and external PF coils.

33B.2.1.2 Central Solenoid The main plasma current is induced by the changing current in the central solenoid, which is essentially a large transformer. It contributes to the inductive flux that drives the plasma, to the shaping of the field lines in the divertor region, and to vertical stability control. The central solenoid is made of six independent coil packs that use a niobium-tin (Nb_3Sn) cable-in-conduit superconducting conductor, held together by a vertical pre-compression structure. The central solenoid is illustrated in Fig. 33B.5.

Each coil is based on a stack of multiple pancake winding units that minimize joints. A glass-polyimide electrical insulation, impregnated with epoxy resin, gives a high voltage operating capability, and will be tested up to 29 kV. The conductor jacket material must resist the large electromagnetic forces arising during operation and be able to demonstrate good fatigue behavior. The conductor will be produced as 140 lengths up to 910 meters each.

33B.2.1.3 Poloidal Field Coils The poloidal field (PF) coils con-trol the vertical and radial position of the plasma, and contribute to maintaining the plasma's shape and stability. The poloidal field is created both by the PF coils and by the current in the plasma itself.

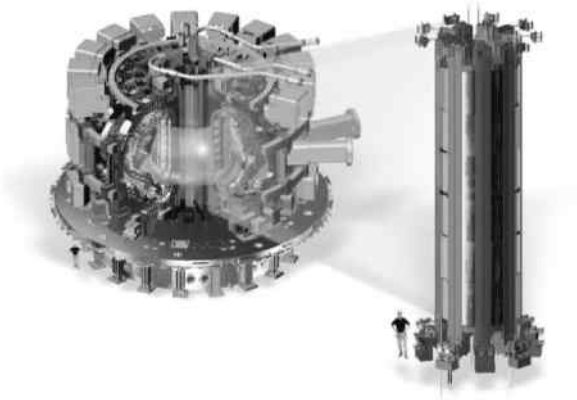


FIG. 33B.5 CENTRAL SOLENOID (*Source*: US ITER [33B.1])

The poloidal field coil system consists of six horizontal coils placed outside the toroidal magnet structure. Due to their size, the actual winding of five of the six poloidal field coils will take place in a dedicated, 257-meter-long coil winding building on the ITER site. The smallest diameter poloidal field coil will be manufactured offsite and delivered as a finished coil.

The ITER poloidal field coils are made of Nb-Ti cable-in-conduit conductors. Two different types of strands are used according to operating requirements, with each strand type displaying differences in high-current and high-temperature behavior.

33B.2.1.4 Correction Coils The correction coils consist of nine window-framed shaped coils attached to the top, outside perimeter, and bottom of the TF coil set. These coils provide a means to correct field errors due to manufacturing and assembly imperfections.

33B.2.2 Vacuum Vessel and Internal Components

The vacuum vessel serves as the plasma chamber and first containment barrier. Inside the vacuum vessel are the internal, replaceable components, including blanket modules, divertor cassettes, and port plugs such as the limiter, heating antennae, test blanket modules, and diagnostics modules. These components absorb the radiated heat as well as most of the neutrons from the plasma, and protect the vessel and magnet coils from excessive nuclear radiation and heating.

The heat deposited in the internal components and in the vessel is rejected to the environment by means of the tokamak cooling water system. It is comprised of individual heat transfer systems. Some elements of these heat transfer systems are also employed to bake and consequently clean the plasma-facing surfaces inside the vessel by releasing trapped impurities. The system is also designed to prevent the possibility of releases of tritium and activated corrosion products to the environment.

33B.2.2.1 Vacuum Vessel The torus-shaped vacuum vessel is located inside the bore of the TF coils and provides the low gas pressure conditions needed to initiate and maintain a fusion reaction plasma. In this torus-shaped chamber, the plasma particles follow the magnetic field surfaces, thereby avoiding contact with the vessel walls. The magnet system together with the vacuum vessel and internals are supported by gravity supports, one beneath each TF coil.

The ITER vacuum vessel will be twice as large and 16 times as heavy as any previous tokamak chamber, with an internal diameter of 6 meters. It will measure a little over 19 meters across by 11 meters high, and weigh in excess of 5,000 tons [33B.4].

The vacuum vessel, illustrated in Fig. 33B.6, will have double steel walls, with the interspace filled with stainless steel shielding and cooling water. The plasma facing surfaces of the vessel will support the in-vessel coils and a continuous layer of blanket modules that will provide shielding from the high-energy neutrons produced by the fusion reactions.

Forty-four ports will provide access to the vacuum vessel for remote handling operations, diagnostic systems, heating, and vacuum systems: 18 upper ports, 17 equatorial ports, and 9 lower ports.

