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Held at DoubleTree by Hilton Hotel Washington DC
Silver Spring, MD
July 17–18, 2017

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Edited by:

Robert J. Wolfgang
Yiu K. Law
Thomas G. Scarbrough
U.S. Nuclear Regulatory Commission

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Abstract

The 2017 Symposium on Valves, Pumps, and Inservice Testing for operating and new reactors, jointly sponsored by the American Society of Mechanical Engineers and the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic, and regulatory issues associated with inservice testing programs at nuclear power plants, including the design, operation and testing of valves, pumps, and dynamic restraints. The symposium provides an opportunity to discuss improvements in design, operation, and testing of valves, pumps, and dynamic restraints that help to ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives on the improvement of testing programs and methods for valves and pumps at nuclear power plants.

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Robert Parry
Co-Chairman, Symposium Steering Committee

Robert J. Wolfgang
Co-Chairman, Symposium Steering Committee
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American Society of Mechanical Engineers

Yiu K. Law
U.S. Nuclear Regulatory Commission

Ronald C. Lippy
True North Consulting, LLC

Steven M. Unikewicz
NuScale Power

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The views expressed in these proceedings are those of the individual authors and do not necessarily reflect the views or policies of the U.S. Nuclear Regulatory Commission and other participating Federal agencies.

The papers have been copy edited and recast into a standard format. By consensus, English units have been used as an expression of current industry practice with metric units also indicated where possible.

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Symposium Co-Chair

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Division of Engineering
U.S. Nuclear Regulatory Commission
Symposium Co-Chair

Ronald C. Lippy
True North Consulting, LLC
Chair of the ASME Operation and Maintenance Standards Committee

Opening Addresses:
Mary Jane Ross-Lee
Deputy Director, Division of Engineering, Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

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Implementation of ASME OM Requirements in IST Programs in Spain, Special Focus on ISTA General Requirements

Francisco Fiol Martínez
Program Engineer
Tecnatom, s.a.
ASME OM ISTE Member

Jesús García Rocasolano
Program and Valve Engineer
Tecnatom, s.a.
ASME OM Main Committee Member

Abstract

Throughout the world, inservice testing (IST) programs are usually required by the regulatory body that holds authority over the site. IST programs have several sources. Typically, these include IST codes and standards, plant technical specifications, final safety analysis reports, and should the plant have developed it, the probability risk assessment. Rulemaking clarifications, modifications, and requirements play a key role connecting all applicable documentation. In Spain, the Spanish Regulatory Body, Consejo de Seguridad Nuclear (CSN), requires all nuclear power plants (NPPs) to develop and implement an IST program according to the codes and standards of the country of design origin. As a result, all Spanish NPPs that have been designed in the United States follow an IST approach based on Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, “Codes and standards,” and the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code). To be able to operate, Spanish NPPs must have an official document called “MISI,” which stands for “Manual of In-Service Inspection.” The scope of this manual is wide: at the very least, MISIs include in their scope the ASME OM Code; ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI; and the requirements of 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities,” Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.” In this presentation, we explain how we intertwine U.S. Nuclear Regulatory Commission (NRC) regulations with our regulatory body’s regulations and applicable codes and standards, specially focusing on ASME OM Code, Subsection ISTA, requirements.

A Brief Disclaimer

This paper is a summary of how the Spanish regulations and U.S. regulations are interrelated. We have tried to be as neutral as possible. Sometimes we will provide an opinion. In these cases, it will be made very clear to the reader, since we will use expressions such as “in our opinion” or “we believe.” All of the opinions in this document are solely our own and do not reflect the position of either the ASME OM Code or Tecnatom, s.a., the company that currently employs both of us.

Short Introduction/Spanish Nuclear Industry

Most Spanish NPPs are American designed (either a boiling-water reactor (BWR) (General Electric) or a pressurized-water reactor (PWR) (3-Loop Westinghouse) and built between the 1970s and early 1980s. The main design characteristics and data are summarized in the chart below:

Name	**Thermal Power (MWt)**	**Electric Power (MWe)**	**Design**	**Construction Permit**	**Initial Operation**
Sta. María de Garoña	1,381	466	BWR (GE-3/Mark I)	1963	1966
Ascó I	2,941	1,032	PWR (WE 3-loop)	1974	1982
Ascó II	2,941	1,027	PWR (WE 3-loop)	1975	1985
Almaraz I	2,947	1,049	PWR (WE 3-loop)	1973	1980
Almaraz II	2,947	1,044	PWR (WE 3-loop)	1973	1983
Cofrentes	3,237	1,092	BWR (GE-6/Mark III)	1975	1984
Trillo	3,010	1,066	PWR (KWU 3-loop)	1979	1987
Vandellós II	2,941	1,087	PWR (WE 3-loop)	1980	1987

Seven of the eight NPPs currently operating in Spain have been designed in the United States, either by General Electric or Westinghouse. The eighth nuclear power plant was designed by Siemens/KWU (Kraftwerk Union). Since the nuclear technology has been imported in its majority, most of the codes and standards required in Spanish NPPs have been developed in the United States.

CSN, Spanish Regulatory Body

Spain has its own regulatory body, CSN, for all radiological activities. Since its inception in 1980, CSN[1] has been an independent entity and has had the power to draw up and approve technical instructions, circulars, and guides relating to nuclear and radioactive facilities and activities relating to nuclear safety and radiological protection.

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[1] The first organization overseeing radiological activities in Spain was JEN (Junta de Energía Nuclear—Nuclear Energy Joint) created in 1966 and superseded by CSN in 1980.

Inservice Inspection and Testing in Spain

In Spain, to be able to operate, every NPP must have been granted an operating permit by the Ministry of Industry. CSN is under the Ministry of Industry and carries out a technical review of all applications for operating permits. To obtain an operating permit, the utility has to prepare an application. The content of this application is detailed in the Royal Decree 1836/1999 of December 3. Article 20 states the following:

> The application for the operating permit must be accompanied by the following documents, updating where appropriate the contents of those submitted when requesting the construction permit:
>
> […]
>
> 3. Operating standards under normal and accident conditions. These standards and the procedures through which they are developed must refer to the facility overall and to the different systems of which it is made up.
>
> c) Operating technical specifications. These shall contain the limit values of variables affecting safety, the actuation limits of automatic protection systems, the minimum operating conditions, <u>the programme of revisions, calibration and periodic inspections of systems and components and operational control.</u>

Operating permits require plant technical specifications (TS) to be kept up to date. U.S. plant TS require an inservice inspection (ISI)/IST program based on a 10 CFR 50.55a approach to ASME Codes and Standards, with the conditions, exceptions, and alternatives specifically approved by the Spanish regulatory body, CSN. This can be appreciated in the following paragraph, typical of a Spanish plant TS (similar to the NRC Standard Technical Specifications (STS)):

> An In-Service Inspection Program will be established to oversee in-service inspection and in-service testing activities of ASME Class 1, 2 and 3 Components. This program shall comply with the following requirements:
>
> - 10 CFR 50.55a(f) and (g) with the limitations and modifications established in 50.55a, with the exceptions approved by the CSN.
> - Requisites specifically established by the CSN.
> - Alternatives to 10 CFR 50.55a specifically approved by the CSN.

The main difference in ISI/IST activities between STS and Spanish plants' TS is that the ASME OM Code is not mentioned at all in the Spanish TS. ASME BPV Code, Section XI, is referenced to define weekly, monthly, quarterly, and other intervals, whereas STS refer to the ASME OM Code to define these intervals. This is probably an update mismatch coming from a time when the ASME OM Code did not exist and IST of pumps, valves, and snubbers was addressed under Section XI.

IS-23, “*Instruction number IS-23, on in-service inspection at nuclear power plants”*

The second most important document regulating many ISI/IST/Appendix J activities in Spain is IS-23, “*Instruction number IS-23, on in-service inspection at nuclear power plants”*, published in the Official State Gazette, number 283, November 24, 2009. IS-23 helps define, explain, and intertwine most of the ISI/IST codes and standards.

IS—Instrucciones de Seguridad or “safety instructions” in English—are the following, as defined by CSN:

> Technical Codes applicable to nuclear safety and radiation protection which have to be abided by all subjects under their jurisdiction, once they have been published in the Official State Gazette.
>
> Regarding their legal nature, they constitute rulemakings, integrated in Spanish rulemaking. Rule breaking of these Safety Instructions is considered as administrative infraction.
>
> In the process of Safety Instruction, the participation from stakeholders and the public in general are encouraged and their opinions considered. Furthermore, previous to their approval, they are communicated to the Congress and regarding those that oversee radiological protection are communicated even to the European Union.

The introduction to IS-23 states the following:

> At present, and in view of the absence of Spanish standards governing these activities, the nuclear power plants carry out their inservice inspection programmes in accordance with the standards defined in the regulations of the country of origin of the technology and accepted in the operating permits, the basic standards applied being Section XI of the Code of the American Society of Mechanical Engineers (ASME) and the Operation and Maintenance Code of this Association (ASME OM Code), required by the Technical Specifications. Consequently, this code is considered to be an acceptable reference for the drawing up of the in-service inspection and testing programmes defined for these facilities, which are included in the document known as Manual of In-Service Inspection (MISI).

Note that in IS-23, both ASME BPV Code, Section XI, and the ASME OM Code are specifically referenced when the TS are mentioned.

The objective of IS-23 is made very clear:

> The objective of this Instruction is to define the requirements made by the Nuclear Safety Council to the licensees of the nuclear power plants regarding the

> establishment of an In-Service Inspection programme guaranteeing that safety-related structures, systems and components (SSC), and certain safety significant SSC's, maintain their structural integrity and operating capacity such that they operate within the defined limits or, otherwise, that the licensees may implement the corrective measures required to restore the required safety conditions.
>
> The requirements set out in the present Instruction are applicable to all the nuclear power plants throughout their operating lifetime.

In the same document, many elements and concepts original from an ISI/IST U.S.-based approach are recognized and defined: reactor coolant pressure boundary (two definitions are provided, one for U.S. plants and one for German plants), safety-significant and safety-relevant elements, preservice inspection, inspection interval, inspection period, leakage test, integrated containment leakage rate test, local containment leakage test, and others.

Further along, the responsibilities are established and a general scope regarding ISI/IST activities is introduced:

> Each nuclear power plant operating permit licensee shall oversee the performance or status of safety significant structures, systems and components (SSC) by applying systematic inspection and testing programmes defined by the licensee himself on the basis of what is specified in section four of this Instruction. The scope of the programme shall include the following: —The reactor coolant pressure boundary. —Safety-related SSC's. —Safety significant SSC's considered as a result of the application of specific programmes (risk-informed inspection programmes, erosion-corrosion programmes, etc.) or others required by the CSN.

Further along in the document, there is a specific statement:

> Each licensee shall draw up an in-service inspection and testing programme including representative samples of all the SSC's included within the scope defined in section three of this Instruction.

And now here is the definition of Manual of Inservice Inspection, its lifespan, and its scope:

> The in-service inspection and testing programmes shall be defined for an inspection interval and shall be developed in detail in a document known as "Manual of InService Inspection" (MISI). This document shall include at least the following programmes:
>
> - Non-destructive Examination (NDE) programme.
> - Supports and snubbers programme.
> - Pump and valve testing programme.
> - Pressure testing programme.

- Containment testing programme.
- Steam generators programme (at those plants where this is applicable).

ISI/IST scoping is defined in IS-23 in the following manner:

> The definition of the programmes for each interval, as regards scope, frequency and inspection or testing methods, shall meet to the requirements of the Technical Specifications (TS), the standards applicable in each case or defined by the CSN in the Operating Permit or instructions or requirements issued by the CSN.

Also, 10-year intervals are defined much in the same way as in the United States:

> The inspection intervals have a duration of ten years as from the entry into commercial operation of the plant and shall be maintained throughout the service lifetime of the facility. The duration of the interval may be increased or decreased by no more than 12 months depending on the operating conditions of the plant, as long as this is permitted by the applicable standards.

IS-23 requires that the MISIs be kept up to date. This may be either because of 10-year interval updates, which would result in ASME OM Code, ASME BPV Code, Section XI, Editions and applicable Code Case updates, or minor updates, typically prior to a refueling outage to incorporate design modifications, operating experience, corrections, new specific requirements, granted reliefs, etc.:

> 5.1. The licensees shall draw up the MISI document including the programme of inspections and tests to be carried out over an interval of 10 years. This document shall be updated at least at the beginning of each interval, the applicable standards being used for this task. Updating for other reasons, such as changes in the programmes as a result of new requirements, design modifications, detected errors, corrections, etc., shall be reported to the CSN six months prior to the beginning of each refuelling outage, including in each case the corresponding justification.

Note also that the MISI's reporting schedule is established in IS-23:

> Changes in MISIs:
>
> Three months before the refuelling outage, the licensee shall submit the revised MISI, or failing this, the sheets that constitute the new revision, in accordance with the provisions of the previous paragraph and with the comments of the CSN were they to exist.

Refueling outage and operating ISI/IST activities reporting:

The licensees shall submit the documentation associated with the inspection and testing programmes for each refuelling outage and operating cycle and with the corresponding results.

Inspection period results:

The final results reports corresponding to years in which an inspection period comes to an end shall include a specific chapter recapitulating on the inspections and tests performed throughout this entire period, specifying compliance with the applicable requirements, inspection percentages, testing requirements, etc. and evaluating the results obtained, root cause analyses where required and corrective actions deriving therefrom.

MISIs: Inservice Inspection and Inservice Testing Programs in Spain

MISIs are ranked as Basic Documents. Hierarchically, this plant document is only below Official Exploitation Documents (i.e., final safety analysis report, plant TS, etc.). MISIs in Spain thus include what in the United States are usually several different programs. The following is an example of a typical MISI's scope and structure:

(1) General Requirements—In this chapter, all applicable codes and standards, regulations, technical analysis, as well as important communications (granted exemptions, provisions, etc.) with CSN are included. This chapter is applicable to the rest of the chapters. This chapter also establishes the MISI's general scope.

(2) Nondestructive Examination of Class 1 Piping and Components—This chapter includes usually risk-informed ISI of piping and also ISI of components. These examinations would be under Subsections IWA and IWB.

(3) Nondestructive Examination of Class 2 Piping and Components—This chapter may include risk-informed ISI of piping and also ISI of components. These examinations would be under Subsections IWA and IWC.

(4) Nondestructive Examination of Class 3 Piping and Components—This chapter includes ISI of piping and components. These examinations would be under Subsections IWA and IWD.

(5) Nondestructive Examination of Piping Supports and Nondestructive Testing of Snubbers—Support examinations are under Subsections IWA and IWF. Examination and testing of snubbers are under Subsections ISTA and ISTD.

(6) Pump Testing Program—This chapter includes all IST pump requirements and is under Subsections ISTA and ISTB.

(7) Valve Testing Program—This chapter includes all IST valve requirements and is under Subsections ISTA and ISTC.

(8) Pressure Testing Program—This chapter includes all IST valve requirements and is under Subsections ISTA and ISTC.

(9) Primary Containment Testing Program—This chapter includes all Appendix J testing requirements. (Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," and Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," July 2012 are also considered).

(10) Primary Containment Inspection Program—This chapter includes ISI of containment structures systems and components. These examinations would be under Subsections IWA, IWE (metallic containment), and IWL (concrete containment).

(11) Annexes—These include ISI/IST piping and instrumentation diagrams, sketches, isometric drawings, and interference sheets.

Other chapters may be applicable depending on plant design and/or specific requirements: Steam Generator Tubing Inspection Program, Turbine Valve Testing Program, etc. MISIs are usually over 1,500 pages long and oversee all ISI/IST activities in an NPP.

MISIs do not include the distribution of activities in the refueling outages belonging to the same interval. They specify all areas under ISI/IST scope and establish requirements, corrective actions, scope expansions, acceptance criteria, etc. Outage Inspection Programs are developed from MISIs, and in these documents, procedures to be used are defined. Outage Inspection Reports close the loop.

We believe that including everything regarding ISI/IST activities in one single document helps to organize ISI/IST activities and requirements. First, during 10-year interval updates, both the ASME OM Code and ASME BPV Code, Section XI, applicable editions will be updated at the same time. Second, regarding ASME OM scope explicitly, the same edition will apply for pumps, valves, and snubbers. We think both of these factors help to implement a coherent and comprehensive ISI/IST program.

Scoping in MISIs

In the MISIs, a general scope is established in Chapter 1, "General Requirements." This general scope is mainly based on:

- 10 CFR 50.55a
- Regulatory Guide 1.26, Revision 1, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants"
- Standard Review Plan, Section 3.2.2, "System Quality Group Classification"

Other applicable documentation often considered for ISI/IST scope definition includes the following:

- Standard Review Plan, Section 3.6.1, "Plant Design for Protection against Postulated Piping Failures in Fluid Systems Outside Containment"
- Standard Review Plan, Section 6.6, "In-Service Inspection and Testing of Class 2 and 3 Components"
- Standard Review Plan, Section 3.9.6, "Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints"

This general scope is applicable to the rest of the chapters of the document. It is in this general scope where all systems under ISI or IST are included. Specific scoping takes place in each individual chapter.

Closing in on IST, there is a specific chapter for each of the components under ASME OM scope: pumps, valves, and snubbers. It is in these chapters where components are individually identified and their examination and testing requirements established and explained.

As a general rule, in Spain, IST programs have in scope over 20 pumps, 500 valves, and 100 snubbers.

Scoping According to 10 CFR 50.55a and Its Impact on Spanish NPPs

As of the date of the elaboration of this document (May 2017), the NRC's next final rule is pending publication. In the proposed rulemaking of September 18, 2015 (80 FR 56820) preceding the final rulemaking, the NRC envisaged eliminating Class 1, 2, and 3 for scoping of the IST program definition. Instead, the NRC proposed to implement in 10 CFR 50.55a the same approach for scoping as that of Standard Review Plan, Section 3.9.6, and the ASME OM Code, ISTA-1100. The intent is to align both NRC requirements and ASME OM Code requirements. These requirements do not limit IST scope to ASME Class 1, 2, or 3; instead, they require the licensee to analyze which components fulfill one of the safety functions as defined in ISTA-1100 (a), (b), and (c). If a component fulfills one or more of the safety functions defined there, then the component must be included in the applicable IST program. Depending on when the plant was built, this could lead to a small IST scope expansion (post-Regulatory Guide 1.26 plants) or a major IST scope expansion (pre-Regulatory Guide 1.26 plants).

IS-23 refers to SSCs, not explicitly considering Class 1, 2, and 3 components. In the plant TS, 10 CFR 50.55a is referenced and, as shown previously, Class 1, 2, and 3 are used as a way of defining scope. It is important to note that once the 10 CFR 50.55a is passed (Final Rulemaking), it is also applicable to Spanish NPPs. In our experience, this process in Spain would probably take a little more time than in the United States (30 days), but nevertheless, scope expansion would inevitably follow the publication of the Final Rulemaking.

All U.S.-designed Spanish NPPs except C.N. Garoña were designed and built considering Regulatory Guide 1.26, and thus most safety components have a Class Group classification according to their design function. This means that for Spanish NPPs, the foreseeable scope expansion will be limited and of no great impact. Currently, some Spanish NPPs have a few nonclass components already in their IST scopes as a result of MISI revisions. This is of course in line with one of the initial statements of Standard Review Plan, Section 3.9.6: "The review should also include any other pumps, valves, and dynamic restraints not categorized as ASME BPV Code Class 1, 2, or 3 that have a safety-related function."

We think this is a clear example of how Spanish nuclear regulations, international applicable codes and standards, and U.S. nuclear regulations are coordinated in the Spanish nuclear industry.

ASME BPV Code, Section XI versus ASME OM Scope: The Snubber Case in Spain

In the United States, as some plants are migrating their snubber IST programs from the ASME BPV Code, Section XI, to the ASME OM Code, scoping issues have arisen. Some plants have a great snubber population (up to 500 snubbers per unit). Scoping criteria under Section XI have certain exemption provisions. The main exemption criteria are diameter, pressure, and temperature (almost all lines under 10.16 centimeters (4 inches) in diameter or 1,900 kilopascals (275.6 pounds per square inch) pressure and 95 degrees Celsius (203 degrees Fahrenheit) temperature are exempted from ASME BPV Code, Section XI, requirements). Many snubbers have been placed in lines exempt under Section XI and thus have been exempt from examination and testing under Section XI requirements. However, under the ASME OM Code, all snubbers performing one or more of the safety functions defined under ISTA-1100 (a), (b), and (c) must be included in the IST scope. This may result in a significant scope expansion for certain NPPs.

The situation in Spain does not seem to be an issue at all.

On the one hand, in Spain, snubber program migration from the ASME BPV Code, Section XI, to the ASME OM Code took place in the 1990s, when Spanish NPPs initiated their second 10-year intervals. In those times, one of the applicable codes for snubbers approved by 10 CFR 50.55a was Part 4 of ASME/ANSI OMA-1988 Addenda to ASME/ANSI OM-1987.

On the other hand, the number of snubbers in scope in Spanish NPPs varies significantly from reactor to reactor (some have around 150 per unit and others less than 20). When the plants were built in Spain, the number of snubbers per unit was around 500. Further down the road, this was demonstrated to pose an enormous amount of work, and the number of snubbers in Spanish NPPs was greatly reduced. Many snubbers were dismounted after piping seismic analysis demonstrated they were unnecessary. Furthermore, in Spanish NPPs, only a few snubbers are located in lines that would be exempt under Section XI scope requirements, thus not posing a scope expansion issue when Spanish snubber IST programs migrated from Section XI to the ASME OM Code.

Conclusions

In our paper, we expected to give a glimpse of how a small country such as Spain, with no original nuclear technology, keeps up with codes and standards focused on nuclear safety and regulations. Neither the Spanish NPP industry nor the CSN have the weight and size of their U.S. counterparts. This is why we are integrated into most of the nuclear international organizations, regulatory and industry alike, not only in the United States but also in Europe.

There is one code, but there are many plants, not only in the United States but also overseas. The great challenge we face is how to integrate such a wide population, both technologically and culturally, so that throughout the world, we do not only apply the same code but also fully understand its intent and thus implement it properly.

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Terry Turbopump Expanded Operating Band

Douglas M. Osborn, Kyle Ross, Jeff Cardoni, and Matt Solom
Sandia National Laboratories[2]

Haihua Zhao and James O'Brien
Idaho National Laboratory

Karen Vierow-Kirkland
Texas A&M University

Mark Bergman
General Electric Power Co.

Randy Bunt
Southern Nuclear Co.

Abstract

The Terry turbine is a small, single-stage, compound-velocity impulse turbine originally designed and manufactured by the Terry Steam Turbine Company, purchased by Ingersoll-Rand in 1974. Terry turbines are currently manufactured and marketed by Dresser-Rand. Terry turbines were principally designed for waste-steam applications. Terry turbopumps are ubiquitous in the U.S. nuclear fleet as a steam-driven turbopump in either the reactor core isolation cooling (RCIC) system and high-pressure coolant injection systems for boiling-water reactors (BWRs) or in the auxiliary feedwater (AFW) system for pressurized-water reactors (PWRs).