Because the vacuum vessel is the primary containment barrier against release of tritium and activated dust, it is being constructed according to RCC-MR, the French nuclear code. Due to the double wall construction and high water pressure, it must also meet

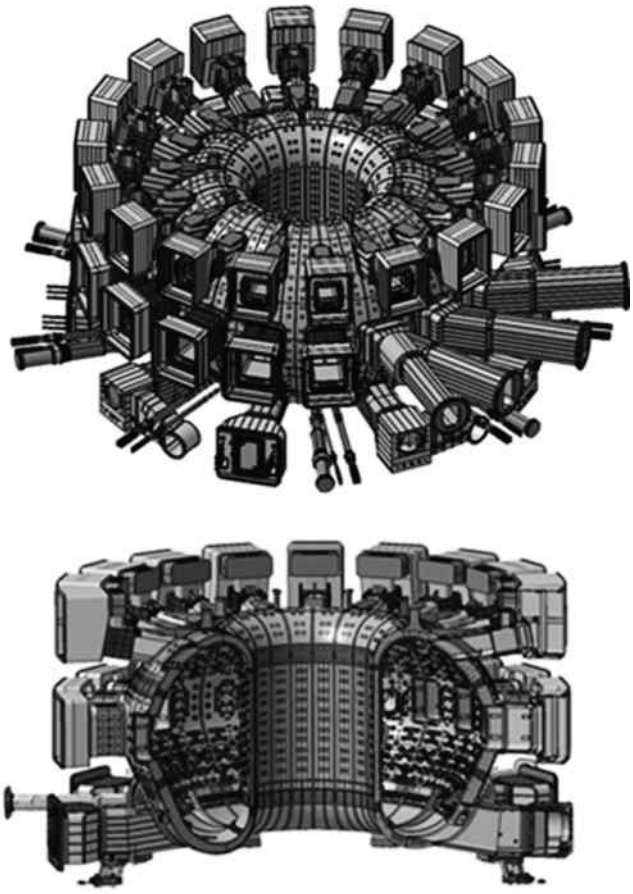


FIG. 33B.6 VACUUM VESSEL WITH PORT EXTENSIONS (*Source*: ITER Organization 33B.1)

the essential French safety requirements for nuclear pressure equipment [33B.5].

33B.2.2.2 Blanket System The blanket covers the interior surfaces of the vacuum vessel, providing shielding to the vessel and the superconducting magnets from the heat and neutron fluxes of the fusion reaction. The neutrons are slowed down in the blanket, where their kinetic energy is transformed into heat energy and collected by the cooling water system.

For purposes of maintenance on the interior of the vacuum vessel, the blanket wall is modular. It consists of 440 individual blanket modules, each measuring 1×1.5 meters and weighing up to 4.6 tons. Each module has a detachable first wall, which directly faces the plasma and removes the plasma radiation and charged particle heat load, plus a semi-permanent blanket shield dedicated to the neutron shielding. The blanket system is illustrated in Fig. 33B.7 [33B.6].

The ITER blanket is one of the most critical and technically challenging components in ITER: Together with the divertor, the blanket directly faces the plasma. Because of its unique physical properties, beryllium has been chosen as the element to cover the plasma facing surface, "first wall" of the blanket. The rest of the blanket shield layers will be made of high-strength copper backed by stainless steel with internal water-cooling channels.

33B.2.2.3 Divertor Located at the very bottom of the vacuum vessel, the divertor collects and neutralizes the charged particles leaving the plasma including the inert helium "ash" and directs these neutral gas particles via the vacuum pumping system to the exhaust processing system. The divertor consists of 54 remotely-removable cassettes, each holding three plasma-facing component assemblies, or targets, as illustrated in Fig. 33B.8. These are the inner and the outer vertical targets, and the dome. The targets are situated at the intersection of magnetic field lines where the high-energy plasma particles strike the components and their kinetic energy is transformed into heat. The heat flux received by these components is extremely intense and requires active water-cooling. The choice of the surface material for the divertor is an important one [33B.6]. Only a few materials are able to withstand temperatures of up to 3,000 Celsius for the projected 20-year lifetime of the ITER machine; these materials will be tested during ITER operations.

33B.2.2.4 Internal Coils There are two sets of the magnetic coils inside the vacuum vessel: The vertical stability coils and the edge-localized mode (ELM) control coils. The vertical stability coils consist of continuous windings above and below the midplane that provide fast vertical position control of the plasma. The ELM coils consist of nine sets of three window-framed coils that produce a resonant magnetic perturbation, which limits the energy in ELM events or suppresses the ELMs altogether. Unmitigated