Prior to the accidents at Fukushima Daiichi, assumptions and modeling of the performance of Terry turbopumps were based mostly on generic vendor use of the guidance in National Electrical Manufacturers Association (NEMA) SM23, "Steam Turbines for Mechanical Drive Service" [1]. However, the RCIC/AFW system performance (i.e., the Terry turbopump) under beyond-design-basis event (BDBE) conditions is poorly known and largely based on conservative assumptions used in probabilistic risk assessment (PRA) applications. For example, common PRA practice holds that battery power (direct current (dc)) is required for RCIC operation to control the vessel water level, and that loss of dc power results in RCIC flooding of the steamlines and an assumed subsequent failure of the RCIC turbopump system. This assumption for PRA implies that RCIC operation should terminate on battery depletion, which can range from 4 to 12 hours. In contrast, real-world observation from Fukushima Daiichi

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[2] Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC, a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA-0003525. SAND2017-4246C.

Unit 2 shows that RCIC function was not terminated by uncontrolled steamline flooding or loss of control power and, in fact, provided coolant injection for nearly 3 days [2].

There is a current effort being undertaken by the U.S. industry, the U.S. Department of Energy (DOE), and the Government of Japan to investigate the true operating band of the Terry turbopump for BDBE conditions. This paper provides a summary of the experimental and modeling efforts to date.

Introduction

The overall goal of the project is to understand the real-world behavior of Terry turbopump operation under beyond-design-basis (BDB) conditions in order to advance the predictive fidelity and applicability to emergency and severe accident prevention and mitigation. Accurate characterization of the RCIC/AFW system could have fleetwide impacts on how emergency operating procedures and severe accident management guidelines will be implemented (e.g., knowing that a Terry turbopump will last longer than an hour or two after direct current power is lost will allow operators to consider other options for plant recovery or accident mitigation). Further, investigation of severe accident performance may also provide insights into means to improve severe accident performance.

The purpose of this research is to develop a dynamic and mechanistic system-level model of the RCIC/AFW turbine/pump system capable of predicting system performance under BDB conditions that include two-phase water ingestion into the Terry turbine at various potential operating pressures, and to characterize its ability (or inability) to maintain adequate water injection with sufficient pump head under degraded operating conditions. This model will also demonstrate the self-regulating mode of operation as was observed in the Fukushima Daiichi Unit 2 accident, where RCIC ran uncontrolled and successfully maintained reactor water inventory for nearly 3 days [2].

This work is the first step towards developing an experimentally and thermodynamically based analytical model of the steam-driven RCIC/AFW system operation with mechanistic accounting of liquid water carryover and pump performance degradation, to be used in system-level codes like MELCOR or MAAP. The scaled and full-scale Terry turbopump experiments and modeling will support an improved understanding of plant risk, improve plant operations, and provide the technical basis for improving the reliability of an essential plant system as shown in the three main categories below[3]:

(1) **Regulatory/Risk:** Test data can reduce plant operational risk and improve regulatory compliance.

- improved incident response timing and prediction of RCIC performance to determine staffing needed to implement BDB mitigation activities

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[3] Letter from BWR Owners' Group to DOE Office of Nuclear Energy's Federal Programs Manager, Richard A. Reister, BWROG-14066, November 21, 2014.

- improved response to regulatory changes associated with post-Fukushima lessons learned
- a better prediction of the core damage frequency reduction associated with implementation of BDB mitigation activities

(2) **System Improvement:** Improve system reliability; operation of an essential system needed to mitigate or prevent risk-dominated accidents

- identifies RCIC enhancements and changes in maintenance practices to meet Fukushima lessons learned
- provides performance data on refurbished hardware (including instrumentation and controls)
- provides for system performance conditions for station blackout-like conditions to allow for proper quantification of needed system margins

(3) **Plant Operations:** Improve operations during a BDBE to mitigate the accident under a wide range of plant conditions

- identifies optimal approaches to operate RCIC during a long-term station blackout and loss of heat sink
- provides data to support identification of RCIC performance conditions that could complicate or challenge FLEX implementation
- identifies proper handoff conditions from RCIC to FLEX

Experimental Hypothesis

The Terry turbopump (RCIC/AFW) system has the capability to operate long term (days) in an extended range of steam pressures (0.52 to 8.31 megapascals (MPa) (75 to 1,205 pounds per square inch gauge (psig)). The current range is 1.14 to 8.31 MPa (165 to 1,205 psig), varied steam quality (100 percent to 0 percent; currently 100 percent), and increased lube oil temperature conditions (102 to 149 degrees Celsius (C) (215 to 300 degrees Fahrenheit (F)); currently, 71 degrees C (160 degrees F) with limited or no control features active.

Basis for Hypothesis

The events at Fukushima Daiichi, qualitative analysis, and experience in other industries demonstrate that the Terry turbopump has significant additional operating flexibility than is credited and currently being used in plant operations. In particular, operating experience is indicating that the Terry turbopump system was qualified for plant operations to a small subset of its capability; expanding this operating band through modeling and testing provides operational flexibility to further preclude the occurrence of core damage events (such as those at Fukushima and other types of BDBEs) at minimal cost to the fleet of plants (e.g., update the operations procedures and train staff on its capability).

The RCIC systems in Fukushima Daiichi Units 2 and 3 operated for extended periods of up to 68 hours under various reactor pressure vessel (RPV) pressure and suction temperature values [2]. Data indicate the turbopump also ran in a "self-regulating" mode; steam quality impacted the turbine speed such that RPV makeup maintained a relatively steady level without any electronic feedback control.

The Terry turbopump is used in a wide variety of commercial applications that are not as well controlled as the nuclear industry design limits. The history of the Terry turbopump dates back to the early 1900s, and the pumps have a reputation of reliable and rugged performance under a broad range of operating conditions. It is commonly known in the industry that they can run with water ingestion into the turbine.

Additionally, experience in the nuclear industry reflects the robustness of these systems. The turbine and pump have injected water into the RPV/steam generator for extended times in response to rare events and have been tested every cycle at both 1.03 and 6.9 MPa (150 and 1,000 psig). In addition, a turbine qualification test was run at extreme conditions, including ingestion of a large slug of water with no loss of function or damage to the turbine [3].

Experimental Technical Advisory Group

The purpose of the Nuclear Grade Terry Turbopump Advisory Group (Turbo-TAG) is to provide oversight and direction for experimental research into the expanded operating limitations of the Terry turbopumps used in the nuclear industry. The Turbo-TAG will ensure that the elements of the plan are met and ensure the checks and balances in each milestone to enable test suite expectations are met, the project remains within scope, and predetermined expenditures are appropriate to minimize programmatic risk.

The objectives of the Turbo-TAG are the following:

- Ensure that the proposed project plan is followed.
- Ensure that test suite expectations are within scope and expenditures are followed.
- Ensure that stakeholders are kept apprised of the plan's progress.
- Ensure that stakeholder direction is incorporated into the plan's logistics.

The scope of the Turbo-TAG includes the following:

- Develop and ensure execution of the experimental plan development, first-principle analytical modeling, full-scale component testing and modeling, basic scientific Terry turbopump testing and modeling, and full-scale testing and modeling.
- Ensure that the test suite expectations of the plan are met and communicated to the stakeholders.
- Ensure that checks and balances in each milestone will enable year-end "hold points," and ensure that the project remains within scope and predetermined expenditures are followed.

The Turbo-TAG deliverables and schedule are the following:

- Provide budget projections and expenditure reporting to the stakeholders quarterly.
- Plan updates to the stakeholders quarterly.
- Schedule updates and adjustments to the proposed schedule in the plan at a minimum of quarterly and report to the stakeholders.
- Provide closure reports on each completed milestone of the plan within 90 days of completing the last task of that milestone.

The Turbo-TAG, which consists of engineers from the Pooled Inventory Management, the BWR Owners' Group (BWROG), PWR Owners' Group (PWROG), Electric Power Research Institute, DOE, Japan (Institute of Applied Energy), GE-Hitachi, and Texas A&M University, has identified multiple benefits of direct value to the utilities from this program. This technical advisory group will also provide feedback and recommendations to the Nuclear Strategic Issues Advisory Committee for U.S. industry programmatic decisions.

Experimental Expectations

The overarching question to be addressed for each milestone discussed below is—

> Given the differences exhibited between the modeling and the test data and with extrapolated simulation performance, do the current system models for RCIC/AFW operation provide adequate confidence in the proposed RCIC/AFW operation outside of the normal operational band?

The level of *adequate confidence* will be decided by the Turbo-TAG with input from the BWROG and PWROG. Generally, the advancing milestones reduce uncertainty and increase confidence in the plans for extended operation and may be needed to fully confirm planned operations. Based on the modeling and testing results and insights, and before the summary reports are completed, the Turbo-TAG will achieve the following expectations for each of the following milestones:

Milestone 2—Principles and Phenomenology

- Assess the efforts needed to complete Milestones 3 and 4.
- Assess the efforts needed to scope an existing full-scale test facility for Milestone 5.
- Conduct an initial scope of the development of a detailed experimental plan and initial cost estimates for Milestone 5.
- Conduct an initial scope of the development of a detailed experimental plan and initial cost estimates for Milestone 6.

Milestone 3—Full-Scale Component Testing[4]

- Full-scale component test results will reduce the uncertainty in specific model parameters compared to only Milestone 4 testing and associated modeling.
- These efforts benefit the selection of a full-scale test facility, inform the development of a detailed full-scale experimental plan, and further refine the cost estimates for the Milestone 5 and 6 efforts.

Milestone 4—Terry Turbopump Basic Science Experiments

- The Terry turbopump basic science test results will reduce the uncertainty in specific model parameters.
- These efforts benefit the selection of an integral full-scale test facility, inform the development of a detailed integral full-scale experimental plan, and further refine the cost estimates for the Milestone 5 and 6 efforts.

The generic technical approach for Milestone 4 (and Milestones 5 and 6) will include these steps:

(1) Model the planned tests.
(2) Test performance for a specified test matrix.
(3) Analyze tests across the test matrix range.
(4) Compare model analyses to test results.
(5) Report differences and possible technical reasons.
(6) Extrapolate to full-scale BDBE conditions.
(7) Turbo-TAG evaluates expectations and *adequate confidence* (as specified above).

Milestone 5—Integral Full-Scale Experiments for Long-Term Low-Pressure Operations

- These test results will reduce the uncertainty in specific model parameters.
- These efforts inform the development of a detailed integral full-scale experimental plan and provide further refinements of the cost estimates for the Milestone 6 efforts.

Milestone 6—Integral Full-Scale Experiments Replicating Fukushima Daiichi Unit 2 Self-Regulating Feedback

- These test results will reduce the uncertainty in specific model parameters.

Milestone 7 is an integration of the Milestone 3–6 modeling efforts.

Milestone 3 and 4 Experimental Matrices

First principles and initial scope modeling for feasibility, funded by the DOE and Japan through the Institute of Applied Energy, was performed in 2015 and 2016. Additionally, modeling insights, scope discussions, and value assessments with industry stakeholders (domestic and

[4] Efforts are to be conducted in parallel with Milestone 4 and will inform modeling efforts for Milestones 4–6.

international) have been completed to form the basis of the Terry turbopump expanded operating project plan. As efforts for Milestone 2 (Principles and Phenomenology) neared completion in 2016, the Turbo-TAG, in conjunction with Sandia National Laboratories (SNL) and Idaho National Laboratory (INL), identified a suite of component experiments that could inform the later efforts of the Terry turbopump expanded operating band program. Milestones 3 and 4 are intended to provide information that will allow for the overall effort to better design, scale, and model the full-scale steam experiments (i.e., Milestones 5 and 6).

The Milestone 3 and 4 experiments are intended to be conducted at low pressures and flow rates such that a university or small research facility could conduct them within an achievable timeframe. Texas A&M University has been identified by the Turbo-TAG as the suitable location for this effort. Additionally, Texas A&M currently has a DOE-funded Nuclear Energy University Programs project, entitled "Multi-phase Model Development to Assess RCIC System Capabilities under Severe Accident Conditions." The project goal is to provide analysis methods for evaluation of RCIC system turbomachinery performance under multiphase conditions.

For Milestone 3, Full-Scale Component Testing, the components under investigation will be GS-series Terry turbine nozzles, governor valves, trip/throttle valves, lubrication oil, and bearings [4]. The Milestone 3 efforts are currently divided into four areas of experiments:

(1) free jet testing
(2) GS-series[5] Terry turbopump governor valve and trip/throttle valve testing
(3) lube oil testing
(4) bearing tests

Flow visualization results from the free jet testing will benefit detailed computation efforts, since the impulse of the steam jet has a first-order influence on the turbine wheel velocity. The governor valve and trip/throttle valve testing will provide insights into steam flow versus stem position for flow coefficients (C_v). The lube oil and bearing testing will provide insights into long-term operations for full-scale testing.

Milestone 4, Terry Turbopump Basic Science Experiments, is intended to provide information that will allow for the overall effort to better design, scale, and model the full-scale testing (i.e., Milestones 5 and 6), if the Turbo-TAG determines it is necessary to proceed to the subsequent milestones [4]. The Milestone 4 efforts are divided into three areas of experiments:

(1) Z-1[6] Terry turbopump testing
(2) GS-series Terry turbopump full-scale air testing technique confirmation
(3) initial scoping of Fukushima Unit 2 uncontrolled feedback with Z-1 Terry turbopump

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5 GS-1 and GS-2 Terry turbopumps are the most common types of Terry turbopumps in the U.S. nuclear fleet.
6 Z-1 Terry turbopumps are smaller scale (about 10 percent the power of the GS-series) Terry turbopumps.

The Z-1 and GS-series Terry turbopump tests will provide data for continued modeling efforts, provide initial operational/field data on GE-Hitachi's incipient failure equipment, and provide initial investigations into potential failure modes of a GS-series Terry turbopump under a BDBE. These efforts will also provide initial confirmatory data for the Milestone 5 and 6 full-scale tests. The initial scoping of uncontrolled feedback with a Z-1 turbopump will also provide confirmation that Fukushima Daiichi Unit 2 observations are potentially applicable across all Terry turbopump models.

The modeling efforts for Milestones 3 and 4 are specific to system-level modeling (e.g., SAMPSON, RELAP-7, and MELCOR), as well as detailed computations (e.g., computational fluid dynamics (CFD)), and will be parallel efforts with their associated experimental phase. These modeling aspects are to be integrated and iterated with the Milestone 3 and 4 experimental efforts. Table 1 and Table 2 show the Gantt chart and overall work flow of the Milestone 3 and Milestone 4 efforts, respectively, for the 26-month performance period.

MELCOR Modeling Efforts

MELCOR is a fully integrated, engineering-level computer code that models the progression of severe accidents in light-water reactor nuclear power plants [5]. MELCOR is being developed at SNL for the U.S. Nuclear Regulatory Commission as a second-generation plant risk assessment tool and the successor to the Source Term Code Package. A broad spectrum of severe accident phenomena in both boiling- and pressurized-water reactors is treated in MELCOR in a unified framework. These include thermal-hydraulic response in the reactor coolant system, reactor cavity, containment, and confinement buildings; core heatup, degradation, and relocation; core concrete attack; hydrogen production, transport, and combustion; and fission product release and transport behavior. Current uses of MELCOR include estimation of severe accident source terms and their sensitivities and uncertainties in a variety of applications.

Centrifugal pump modeling capabilities employing homologous pump curves were recently added to MELCOR as a proof-of-concept in support of the Terry turbopump modeling efforts [4]. Two sets of built-in curves using a generic algorithm were included, similarly to RELAP-5 and similar to Westinghouse and Bingham-brand pumps. This allows the use of homologous definitions without a comprehensive knowledge of pump characteristics. The user can adjust (i.e., scale) the built-in curves by specifying problem-dependent design numbers such as rated pump speed, rated head, and rated torque. Given sufficient pump information, the user may also uniquely specify homologous curves. The pump source terms require an implicit or semi-implicit solution for stability given the large (relative to the current condition) time steps necessary for efficient severe accident simulations. MELCOR originally represented pumps as an explicit pressure (ΔP) term in its momentum/velocity equation.

Taking advantage of the centrifugal pump modeling features, homologous head and torque curves have been constructed from representative RCIC pump data from Fukushima Daiichi Unit 2 and defined in the simplistic MELCOR test model described in Figure 1. In considering the simplistic model, it is important to realize that it was designed to support key phenomena and trends associated with the Fukushima Daiichi Unit 2 accident, but it is not a full representation of the reactor system. Exercising the new pump modeling features increases the realism of the model, but the model remains simplistic. Including the homologous curves has placed the responsibility of calculating RCIC pump dynamics on the system-level code, such as MAAP or MELCOR, rather than on the user. In the case of MELCOR, the user, through control functions, remains responsible for calculating the shaft torque developed by the Terry turbine, but the pump response and speed response of the RCIC/AFW system as a whole become the system-level model's responsibility. Noteworthy with respect to the homologous curves constructed for use in this Terry turbopump modeling effort is that the generic algorithms are not MELCOR specific; they could be utilized just as well in RELAP, TRACE, and MAAP calculations.

The computer-aided drafting and CFD accomplishments described in Reference [6] have critically informed the latest system-level model solution (i.e., the homologous-curve solution) with respect to the following:

- the approach angle of a steam jet relative to the RCIC turbine wheel
- the Mach number (approximately 3 at operating pressures) of a steam jet entering a bucket on a turbine wheel
- the Mach number (approximately 2 at operating pressures) of a steam jet leaving a bucket on a turbine wheel

Additional information needs in the ongoing RCIC modeling work include the following:

- The number and size of the steam nozzles consistent with the performance information of a particular RCIC turbine. For example, a GS-1 model Terry turbine has 5 steam nozzles, while a GS-2 model Terry turbine has 10 steam nozzles.
- The flow characteristics of an RCIC turbine governor valve and the minimum flow area of a fully open governor valve.
- The state of the condensate storage tank recirculation valves in the Fukushima Daiichi Unit 2 accident after switchover of RCIC suction to the wetwell. For example, were the valves closed at switchover?

The RPV results of the Fukushima Daiichi Unit 2 simulation, shown in Figure 2, utilize the new homologous pump features for a system-level model and are intended to be carried forward in future Terry turbopump modeling work. The model is expected to add needed realism to Fukushima Daiichi Unit 2 accident simulations and will inform the design of full-scale testing configurations.

RELAP-7 Modeling Efforts

As part of the efforts to understand the unexpected "self-regulating" mode of the RCIC systems in the Fukushima Daiichi Unit 2 accidents and extend BWR RCIC and PWR AFW operational range and flexibility, mechanistic models for the Terry turbine, based on SNL's 2015 efforts [6], have been developed and implemented in the RELAP-7 code to simulate the RCIC system. RELAP-7 is a new reactor system safety analysis code currently under development at INL [7][8]. A fully implicit and strongly coupled RCIC system model had been developed in the RELAP-7 code and used for simplified BWR station blackout simulations in the past [9][10][11][12]. In that simulation, a generic turbine model was used to conserve mass and energy, while the turbine operation characteristic curves were used to obtain the nondimensional mass flow rate and thermal efficiency. This model could be used for simulating RCIC off-design behavior if off-design operation characteristic curves were available. However, no such curves currently exist for the Terry turbine system due to its unique pure impulse design.

INL modified the SNL Terry turbine model [6] and implemented those models into the RELAP-7 code [13]. This effort has been focused on normal working conditions. More complex off-design conditions will be pursued in later years when more data are available. In the SNL Terry turbine model, the turbine stator inlet velocity is provided according to a reduced-order model, which was obtained from a large number of CFD simulations. In the RELAP-7 effort, an alternative method using an under-expanded jet model was applied to obtain the velocity and thermodynamic conditions for the turbine stator inlet, which is simple, generic, and suitable for use in system analysis codes.

The RELAP-7 Terry turbine is composed of two parts:

(1) nozzle model, which predicts mass flow rate through the turbine and inlet conditions for the rotor (using semicircular buckets)
(2) turbine rotor model, which describes the balance of angular momentum of the wheel

A RELAP-7 input model, as shown in Figure 3, has been developed to test the Terry turbine system. The input model is composed of a Terry turbine model, coupled pump, a check valve on the waterline, and connecting pipes and time-dependent volumes at the boundary. The check valve is needed to prevent reverse flow through the pumpline when the system just starts. The boundary conditions are also shown in Figure 3. Two different turbine outlet pressures at 193 kilopascals (kPa) (28 pounds per square inch (psi)) and 300 kPa (43.5 psi) used for the Terry turbine nozzle test are applied in the simulations.

Table 3 shows the major parameters for the turbine and pump. These values are taken from the SNL MELCOR case [6], which is based on an RCIC system for a generic 2,000-megawatt thermal BWR. Note that the rated pump head is not an input parameter. Since both the impulse conversion coefficient and the pump efficiency are unknown, INL used two known conditions to *best fit* for the model at the turbine outlet pressure at 193 kPa (28 psi):

(1) the rated turbine speed and torque
(2) the water mass flow rate through the pump, which is about 10 times the steam mass flow rate through the turbine

The two parameters are then fixed for the other turbine outlet condition, and the simulation was run for 100 seconds to reach steady state. The time step in the beginning is 0.001 seconds and gradually increases to 0.01 seconds at the elapsed time of 10 seconds and maintains this value. The nozzle parameters rapidly reach the steady-state values shown in Table 4. It takes about 1 second for the pump head to reach steady state. The calculated steady-state pump head is 755 meters, which is very close to the rated value. INL did not know the exact nominal operation condition for the RCIC system in this case. Therefore, it is difficult to obtain exact rated pump head value with just approximate operation parameters.

Other major parameters of interest, such as the shaft work, rotational speed, and pump torque, take more than 1 minute to reach steady state, as shown in Figure 4 through Figure 6, respectively. The calculated RCIC rotational speed at a steady state of 446 radians/second (radians/s) is very close to the rated speed of 450 radians/s shown in Table 3. The calculated pump torque at steady state is 441 newton-meters (N-m) (325 ft-lb), again very close to the rated value of 449 N-m (331 ft-lb). The calculated steady-state shaft work is very close to the rated value—197 kilowatts versus 202 kilowatts (450 radians/s × 449 N-m). The mass flow rate through the pump is about 10 times the rate through the turbine at steady state, which is the expected ratio for a typical RCIC system [14].

The newly developed nozzle models and modified turbine rotor model according to the SNL work [6] have been implemented into RELAP-7 [13], along with the SNL Terry turbine model. A new RELAP-7 pump model has also been developed and implemented to couple with the Terry turbine model. Both the INL RCIC model and the SNL RCIC model produce results matching major rated parameters such as rotational speed, pump torque, and turbine shaft work for the normal operation condition. However, the SNL model is more sensitive to the turbine outlet pressure than the INL model.

The next step for INL will be to further refine the Terry turbine models by including two-phase cases so that off-design conditions can be simulated. The pump model can also be enhanced with the use of the SNL homologous curves.

Conclusions

Observations of the performance of the RCIC system during the Fukushima Daiichi Unit 2 accident indicated that Terry turbopump functions continued well beyond the time of battery depletion in a self-regulating mode of operation and provided reactor coolant injection for nearly 3 days. An international effort has been initiated to investigate the robustness of the Terry turbopump. The effort is intended to promote a more complete understanding of the phenomena associated with RCIC/AFW system performance. An advisory group including representatives from the U.S. nuclear industry, academia, the DOE National Laboratories, and the Government of Japan has been formed to support technical activities including the following:

- scaled and separate effects experiments
- full-scale air and steam experiments
- analytical modeling and system-level analysis (e.g., RELAP-7 and MELCOR)

Initial testing efforts are under way at Texas A&M University. Full-scale testing with an actual nuclear-grade Terry turbopump will follow.

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Table 1. Milestone 3 Gantt Chart (1–26 months) [4]

Terry Turbopump Expanded Operating Band Gantt Chart														
		Month												
Experimental Deliverable	**Duration**	1-2	3-4	5-6	7-8	9-10	11-12	13-14	15-16	17-18	19-20	21-22	23-24	25-26
Milestone 3 – Full-Scale Component Experiments														
NHTS Lab Facility Upgrades	3 months													
Free Jet Test facility preparation	2 months													
Free Jet Test facility test execution	8 months													
Turbomachinery Lab Facility Upgrades	1 month													
GS-series Governor & Trip/Throttle Valves Testing facility preparation	2 months													
Governor & Trip/Throttle Valves Testing facility test execution	4 months													
Oil Test facility preparation	2 months													
Oil Test facility test execution	5 months													
Bearing Test facility preparation	2 months													
Bearing Test facility test execution	4 months													
Report Deliverable	**Duration**	1-2	3-4	5-6	7-8	9-10	11-12	13-14	15-16	17-18	19-20	21-22	23-24	25-26
TAMU Free Jet Test facility data analysis and report	2 months													
TAMU Governor & Trip/Throttle Valves Testing facility data and analysis report	2 months													
Oil Test facility data and analysis report	2 months													
Bearing Test facility data and analysis report	2 months													
SNL & IAE experimental experts at TAMU	24 months													
Industry Staff input on experimental efforts	4 months													
Industry Contributions and Review of Milestone 3 reports	4 months													

Table 2. Milestone 4 Gantt Chart (1–26 months) [4]

Terry Turbopump Expanded Operating Band Gantt Chart														
		Month												
Experimental Deliverable	**Duration**	1-2	3-4	5-6	7-8	9-10	11-12	13-14	15-16	17-18	19-20	21-22	23-24	25-26
Milestone 4 – Terry Turbopump Basic Science Experiments														
NHTS Lab Facility Upgrades	3 months													
Z-1 Turbopump Test facility preparation	6 months													
Z-1 Turbopump Test facility test execution	6 months													
Turbomachinery Lab Facility Upgrades	1 month													
Full-Scale Technique Test facility preparation	2 months													
Full-Scale Technique Test facility test execution	3 months													
Scoping Uncontrolled Feedback Test facility preparation	1 months													
Scoping Uncontrolled Feedback Test facility test execution	3 months													
Report Deliverable	**Duration**	1-2	3-4	5-6	7-8	9-10	11-12	13-14	15-16	17-18	19-20	21-22	23-24	25-26
Z-1 Turbopump Test facility data and analysis report	3 months													
Full-Scale Technique Test facility data and analysis report	3 months													
Scoping Uncontrolled Feedback Test facility data and analysis report	3 months													
SNL & IAE experimental experts at TAMU	24 months													
Industry Staff input on experimental efforts	4 months													
Industry Contributions and Review of Milestone 4 reports	4 months													

Table 3. Terry Turbine and Pump Parameters [13]

Model Parameters	Value
Turbine wheel radius (r)	0.3 m
Turbine inlet/outlet angle (β)	π/4 radians
Number of nozzles	5
Total nozzle throat area	1.2315e-4 m^2
Total nozzle exit area	2.048e-4 m^2
Turbine moment of inertia (I)	10 kg-m^2
Impulse conversion coefficient (c_{IC})	0.98
Rated RCIC speed (ω_0)	450.295 radians/s (4300 rpm)
Rated pump torque (T_{p0})	449 N-m
Pump efficiency (η_p)	0.52
Rated pump head	766 m (7.52 MPa)

Table 4. Important Terry Turbine Nozzle RELAP-7 Calculation Results for Turbine Outlet Pressure at 193 kPa [13]

Parameters	Value
Pressure at nozzle inlet	7.500028e+06 Pa
Pressure at nozzle exit	5.713117e+05 Pa
Mach number at nozzle exit	2.295
Velocity at the nozzle exit	872 m/s
Velocity at the end of virtual nozzle	928 m/s

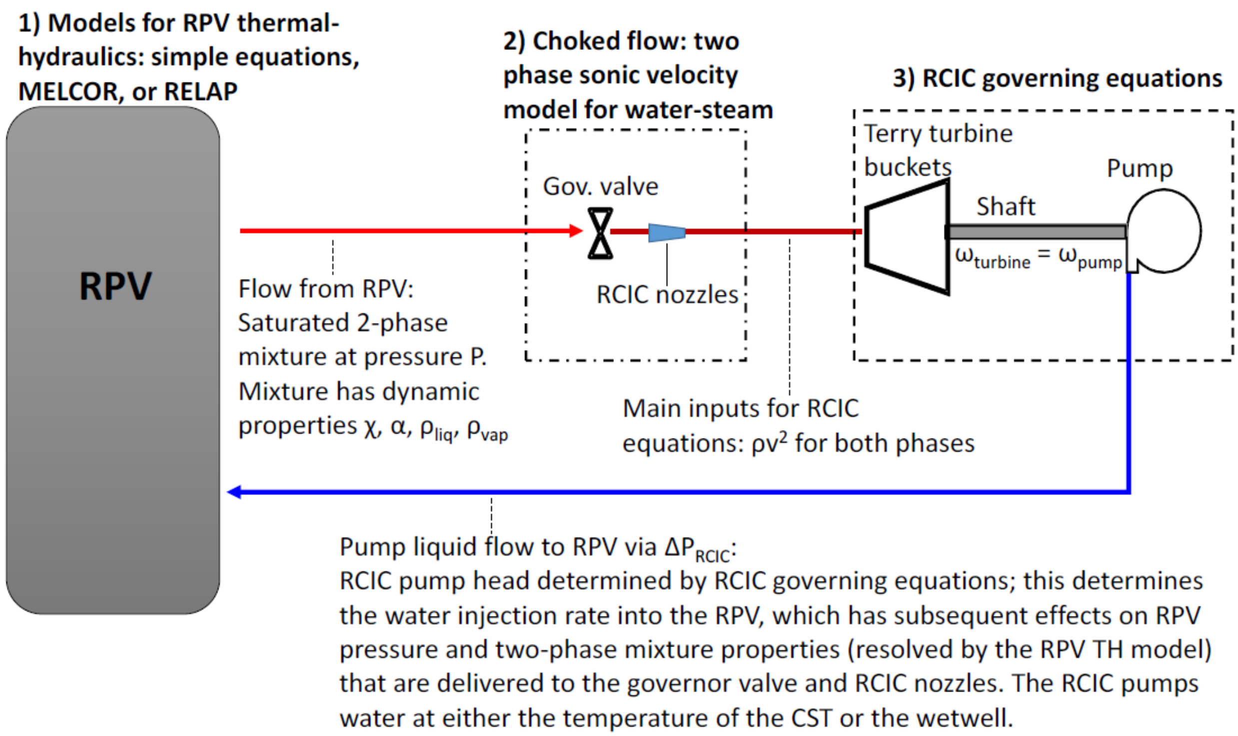


Figure 1. Simplified Representation of Physical Coupling in MELCOR Test Model [6]

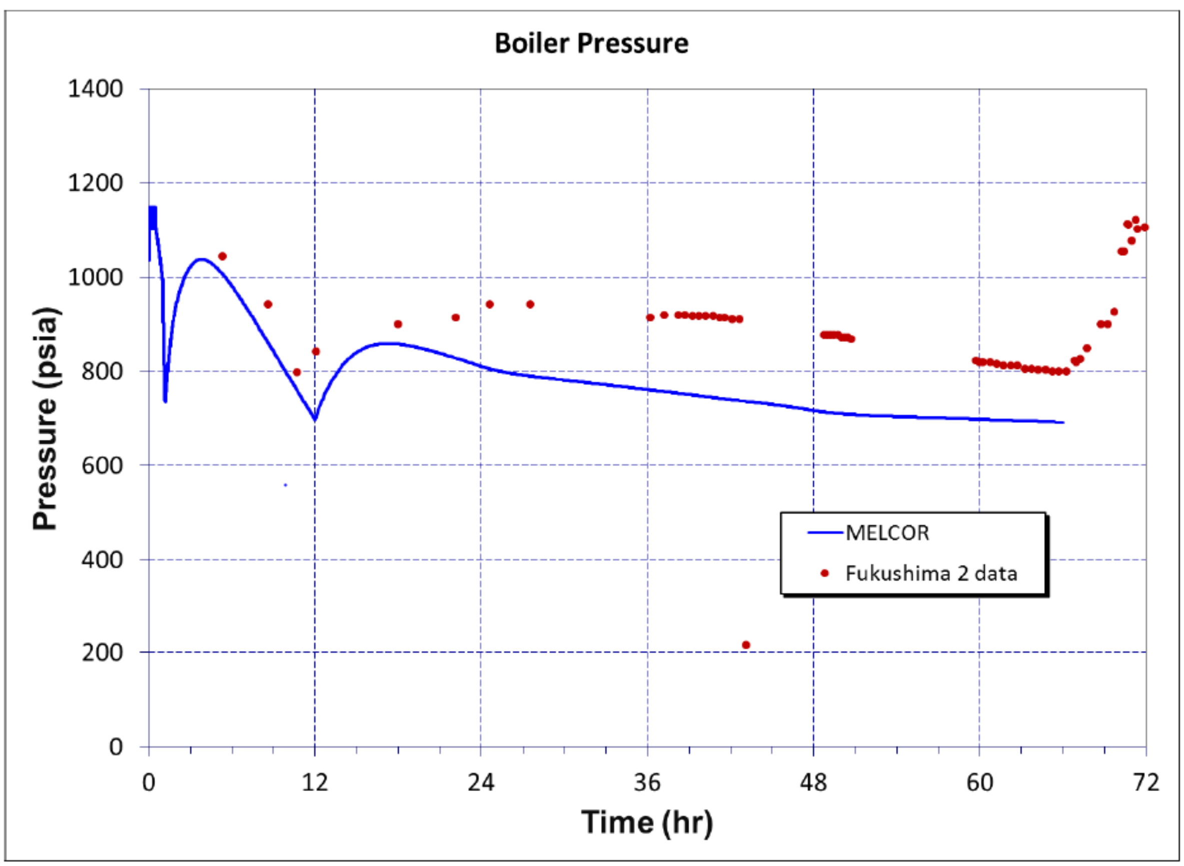


Figure 2. RPV Pressure from Revised MELCOR Model and Fukushima Unit 2 Data [6]

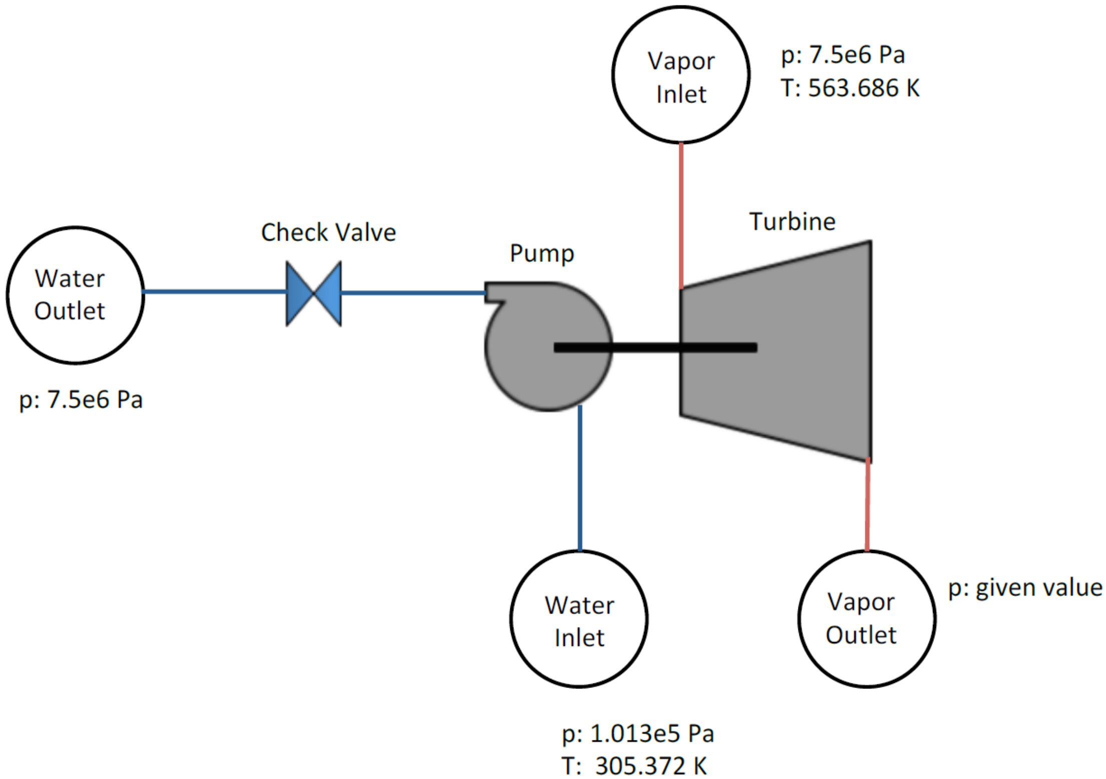


Figure 3. RELAP-7 Terry Turbine RCIC System Test Model [13]

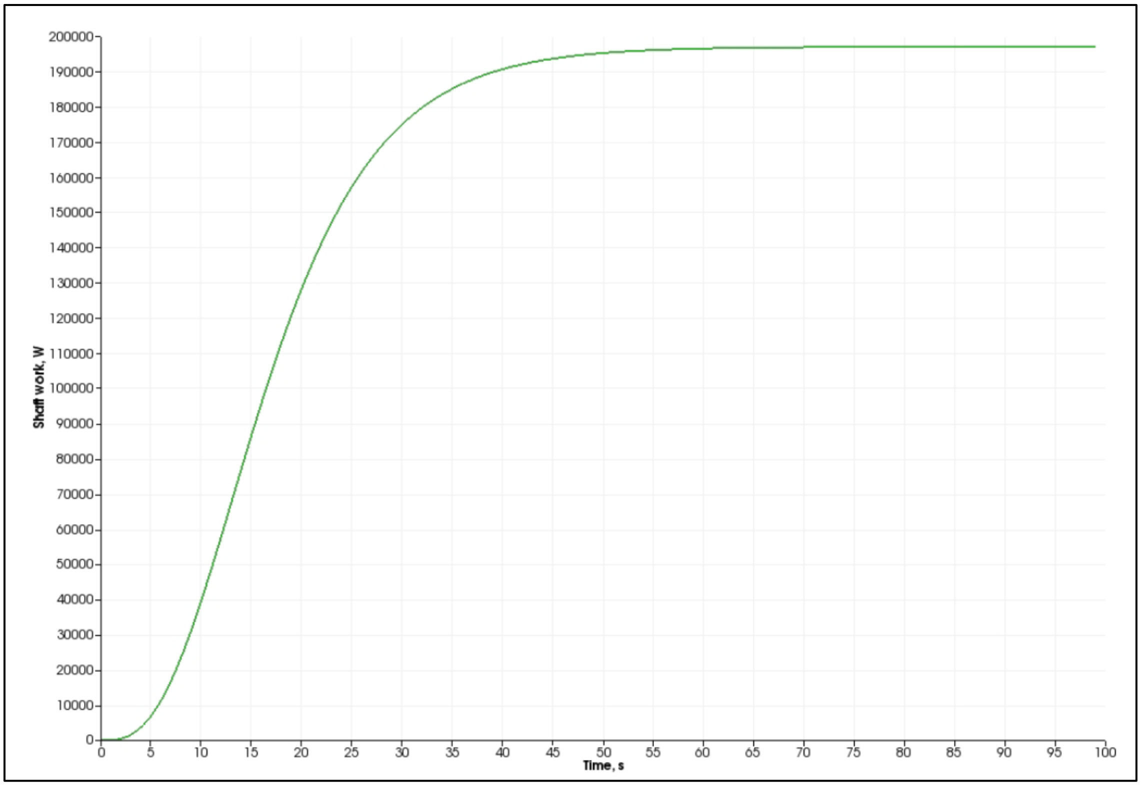


Figure 4. Shaft Work Calculated by the RELAP-7 Terry Turbine RCIC System Test Model for Turbine Outlet Pressure at 193 kPa [13]

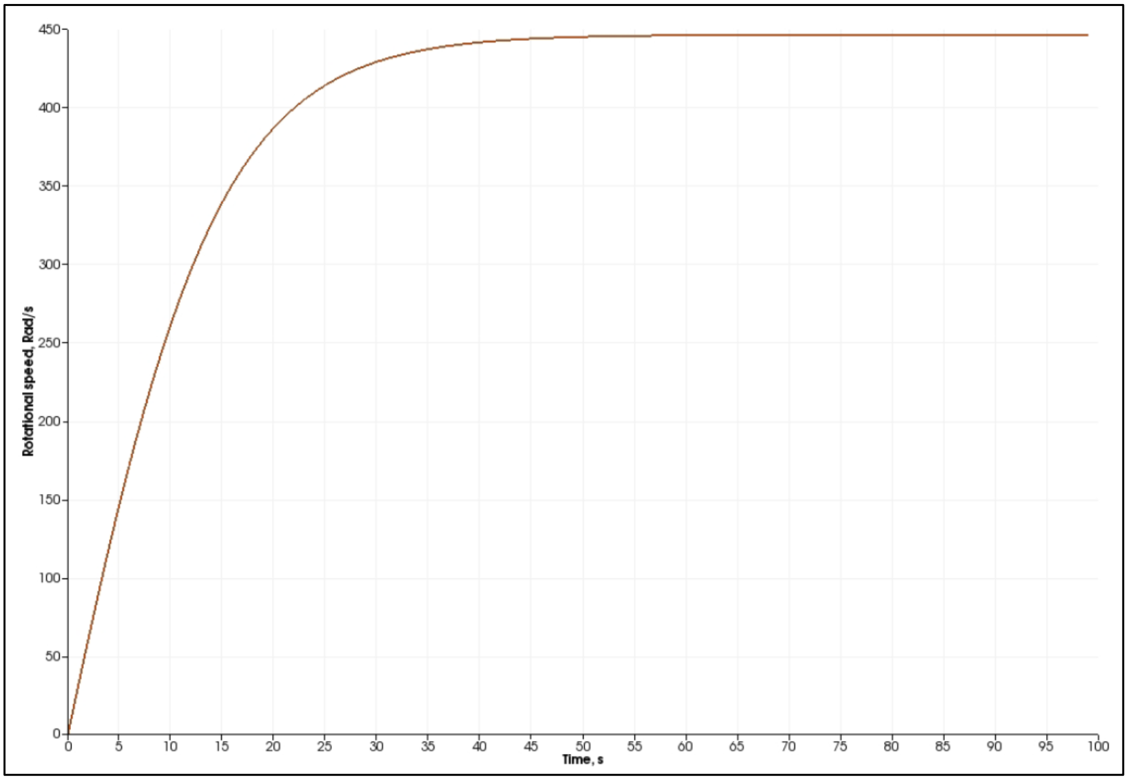


Figure 5. Rotational Speed Calculated by the RELAP-7 Terry Turbine RCIC System Test Model for Turbine Outlet Pressure at 193 kPa [13]

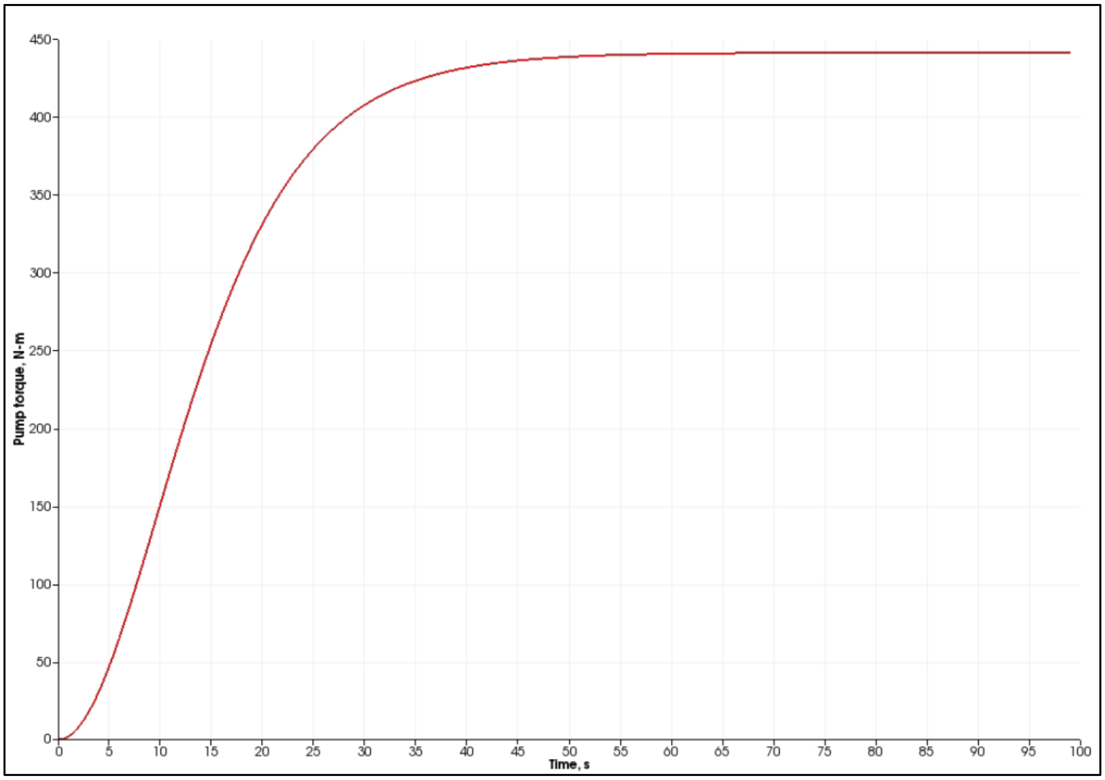


Figure 6. Pump Torque Calculated by the RELAP-7 Terry Turbine RCIC System Test Model for Turbine Outlet Pressure at 193 kPa [13]

Realignment of ASME Operations Maintenance Committee Improving Responsiveness and Efficiency

Thomas Ruggiero, P.E.
Exelon, Retired
Vice Chairman ASME OM

Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code) was developed when it was decided to move pump and valve inservice testing (IST) requirements from the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, to a standalone code. The code review process structure at the time was quite small and generally consisted of changing Section XI Subsections IWP and IWV into OM Code language. At the same time, new testing techniques were being developed that included check valve condition monitoring and current trace testing of motor-operated valves (MOVs). This necessitated adding groups that were specific to these new initiatives.