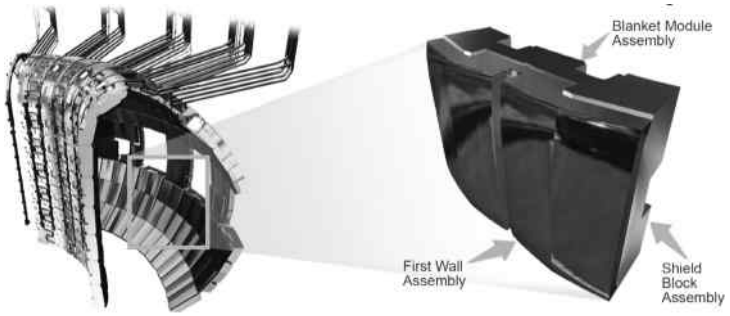


FIG. 33B.7 BLANKET MODULE ASSEMBLY (*Source*: US ITER [33B.1])

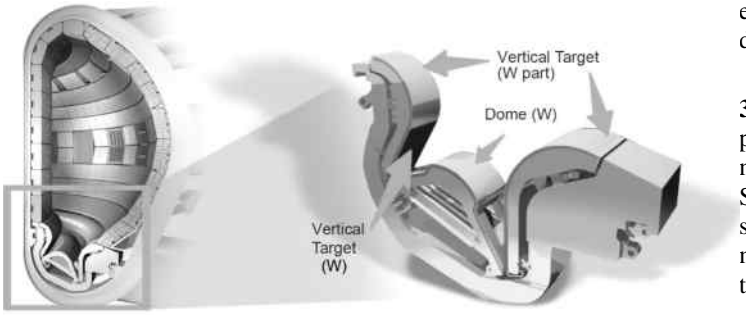


FIG. 33B.8 DIVERTOR MODULE (*Source*: ITER Organization and US ITER [33B.1])

ELMs would cause substantial erosion of the plasma-facing components, especially the divertor.

33B.2.3 Cryostat and Thermal Shield

The cryostat is a large, stainless steel structure surrounding the tokamak that provides the insulating vacuum for the superconducting magnets, much like a giant thermos bottle. It consists of a single wall cylindrical construction, reinforced by horizontal and vertical ribs. The cryostat is 29.3 meters tall and 28.6 meters in diameter [33B.8].

The cryostat has many openings, some as large as 4 m in diameter, which provide access to the vacuum vessel for cooling systems, magnet feeders, auxiliary heating, diagnostics, and the removal of blanket and divertor components. Large bellows are used between the cryostat and the vacuum vessel to allow for differential thermal contraction and expansion in the structures. The cryostat is completely surrounded by a 2-meter-thick concrete bioshield.

The thermal shield is a set of stainless steel panels, cooled with supercritical helium at 80 K, which provide a thermal radiation barrier between the magnet set and any warm surfaces (i.e. vacuum vessel and cryostat) [33B.9].

33B.2.4 Ancillary Systems

The ancillary systems include the port-mounted systems to diagnose the plasma and to heat the plasma and assist with driving internal plasma currents.

33B.2.4.1 Diagnostics An extensive array of diagnostic tools will be installed on the ITER machine to provide the measurements necessary to control, evaluate and optimize plasma performance and to further the understanding of burning plasma physics. Parameters measured by diagnostics include temperature, density, impurity concentration, and particle and energy confinement times.

The system will comprise about 50 individual measuring systems drawn from the full range of modern plasma diagnostic techniques, including lasers, X-rays, neutron cameras, impurity monitors, particle spectrometers, radiation bolometers, pressure and gas analysis monitors, and optical fibers [33B.10].

Because of the harsh environment inside the vacuum vessel, these systems will have to cope with a range of phenomena not previously encountered in diagnostic implementation, all while t performing with great accuracy and precision. The levels of neutral particle flux, neutron flux and fluence will be respectively about 5, 10, and 10,000 times higher than the harshest conditions experienced in today's magnetic fusion machines, while the pulse duration will be about 100 times longer.

33B.2.4.2 Heating and Current Drive Systems The plasma temperatures inside the ITER tokamak must reach greater than 150 million Celsius—or ten times the temperature at the core of the Sun—in order for the gas in the vacuum chamber to reach the plasma state and for efficient fusion reactions to occur. The hot plasma must then be sustained at these extreme temperatures in a controlled way in order to extract net energy.

ITER will rely on three sources of external heating which will work in concert to provide the required input plasma heating power of 50 MW: Neutral beam injection and two sources of high-frequency electromagnetic waves [33B.11]. The characteristics of these systems are listed in Table 33B.2.

TABLE 33B.2 HEATING AND CURRENT DRIVE SYSTEMS OF ITER [33B.11]

Heating system characteristic	Neutral beam (NB)	Electron cyclotron (EC)	Ion cyclotron (IC)
Energy or frequency	1 MeV	170 GHz	40–55 MHz
Power injected-per unit equatorial port (MW)	16.5	20	20
Number of units for the first phase	2	1	1
Total Power (MW) for the first phase	33	20	20

33B.2.5 Balance of Plant Systems

ITER will require large capacity fueling, vacuum, cooling water, cryogenic, and electrical systems.

33B.2.5.1 Fuel Cycle Systems The deuterium and tritium fuels used in ITER will be processed in a closed cycle, as illustrated schematically in Fig. 33B.9.

As a first step to starting the fusion reaction, all air and any gas impurities must be evacuated from the vacuum vessel. The main pumping system consists of a set of six torus exhaust cryo-pumps. The cryo pump panels will be cooled with supercritical helium in order to condense the deuterium and tritium and other gas streams.

Low-density gaseous fuel is then introduced into the vacuum vessel by a gas injection system. Once the fuel is in the vacuum chamber, an electrical current is applied via the central solenoid coil system which causes the gas to break down electrically, become ionized, and form a plasma.

A second fuelling system, a pellet injector, will also be used at ITER. The pellet injector operates like a highly-efficient ice maker for frozen fuel pellets. An extruder punches out several millimeter-sized deuterium-tritium ice pellets that are propelled

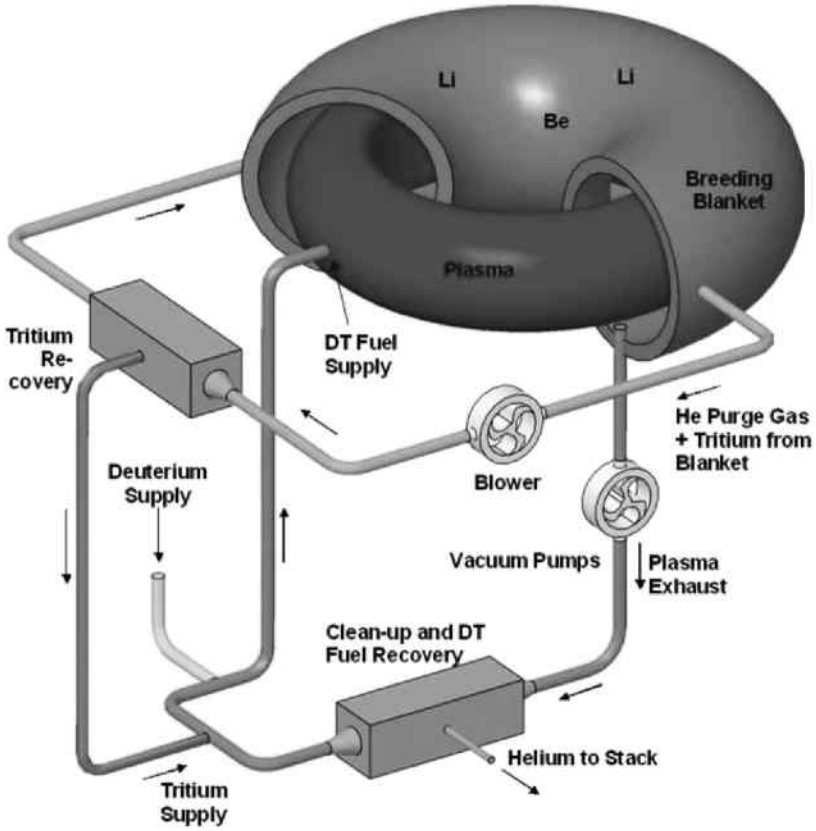


FIG. 33B.9 FUEL CYCLE SCHEMATIC (*Source*: ITER Organization [33B.1])

by a gas gun at approximately 300 m/s—fast and cold enough to penetrate deep into the plasma core where they vaporize and deposit fresh fuel. The frozen pellets are injected through a guide tube located in the inner wall of the vacuum vessel and another guide tube for outer wall injection [33B.12].

Pellet injection is the principal tool used to control plasma density and is also efficient at controlling Edge Localized Modes, or ELMs. Injecting small frozen deuterium pellets in the edge plasma, has been shown to be effective in ELM mitigation [33B.12].

Less than 1 g of fusion fuel is present in the vacuum vessel at any moment in time. The divertor, located at the bottom of the vacuum vessel, permits recycling of any fuel that is not consumed: Unburned fuel flows to the divertor, is pumped out and separated from helium produced during the fusion reaction, mixed with fresh tritium and deuterium, and is re-injected into the vacuum chamber.

33B.2.5.2 Cooling Water System ITER will be equipped with a cooling water system to manage the heat generated during operation of the tokamak. The internal surfaces of the vacuum vessel (first wall blanket and divertor) must be cooled to less than 600°C only a few meters from the 150-million-degree plasma.

Water will be used to remove heat from the vacuum vessel and its components, and to cool auxiliary systems such as radio frequency heating and current drive systems, the chilled water system (CHWS), the cryogenic system, and the coil power supply and distribution system. The cooling water system incorporates multiple closed heat transfer loops plus an open-loop heat rejection system (HRS). Heat generated in the plasma during the deuterium-tritium reaction will be transferred through the tokamak cooling water system (TCWS) to the intermediate component cooling water system (CCWS), and to the HRS, which will reject the heat to the environment. The cooling water system must reject over 1 GW of thermal energy.