Although that was several decades ago, these groups remained, and over the years, it was identified that actions, such as Inquiries, were taking much too long to process. This became abundantly clear with the development of the newly published Mandatory Appendix IV for air-operated valve (AOV) testing.

This paper discusses how the Code Committee became the organization that it is and how a new realignment will streamline the code process and make it more efficient and responsive to the industry/regulatory needs.

Introduction

The ASME OM Code has been around for several years. Originally, IST requirements were included in ASME BPV Code, Section XI. ASME recognized that component operation and operational testing did not fit in the ASME BPV Code because that series of codes is geared towards pressure boundary integrity and not component functionality. As a result, Subsections IWP and IWV in Section XI were to be moved to a new code, *Operation and Maintenance of Nuclear Power Plants* (OM Code). This process began in the late 1970s.

When IST was included in the BPV Code, it was simply for pumps and valves. The transition from BPV to OM took a good deal of time, in this author's opinion, because rather than simply a reformat of the BPV into OM, the OM Standards Committee saw issues that it believed needed to be amplified and corrected. Therefore, the desire to "make it better" delayed the transition from BPV to OM.

At the same time, or shortly thereafter, new testing techniques were developed, as well as better ways to address operational readiness. These initiatives seriously overloaded the original OM Standards Committee. The existing Standards Committee recognized that it needed to be more responsive and efficient.

Standards Committee Organization Prior to This Realignment

The organization of the ASME OM Code prior to the realignment was based on what was needed shortly after it was moved from the ASME BPV Code, Section XI. The original organization consisted of a Pump Subcommittee (SC) and a Valve SC reporting directly to the Standards Committee. The release of U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” dated June 28, 1989, and check valve condition monitoring created a large workload that could not be effectively handled by the Valve SC on its own, which resulted in the spin-off of separate working groups (WGs). The SC Codes was added when Standards and Guides were added to OM. In general, the organization of the Standards Committee was vertical.

Reporting to the OM Standards Committee was SC Codes. SC Codes had WGs that reported to it. There were WGs for each of the OM subsections. In addition, specific WGs included Safety and Relief Valves (coming over from the Power Test Code), Check Valve Condition Monitoring, MOV Testing, AOV Testing, Risk-Informed, Snubbers, and New Reactors. Each of these WGs had its own agenda items and, in some instances, spun off task groups (TGs) for specific actions. For example, at one time, there was a TG Vibration that reported up through the WG ISTB for Pumps. Each WG, and in some cases, the TGs had a chair and a secretary, along with all of the associated administration.

The Reasons for Realignment

To understand the reason for the realignment, it was necessary to revisit the intentions of the ASME OM Standards Committee, as well as the experiences over the last several years. Several illustrations follow:

- The average time to produce needed Code revisions is simply too long. In some instances, the necessary Code changes stretched out to years, and in one case, a decade.

- The Inquiry process, in some cases, became a back door for users to provide ammunition to debate with the regulator or with their own management. This is not the purpose of that process. An Inquiry is for the industry to request or receive clarification or explanation of the Code.

- There are several recent instances of “global” Code changes that are handled by individual WGs. For example, verification of obturator movement was handled separately by each of the valve WGs instead of being assigned to a single WG.

- A new significant workload will be small modular reactors, as well as Generation IV Reactors. A significant amount of work is required for the Code to be ready for the small modular reactors.
- The technology and methods that the Code currently uses have not changed in decades.
- Budgets for meetings are disappearing with OM competing with the industry owners' groups for available travel budget.

In summary, code activities have become inefficient.

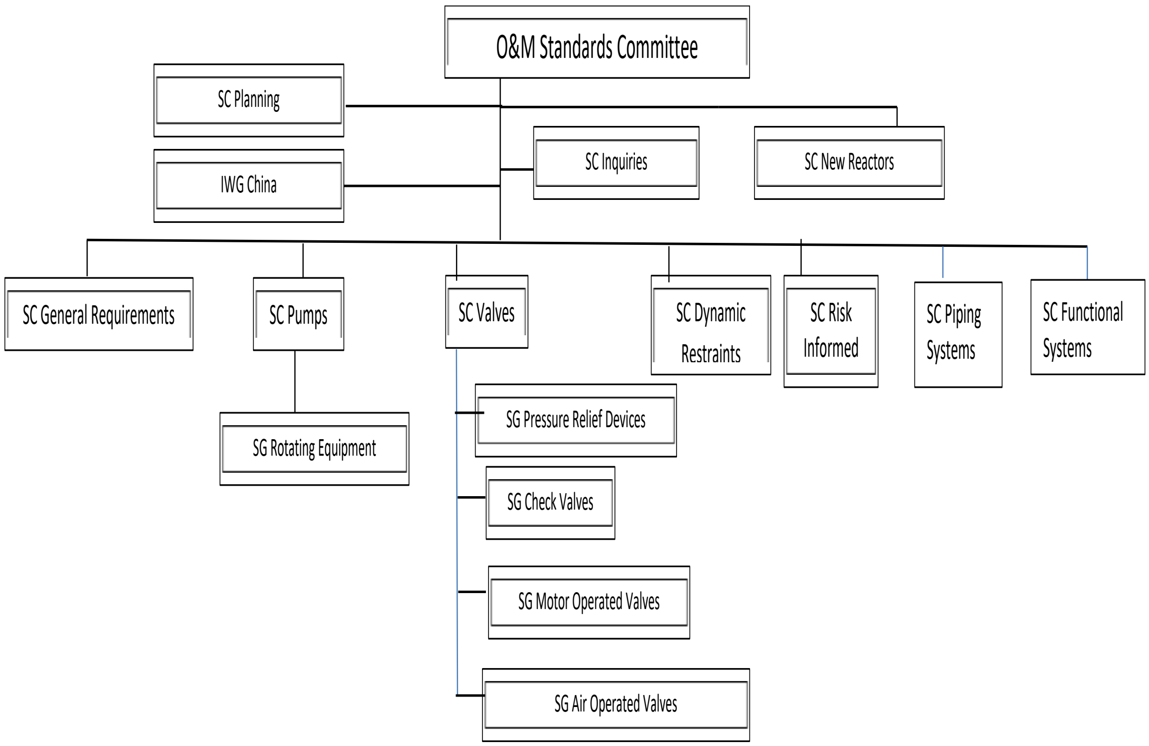
ASME OM Code New Alignment

The goals of the realignment are the following:

- Avoid redundant work—Activities that might affect multiple Code subsections and/or components need to be handled as a common global item. To minimize redundancy in work effort and save review time, resources, and processing, each individual WG should not be working on these activities independently.
- Respond to Inquiries more quickly—Inquiries are generated when a user community has a problem that needs to be resolved. This means that an answer needs to be forthcoming as soon as possible.
- Manage workload—Code workload needs to be spread over the available resources such that no group is delaying action because it does not have the resources to work on it.
- Keep everyone informed—The Standards Committee must know what all of the subtier groups are working on and be able to accelerate or, if applicable, stop work that is not needed or required.
- Be ready for new technology/plant types—The Standards Committee needs to be aware of and responsive to better ways to ensure operational readiness.
- Provide help where it is needed—The Standards Committee has to be in a position to lend help within the industry where the user community has difficulty or lacks understanding of requirements.

The bottom line: OM needs to be more efficient.

The New Alignment of ASME Operations and Maintenance Committee



In general, the realignment flattens the organization; makes WGs responsible to the consensus process that resides in the Standards Committee; and avoids large standing WGs, which in the past generated their own work (i.e., they worked in silos), sometimes creating redundant work efforts.

Responsibilities of Each Group

This SC will strategically advise the Standards Committee and subordinate committees on any new IST requirements that should be implemented into OM Divisions 1, 2, and 3.

Special Subcommittee on Inquiries

This Special Committee addresses all technical Inquiries. The membership is not permanent. This group will assemble a special group to address non-intent Inquiries.

SC New Reactors

This SC will advise the Standards Committee and subordinate committee on changes that should be implemented into OM Divisions 1, 2, and 3, for new nuclear reactors. Note that the work involved may be done by this group or by another group within the organization based on the workload and required skill set.

China International Working Group

The China International Working Group (IWG) provides for the participation in OM standards development by OM expert members based in China. The IWG reviews and comments on proposed changes and additions to OM Code Divisions 1, 2, and 3. The IWG can also coordinate with the appropriate SC to initiate and process proposed standard actions for Divisions 1, 2, and 3.

Subcommittee General Requirements

This SC is responsible for the development and maintenance of IST general requirements. It is responsible for the content in Division 1: Subsection ISTA, Nonmandatory Appendices A and M.

Subcommittee Pumps

This SC is responsible for the development and maintenance of IST requirements for pumps. It is responsible for the content in Division 1: Subsection ISTB, Subsection ISTF, and Mandatory Appendix V. It will advise the Subgroup—Rotating Equipment as that subgroup will be researching other more efficient ways to verify pump operational readiness.

Subgroup Motor-Operated Valves (Reports to Subcommittee Valves)

This subgroup is responsible for the development and maintenance of IST requirements for motor-operated valves. It is responsible for the content in Division 1: Mandatory Appendix III.

Subgroup Air-Operated Valves (Reports to Subcommittee Valves)

This subgroup is responsible for the development and maintenance of IST requirements for air-operated valves. It is responsible for the content in Division 1: Mandatory Appendix IV.

Subcommittee Dynamic Restraints (Snubbers)

This SC is responsible for the development and maintenance of IST requirements for dynamic restraints (snubbers). It is responsible for the content in Division 1: Subsection ISTD, Nonmandatory Appendices B, C, D, E, F, G, and H.

Subcommittee Risk-Informed Activities

This SC is responsible for the development and maintenance of risk-informed IST requirements. It is responsible for the content in Division 1: Subsection ISTE, Nonmandatory Appendices K and L; and Division 2: Part 29.

Subcommittee Piping Systems

This SC is responsible for the development and maintenance of IST requirements for piping systems. It is responsible for the content in Division 2: Part 3; and Division 3: Part 7.

Subcommittee Functional Systems

This SC is responsible for the development and maintenance of IST requirements for functional systems. It is responsible for the content in Division 2: Parts 12, 16, 21, 26, and 28; and Division 3: Parts 5, 11, 19, and 23.

Inquiries

It is understood that Inquiries must be responded to as quickly as possible. Requirement or non-intent Inquiries are those that can be answered with a simple “yes” or “no”. It is these that will benefit from this new process. Intent Inquiries are those written for clarification of something in the Code whose intent is not clear. By rule, intent Inquiries require a Code Change. This, by necessity, will take longer. Inquiry writers need to be aware that most Inquiries can be answered as requirement Inquiries, and they need to consider this as they are writing their Inquiries.

All Inquiries will be submitted through the ASME Web site. The ASME Secretary will contact the SC Inquiries Chair by phone or by e-mail and inform the Chair of the Standards Committee.

The SC Inquiries Chair decides which of the SC Chairs should head up the Inquiry response and determines whether it is an intent Inquiry or not. (Intent Inquiries go to the appropriate SC). The Standards Chair selects six to eight members (which may include the Standards Chair and/or the Inquiries SC Chair), maintaining the consensus balance of interest, to answer the Inquiry.

Reporting Relationships and Work Scope

TGs are considered temporary and are to be focused on a special need or technical aspect. They can be formed under any of the higher tier committees for the purposes of achieving something specifically for that committee. Anyone may be assigned to a TG, such as technical specialists who are not formally members of the ASME Committee membership. As such, the work scope and output of TGs are controlled by the committee to which they directly report, which may be a subgroup, SC, or even the Standards Committee. This means that the group that created the SG or TG is apprised of the specific activities the SG or TG is working on and what the group’s overall workload is. The SC approves the scope of the SG or TG.

The SG or TG can propose items that the group members believe are needed but the SC needs to approve work on those items. In turn, the SC gets buy-in from the Standards Committee to work on those items and to ensure that other groups are not working on the same or similar items that could be combined or worked on by a different group. If SG or TG activities are complete, the SG or TG is sunset, and its members are rolled into the SC.

The bottom line is that TGs are spun off from the SC to generate a specific product. Once that specific product is complete, published, or dropped, the WGs or TGs fold back into the parent SC. Also, future TGs should have total membership limited to the range of five to eight members. Going forward, large TGs with membership numbers that rival the Standards Committee's total membership are discouraged.

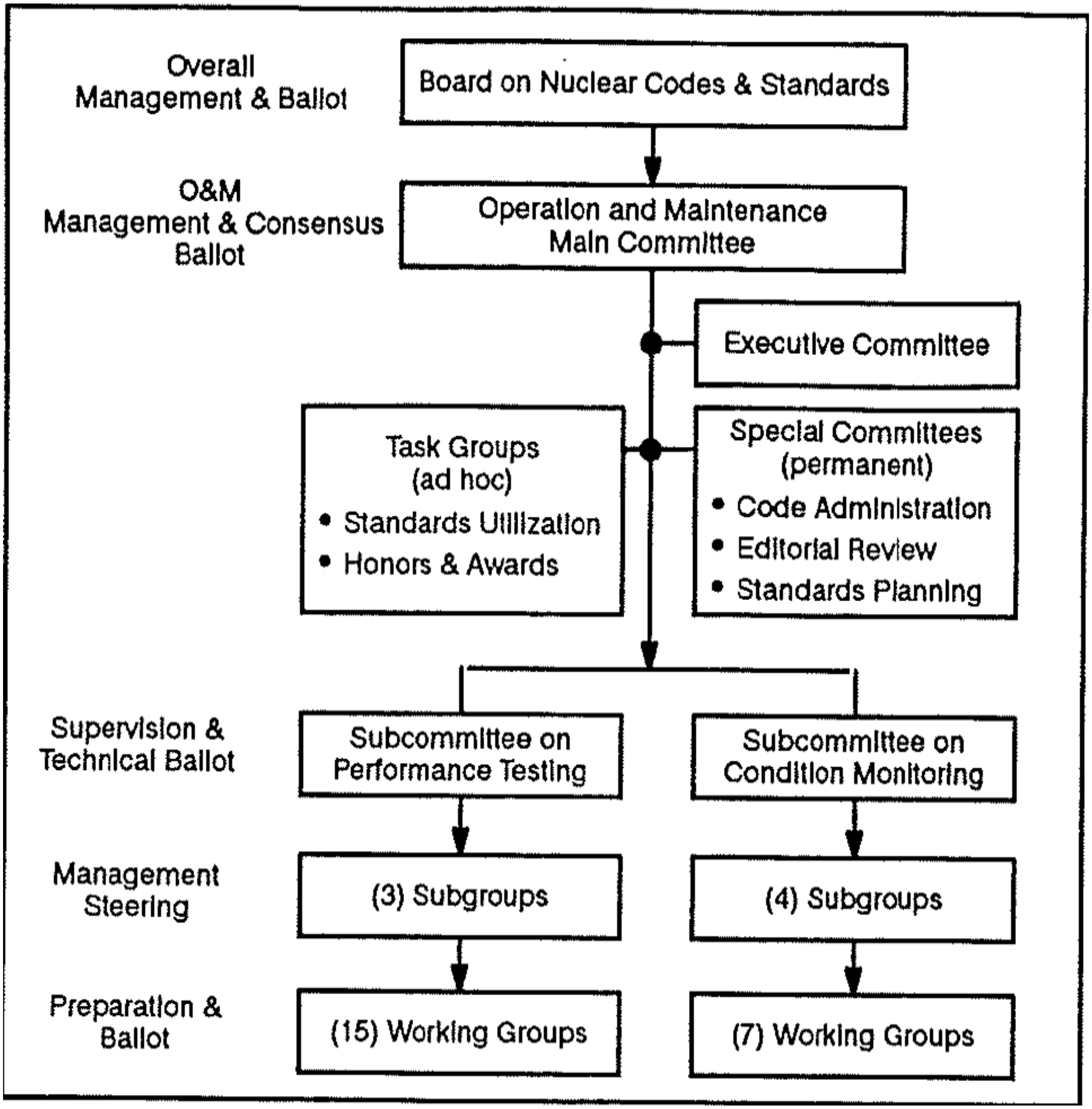
Conclusion

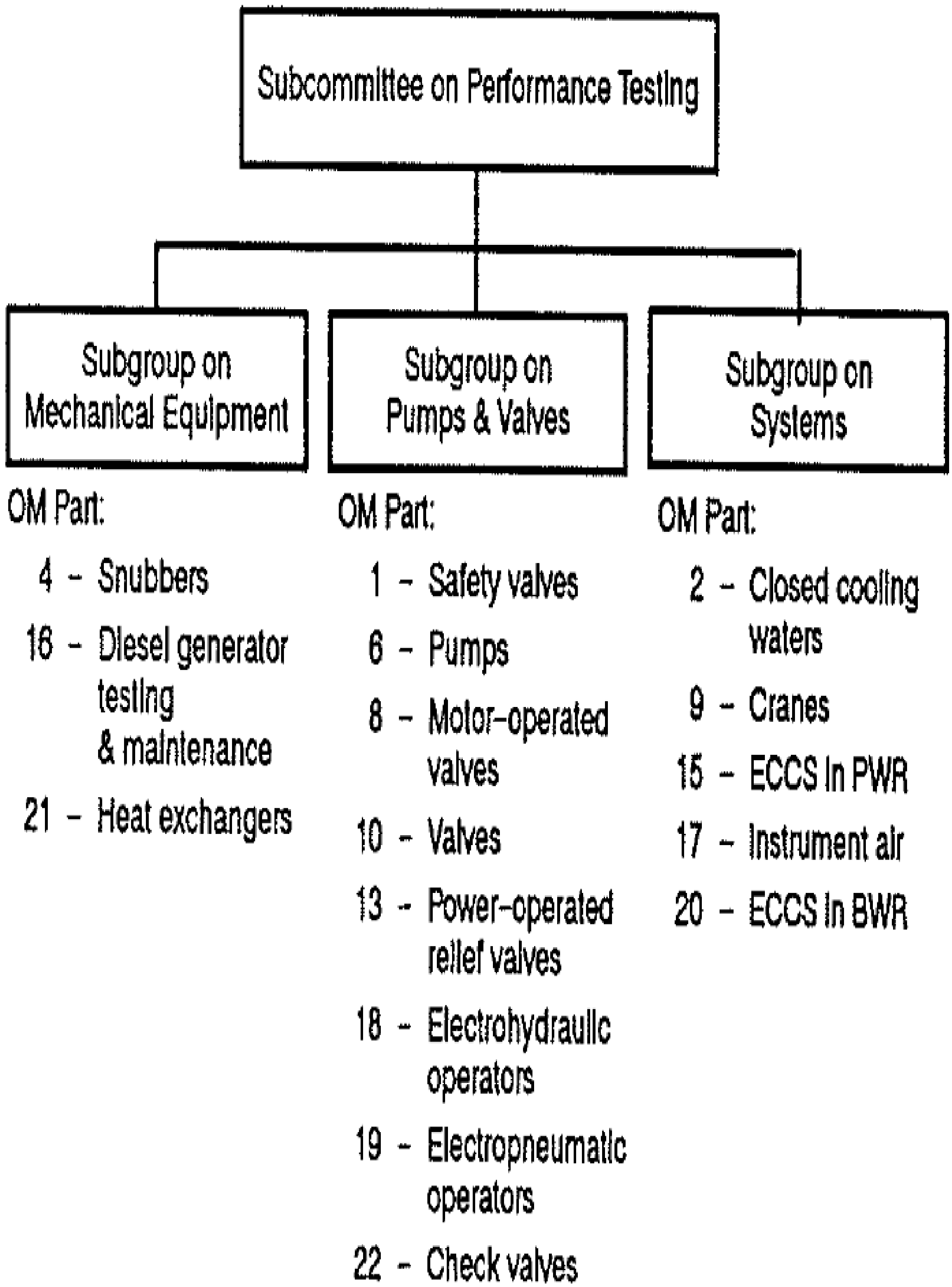
The new alignment has been in operation for one meeting. It will take some time before all of the final goals as to group size are realized; however, redundancy should cease to be an issue. The following groups have been eliminated in this new alignment:

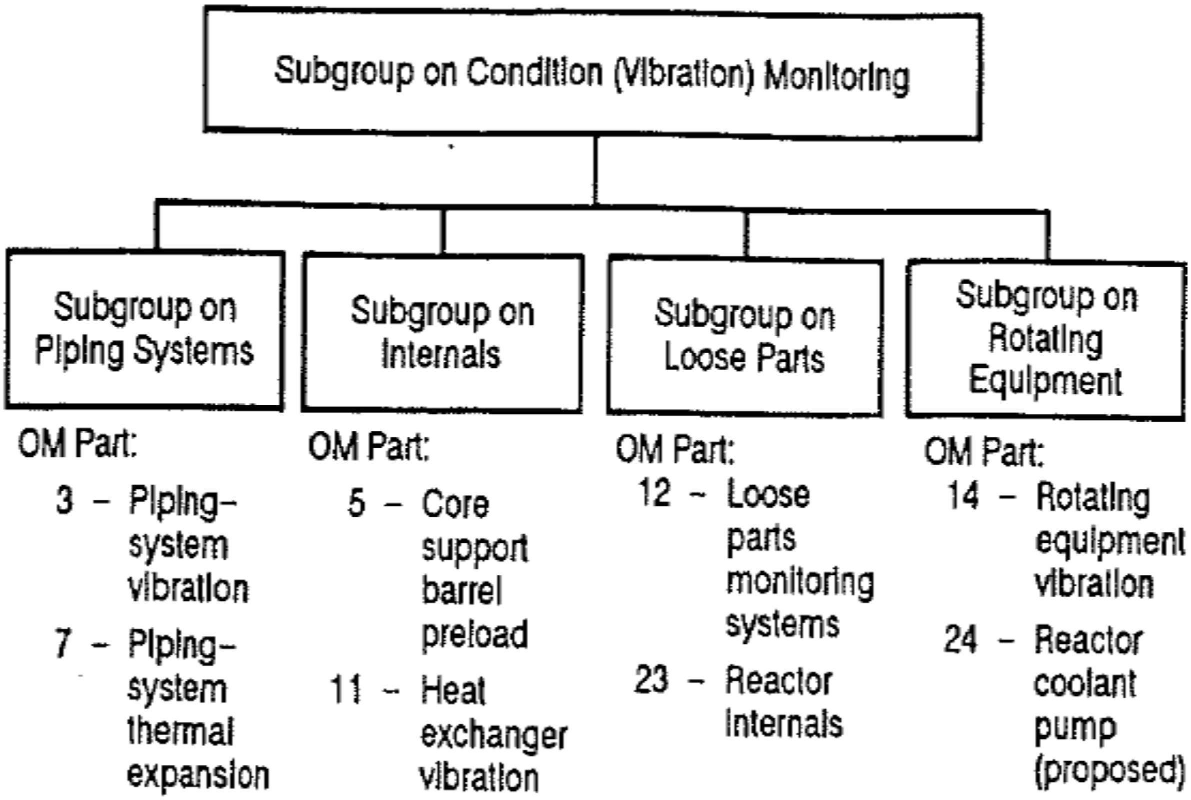
SC Codes
SG Diesel Generators
SG Heat Exchangers
SG Loose Parts
SG OM-29
SG Reactor Internals and Heat Exchangers
SG RTDs
TG Pump Performance Based IST
TG Pneumatically Operated Valves

ASME OM Organization in the Early Days

This attachment illustrates how the OM Committee was organized in the late 1980s (at the time when OM migrated from ASME BPV Code, Section XI). You will note that the Committee has a much flatter organization today.


Overall
Management & Ballot
Board on Nuclear Codes & Standards
O&M
Management & Consensus
Ballot
Operation and Maintenance
Main Committee
Executive Committee
Task Groups
(ad hoc)
• Standards Utilization
• Honors & Awards
Special Committees
(permanent)
• Code Administration
• Editorial Review
• Standards Planning
Supervision &
Technical Ballot
Subcommittee on
Performance Testing
Subcommittee on
Condition Monitoring
Management
Steering
(3) Subgroups
(4) Subgroups
Preparation &
Ballot
(15) Working Groups
(7) Working Groups


Subcommittee on Performance Testing
Subgroup on Mechanical Equipment
Subgroup on Pumps & Valves
Subgroup on Systems
OM Part:
4 - Snubbers
16 - Diesel generator testing & maintenance
21 - Heat exchangers
OM Part:
1 - Safety valves
6 - Pumps
8 - Motor-operated valves
10 - Valves
13 - Power-operated relief valves
18 - Electrohydraulic operators
19 - Electropneumatic operators
22 - Check valves
OM Part:
2 - Closed cooling waters
9 - Cranes
15 - ECCS in PWR
17 - Instrument air
20 - ECCS in BWR


Subgroup on Condition (Vibration) Monitoring
Subgroup on Piping Systems
Subgroup on Internals
Subgroup on Loose Parts
Subgroup on Rotating Equipment
OM Part:
3 – Piping-system vibration
7 – Piping-system thermal expansion
OM Part:
5 – Core support barrel preload
11 – Heat exchanger vibration
OM Part:
12 – Loose parts monitoring systems
23 – Reactor internals
OM Part:
14 – Rotating equipment vibration
24 – Reactor coolant pump (proposed)

Pump and Valve Inservice Testing—
How Pump and Valve Testing Evolved

Thomas Ruggiero, P.E.
Exelon, Retired
Vice Chairman ASME OM, ASME Fellow

Abstract

The ASME *Operation and Maintenance Code* (OM Code) was developed when it was decided to move pump and valve inservice testing (IST) requirements from ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, to a standalone code. IST for pumps was originally in ASME BPV Code, Section XI IWP, and for Valves, IWV. Safety and relief valves were a Power Test Code and not in the scope of the ASME BPV Code. IWP and IWV were developed after plants had been designed and built. The desire was that no backfits were to be required to comply with IST requirements. After the 1986 Edition, IWP and IWV requirements were moved into the OM Code. Appendix I to OM was formerly the Power Test Code.

While this was going on, the U.S. Nuclear Regulatory Commission (NRC) issued what has been called “the Richardson Letter.” Among other things, that letter specified that IST for pumps better assess the condition of the pumps by putting higher accuracy instrumentation on the test pipe. For many plants, this was the minimum recirculation pipe. Over time, the OM Committee was able to reach agreement that if a centrifugal pump were tested “back on its curve,” increased instrument accuracy would be meaningless. This was the genesis of what we now call “comprehensive pump testing.” Additionally, several alternative methods for valve testing had been developed. It became clear that simple periodic stroke timing of a power-operated valve was simply not adequate for detecting degrading performance.

This presentation will discuss how pump and valve IST evolved to what it is today and discuss what might be alternatives in the future. I want to thank Robert Parry, who provided some insights into this presentation, specifically where my memory needed a bit of jogging.

A Short Disclaimer

This paper, for the most part, is a timeline of how the OM Code evolved since its inception in the late 1970s. I will discuss some of the major issues and changes since the beginning and where I think we are going in the future. Much of what I present is documented in correspondence and meeting minutes. Some was not written and is my personal recollection. I was there as a member of a working group under Section XI, as well as the first meetings in the OM organization. Given time constraints and other logistics, I cannot discuss everything that went on. For the most part, I will be presenting history. There will be a few areas where I offer an opinion. Those opinions are solely my own and do not reflect the position of ASME, the OM Code, or any of the companies that have been my employer.

Introduction

The Committee on Operation and Maintenance of Nuclear Power Plants (OM Committee) was formed in June 1975 when the American National Standards Institute (ANSI) N45 Committee on Reactor Plants and Their Maintenance was disbanded. ASME assumed oversight and responsibility for several N45 committees that related to requirements contained in the ASME BPV Code, Sections III and XI. The Section XI subgroup on pumps and valves was transferred to the OM Committee in 1979 as the OM Working Group on Pumps and Valves, reporting to the Subcommittee on Performance Testing. This was as directed by the ASME Board of Nuclear Codes and Standards.

Originally, IST requirements were included in ASME BPV Code, Section XI. ASME recognized that component operation and operational testing did not fit in the BPV Code because that series of codes is geared towards pressure boundary integrity and not functionality. The plan was that the OM parts would be standards (similar to ASME B16.34), which would be referenced in IWP and IWV of ASME BPV Code, Section XI. So, for a time, there existed both OM working groups and a Section XI Subcommittee. In effect, there was a parallel committee setup that became cumbersome. This was brought to a head, so to speak, in a letter from Robert Bosnak, the NRC member of the BPV Committee, to Lawrence Chockie, Chairman of that committee. The distillation of the letter is that the NRC member believed that the current system, in which two groups with different reporting relationships having the same scope, was not working. The result was that Subsections IWP and IWV were to be moved to a new code, *Operation and Maintenance of Nuclear Power Plants*. The first publication of the OM Code was ASME/ANSI OM-1987.

It took several years to move from ASME BPV Code, Sections IWP and IWV, to OM Part 6 and Part 10. Parts 6 and 10 were eventually repackaged into Subsections ISTA, ISTB, and ISTC in the ASME OM Code. OM Part 1, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices," and Part 13, "Power Operated Relief Valves," became Appendix I.

A Component Code

In the foregoing section, we noted the addition of a verification flow test. This is, frankly, outside the original scope of the OM Code. However, verification was already included for MOV current trace testing.

The OM Code IST demonstrates operational readiness. IST requirements must have their foundation in the original preoperational and startup test program. There were shortfalls—some in design and some in testing. Frequency of testing limits this demonstration (pump quarterly versus refueling).

The OM Code is not a system code nor does it have "explicitly stated objectives." In some cases, the OM Code was revised to clearly state what was to be included or excluded. The OM Code is not a document that provides all of the implementation details. Said another way, the

OM Code is not a prescriptive instruction manual. It sets out what has to be done, but all of the implementation detail is not included in the OM Code.

IST is not an operability document, although some component test programs provide information and insights that are closer to operability than in our original testing requirements. IST is to detect deviations from a condition that was previously determined to be acceptable. Understanding the cause of the deviation, and correcting it, is the important element for IST.

Major Changes Going to OM 6 and OM 10 from IWP, IWV

The change from IWP to IWV brought other changes. The scope was no longer limited to only those components that were classified as ASME Class 1, 2, or 3. Preservice testing for pumps was added (valves already required preservice testing to establish a baseline for comparisons with subsequent IST). The requirement for measurement of pump bearing temperature was removed. The OM Committee determined after careful examination that bearing temperatures were not providing meaningful results for detecting pump degradation.

There was also a position in OM that detection of pump degradation from hydraulic performance was problematic. This is the period of time when OM was developing trending of vibration as a better indicator of pump degradation. As far as pump IST went, pump testing on the minimum flow recirculation was permitted. At the time, pressurized-water reactors, for the most part, were testing on minimum flow recirculation lines. There was no consideration of what the flow rate needed to be or the pump’s best efficiency point (BEP). There was no requirement as to the pump flow rate, nor was there any consideration of what the test flow rate was in comparison to what was required for the pump’s safety function. Safety function flow rate was verified periodically via the plant technical specifications. It now seems obvious that hydraulic testing of pumps with very little flow, and likely no instrumented flow measurement, would not ensure operational readiness nor be able to predict degrading performance.

Boiling-water reactors (BWRs) were generally designed with test loops in addition to the pump minimum flow lines that are typical for centrifugal pumps. Those test loops could, in most cases, pass almost the design-basis flow rate specified for the pump. Pressurized-water reactors did not have these additional test loops. All that was required is sufficient fluid inventory to run the test. Indeed, that requirement went in because some users were actually starting pumps with empty sumps.

Valve testing was simply stroke time, exercise, and leak rate testing. Check valve “open and inspect” made its first appearance. There were also “nonintrusive” techniques to inspect a check valve. However, condition monitoring for check valves and current trace testing for motor-operated valves (MOVs) were still in development.

During this time, the OM Code working groups were trying to reduce the need for relief requests to the NRC, but it was also clear at the time that IST was not predicting pump and valve failure. This was the subject of much discussion between the NRC and the OM Standards Committee. Recall that this was also the time when the NRC was reviewing test data, investigating component failures, and gathering the data that formed the basis for Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989.

There were many discussions among the committee members as well as with the NRC. A letter that was to change IST fundamentally was the Richardson Letter.

The Richardson Letter and the Dawn of Comprehensive Pump Testing

The NRC sent a letter, dated September 9, 1991, from James E. Richardson, then the Director of the NRC's Division of Engineering Technology, to the then ASME OM Code Chairman, Forrest Rhodes. ASME OM responded in a letter dated November 6, 1992. The NRC letter was described as bridging the gap between how the NRC thought pumps and valves would perform when plants licensed and what has been observed in the intervening time. The letter went on to state that verifying pumps and valves (e.g., within scope) can perform their intended function, then periodically determining the condition by measuring or observing changes from baseline testing.

The letter had several points. These included that the scope of IST should not be limited to ASME BPV Code, Section III, components (diesel generator valves and pumps, skid-mounted equipment). The letter stated that the design-basis function needed to be understood (open and closed, open only, etc.). Verification should be at design-basis conditions, or when not possible by test, verified by analysis. Finally, it specified that results be trended to find degrading components.

It is clear that much of this is beyond what the ASME OM Code is intended to be. However, one provision, to add instrumentation to pump test loops, had a major effect. The problem is that when a centrifugal pump is run at very low flow (far away from BEP and way back on its curve) very small changes in total developed head would result in large changes in flow rate. So, trying to correlate a change in pressure to a flow rate off a curve in this very flat region of the curve was beyond the capability of any flow measurement device. After much discussion, the OM Committee decided that testing at a higher flow rate would be required. The proposed solution is now called the "comprehensive pump test."

This was an interesting problem. For the most part, those plants that had test loops with substantial flow capability (usually BWRs) really did not have the problem. Plants that tested on minimum flow had an issue. The quandary here is that the OM Code did not want to require backfits. The solution was to come up with pump categories that allowed pumps that were not used continuously to be tested only when larger flows were possible. Of course, the OM Code does not say that, but in fact, that is the reasoning. Also, comprehensive pump testing, as originally conceived, included oil analysis. That was a major stumbling block and was removed. A second stumbling block that held up approval was motor current. The stated reason was that motors are outside the scope of the OM Code. So, why are pump motors not allowed to be used to verify the health of a pump when motors are frequently used to verify the health of an MOV? In my opinion, comprehensive pump testing is not "comprehensive" at all. It is simply testing the pump close to its BEP where better results are achievable. Sadly, this complicated the situation for BWRs because they could do the larger flow test quarterly. Yet, because the quarterly and comprehensive tests had different acceptable bands, you could not add the comprehensive pump test result into the trend with the other tests. More on this further on.

So, trending a comprehensive pump test, a better test, could take up to 6 years (a test every 2 years with at least three tests to form a trend). A plant that could do a higher flow test at any time, if you used the same acceptance criteria (both quarterly and every 2 years), could have 16 points to establish a trend over the same 6 years. Before we leave this, one more point. The purpose of trending, and "alert" versus "required action" limits, is that if you see a degrading trend, you can predict when you need to rework the pump. Therefore, to say that you need to justify a pump that just went below the required action limit, when it had been in the alert limit for some time, appears to be a case of poor planning because it would have been prudent to expect that at some point you would need to rework the pump. Also, when a pump is rebaselined, you need to do an analysis. It goes without saying that such analysis needs to show that the pump is still healthy. I have seen pump manufacturer reports that show major impeller damage, with the pump manufacturer recommending repair or replacement of the rotating assembly. Nevertheless, the Owner was attempting to use that report to rebaseline the pump. I think the lesson here is that you need to do the right thing.

Although what is called "comprehensive" pump testing was incorporated into the OM Code, there were still three issues that were preventing the NRC from endorsing the OM Code. These were test flow rate, high-end acceptance criteria for flow, and Group B tests.

As previously mentioned, a big issue was that the pump be tested in a flow region where meaningful and trendable data could be obtained. While this was going on, proof of licensing flow rate was removed from the new Standard Technical Specifications and replaced by reference to the OM Code. The problem is that the OM Code is a component code, and the verification flow test was really not the intent of the OM Code. A compromise was the inclusion of the flow verification test. This took quite a bit of negotiation.

The next issue was the percent of flow on the high end that would put a pump in the required action range. Part of this discussion had to do with how the pump test was set up. Finally, an agreement has been reached. A complication here is that acceptance criteria, as well as instrument accuracy requirements, are different for the quarterly test versus the comprehensive test. This will not be an issue for new generation plants, as noted further on.

Finally, the Group B test is only a go/no go test to ensure that the pump can start and come up to its reference point. Recall that Group B was put in place because those pumps so classified likely could not get the higher flow rates during the quarterly test to provide meaningful data.

What Happened to Time to Analyze Results?

OM-6 and OM-10 had carried over from IWP and IWV a provision that allowed 96 hours to analyze results. The concern here was that some were adding the 96 hours to their technical specifications limiting conditions for operation clock. This was never intended, and it was an area of concern to the NRC. It is often very difficult to remove something from a code once it gets in. Most agreed that the infamous 96 hours needed to go. The problem is that the action required a justification for removing it. So, what was the justification?

In the mid-1970s, when analysis was being considered, members debated what the timing should be. Realize that at that time, IST data were typically gathered by an operating crew and left for an engineer to interpret. So, how long should be allowed for that interpretation? This is not a joke, because I was there and heard it with my own ears. The test might be run at off hours, so if it is a long weekend, it would be okay to let the evaluation wait until the engineer got back to the plant. Ninety-six hours is a 4-day weekend. This was not written down anywhere that I have been able to find, but that was the justification. Finally, OM removed the time requirement from the Code. Now, as we all know, IST procedures need to be written such that the acceptance criteria are in the procedure that does the test.

Check Valve Condition Monitoring

Check valve condition monitoring was one of the first attempts at putting together out-of-the-box thinking for IST. In many ways, it was an attempt to make IST more meaningful and efficient. Condition monitoring for check valves was the beginning of doing similar things for other valve types. The deal here though is that identifying requirements rather than a procedure for how to do something leaves open a larger window to do it incorrectly. Condition monitoring needs more skill and training to implement correctly. It was a first attempt to move away from prescriptive requirements. It is a better way to do things, but it does involve more discussion with peers and management who may not have a good understanding of intent.

Stroke-Time Testing of Alternating Current Motor-Operated Valves

As mentioned previously, there was evidence that the early code was not predicting valve failure. One case in point was stroke-time testing of alternating current (ac) MOVs. An ac motor will operate at the same speed if it is operating at all. So, stroke timing an ac MOV really didn't yield any trend at all. The OM Code eventually developed current trace testing. This method could predict a degraded valve very well. The problem though is, while stroke-time testing is a yes or no type test, current trace testing requires an evaluation by someone who is trained to use this method. So when someone asks the valve engineer where in the OM Code it says that a valve is unacceptable, he must turn to the person who is skilled at this method.

Air-Operated Valves

By this time, most of us are familiar with the new Appendix IV having to do with air-operated valves (AOVs). This appendix has been in development for too many years. Its development really tested what was the original scope of OM as a code that determined component degradation from a previously acceptable point. The biggest holdup, and the reason for many industry comments, had to do with design-basis verification.

Before Appendix IV, there was OM Part 19, "Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants." OM 19 has received several negatives on its ballot(s), including the following:

How specific requirements from OM 19 related to the development of an AOV Program?

There were not clear cut High Safety Significant (HSSC) requirements and Low Safety Significant (LSSC) requirements.

There were no grouping details as there were in the OMN-12 Code Case.

What are the margins and how they are used to determine test intervals?

Dealing with design bases capability determinations in an IST Document.

What other ISTC requirements are to be maintained?

OM reached out to industry groups to solicit ideas on how to address AOV requirements. Among its questions were whether changes are needed to improve the current IST requirements for pneumatically (AOVs) and hydraulically operated valves (HOVs) and whether Code Case OMN-12 requirements should be incorporated into the mandatory IST requirements for high-risk valves?

Other questions included: for LSSC valves, should ISTC require more stringent testing for Joint Owners' Group AOV Program Category 1 AOVs by adopting the OMN-12 HSSC position as a mandatory requirement? Should the current requirements for IST be maintained for Joint Owners' Group AOV Category 2 AOVs, or should we adopt the OMN-12 LSSC position as a mandatory requirement? If current ISTC requirements for Category 2 AOVs are maintained, should the ISTC section reference Code Case OMN-12 or OM Part 19 for Owner-augmented program testing requirements?

What came out of this was the working group for AOVs.

Plans for the Future

The nuclear industry has changed. The OM Code started as a code that provided rules for IST for plants that were already built. Because of that, the rules were arranged to allow quite a bit of latitude so as to avoid requiring a plant to make any physical changes. This involved a lot of compromise. Additionally, IWP and IWV, as well as OM Parts 6 and 10, for the most part, used deterministic techniques with very clear, black or white acceptance criteria. Testing interval (time between tests) was eventually set based on the ability to do the test based on plant operation. There was little regard for duty cycle of the component. For example, a Category A valve is leak tested up to every 2 years. We know that a typical valve with a hard metal-to-metal seat can be close to zero leakage when it is new. We also know that if it is infrequently cycled, 2 years from when it is installed, it would still have a very good sealing capability. We also know that if it were cycled frequently, say once a month, we could expect that leak rate would go up significantly. So, the logic is that we should be leak checking a high-cycle valve more frequently.

Small modular reactors typically will have longer fuel cycles, and some may not need to be refueled at all. There have been requests to allow exercising at durations up to 4 years. The OM Code, in my opinion, cannot allow that because motor actuator manufacturers have told us that a valve must be cycled at least every 2 years to prevent the actuator grease from hardening or separating. OM is pursuing new criteria for valves where the testing interval may be more condition based, rather than simply by calendar time or plant fuel cycle.

Pumps did not typically have test loops that permitted substantial flow. However, new-build plants should have that capability built in as the original design. This means that pump categories and different tests for periodic versus shutdowns should no longer be necessary. The result is better testing with more data points to trend. We have checked on the operational health of MOVs using the motor itself to diagnose what is going on in the valve. However, since OM Code scope does not include pump motor testing, we resist using the pump motor to verify the health of the pump. There are technologies currently available and used in other industries that do exactly that. We need to be looking at those.

Conclusion

The foregoing presents a timeline of some of the major evolutionary changes to today's OM Code. The presentation also provides, along with some personal reflections and observations of the author, the direction that the OM Code will be going. We note that the original OM Code was written to fit plants that were either already in operation or well on their way to operation. The future of the OM Code needs to consider how to make IST more meaningful and recognize more efficient techniques. The OM Code also needs to consider completely new plant designs and add guidance to make certain that the required components have the required provisions to allow assurance of operational readiness.

References

(1) ASME OM Code 2001.

(2) Letter from Robert Bosnak to Lawrence Chockie, “Procedure for Referencing O&M Standards in Section XI,” October 13, 1987.

(3) Letter from James E. Richardson, NRC Director, Division of Engineering Technology, to Forrest Rhodes, Chairman ASME O&M, September 9, 1991

(4) Letter from Forrest Rhodes, Chairman ASME O&M, to James E. Richardson, NRC Director, Division of Engineering Technology, November 6, 1992

(5) Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” dated June 28, 1989.

Expectations for Inservice Testing Programs at New Nuclear Power Plants[7]

Thomas G. Scarbrough
Mechanical Engineering Branch
Division of Engineering and Infrastructure
Office of New Reactors
U.S. Nuclear Regulatory Commission

Abstract

In a series of Commission papers, the U.S. Nuclear Regulatory Commission (NRC) described its policy for inservice testing (IST) programs to be developed and implemented at nuclear power plants licensed under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants." This paper discusses the expectations for IST programs based on those Commission policy papers as applied in the NRC staff review of combined license (COL) applications for new reactors. For example, the design and qualification of pumps, valves, and dynamic restraints through implementation of American Society of Mechanical Engineers (ASME) Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants," as accepted in NRC Regulatory Guide (RG) 1.100, Revision 3, "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," issued September 2009, will enable IST activities to assess the operational readiness of those components to perform their intended functions. ASME has updated the *Operation and Maintenance of Nuclear Power Plants* (OM Code) to improve the IST provisions for pumps, valves, and dynamic restraints that are incorporated by reference in the NRC regulations with applicable conditions. In addition, lessons learned from performance experience and testing of motor-operated valves (MOVs) will be implemented as part of the IST programs together with application of those lessons learned to other power-operated valves (POVs). Licensee programs for the regulatory treatment of nonsafety systems (RTNSS) will be implemented for components in active nonsafety-related systems that are the first line of defense in new reactors that rely on passive systems to provide reactor core and containment cooling in the event of a plant transient.

This paper also discusses the overlapping testing provisions specified in ASME Standard QME-1-2007; plant-specific inspections, tests, analyses, and acceptance criteria; the applicable ASME OM Code as incorporated by reference in the NRC regulations; specific license conditions; and initial test programs as described in the final safety analysis report (FSAR) and applicable RGs.

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7 This paper was prepared by staff of the U.S. Nuclear Regulatory Commission (NRC). It may present information that does not currently represent an agreed-upon NRC staff position. The NRC has neither approved nor disapproved the technical content.

I. Introduction

The NRC has issued COLs for the construction and operation of several nuclear power plants in the United States under 10 CFR Part 52. The COL licensees are developing their preservice testing (PST), IST, and MOV testing programs to support the operation of those nuclear power plants. This paper discusses the expectations for IST programs (including the PST and MOV testing programs) for new nuclear power plants.