33B.2.5.3 Cryogenic System A cryoplant on the ITER platform will be used to create and maintain low-temperature conditions for the magnet, vacuum pumping and some diagnostics systems.

The cryoplant is composed of helium and nitrogen refrigerators combined with an 80 K helium loop. Storage and recovery of the helium inventory (25 tons) is provided in warm and cold (80 K and 4 K) gaseous helium tanks. Three helium refrigerators supply the required cooling power via an interconnection box providing the interface to the cryodistribution system. Two nitrogen refrigerators provide cooling power for the thermal shields and the 80 K pre-cooling of the helium refrigerators. The ITER cryogenic system will be capable of providing cooling power at three different temperature levels: 4 K, 50 K, and 80 K.

The ITER cryogenic system will be the largest concentrated cryogenic system in the world with an installed cooling power of 85 kW at 4.5 K (helium) and 1300 kW at 80 K (nitrogen). After the Large Hadron Collider at CERN, it is the largest cryogenic system ever built [33B.13].

33B.2.5.4 Electrical System and Power Supplies Electricity requirements for the ITER plant and facilities will range from 150 MW to up to 620 MW for peak periods of 30 seconds during

plasma operation. Power will be provided through a 1-km extension of the 400 kV circuit that already supplies the nearby CEA Cadarache site [33B.14].

ITER will have a steady state distribution system to supply the electricity needed to operate the entire plant, including offices and the operational facilities. The cooling water and cryogenic systems will together absorb about 80% of this supply.

A second pulsed power system will be used during plasma operation to provide the superconducting magnet coils and the heating and current drive systems with the large amount of power required. Electricity from the 400 kV circuit will be transformed to an intermediate level (69 kV) via three step-down transformers.

33B.2.6 Assembly and Maintenance

ITER assembly will require a substantial number of special purpose tools, and maintenance of the internal components will require remote handling.

33B.2.6.1 Assembly The ITER Organization has overall responsibility for the successful integration and assembly of components delivered to the site by the seven ITER Members. This scope includes the assembly of the tokamak, with its estimated one million components, and the parallel installation and integration of plant systems such as radio frequency heating, plus fuel cycle, cooling water and high voltage electrical systems [33B.15].

Components provided by the ITER Mmembers as in-kind contributions will be assembled on site in pre-determined sequences. The order and timeline for assembly events has been carefully planned in an assembly schedule that contains 40,000 lines for machine assembly alone. Assembly operations will require 1.5 million person hours extending over a period of four years.

The principal assembly activities will be performed in the Tokamak Building, where the ITER device will be installed inside of a partially embedded, concrete bioshield. For the duration of assembly activities, the Tokamak Building will be operated as a "clean area" and maintained at a constant temperature to avoid dimensional changes in the largest components. Pre-assembly activities will take place in the adjacent Assembly Building.

Assembly of the ITER tokamak will proceed in a "bottom-up" fashion. Beginning with the base section of the cryostat—the single largest and heaviest component of the ITER machine—assembly operations will continue with the lower cryostat components, the nine large, 40 sub-assembled sectors (made up of a vacuum vessel sector, surrounding thermal shields, and two toroidal field coils), and finally the components at the top of the machine.

Accurate alignment of tokamak elements, particularly of the magnet system and in-vessel components, is essential to the successful operation of the machine. Assembly sequences have been planned with this in mind, and will utilize sophisticated optical metrology techniques at each step of the assembly process. Dimensional control will be critical to ensuring that components adhere to tolerances, and to recording the "as-built" status of the machine, which will be directly compared against ITER's computer-aided-design (CAD) models in order to correct eventual deviations in alignment before they accumulate.

33B.2.6.2 Remote Maintenance When operation begins, it will be impossible to make changes, conduct inspections, or repair any of the tokamak components in the activated areas other than by remote handling. Highly reliable and robust remote handling techniques will be necessary to manipulate and exchange components weighing up to 50 tons. The reliability of these techniques will also impact the length of the machine's shut-down phases.

All remote handling techniques developed for ITER operate on the same general procedure. A remote manipulator (Fig. 33B.10) is used to detach the component; the component is removed through a port and placed into the docked transport cask; a temporary door is placed over the vacuum vessel access port; and the cask is closed to prevent contamination. The cask is moved on air bearings along to the Hot Cell Facility. A similar docking occurs at the Hot Cell Facility and the component is removed to be repaired or replaced. The process is then reversed to bring that component back to the vacuum vessel.