II. NRC Regulations

The NRC regulations in 10 CFR Part 52 provide a process for the licensing of new nuclear power plants in the United States as an alternative to the process described in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." Subpart C, "Combined Licenses," of 10 CFR Part 52, beginning with 10 CFR 52.71, "Scope of Subpart," sets out the requirements and procedures applicable to the issuance of COLs for nuclear power facilities. The NRC regulations in 10 CFR 52.79, "Contents of Applications; Technical Information in Final Safety Analysis Report," specify the contents of COL applications and the technical information to be provided in an FSAR. For example, paragraph (a)(11) in 10 CFR 52.79 requires a COL applicant to provide in its safety analysis report, at a level sufficient to enable the NRC to reach a final conclusion on all safety matters that must be resolved before COL issuance, a description of the programs and their implementation necessary to ensure that the systems and components meet the requirements of the ASME *Boiler and Pressure Vessel Code* (BPV Code) and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code) in accordance with 10 CFR 50.55a, "Codes and standards." Paragraph (a)(37) in 10 CFR 52.79 requires that COL applications include information necessary to demonstrate how operating experience insights have been incorporated into the plant design. In addition, paragraph (a)(41) in 10 CFR 52.79 requires that COL applications include an evaluation of the standard plant design against the revision of the NRC's NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," in effect 6 months before the docket date of the application.

The NRC has incorporated by reference the 1995 Edition through the 2006 Addenda of the ASME OM Code in 10 CFR 50.55a with regulatory conditions. In September 2015, the NRC issued in the *Federal Register* a proposed rulemaking to incorporate by reference the ASME OM Code up through the 2012 Edition with regulatory conditions. Beginning with the 2009 Edition, the ASME OM Code includes a new Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants," that replaces the quarterly stroke-time testing provisions for MOVs in the ASME OM Code with periodic exercising on a refueling outage frequency and diagnostic testing on an interval of up to 10 years based on capability margin. Beginning with the 2012 Edition, the ASME OM Code includes PST and IST provisions for pyrotechnic-actuated (squib) valves in new nuclear power plants. Among the regulatory conditions for new reactors in the proposed 10 CFR 50.55a rule are provisions for periodic verification of the design-basis capability of power-operated valves (POVs) to perform their safety functions; bidirectional testing of check valves; flow-induced vibration monitoring; and RTNSS in new reactors with passive emergency cooling systems.

The NRC staff is preparing the final rulemaking to incorporate by reference the ASME OM Code up through the 2012 Edition in 10 CFR 50.55a, which is planned for issue in 2017. The NRC staff is considering a future rulemaking to incorporate by reference into 10 CFR 50.55a the 2015 Edition and 2017 Edition of the ASME OM Code. The 2017 Edition of the ASME OM Code includes a new Appendix IV, "Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants," to improve the IST provisions for air-operated valves (AOVs) by supplementing the quarterly stroke-time testing provisions with periodic performance assessment tests for AOVs with high safety significance.

The current NRC regulations in 10 CFR 50.55a(f)(4)(i) state that inservice tests to verify operational readiness of pumps and valves whose function is required for safety, conducted during the initial 120-month interval, must comply with the requirements in the latest edition and addenda of the ASME OM Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date scheduled for initial fuel loading under a COL issued under 10 CFR Part 52 or the optional ASME OM Code Cases listed in NRC RG 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code," subject to the limitations and modifications listed in 10 CFR 50.55a. In response to a public comment from ASME, the NRC staff is considering, as part of a future proposed 10 CFR 50.55a rulemaking, the relaxation of this time period prior to initial fuel loading for compliance with the latest edition of the ASME OM Code for the initial 120-month IST program interval.

III. Commission Policy on New Reactor Designs

Commission papers SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," dated January 12, 1990; SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," dated April 2, 1993; SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," dated March 28, 1994; and SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY-94-084)," dated May 22, 1995, and their staff requirements memoranda (SRM), discuss design aspects related to IST programs for new reactors. In a public memorandum to file dated July 24, 1995, the NRC staff consolidated the guidance in SECY-94-084 and SECY-95-132 and their respective SRM. The guidance in these Commission papers and the NRC staff memoranda are summarized in the following paragraphs.

In SECY-90-016, the NRC staff recommended that the Commission approve four IST provisions for safety-related pumps and valves in evolutionary light-water reactors:

(1) Piping design should incorporate provisions for full flow testing (maximum design flow) of pumps and check valves.

(2) Designs should incorporate provisions to test MOVs under design-basis differential pressure.

(3) Check valve testing should incorporate the use of advanced, nonintrusive techniques to address degradation and performance characteristics.

(4) A program should be established to determine the frequency necessary to disassemble and inspect pumps and valves to detect unacceptable degradation that cannot be detected through the use of advanced, nonintrusive techniques.

The NRC staff considered these provisions to be necessary to provide adequate assurance of the operability of the components.

In the SRM dated June 26, 1990, on SECY-90-016, the Commission approved the NRC staff's position as supplemented in the staff's response dated April 27, 1990, to the Advisory Committee on Reactor Safeguards. In that response, the staff agreed with the Advisory Committee's recommendations to emphasize the provisions of Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989, for evolutionary plants; to resolve check valve testing and surveillance issues; and to indicate how these provisions are to be applied to evolutionary plants. The staff also agreed that the provisions should permit consideration of proposed alternatives in meeting inspection and surveillance requirements. The Commission noted that due consideration should be given to the practicality of designing test capability, particularly for large pumps and valves.

In SECY-93-087, the NRC staff recommended that the Commission approve the position that the recommended IST requirements for evolutionary plants also be imposed for passive ALWR plants. The staff noted that additional IST requirements may be necessary for certain pumps and valves in passive plant designs. This necessity was said to arise because passive safety systems rely heavily on the proper operation of certain equipment (such as check valves and depressurization valves) to mitigate the effects of accidents and to shut down the reactor. Depressurization valves are operated by pyrotechnic (squib) actuators in some new reactor designs. In its SRM dated July 21, 1993, the Commission noted that the staff planned to provide more detail in a future paper.

In SECY-94-084, the NRC staff provided recommendations to the Commission pertaining to technical and policy issues related to RTNSS equipment in passive ALWR plants, including IST of pumps and valves. In its SRM dated June 30, 1994, the Commission responded to those recommendations with specific directions to the staff. With respect to IST, the Commission directed that the staff clarify the recommendations.

In SECY-95-132, the NRC staff provided a revision to the staff recommendations in SECY-94-084, based on the Commission's direction in the SRM dated June 30, 1994. With respect to IST activities for passive plant designs, the staff stated the following in SECY-95-132:

> [the] unique passive plant design relies significantly on passive safety systems, but also depends on non-safety systems (which are traditionally safety-related systems in current light water reactors) to prevent challenges to passive systems.

Therefore, the reliable performance of individual components is a significant factor in enhancing the safety of passive plant designs.

The staff recommended that the following provisions be applied to passive ALWR plants to provide assurance of proper component performance:

- Nonsafety-related piping systems with functions that have been identified as important by the RTNSS process should be designed to accommodate testing of pumps and valves to ensure that the components meet their intended functions.

- To the extent practicable, the passive ALWR piping systems should be designed to accommodate the applicable ASME OM Code requirements for quarterly testing of valves. However, design configuration changes to accommodate quarterly testing required by the OM Code should be made only if the benefits of the test outweigh the potential risk.

- The passive system designs should incorporate provisions (a) to permit all critical check valves to be tested for performance, to the extent practicable, in both the forward- and reverse-flow directions, although the demonstration of a nonsafety direction test need not be as rigorous as the corresponding safety direction test, and (b) to verify the movement of each check valve's obturator during IST by observing a direct instrumentation indication of the valve position such as a position indicator or by using nonintrusive test methods.

- The passive system designs should incorporate provisions to test safety-related POVs under design-basis differential pressure and flow. Similarly, to the extent practicable, the design of nonsafety-related piping systems with functions that have been identified as important by the RTNSS process should incorporate provisions to test POVs in the system to ensure that the valves meet their intended functions under plant design-basis conditions.

- To the extent practicable, provisions should be incorporated in the design to ensure that MOVs in safety-related systems are capable of recovering from mispositioning.

In its SRM dated June 28, 1995, the Commission approved the recommendations in SECY-95-132. With respect to the IST recommendations, the Commission directed that the staff clarify the recommendation and clearly differentiate the types of testing that are to be performed to ensure the design-basis capability of safety-related POVs prior to installation, prior to initial startup, and during the operational phase (i.e., qualification tests and preoperational tests).

In a public memorandum dated July 24, 1995, the NRC staff provided a consolidated list of the Commission's prior approved policy and technical positions associated with RTNSS equipment in passive plant designs discussed in SECY-94-084 and SECY-95-132 and their associated SRM. As directed by the SRM dated June 28, 1995, the staff memorandum clarified that the design capability of safety-related POVs should be demonstrated by a qualification test prior to installation. Prior to initial startup, the memorandum stated that POV capability under design-basis differential pressure and flow should be verified by a preoperational test. During the operational phase, the memorandum stated that POV capability under design-basis differential pressure and flow should be verified periodically through a program similar to that developed for MOVs in GL 89-10.

IV. NRC Regulatory Guidance and Generic Correspondence

In 1989, the NRC issued GL 89-10 based on operating experience issues with MOV performance and the results of the implementation of NRC Bulletin 85-03, “Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings,” dated November 15, 1985, at operating nuclear power plants. In GL 89-10, the NRC asked licensees of nuclear power plants to perform dynamic testing of safety-related MOVs where practicable to verify their design-basis capability. In response to GL 89-10, nuclear power plant licensees conducted flow tests of many safety-related MOVs to evaluate their performance and identified a wide range of MOV capability issues. Nuclear power plant licensees expended significant resources to resolve the MOV performance issues identified as part of their GL 89-10 programs. The NRC staff conducted inspections of the development, implementation, and completion of the GL 89-10 programs at operating nuclear power plants.

On September 18, 1996, the NRC issued GL 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” to request that nuclear power plant licensees establish a program to periodically verify the design-basis capability of safety-related MOVs. The Joint Owners’ Group (JOG) developed an MOV testing program in response to GL 96-05 based on flow testing of a sample of MOVs over a 5-year period at most nuclear power plants. For those valves within the scope of the JOG testing program, it determined the maximum valve factors for gate and globe valves and bearing friction coefficients for butterfly valves. Most licensees of current operating plants apply information from the JOG MOV Program for maximum gate and globe valve factors and butterfly valve bearing friction coefficients as part of their GL 96-05 programs for valves within the JOG scope. For valve designs outside the JOG scope, licensees determine valve friction coefficients on a plant-specific basis. In that the JOG MOV Program did not address actuator output, each licensee addresses actuator output capability including justification of motor torque, stem friction coefficient, load sensitive behavior (or rate of loading), actuator efficiency, degraded voltage, and temperature effects on a plant-specific basis.

Based on MOV lessons learned, the NRC included a requirement in 10 CFR 50.55a(b)(3)(ii) for nuclear power plant licensees to establish a program to ensure that MOVs continue to be capable of performing their design-basis safety functions to supplement the quarterly stroke-time testing provisions for MOVs in the ASME OM Code. GL 96-05 programs at operating nuclear power plants can be used to help satisfy the MOV design-basis capability requirement in 10 CFR 50.55a. In addition, ASME developed Code Case OMN-1, “Alternative Rules for Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light Water Reactor Power Plants,” to allow an MOV diagnostic test program with static and dynamic testing as an alternative to the quarterly MOV stroke-time testing provisions in the ASME OM Code. Subsequently, ASME developed Appendix III to the OM Code to replace quarterly MOV stroke-time testing with periodic exercising and diagnostic testing.

For POVs other than MOVs, licensees address performance capability through implementation of the ASME OM Code, as incorporated by reference in 10 CFR 50.55a, and lessons learned from the MOV program. The NRC issued Regulatory Issue Summary (RIS) 2000-03, “Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves Under Design Basis Conditions,” dated March 15, 2000, to provide guidance for programs to verify the design-basis capability of POVs at nuclear power plants. In RIS 2000-03, the NRC staff referenced a program developed by the JOG for periodic verification of the design-basis capability of AOVs with NRC staff comments on the JOG AOV program. In the RIS, the NRC staff indicated that it would continue to monitor licensee activities to ensure that POVs are capable of performing their safety-related functions under design-basis conditions. In an attachment to RIS 2000-03, the NRC staff provided a list of attributes to support the development of a successful POV program at nuclear power plants.

In preparation for the licensing of new nuclear power plants, the NRC staff issued RG 1.206, “Combined License Applications for Nuclear Power Plants (LWR Edition),” to address the development of COL applications. Section 3.9.6 in RG 1.206 provides guidance for COL applicants to describe their functional design, qualification, and IST programs for pumps, valves, and dynamic restraints. The NRC staff is considering a revision to RG 1.206 to incorporate lessons learned from the licensing of new nuclear power plants.

NUREG-0800, SRP Section 3.9.6, “Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints,” provides guidance for NRC staff review of design certification and COL applications describing the functional design, qualification, and IST programs for pumps, valves, and snubbers. In particular, SRP Section 3.9.6 addresses NRC staff review of the functional design and qualification of pumps, valves, and snubbers; IST programs for pumps, valves, and snubbers; relief requests and alternatives to the ASME OM Code; new reactor inspections, tests, analyses, and acceptance criteria (ITAAC); COL action items and certification requirements; and operational program description and implementation. SRP Section 3.9.6 incorporates lessons learned from operating experience into acceptance criteria for the NRC staff review of design certification and COL applications.

RIS 2012-08, Revision 1, “Developing Inservice Testing and Inservice Inspection Programs under 10 CFR Part 52,” dated July 17, 2013, describes the NRC staff position on IST and inservice inspection programs developed for nuclear power plants licensed under 10 CFR Part 52. As noted in this RIS, several years may elapse between the time when a design certification is granted and when a COL application is submitted referencing that certified design. Further, the construction of a nuclear power plant will require several years from the time of COL issuance until the commencement of fuel loading.

Therefore, design certification and COL applicants and holders need to be aware of the interrelated requirements in 10 CFR 50.55a and 10 CFR Part 52 regarding the development and implementation of inservice inspection and IST programs for nuclear power plants to be licensed under 10 CFR Part 52. In particular, the IST programs described in design certification and COL applications may reference a specific edition and addenda of the ASME OM Code many years prior to the actual construction of a nuclear power plant. As noted earlier in this paper, the current NRC regulations in 10 CFR 50.55a(f)(4)(i) state that inservice tests to verify operational readiness of pumps and valves, whose function is required for safety, conducted during the initial 120-month interval must comply with the requirements in the latest edition and addenda of the ASME OM Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date scheduled for initial fuel loading under a COL issued per 10 CFR Part 52 or the optional ASME OM Code Cases listed in RG 1.192, subject to the limitations and modifications listed in 10 CFR 50.55a.

As discussed in RIS 2012-08, Revision 1, the COL holder may request use of the ASME OM Code edition and addenda referenced in its FSAR description of the IST program for the initial 120-month IST program as an alternative in accordance with 10 CFR 50.55a(z). In evaluating such an alternative request, the NRC staff will review the differences between the ASME OM Code edition and addenda specified in the FSAR and the most recent edition and addenda incorporated by reference in 10 CFR 50.55a 12 months before the planned fuel load for the new nuclear power plant. RIS 2012-08, Revision 1, also indicates that a COL applicant or holder may propose a risk-informed IST program, although the NRC staff recognizes the challenges associated with the absence of plant-specific component history at new nuclear power plants.

The NRC staff updated NUREG-1482, Revision 2, “Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants—Final Report,” issued October 2013, to incorporate lessons learned from IST programs and component performance at currently operating nuclear power plants and from the review of IST program descriptions in COL applications for new nuclear power plants. In NUREG-1482, the NRC staff describes the regulatory basis for IST programs and provides guidance for the development of IST programs including scope, IST program documentation, preconditioning, specific component testing, and new reactor IST programs. The NRC staff will consider a future update to NUREG-1482 based on recent revisions to the ASME OM Code and 10 CFR 50.55a rulemaking.

The NRC staff issued RG 1.100, Revision 3, to accept ASME Standard QME-1-2007 with regulatory positions. This ASME standard specifies provisions and guidelines for qualifying active mechanical equipment over the expected range of service conditions, including design-basis events. ASME QME-1-2007 provides general qualification provisions for active mechanical equipment and specific qualification provisions for pumps, valves, and snubbers. For example, Section QV, “Functional Qualification Requirements for Active Valve Assemblies for Nuclear Power Plants,” in ASME QME-1-2007 incorporates the lessons learned from MOV operating experience and testing to provide assurance of the functional capability of active valve assemblies, including POVs, check valves, and relief valves.

The NRC prepares inspection procedures to provide guidance for NRC inspectors to evaluate construction and operating activities, such as programs, procedures, installation, testing, maintenance, and corrective actions, at nuclear power plants to provide assurance of their safe construction and operation. With respect to new nuclear power plants, NRC Inspection Procedure (IP) 73758, "Part 52, Functional Design and Qualification, and Preservice and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints," dated April 19, 2013, provides guidance for NRC inspections to evaluate the establishment, implementation and results of functional design and qualification of pumps, valves, and snubbers; and the PST and IST programs for pumps, valves, and snubbers during construction of nuclear power plants licensed under 10 CFR Part 52. IP 73758 is based on the NRC approach for MOV inspections to evaluate the development, implementation, and completion of the GL 89-10 programs at nuclear power plants. IP 73758 includes inspection guidance for each programmatic inspection phase and describes specific MOV, AOV, and squib valve inspection activities.

The NRC staff has prepared several inspection procedures related to component installation, ITAAC, and testing of components in nuclear power plants. For example, IP 62708, "Motor-Operated Valve Capability," provides guidance for the assessment of MOV performance issues and adequacy of a licensee's evaluation of MOV performance. IP 62710, "Power-Operated Gate Valve Pressure Locking and Thermal Binding," provides guidance for the assessment of the extent of condition related to pressure locking and thermal binding of power-operated gate valves. IP 65001.07, "Inspection of ITAAC-Related Installation of Valves," provides inspection guidance for valve installation at new nuclear power plants, including testing and verification to ensure that POVs are capable of performing their safety functions under design-basis conditions. IP 65001.14, "Inspection of ITAAC-Related Installation of Complex Systems with Multiple Components," provides inspection guidance to determine that ITAAC-related tests and verification activities are being conducted in accordance with design specifications, approved procedures, and design criteria. IP 65001.D, "Inspection of the ITAAC-Related Operational Testing Program," provides guidance for the inspection of various types of operational testing to accomplish ITAAC and to ensure that testing is adequate and consistent with regulatory requirements and licensee commitments.

V. Inservice Testing Programs at New Nuclear Power Plants

Based on Commission papers and NRC regulations and guidance, COL licensees should consider several factors when developing their IST programs for new nuclear power plants. These factors are addressed in the following paragraphs:

(1) The qualification program for pumps, valves, and snubbers should be developed in accordance with the provisions specified in the COL licensee's FSAR. In particular, design specifications prepared for design certifications and provisions in the FSARs for COL licensees typically specify the implementation of ASME Standard QME-1-2007 as accepted in RG 1.100, Revision 3, for the qualification of safety-related pumps, valves, and snubbers. The implementation of ASME QME-1-2007, as accepted in RG 1.100, Revision 3, provides assurance of the capability of pumps, valves, and snubbers to perform their safety functions as a foundation for the IST program.

(2) The PST, IST, and MOV testing programs should be developed consistent with their description in the COL FSAR, including the design control document (DCD) provisions in the design certification application that were incorporated by reference in the COL FSAR.

(3) The COL licensee should ensure compliance with the license conditions related to the PST, IST, and MOV testing operational program implementation schedules and completion dates, as well as specific component license conditions (such as squib valve surveillance).

(4) The IST program should be updated from the ASME OM Code edition and addenda specified in the COL FSAR to satisfy the ASME OM Code incorporated by reference in 10 CFR 50.55a 12 months before fuel loading for the initial 120-month IST program. However, a COL licensee may submit a request under 10 CFR 50.55a to implement the IST program described in the COL FSAR for the initial 120-month IST program as an alternative to the requirement to implement the ASME OM Code incorporated by reference in 10 CFR 50.55a 12 months before fuel loading. As part of its 10 CFR 50.55a alternative request, the COL licensee will need to justify any differences with the ASME OM Code edition required by 10 CFR 50.55a(f). See RIS 2012-08, Revision 1, for additional details. As discussed above, the NRC staff is considering a relaxation of the time for establishing the ASME OM Code of record for the initial 120-month IST program.

(5) The IST program should address the conditions specified in 10 CFR 50.55a for the applicable ASME OM Code, except where the COL licensee submits a relief or alternative request in accordance with 10 CFR 50.55a. The *Federal Register* notice, 82 FRN 32934, dated July 18, 2017, for the proposed rulemaking for the 2009–2012 ASME OM Code provided guidance for satisfying the proposed conditions for new reactors. When issued, the final 10 CFR 50.55a rule for the 2009–2012 ASME OM Code will provide updated conditions in response to public comments and detailed guidance in its *Federal Register* notice.

(6) The COL licensee should ensure that the testing of pumps, valves, and snubbers specified in the ITAAC has been completed with the acceptance criteria satisfied. ITAAC testing (such as type testing, preoperational testing, flow testing, and fail-safe testing), QME-1 testing, PST testing, and Initial Test Program (ITP) testing have specific aspects that may be addressed together where applicable.

(7) The COL licensee should review the NRC inspection procedures for ITAAC related to qualification, preoperational testing, flow testing, fail-safe testing, and installed configuration of pumps, valves, and snubbers in preparation for those inspections.

(8) The COL licensee should review IP 73758 in preparation for the NRC staff inspections of the PST, IST, and MOV testing operational programs in support of fuel loading. Considerations in preparing for IP 73758 inspections include the following:

a. The COL licensee should have available the QME-1 qualification documentation for safety-related pumps, valves, and snubbers.

b. The COL licensee should have available the PST and IST program plans for safety-related pumps, valves, and snubbers. These plans should address ASME OM Code testing, non-Code testing (such as POV periodic verification), 10 CFR 50.55a conditions, and COL license conditions for safety-related pumps, valves, and snubbers. The plans should also consider augmented testing of safety-related non-Code Class pumps and valves consistent with 10 CFR 50.55a as discussed in the proposed 10 CFR 50.55a rulemaking, as applicable.

c. The COL licensee should have available the design-basis capability documentation for the sizing, setting, and weak link analyses for POVs (including MOV thrust/torque calculations, and AOV air pressure/spring evaluations). Inspection and testing experience from the GL 89-10 programs at current operating nuclear power plants provide guidance for this documentation.

d. The COL licensee should have plans available for providing assurance of the capability of pumps, valves, and snubbers within the RTNSS scope to perform their safety-significant functions. The ASME OM Code Committee is preparing guidance for these plans.

(9) The COL licensee should be prepared to evaluate the need to revise or modify its PST and IST programs based on new information obtained during the development and implementation of those programs. For example, the COL licensee might obtain design, qualification, installation, or test information that might reveal the need for adjustments to the PST and IST programs for specific pumps, valves, or snubbers to be used in its nuclear power plant.