33B.3 ITER SAFETY AND LICENSING

Safety is a top-priority issue for the project and includes consideration of the safety of the project staff and workers on site, the local population and the environment. French nuclear regulations have been applied throughout the design phase of the project, and will continue to be followed during construction, operation, and decommissioning [33B.16].

The fusion process itself is inherently safe. In a tokamak fusion device, the quantity of fuel present in the vessel at any one time is sufficient for a few-seconds burn only. It is difficult to reach and maintain the precise conditions necessary for fusion; any signifi-

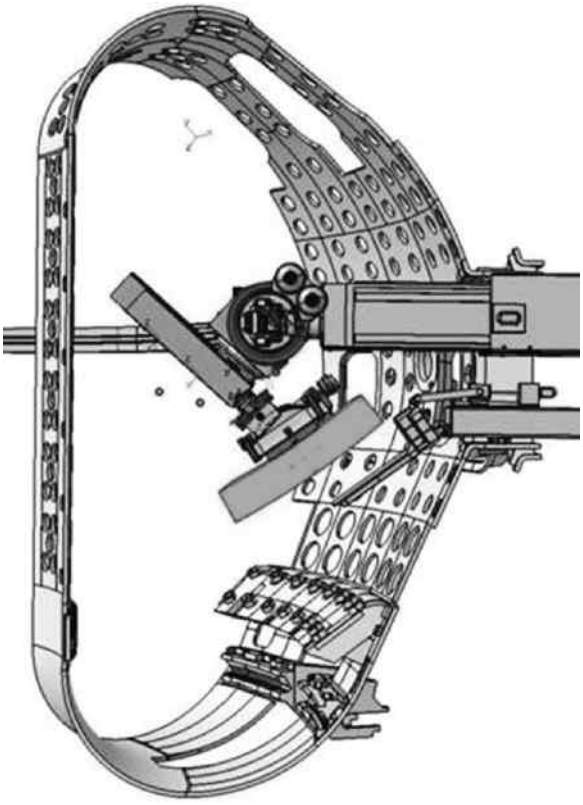


FIG. 33B.10 REMOTE IN-VESSEL MANIPULATOR (*Source*: ITER Organization [1])

cant degradation of these conditions will cause the plasma to cool within seconds and stop the reaction, much in the same way that a gas burner is extinguished when the fuel tap is turned off. There is no danger of a run-away reaction or explosion.

When the highly energetic neutrons interact with the walls of the internal components and the plasma chamber, these materials become activated. In-vessel materials can also become contaminated with small amounts of radioactive dust, mainly beryllium and tungsten, and tritium.

In ITER, confinement of these materials will be based on the Russian doll principle: Materials with the highest radioactive content are located in the very center, surrounded by multiple protective layers. Maintenance and refurbishment of the radioactive elements and components of the tokamak are performed using machines and tools controlled remotely to avoid human exposure to radioactivity. Two-meter-thick concrete walls will completely surround the tokamak. This protective layer is known as the bioshield.

During the operational lifetime of ITER, remote handling will be used to refurbish components of the vacuum vessel. All waste materials will be treated, packaged, and stored on site. The half-life of most radioisotopes contained in this waste is less than ten years. The fusion reaction will produce no long-lived waste: Within 100 years, the radioactivity of the materials will have diminished in such a significant way that the materials can be recycled for use in future fusion plants [33B.17].

The confinement of tritium within the fuel cycle is one of the most important safety objectives at ITER. A multiple-layer barrier system has been designed to protect against spread or release of tritium. The first level of the safety confinement barrier is the vacuum vessel itself: inside this double-steel container, the fusion reaction takes place within a vacuum. All pumps, pipes, valves and instruments leading into the vacuum vessel are highly leak-tight.

Surrounding the first confinement system is a second level of security comprising all vessels or systems that surround the vacuum vessel, including buildings as well as advanced detritiation systems for the recovery of tritium from gas and liquids. In ITER, these highly-developed detritiation systems will work efficiently to keep the fusion fuels recycled within a closed system and maintain any releases well below regulatory limits.

Detritiation systems in ITER have been designed to remove tritium from liquids and gases for reinjection into the fuel cycle. Remaining effluents will be well below authorized limits: Gaseous and liquid tritium releases to the environment from ITER are predicted to have a dosimetry below 10 μSv per year. This is well under ITER's General Safety Objective of 100 μSv per year and 100 times lower than the regulatory limit in France of 1,000 μSv per year. Scientists estimate exposure to natural background radiation to be approximately 2,000 μSv per person per year.

To mitigate seismic risks, the ITER tokamak complex will be made of specially reinforced concrete, and will rest upon bearing pads, or pillars, that are designed to withstand earthquakes. Cadarache, France is classified as an area of moderate seismic activity. The ITER facility will be equipped with seismic sensors around the site to record all seismic activity, however minor.

ITER safety processes will comply with French and international regulations. The ITER installation is classed as a "basic nuclear installation" by French authorities. A successful Public Enquiry was held in 2011, and on 20 June 2012 the ITER Organization was informed in writing by the Autorité de Sûreté Nucléaire (ASN) that—following an in-depth technical inspection—the operational conditions and the design of ITER as described in the ITER safety files fulfilled expected safety requirements. The decree authorizing the creation of the ITER nuclear facility was signed by the French Prime Minister on November 10, 2012, concluding the licensing process for ITER.

As part of its responsibilities as a nuclear operator, the ITER Organization will perform regular checks on the installation during construction and operation. French nuclear authorities will also audit and inspect the ITER Organization's application of regulations.

33B.4 REFERENCES

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PART C NUCLEAR FUSION

33C.1 INTRODUCTION

Nuclear fusion is a process where two light atoms' nuclei (typically hydrogen) fuse at an atomic level and form a heavier nucleus while releasing energy. This contrasts with the nuclear fission process that produces energy by splitting heavier atoms into lighter ones. Energy is created in both of these processes through Einstein's famous equation $E = mc^2$. That equation shows a relationship between mass and energy. In fact, it shows that a very small amount of mass can be converted into enormous amounts of energy. In both the fusion and fission processes, the end products weigh slightly less than the atoms at the start of the process. This loss of mass is converted to energy which can be recovered in reactors in power plants and turned into electricity. The stars, including our Sun, are natural fusion reactors.

A description of the fusion process can be found on the Princeton University Plasma Physics Laboratory website [33C.1] (http://www.pppl.gov/about/fusion-basics).

Light atoms like hydrogen (one proton and one neutron) can fuse together so tightly that they release energy. This will only happen if the two positively charged nuclei get close enough that they overcome the electric force pushing them apart. When the nuclei get close enough, the force that binds protons and neutrons together, the strong force, takes over and pulls the nuclei even closer together.

The sun's core is a natural fusion reactor. Before the sun formed, it was a cloud of gas mostly made up of hydrogen and some helium. At some point, the cloud became so massive that gravity caused it to collapse in on itself and it formed a star. Numerous collisions in the core of the sun freed electrons from ions, forming a plasma state. Plasma is a state of matter along with solids, liquids and gases. It consists of a partially-ionized gas, containing ions, electrons, and neutral atoms. Fusion began in the sun when collisions between ions became so frequent that the ions got close enough to fuse together.

The sun uses gravity to get its nuclei close enough and hot enough to start fusion. On Earth, researchers are trying to build fusion reactors of their own. They try to get atoms close enough by maximizing the number of ions in a small region and the amount of time that they stay close together. In order to do that, reactors get heated to temperatures much hotter than the core of the sun (>100,000,000°C) which converts hydrogen gas into a hydrogen plasma. Strong magnetic fields or high-powered lasers then confine the plasma into a small controllable region where fusion can happen.

33C.2 NUCLEAR FUSION IN THE US

In the United States, much of the research in fusion energy is supported by the Department of Energy's Office of Science, Fusion Energy Sciences (FES) branch. The FES website outlines the fusion program and its mission on its website [33C.2] (http://science.energy.gov/fes/).

The pursuit of fusion energy embraces the challenge of bringing the energy-producing power of a star to earth for the benefit of humankind. The promise is enormous—an energy system whose fuel is obtained from seawater and from plentiful supplies of lithium in the earth, whose resulting radioactivity is modest, and which yields zero carbon emissions to the atmosphere. The pursuit is one of the most challenging programs of scientific research and development that has ever been undertaken. With the support of FES, a devoted, expert, and innovative scientific and engineering workforce has been responsible for the impressive progress in harnessing fusion energy since the earliest fusion experiments over sixty years ago. As a result, we are on the verge of a new age in fusion science during which researchers will undertake fundamental tests of fusion energy's viability. Establishing a deep scientific understanding of the requirements for harnessing and optimizing this process on earth is critical, and the progress has been dramatic.

The science underpinning much of fusion energy research is plasma physics. Plasmas—the fourth state of matter—are hot gases, hot enough that electrons have been knocked free of atomic nuclei, forming an ensemble of ions and electrons that can conduct electrical currents and can respond to electric and magnetic fields. The science of plasmas is elegant, far-reaching, and impactful. Comprising over 99% of the visible universe, plasmas are also pervasive. It is the state of matter of the sun's center, corona, and solar flares. Plasma dynamics are at the heart of the extraordinary formation of galactic jets and accretion of stellar material around black holes. On earth it is the stuff of lightning and flames. Plasma physics describes the processes giving rise to the aurora that gently illuminates the far northern and southern nighttime skies. Practical applications of plasmas are found in various forms of lighting and semiconductor manufacturing, and of course plasma televisions.