The COL licensee may request a public meeting with the NRC staff to help ensure a full understanding of the expectations regarding the IST program for pumps, valves, and snubbers at new reactors during the program development process.

VI. Power-Operated Valve Testing at New Nuclear Power Plants

COL licensees should consider several factors related to POV qualification and testing for new nuclear power plants. These factors are outlined below:

(1) COL FSARs for new nuclear power plants (including the incorporation of the DCD provisions from the applicable certified design) specify implementation of ASME Standard QME-1-2007 as accepted in RG 1.100, Revision 3, for the qualification of safety-related POVs to perform their design-basis safety functions. In particular, Subsection QV-7400, "Qualification Requirements for Power-Operated Valve Assemblies," in ASME QME-1-2007 specifies provisions for the qualification of POVs

used in nuclear power plants. For example, QV-7461 describes the functional qualification of a POV design. QV-7462 describes the extrapolation of the functional qualification to another POV design. QV-7463 describes the demonstration of the functional capability of each production valve of a POV qualified design. QV-7470 describes the post-installation testing and establishment of the IST baseline for each production valve. Squib valves are addressed as applicable to the provisions in Subsection QV-7400 for POVs.

(2) At a new nuclear power plant, tests applicable to safety-related POVs prior to plant startup include the following:

a. Qualification of the POV design by extensive testing, or extrapolation with analysis and limited testing, as described in ASME QME-1-2007 and accepted in RG 1.100, Revision 3.

b. Production valve testing of each POV under dynamic conditions as described in QME-1-2007 and accepted in RG 1.100, Revision 3. QME-1-2007 allows production valve testing to be performed prior to or following POV installation before being relied on to perform its intended function.

c. Post-installation testing and establishment of an IST baseline for each POV under dynamic conditions as described in QME-1-2007 and accepted in RG 1.100, Revision 3.

d. Type testing to demonstrate the capability of the valve to operate under its design conditions, and verification that the as-built valve is bounded by the tests or type tests, as specified in the applicable ITAAC.

e. Preoperational testing (and fail-safe testing if appropriate) of each POV under conditions as specified in the applicable ITAAC.

f. Preservice and inservice testing of each POV within the scope of the IST program as specified in the applicable ASME OM Code incorporated by reference in 10 CFR 50.55a with regulatory conditions.

g. Initial testing for each POV in accordance with the ITP described in the applicable FSAR and appropriate RGs, such as RG 1.68, “Initial Test Programs for Water-Cooled Nuclear Power Plants.”

h. Preservice and inservice testing and surveillance of valves (such as squib valves) as specified in COL license conditions.

A licensee should coordinate its testing activities to allow POV tests to be accomplished together where possible.

(3) A COL licensee of a new nuclear power plant with a passive emergency cooling system should address nonsafety-related POVs within the RTNSS scope to demonstrate their capability to perform high safety-significant functions.

(4) Factors to consider when planning POV testing at new nuclear power plants include the following:

a. The JOG MOV Program did not address all gate, globe, and butterfly valve designs such that the licensee will need to determine an appropriate gate or globe valve factor or butterfly valve bearing friction coefficient for any valve designs outside the scope of the JOG Program.

b. The JOG MOV Program addressed only gate, globe, and butterfly valves such that the licensee will need to determine appropriate friction coefficients for other valve types.

c. The JOG MOV Program did not address actuator output such that each licensee will need to justify actuator assumptions (such as motor torque, stem friction coefficient, load-sensitive behavior or rate of loading, actuator efficiency, degraded voltage, and temperature effects) on a plant-specific basis.

d. New nuclear power plants do not have a history of temperature or radiation conditions in various plant areas for application to POV performance.

e. Valves in new nuclear power plants might have abnormally low friction coefficients based on their limited use during preoperational testing and initial plant operation.

f. New nuclear power plants do not have experience with changes in stem friction coefficient, load-sensitive behavior, actuator efficiency, or temperature effects based on intervals between valve exercising, testing, or lubrication.

g. MOVs need to be evaluated to avoid motor damage caused by improper torque switch setup or overtorque conditions when operating under limit switch control. See, for example, RG 1.106, Revision 2, “Thermal Overload Protection for Electric Motors on Motor-Operated Valves,” issued February 2012.

h. POVs need to be evaluated to avoid damage caused by pressure locking or thermal binding. See, for example, GL 95-07, “Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves,” dated August 17, 1995. Lessons learned from the evaluation of potential pressure locking and thermal binding of gate valves are also helpful in avoiding these phenomena for other valve types, such as globe valves.

Based on the above considerations, the licensee should determine appropriate periodic dynamic testing of selected POVs to justify the assumptions for valve friction, stem friction coefficient, load-sensitive behavior or rate of loading, lubrication intervals, and ambient temperature and radiation effects.

VII. Conclusion

COL licensees are constructing or planning several new nuclear power plants in the United States. As described in the NRC final safety evaluation reports for those COL applications, the NRC staff evaluated the descriptions of the PST, IST, and MOV testing programs provided by the COL applicants in their FSARs, including the incorporation by reference of applicable DCD provisions. Consistent with their FSARs, the COL licensees are developing the PST, IST, and MOV testing operational programs based on NRC regulatory requirements and guidance and applicable license conditions. When developing the PST, IST, and MOV testing programs and planning POV testing, each COL licensee should consider the overlapping testing provisions specified in ASME Standard QME-1-2007; plant-specific ITAAC; PST and IST provisions in the applicable ASME OM Code as incorporated by reference in 10 CFR 50.55a with regulatory conditions; specific license conditions; and ITPs as described in the FSAR and applicable RGs for its new nuclear power plant. The NRC staff has developed procedures for the inspection of the PST, IST, and MOV testing operational programs at new nuclear power plants to provide confidence in the capability of these programs to verify the operational readiness of pumps, valves, and snubbers to perform their safety functions.

VIII. References

American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code*. (Available through ASME Web site.)

ASME *Operation and Maintenance of Nuclear Power Plants*. (Available through ASME Web site.)

ASME Standard QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.” (Available through ASME Web site.)

NRC Bulletin 85-03, “Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings,” November 15, 1985. (Available on NRC Web site.)

NRC Commission Paper SECY-90-016, “Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements,” January 12, 1990, and its Staff Requirements Memorandum (SRM) dated June 26, 1990. (Available on NRC Web site.)

NRC Commission Paper SECY-93-087, “Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs,” April 2, 1993, and its SRM dated July 21, 1993. (Available on NRC Web site.)

NRC Commission Paper SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs," March 28, 1994, and its SRM dated June 30, 1994. (Available on NRC Web site.)

NRC Commission Paper SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY-94-084)," May 22, 1995, and its SRM dated June 28, 1995. (Available on NRC Web site.)

NRC Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," June 28, 1989. (Available on NRC Web site.)

NRC GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," August 17, 1995. (Available on NRC Web site.)

NRC GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor Operated Valves," September 18, 1996. (Available on NRC Web site.)

NRC Inspection Procedure (IP) 73758, "Part 52, Functional Design and Qualification, and Preservice and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints," April 19, 2013. (Available on NRC Web site.)

NRC IP 62708, "Motor-Operated Valve Capability." (Available on NRC Web site.)

NRC IP 62710, "Power-Operated Gate Valve Pressure Locking and Thermal Binding." (Available on NRC Web site.)

NRC IP 65001.07, "Inspection of ITAAC-Related Installation of Valves." (Available on NRC Web site.)

NRC IP 65001.14, "Inspection of ITAAC-Related Installation of Complex Systems with Multiple Components." (Available on NRC Web site.)

NRC IP 65001.D, "Inspection of the ITAAC-Related Operational Testing Program." (Available on NRC Web site.)

NRC NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition." (Available on NRC Web site.)

NRC NUREG-1482, Revision 2, "Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants—Final Report," October 2013. (Available on NRC Web site.)

NRC Public Memorandum dated July 24, 1995. (Available through the NRC's Agencywide Documents Access and Management System (ADAMS) under Accession No. ML003708048.)

NRC Regulatory Guide (RG) 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants." (Available on NRC Web site.)

NRC RG 1.100, Revision 3, "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," September 2009. (Available on NRC Web site.)

NRC RG 1.106, Revision 2, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves," February 2012. (Available on NRC Web site.)

NRC RG 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code." (Available on NRC Web site.)

NRC RG 1.206, "Combined License Applications for Nuclear Power Plants (LWR Edition)." (Available on NRC Web site.)

NRC Regulatory Issue Summary (RIS) 2000-03, "Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves Under Design-Basis Conditions," March 15, 2000 (Available on NRC Web site.)

NRC RIS 2012-08, Revision 1, "Developing Inservice Testing and Inservice Inspection Programs Under 10 CFR Part 52," July 17, 2013. (Available on NRC Web site.)

U.S. Code of Federal Regulations, Title 10, "Energy," Part 50, "Domestic Licensing of Production and Utilization Facilities," and Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plant." (Available on NRC or U.S. Government Publishing Office Web site.)

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Track 2: Pumps

Track Chair: Thomas Robinson, Nebraska Public Power District

Smooth Running Pumps

Betsy Moenkedick, Xcel Energy—Prairie Island
Member of the ASME OM Subcommittee on Pumps

Melvin L. McGaha, Iddeal Solutions
Member of the ASME OM Subcommittee on Pumps

Abstract

Smooth running pumps have been an industry issue since 1988. This caused many nuclear plants to obtain a relief request to use requirements alternative to those specified in the tables in Subsections ISTB or ISTF of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code). ASME OM Code Case OMN-22, "Smooth Running Pumps," was approved in January 2017 for pumps with very low reference value vibration levels. This Code Case specifies the alternative requirements that may be used in lieu of the applicable ASME OM Code subsections.

Introduction

Since commercial nuclear power plants have been implementing the ASME OM Code for pump testing, there have been numerous relief requests submitted for smooth running pumps, either as individual relief requests or global relief for any pump outside of the ranges listed within ISTB for the current Code of Record for various sites. There were no relief requests identified for this paper for Subsection ISTF (first published in the ASME OM Code 2011 Addenda, OMa-2011).

This paper was suggested by the ISTB Subcommittee on pump testing due to the issuance of ASME OM Code Case OMN-22. The new Code Case for smooth running pumps will allow sites to use this Code Case for their smooth running pumps, and once it is approved as part of Regulatory Guide 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code," relief will no longer be required. ISTB Subcommittee is also working on incorporating this change into the next ASME OM Code edition to be published.

Discussion of Smooth Running Pumps

What is a smooth running pump?

Pumps that have very low vibration reference values (less than or equal to 0.05 inches per second (in/sec)) are referred to as "smooth running pumps." A small increase in smooth running pump vibration during ASME OM Code-required inservice testing (IST) causes the pump to exceed ASME OM Code vibration acceptance criteria. For a pump with very low vibration characteristics, the alert range requirements for the tables in Subsections ISTB and ISTF could require unnecessary testing and corrective actions.

The ASME OM Code's applicable paragraph on reference values requires that initial vibration reference values be determined from either the results of preservice testing or the first inservice test. This reference value can then be used to establish the applicable pump test vibration limits.

Vibration limits in the applicable pump test acceptance criteria tables (ASME OM Code-2004 Edition through 2006 Addenda and 2012 Edition Table ISTB-5121-1) are either fixed at an absolute value of 0.325 in/sec for "alert" and 0.700 in/sec for "required action," or developed by using a multiplier of the reference value for alert (2.5 times the reference value) and for required action (6 times the reference value). These limits are often referred to as the *absolute* and the *relative* vibration limits.

For pumps with a magnitude of vibration that is an order of magnitude below the 0.325 in/sec absolute alert vibration limit, a relatively small increase or change over time of the vibration magnitude would cause the pump to enter the alert or maybe even the required action range.

Here are some examples:

Relative and Absolute *Limit* Example 1

Reference Value	0.010 in/sec	----------	
Relative Alert Limit	0.025 in/sec	Absolute Alert Limit	0.325 in/sec
Relative Req. Action Limit	0.060 in/sec	Absolute Req. Action Limit	0.700 in/sec

In the above example, the relative limits are the limiting values. A very small change in vibration of greater than 0.015 in/sec will cause an alert declaration, and a small change of greater than 0.05 in/sec will cause a required action or inoperable declaration.

Relative and Absolute *Limit* Example 2

Reference Value	0.028 in/sec	----------	
Relative Alert Limit	0.070 in/sec	Absolute Alert Limit	0.325 in/sec
Relative Req. Action Limit	0.168 in/sec	Absolute Req. Action Limit	0.700 in/sec

In the above example, the relative limits are the limiting values. These gaps are larger than in Example 1; however, vibration changes of this magnitude can easily occur and may be attributed to variation in system flow, data acquisition errors, instrument accuracy, or other noise sources that would not be associated with degradation of the pump.

Based on a small acceptable change that results when deriving the relative alert and required action limits, pumps with very low vibration reference values could be subjected to unnecessary testing and corrective action.

For this reason, several Owners have submitted relief requests to use a minimum vibration reference level of 0.05 in/sec for pumps with very low vibration reference values. These same plants committed to include these pumps with very low reference values in their predictive maintenance (PdM) program.

Relative and Absolute *Limit* Example 3: Typical Industry Relief Request

Reference Value	0.050 in/sec	----------	
Relative Alert Limit	0.125 in/sec	Absolute Alert Limit	0.325 in/sec
Relative Req. Action Limit	0.300 in/sec	Absolute Req. Action Limit	0.700 in/sec

For the example above, with a minimum reference value of 0.05 in/sec, the corresponding relative alert limit is 0.125 in/sec and the relative required action limit is 0.300 in/sec.

How did smooth running pumps become an industry problem?

The 1987 Edition of the ASME OM Code was first referenced in the 1989 Edition of the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, IWP. The 1988 Addenda OMa-1988, which was an addenda to the 1987 Edition, was adopted for use for IST programs. It was subsequently approved by the U.S. Nuclear Regulatory Commission (NRC) as part of rulemaking. However, the IST requirements converted from IWP to the ASME OM Code no longer allowed for the lower range. Part 6, “Inservice Testing of Pumps in Light-Water Reactor Power Plants,” of the ASME OMa Code in 1988 became the governing requirements for pump testing at U.S. nuclear plants. Table 3, “Ranges for Test Parameters,” became the new requirement for pump reference values. However, this table eliminated the smooth running pump parameters. (See Table 3 in Attachment 1.)

Pump vibration reference value requirements are shown in the applicable “Reference Values” section of each ASME OM Code. Prior to 1988, the “Inservice Testing of Pumps” was part of Subsection IWP (Inspection of Water Cooled Reactor Pumps), “Inservice Testing of Pumps in Nuclear Power Plants.” Table IWP-3100-2 showed the allowable ranges of test quantities (see Table IWP-3100-2 in Attachment 1). The 1986 Edition of ASME BPV Code, Section XI IWP, and Table IWP-3100-2 had a test quantity listed for pumps having V_r (vibration range) of $0 \leq V_r \leq 0.5$ *mils* for smooth running pumps. When the 1989 Edition of ASME BPV Code, Section XI, endorsed OMa-1988 OM Code Part 6, the low end of acceptable performance became $\leq 2.5\ V_r$. The lower range for smooth running pumps was no longer part of the ranges for test parameters. Palo Verde actually had a paper published in NUREG/CP-0152, Volume 3, “Proceedings of the Sixth NRC/ASME Symposium on Valve and Pump Testing,” for the 2000 symposium (17 years ago) identifying this issue when Palo Verde performed the update for its second 10-year IST interval in 1998. The original IWP vibration requirement for pumps with displacement reference values less than 0.5 mils was 1 to 1.5 mils for the alert range. However, the OM-6 Code had no fixed minimum alert since it allows only 2.5 to 6 times the reference value for the alert range. These conditions led to the development of relief requests for smooth running pumps.

Relief Requests and Supplemental Monitoring in the Industry

The NRC has authorized alternative vibration acceptance criteria for smooth running pumps on a case-by-case basis in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(a)(3) or 10 CFR 50.55a(z)(2). Since the smooth running pump parameters were eliminated from the 1988 ASME OMa Code, nuclear plants across the industry needed to submit relief requests to the NRC to use a minimum vibration reference level of 0.05 in/sec for pumps with very low baseline vibration values with a pump vibration velocity measurement of ≤0.050 in/sec when establishing the vibration reference value. For these pumps with very low vibration values, the following vibration velocity criteria shall be applied to any vibration test points qualifying for the use of the "minimum reference" value. For the minimum reference value of 0.05 in/sec, the corresponding relative alert limit of 0.125 in/sec and relative required action limit of 0.300 in/sec is allowed. These same plants committed to including these pumps with very low reference values in their PdM program.

Nuclear plants employ a PdM program, which typically monitors certain rotating equipment, as well as other components. PdM program activities go beyond the IST vibration requirements for pumps by performing a more complete vibration signature analysis. Also, other technologies, such as oil sampling and analysis and thermography analysis, are included. Some plants also perform motor analysis in the PdM program.

Measured PdM parameters that are outside the normal operating range, or are determined by analysis to be trending towards an unacceptable degraded state, are entered into the Owner's corrective action program with appropriate actions taken to resolve the issue. These actions might include increased monitoring to establish the rate of change, review of component-specific information to identify cause, or removal of the pump from service to perform maintenance. These actions are consistent with the IST objective of monitoring for degradation in safety-related components.

Since the change in the industry in 1988, there have been numerous relief requests submitted by different nuclear power plants.

Alternative requests for smooth running pumps should specify a minimum vibration reference value (≤0.05 inches per second), and these smooth running pumps must be included in a PdM program. As described in Section 5.4, "Monitoring Pump Vibration in Accordance with ISTB," of NUREG-1482, Revision 2, "Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants, Final Report," issued October 2013, several plants have requested an alternative to the vibration acceptance criteria of Subsection ISTB for smooth running pumps, and the NRC has approved such requests. However, licensees with such approval must continue to assess the vibration data and monitor increases that may be indicative of a change. In one reported incident, a pump with very low vibration experienced an increase in vibration levels over three successive tests, although the levels remained below the criteria for smooth running pumps. Upon investigating the cause of the increase, the licensee determined that the bearing had degraded and required replacement.

Reviews of the various relief requests, identified through the Inservice Testing Owners Group members, the NRC, and others within the nuclear industry, indicate there are approximately 12 sites in the United States that currently have smooth running pump relief requests approved for use as part of their IST programs. These relief requests vary from specific relief for an individual pump or a number of relief requests for pump types across multiple systems. In many cases, these pumps are jockey/keep fill pumps that are signal-actuated pressure demand on a recirculation line and provide makeup as needed to prevent water hammer in the emergency core cooling system piping. In most cases, the PdM programs monitor the pumps and analyze changes in vibration spectrum or spectral content over time, look for trends in the changes, and attempt to determine the reasons for the changes. If changes are determined to be from an equipment problem, rather than changes in operating parameters, increased monitoring is established to determine the rate of the trend, and equipment maintenance is scheduled to correct the problem. The maintenance is scheduled before any vendor or industry recommendations or limits of ASME OM Code-2004 Edition through OMb Code-2006 Addenda ISTB are expected to be exceeded.

In some cases, licensees have requested relief and applied the lower ranges for smooth running pumps to any pump that happens to be in the lower range of reference values, or due to repair or replacement activities, may have new reference values that become part of the lower ranges needed to monitor smooth running pumps.

Conclusion

Code Case—Smooth Running Pumps

To alleviate relief requests in the industry, the ASME OM Code Pump subgroup started working towards generating a Code Case for smooth running pumps in the 1990s and has made some progress. Unfortunately, no ASME OM Code Case or ASME OM Code change was made to implement the requirements for smooth running pumps as shown in Subsection IWP of the 1986 Edition of ASME BPV Code, Section XI, as part of any Edition or Addenda issued through the 2017 Edition of ASME OM Code. In 2016, the ASME OM Code Subcommittee on Pumps received an Inquiry. A Code Case was needed to respond to this Inquiry. The Inquiry was answered with the approval of ASME Code Case OMN-22 in January 2017.

With the adoption of ASME Code Case OMN-22, the industry will accrue several benefits. These include, but are not limited to, cost savings from not preparing and submitting relief requests, standardized methodology for smooth running pumps, reduced operability challenges, and allowing more systematic approaches to PdM.

The ISTB Subcommittee is also working to develop the actual Code change to allow for the use of the lower range in all of the applicable tables in ISTB and ISTF for the next Edition of the ASME OM Code. The NRC would be able to review any relief request to use OMN-22 as part of the next 10-year interval update, until the Code Case can be added to Regulatory Guide 1.192, and the subsequent Code change can be incorporated into the OM Code.

References

(1) ASME *Boiler and Pressure Vessel Code*, 1986 Edition, "Rules for Inservice Inspection of Nuclear Power Plant Components," Subsection IWP, "Inservice Testing of Pumps in Nuclear Power Plants."

(2) ASME OM Code Case OMN-22, "Smooth Running Pumps."

(3) ASME OMa Code—1998 Addenda to ASME/ANSI OM-1987, "Operation and Maintenance of Nuclear Power Plants."

(4) ASME OM Code-2004, *Code for Operation and Maintenance of Nuclear Power Plants*, including "ASME OMa Code-2005" and "ASME OMb-2006" Addenda to ASME OM Code-2004.

(5) ASME OM-2012, "Operation and Maintenance of Nuclear Power Plants."

(6) ASME OM Code, Subsection ISTF, "Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants—Post 2000 Plants."

(7) NUREG-1482, Rev. 2, "Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants, Final Report," October 2013 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13295A020).

(8) NUREG/CP-0152, Volume 3, "Proceedings of the Sixth NRC/ASME Symposium on Valve and Pump Testing," July 2000 (ADAMS Accession No. ML003733511).

(9) Regulatory Guide 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code."

(10) Title 10, "Energy," of *Code of Federal Regulations.*

Attachment 1

TABLE IWP-3100-2

ALLOWABLE RANGES OF TEST QUANTITIES

		Alert Range [Note (1)]		Required Action Range [Note (1)]	
Test Quantity	Acceptable Range	Low Values	High Values	Low Values	High Values
P_r	[Note (2))	[Note (2)]	[Note (2)]	[Note (2)]	[Note (2)]
ΔP	$0.93–1.02\Delta P_r$	$0.90-0.93\Delta P_r$	$1.02–1.03\Delta P_r$ 1.0	$< 0.90\Delta P_r$	$> 1.03\Delta P_r$
Q	$0.94–1.02Q_r$	$0.90–0.94Q_r$	$2–1.03Q_r$	$< 0.90Q_r$	$> 1.03Q_r$
V when $0 \leq V_r$ 0.5 mils	0-1 mil	None	1–1.5 mils	None	> 1.5 mils
V when 0.5 mils $< V_r \leq$ 2.0 mils	0-2 V_r mils	None	$2V_r - 3V_r$ mils	None	$> 3V_r$ mils
V when 2.0 mils $< V_r$ 5.0 mils	$0 - (2 + V_r)$ mils	None	$(2 + V_r)–(4 + V_r)$ mils	None	$> (4 - V_r)$ mils
V when $V_r >$ 5.0 mils	$0 - 1.4V_r$ mils	None	$1.4V_r - 1.8V_r$ mils	None	$> 1.8V_r$ mils
T_b	[Note (3)]	[Note (3)]	[Note (3)]	[Note (3)]	[Note (3)]

NOTES:

(1) See IWP-32 30.