33C.3 FUSION ENERGY SCIENCES (FES)

FES has four strategic goals [33C.2] (http://science.energy.gov/pes/):

- Advance the fundamental science of magnetically confined plasmas to develop the predictive capability needed for a sustainable fusion energy source;
- Support the development of the scientific understanding required to design and deploy the materials needed to support a burning plasma environment;
- Pursue scientific opportunities and grand challenges in high energy density plasma science to explore the feasibility of the inertial confinement approach as a fusion energy source, to better understand our universe, and to enhance national security and economic competitiveness, and;
- Increase the fundamental understanding of basic plasma science, including both burning plasma and low temperature plasma science and engineering, to enhance economic competiveness and to create opportunities for a broader range of science-based applications.

Plasma science forms the basis for research that is needed to establish our ability to harness the power of the stars in order to generate fusion energy on earth. The research required for fusion energy's success is intimately tied to rich scientific questions about some of nature's most extreme environments, inside and outside of stars, and has practical implications to industry beyond energy as well.

The FES program mission is to expand the fundamental understanding of matter at very high temperatures and densities and to build the scientific foundation needed to develop a fusion energy

source. This is accomplished by studying plasma and its interactions with its surroundings across wide ranges of temperature and density, developing advanced diagnostics to make detailed measurements of its properties and dynamics, and creating theoretical and computational models to resolve essential physics principles.

The physics of plasmas is at the heart of understanding how stars shine and evolve over billions of years. Plasmas, essentially hot gases of ions and electrons, are found in environments as familiar as fluorescent lighting and lightning bolts, as unimaginably harsh as the centers of stars, and as exotic as the environments surrounding super massive black holes. The science of plasma physics that describes the plasmas in these environments also describes the auroras that gently illuminate the northern and southern skies and the solar corona, where temperatures are far higher than on the sun's surface. At the scale of the very small, plasma physics and materials science combine to enable the exquisitely precise manufacture of semiconductors. Plasma science is also at the heart of advances in efficiencies in the lighting industry.

A more detailed discussion of the technical details involved with fusion research, including device options, confinement principles, fuel cycles, and materials development, is beyond the scope of this overview. But, the reader is strongly encouraged to explore the numerous sources on the internet and elsewhere for further information [33C.3, 33C.4].

Within the context of engineering standards, nuclear fusion is presently considered a research and experimental series of programs within the international scientific community. There are few regulatory guidelines or international standards for governing these efforts in a consistent manner. There are still many unanswered questions relating to the physics and engineering of a demonstration fusion power plant (a device that is planned for the mid-21st century and would follow the current ITER project, which is only in the midst of construction in 2013) [33C.5]. Until these issues are resolved, comprehensive regulation is considered impractical.

33C.4 ASME STANDARDS

To date, existing ASME standards are utilized within the fusion community as a template, guideline and starting point for designing fusion devices. In anticipation of the construction of a fusion power plant, ASME has embarked on studying the development of a fusion code case as part of Section III, sub-group Division 4 [33C.6]. The U.S. Nuclear Regulatory Commission (NRC) has indicated that it will likely assert regulatory jurisdiction over commercial fusion energy devices necessitating some formal codification by that time [33C.7].

Informal discussions to codify fusion within the ASME date back to 2004. A committee of qualified individuals comprising a cross-section of ASME, fusion and industrial community members was formed in 2010 to begin to scope and define a potential ASME code for commercial fusion energy devices. Meetings are held several times per year and are open to the public.

In 2011, the committee issued the first draft of a Roadmap for the development of code rules for fusion energy devices (FED) [33C.8]. The intent is to define a set of rules for the design and operation of next-generation facilities for both magnetic fusion and inertial confinement fusion. There are numerous technologies involved with fusion that have never been addressed previously by ASME. While some components (such as vacuum vessels/chambers) can be modified from the existing ASME code to a new fusion code, the current consensus is that a complete new set of rules be developed specifically for these new devices to cover design, construction and inspection/testing. In addition, it is anticipated that operation and maintenance requirements for these FED's will also require a new set of rules or major modifications to the existing ASME code.

As part of the Roadmap, a basic framework for a code has been proposed for the distinct areas of a fusion power station. Among them are such complex systems as magnets (both resistive and superconducting), cryogenic operations, high heat flux environments, internal components (such as first walls, blankets, divertors, and shields), tritium cycling, neutral beams, remote handling, and radwaste treatment and storage. Many of these are beyond the scope of anything encompassed by an ASME code previously, making the effort to codify fusion even more challenging. Many new materials are involved as well with properties required in temperatures ranging as low as 4 K.

At present, initial efforts will focus on outlining design codes for fusion technologies that are well known and understood, such as resistive magnets and vacuum vessels. As experts in specific fields can contribute (such as has been done with recently with ceramic materials and windows), it will add to the database of knowledge that can be consolidated into a new code for fusion. Sections will be added as appropriate with placeholders left for unresolved issues.

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