(2) P_r shall be within the limits specified by the Owner in the record of tests (IWP-6000).

(3) T_b shall be within the limits specified by the Owner in the record of tests (IWP-6000).

(Source: ASME BPV Code, Section XI)

TABLE 3

RANGES FOR TEST PARAMETERS

Pump Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range
Centrifugal and vertical line shaft [Note (2)]	<600 rpm	V_d or V_v	$\leq 2.5\ V_r$	$>2.5\ V_r$ to $6\ V_r$ or >10.5 mils	$>6\ V_r$ or >22 mils
Centrifugal and vertical line shaft [Note (2)]	≥600 rpm	V_v or V_d	$\leq 2.5\ V_r$	$>2.5\ V_r$ to $6\ V_r$ or >0.325 in./sec	$>6\ V_r$ or > 0.70 in./sec
Reciprocating		V_d or V_v	$\leq 2.5\ V_r$	$>2.5\ V_r$ to $6\ V_r$	$>6\ V_r$

NOTES:

(1) Vibration parameter per Table 2. V_r is vibration reference value in the selected units.

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

(Source: ASME OM Part 6)

Attachment 2

Case OMN-22

Smooth Running Pumps

Inquiry: What alternative to the requirements for alert and required action vibration acceptance criteria may be used when applying the applicable Code reference value paragraph in Subsections ISTB and ISTF in the ASME OM Code and the applicable Code pump test acceptance criteria tables listed in ASME OM Code (listed in Table 1 below) when vibration readings, taken to establish reference values, are extremely low, such as ≤ 0.050 inches/sec?

Reply: It is the opinion of the Committee that the following alternative requirements may be used in lieu of the applicable Code reference value paragraph in Subsections ISTB and ISTF in the ASME OM Code and the applicable Code pump test acceptance criteria tables in the ASME OM Code (listed in Table 1 below) for pumps with very low reference value vibration levels.

APPLICABILITY

ASME OM Codes as specified in Table 1 below.

Table 5. Paragraph and Table Cross-Reference

Code / Standard	"Reference Values" Para. Number	Centrifugal Pump Table	Vertical Line Shaft Centrifugal Pump Table	Positive Displacement Pump Table
OM CODE-2015	ISTB-3300 ISTF-3300	Table ISTB-5121-1 Table ISTF-5120-1	Table ISTB-5221-1 Table ISTF-5220-1	Tables ISTB-5321-1, ISTB-5321-2 Tables ISTF-5320-1, ISTF-5320-2
OM CODE-2012	ISTB-3300 ISTF-3300	Table ISTB-5121-1 Table ISTF-5120-1	Table ISTB-5221-1 Table ISTF-5220-1	Tables ISTB-5321-1, ISTB-5321-2 Tables ISTF-5320-1, ISTF-5320-2
OM CODE-2011	ISTB-3300 ISTF-3300	Table ISTB-5121-1 Table ISTF-5120-1	Table ISTB-5221-1 Table ISTF-5220-1	Tables ISTB-5321-1, ISTB-5321-2 Tables ISTF-5320-1, ISTF-5320-2
OM CODE-2009	ISTB-3300	Table ISTB-5121-1	Table ISTB-5221-1	Tables ISTB-5321-1, ISTB-5321-2
OMb CODE-2006	ISTB-3300	Table ISTB-5121-1	Table ISTB-5221-1	Tables ISTB-5321-1, ISTB-5321-2
OMa CODE-2005	ISTB-3300	Table ISTB-5121-1	Table ISTB-5221-1	Tables ISTB-5321-1, ISTB-5321-2
OM CODE-2004	ISTB-3300	Table ISTB-5121-1	Table ISTB-5221-1	Tables ISTB-5321-1, ISTB-5321-2
OMb CODE-2003	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OMa CODE-2002	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OM CODE-2001	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OMb CODE-2000	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OMa CODE-1999	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OM CODE-1998	ISTB-3300	TABLE ISTB-5100-1	TABLE ISTB-5200-1	TABLES ISTB-5300-1, ISTB-5300-2
OMb CODE-1997	ISTB 4.3	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1
OMa CODE-1996	ISTB 4.3	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1
OM CODE-1995	ISTB 4.3	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1
OMc CODE-1994	ISTB 4.3	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1	TABLE ISTB 5.2.1-1
OMb CODE-1992	ISTB 4.3	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a
OMa CODE-1991	ISTB 4.3	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a
OM CODE-1990	ISTB 4.3	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a	TABLE ISTB 5.2-2a

Requirements

For pumps with very low baseline vibration values with a pump vibration velocity measurement of ≤ 0.050 in/sec when establishing the vibration reference value, a minimum reference value of 0.050 in/sec shall be used to establish the acceptable range, Alert Range and Required Action Range in accordance with the applicable pump test acceptance criteria table listed in Table 1 above.

The individual vibration measurements for pumps within the scope of this Code Case shall be documented within the Inservice Testing (IST) program for trending of pump performance.

For these pumps with very low vibration values, the following vibration velocity criteria shall be applied to any vibration test points qualifying for the use of the "minimum reference" value:

Acceptable Range: ≤ 0.125 in/sec
Alert Range: > 0.125 in/sec to 0.300 in/sec
Required Action Range: > 0.300 in/sec

Supplemental Monitoring

Pumps that will use the "minimum reference" value for one or more vibration points shall be included in the Owner's Predictive Maintenance (PdM) program. The PdM program shall apply predictive monitoring techniques and perform vibration analysis beyond the trending of vibration levels specified in the ASME OM Code to provide early identification of pump performance issues. The Owner shall determine which PdM Supplemental Monitoring activities will be utilized on the pump.

At a minimum, the Owner shall perform spectral analysis of measured vibration of the applicable pumps. The Owner shall document the conclusion of the PdM performance analysis on the pump test record prior to the subsequent test with a conclusion of acceptable, degrading but acceptable, or unacceptable. Corrective action shall be initiated when an unacceptable trend in performance is identified.

Corrective Action

If a measured pump vibration parameter falls within the alert range or the required action range specified above, then the Owner shall follow the required actions within the edition/addenda of the applicable Code (for example, ISTB-6200 or ISTF-6200 for the 2015 Edition of the ASME OM Code). The alert and required action ranges are established in accordance with this Code Case rather than the referenced pump tables.

If a PdM Supplemental Monitoring activity identifies a parameter outside the normal operating range or identifies a trend toward an unacceptable degraded state, action shall be taken to (1) identify and document the condition in the corrective action program established in accordance with the Owner's Quality Assurance Program, (2) increase monitoring to establish the rate of change of the monitored parameter, (3) review component-specific information to identify the degradation cause, (4) develop a plan to remove the pump from service to perform maintenance prior to significant performance degradation, and (5) address potential common cause issues applicable to other pumps based on the results of the analysis of the specific pump performance.

Condition Monitoring of Rotating Equipment in Nuclear Power Plants

Ronny Jacks
Sr. Engineer, IST and Engineering Programs
DELTA
ENERGY SERVICES, LLC
www.workdelta.com

Abstract

This presentation provides an overview of condition monitoring for rotating equipment in nuclear power plants. Specific condition monitoring technologies addressed include vibration analysis, lube oil analysis, thermography, and motor current signature analysis. Plant and equipment parameters, such as motor electrical and plant process parameters, useful for evaluating equipment condition, are also identified. The technologies are examined based on availability, cost effectiveness, and importance to a condition monitoring program. Although vibration analysis and oil analysis are the primary emphasis for performing condition monitoring, the interrelationships between the technologies, techniques and other readily available plant data explored here demonstrate how a more complete and accurate diagnosis of the condition of a machine set can be determined. A discussion of each technology includes the various machine set faults that the technology will identify, as well as how the overlapping technologies improve the effectiveness of a condition monitoring program.

Introduction

Condition monitoring of rotating equipment is the process of monitoring various operating characteristics of a machine or machine set to identify changes that may be indicative of a developing fault, thus allowing maintenance to be scheduled prior to equipment failure. An added benefit of condition monitoring is the ability to better understand how the machine set reacts to normal and abnormal plant operating conditions and how those conditions impact the long-term operation of the equipment.

Rotating Equipment Applicable to a Condition Monitoring Program

Horizontal shaft rotating machines
• Turbines, generators, exciters
• Motors
• Pumps
• M-G sets
• Gas turbines—Industrial, air derivative
• Fans—Vane axial, centrifugal
• Blowers
• Chillers
• Centrifugal compressors

Vertical shaft machines
• Pumps and motors
• Cooling tower fans
Reciprocating machines
• Compressors
• Diesels
• Piston pumps
• Vacuum pumps
Gearboxes
Belt-driven machines—HVAC

Technologies, Techniques, and Plant Information

The technologies presented here, when used in conjunction with existing plant programs and information systems, provide a more in-depth picture of a machine's health. The technologies are presented in order of cost effectiveness and importance to a condition monitoring program. Existing plant programs and plant information are included to emphasize the effects that changes in operating parameters and conditions can have on machine set operation, data analysis, and trending. Though oil analysis and vibration analysis are the primary emphasis for performing condition monitoring, the interrelationships among all of these technologies, techniques, and other readily available plant data provide for a more complete and accurate diagnosis of the condition of a machine set. A machine set includes a driver, a piece of driven equipment, and support components such as breakers, relays, and terminations.

Technologies[1]

- **Vibration Analysis—**The process of collecting and analyzing vibration data to monitor the characteristic changes in rotating equipment created by equipment operating conditions or equipment faults.
- **Lube Oil Analysis**—The process of identifying specific oil properties, including those of the base oil and its additives, as well as the presence of contaminants and wear debris from machinery.

[1] Other technologies are available, but the four listed here provide a wide range of information applicable to many machine types and were chosen based on cost and current use in the nuclear industry.

- **Thermography—**A technique for detecting and measuring variations in the heat emitted by various regions of a body and transforming them into visible signals that can be recorded photographically.
- **Motor Current Signature Analysis (MCSA)**—The process by which motor current readings are recorded and analyzed in the frequency domain. It may be used to verify proper electrical characteristics and loading, as well as to help troubleshoot and identify machine set mechanical faults and problems.

Techniques and Plant Information

Motor Electrical Monitoring—The motor parameters (current, voltage, winding temperatures, etc.) should be monitored in accordance with manufacturer's recommendations, industry standards and practices, and plant experience. The following parameters, as applicable and depending on the importance of the machine set, may also activate an audible alarm in the control room as well as be displayed, or available on plant computer systems:

• Current
• Phase balance
• Winding temperatures
• Bearing temperatures
• Cooling water flow rate
• Bearing oil levels
• Winding cooler leakage

Personal Observation (audio, visual, smell, etc.)—This should be standard operating procedure when performing plant walkdowns and system rounds. Listen to equipment operating sounds, and visually inspect the equipment for any signs of changing conditions. Things such as oil or grease smells, excessive leak-off, hotter than normal bearing casings, and change in pitch, pump differential pressure, or discharge pressure could indicate a change in operating characteristics that could point to an equipment problem.

Process Variables—When practical, record the following process data within 1 hour (at steady-state conditions if possible) of the collection of machine set condition monitoring data:

• Machine set/s in service, if more than one available.
• Motor current if available
• Reactor power level
• Any abnormal plant configuration
• System temperature
• System pressure
• System flow if flow may vary
• Machine set speed, if speed may vary
• Any specific plant condition or operating parameters that may or do have an effect on equipment operating characteristics. Document for future reference and information.

Equipment Faults Identified by Technology

Vibration Analysis	**Thermography**
• Rotating member out of balance • Misalignment and bent shaft • Rubs • Damaged rolling element bearings (ball, roller, etc.) • Journal bearings loose in housing • Oil film whirl or whip in journal bearings • Hysteresis whirl • Damaged or worn gears • Mechanical looseness • Faulty belt drive • Unbalanced reciprocating forces and couples • Electrically induced vibration	Electrical systems: • loose or corroded connections • overloads • phase imbalance • short circuits • mismatched or misinstalled components Electrical system exceptions can be detected and identified using absolute temperature criteria published in American National Standards Institute, Institute of Electrical and Electronic Engineers, and National Electrical Manufacturers Association standards. Mechanical systems: • improper lubrication • misalignment • worn components • improper loading • blocked air or water cooling passages
Lube Oil Analysis	**MCSA**
• Bearing wear • Water in oil • Oil breakdown • Improper lubricant • Lubricant contamination	MCSA is a system used for analyzing or trending dynamic, energized systems. Proper analysis of MCSA will assist the technician in identifying: • incoming power quality • stator winding health • rotor static and dynamic eccentricity and general health • coupling health including direct, belted, and geared • load issues • system load and efficiency • bearing health and much more

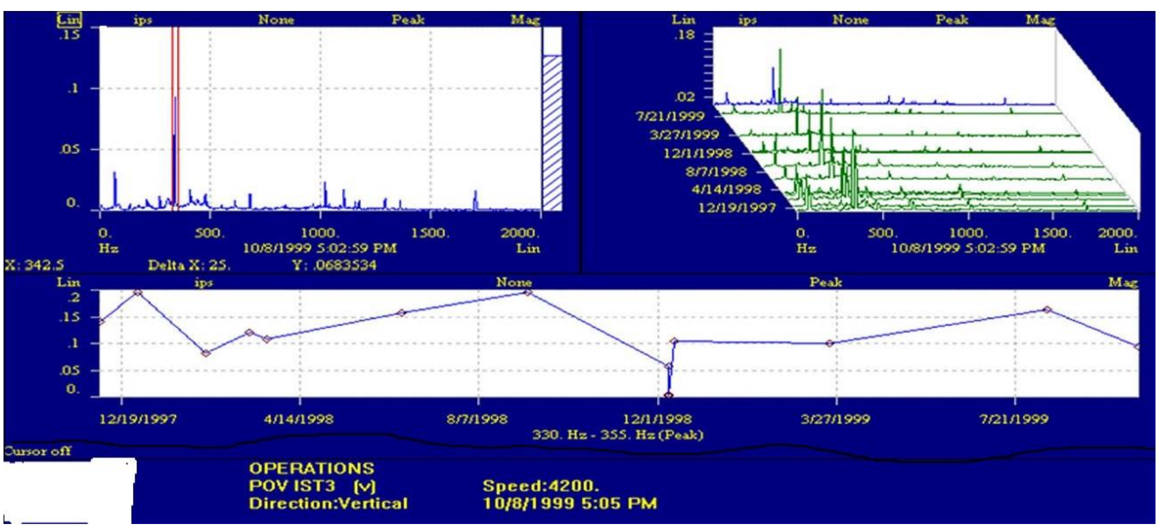
Table 6.1.1. Common predictive technology applications (NASA 2000)

Technologies / Applications	Pumps	Electric Motors	Diesel Generators	Condensers	Heavy Equipment/ Cranes	Circuit Breakers	Valves	Heat Exchangers	Electrical Systems	Transformers	Tanks, Piping
Vibration Monitoring/Analysis	X	X	X		X						
Lubricant, Fuel Analysis	X	X	X		X					X	
Wear Particle Analysis	X	X	X		X						
Bearing, Temperature/Analysis	X	X	X		X						
Performance Monitoring	X	X	X	X				X		X	
Ultrasonic Noise Detection	X	X	X	X			X	X		X	
Ultrasonic Flow	X			X			X	X			
Infrared Thermography	X	X	X	X	X	X	X	X	X	X	
Non-destructive Testing (Thickness)				X				X			X
Visual Inspection	X	X	X	X	X	X	X	X	X	X	X
Insulation Resistance		X	X			X			X	X	
Motor Current Signature Analysis		X									
Motor Circuit Analysis		X				X			X		
Polarization Index		X	X						X		
Electrical Monitoring									X	X	

O&M Best Practices Guide, Release 3.0 6.1

NASA—National Aeronautics and Space Administration

Best Practices Guide, Sample Data and Technology Comparisons



Vibration Spectrum, Waterfall Plot, and 5X Trend

Vibration and Oil Analysis Combined Program. Source: “Integration of Lubrication and Vibration Analysis Technologies,” by Bryan Johnson and Howard Maxwell, Palo Verde Nuclear Generating Station.

Condition	Lube Program	Vibe Program	Correlation
Oil Lubricated Antifriction Bearings	Strength	Strength	Lubrication analysis will detect/can detect an infant failure condition. Vibration provides strong late failure state information.
Oil Lubricated Journal/Thrust Bearings	Strength	Mixed	Wear debris will generate in the oil prior to a rub or looseness condition.
Machine Unbalance	Not Applicable	Strength	Vibration program can detect an unbalance condition. Lube analysis will eventually see the effect of increased bearing load.
Water in Oil	Strength	Not Applicable	Water can lead to a rapid failure. It is unlikely that a random monthly vibe scan would detect the anomaly.
Greased Bearings	Mixed	Strength	It makes economic sense to rely on vibration monitoring for routine greased bearing analysis. Many lube labs do not have enough experience with greased bearings to provide reliable information.
Greased Motor Operated Valves	Mixed	Weakness	Actuators are an important machinery in the nuclear industry. Grease samples can be readily tested; it can be difficult to obtain a representative sample. It can be hard to find these valves operating, making it difficult to monitor with vibration techniques.
Shaft Cracks	Not Applicable	Strength	Vibration analysis can be very effective in monitoring a cracked shaft.
Gear Wear	Strength	Strength	Vibration techniques can predict which gear. Lube analysis can predict the type of failure mode.

Alignment	Not Applicable	Strength	Vibration program can detect a misalignment condition. Lube analysis will eventually see the effect of increased/improper bearing load.
Lubricant Condition Monitoring	Strength	Not Applicable	The lubricant can be a significant cause of failure.
Resonance	Not Applicable	Strength	Vibration program can detect a resonance condition. Lube analysis will eventually see the effect.
Root Cause Analysis	Strength	Strength	Best when both programs work together.

(Source: James Berry, “Good Vibes About Oil Analysis,” http://machinerylubrication.com/Read/36/oil-analysis-vibes)

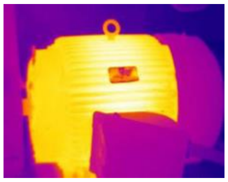
Sample No.	971107-01011
Bottle No.	1001094
Date M-D-Y	11-03-97
Meter Read	0
Oil Hours	0
Oil/Fil Chng	/
Diagnosis	MCL
Status	4
Contamination	
>2 µm	351,570
>5 µm	266,294
>15 µm	35,287
>25 µm	3226
>50 µm	55
>100 µm	0
ISO 2	26
ISO 5	25
ISO 15	22
Silicon	5
Boron	0
Sodium	1
Additives	
Magnesium	3
Calcium	199
Barium	3
Phosphorous	14
Zinc	9
Molybdenum	0

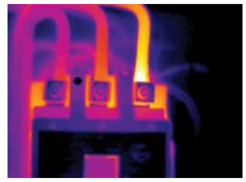
Customer: Sulzer Pumps (Sulzer Pmp)
Pump (Pump)
Cap 8 Pump Bearing Housing (Unit 2982)
Run Per: Simon Bradshaw

Wear Metals	
Iron	105
Chrome	2
Lead	47
Copper	47
Tin	0
Aluminum	0
Nickel	0
Silver	0
Titanium	0
Viscosity	
cSt 40°C	32.0
cSt 100°C	5.4
Viscosity Index	103.7
Oil Condition	
Water PPM	0
Oxidation	.06
Nitration	.08
Acid Number	.25

Typical Oil Analysis Report
(Source: http://machinerylubrication.com/Read/652/black-oil-causes)

Thermography Examples





Electric Motor—Normal Thermography, Circuit Breaker—Hot Connection

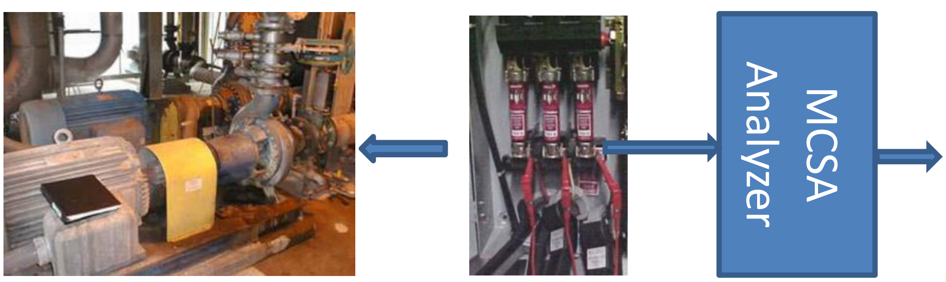
(Source: Author)

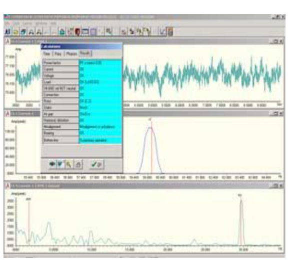
Motor Current Signature Analysis (MCSA)

For more information about MCSA, see www.motordoc.org/wp-content/.../Practical-Motor-Current-Signature-Analysis.pdf

- MCSA uses the electric motor as a transducer, allowing the user to evaluate the electrical and mechanical condition from the motor control center or disconnect.
- An MCSA system allows the user to perform most analysis automatically with limited information required.

For accurate analysis, MCSA systems rely on Fast Fourier Transform (FFT) analysis, much like vibration analysis. MCSA also relies on analysis of demodulated voltage and/or current which involves the removal of the fundamental frequency.





(Source: Author)

Conclusion

The various technologies presented here provide direct insight into the operation and health of a machine set. The use of these technologies, as well as readily available plant information that is typically *not* associated with a predictive maintenance program, provides valuable insight to the trained predictive maintenance technician or engineer. Much of this information is gathered by other plant disciplines and is not reviewed or trended, except for a pass/fail acceptance criterion. When combined with the added information from the oil analysis, vibration analysis, thermography, and MCSA, the operating characteristics and the actions of the machine set to various plant conditions and faults become more readily apparent, as does the overall health of the equipment.

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Safety Injection Pump Performance Analysis and Testing at Westinghouse Waltz Mill Facility

Thomas G. Loebig
Westinghouse Electric Company, LLC
Pittsburgh, PA, USA

David P. Crane
Westinghouse Electric Company, LLC
Pittsburgh, PA, USA

Robert V. Low
Wolf Creek Nuclear Operating Corporation
Burlington, KS, USA

Abstract

Safety-related pumps must meet defined performance criteria. Degradation from age and normal use may eventually require pump replacement or refurbishment. Testing to demonstrate acceptable pump performance would then be required. Westinghouse recently recommissioned an existing test loop at its Waltz Mill site which is capable of testing typical intermediate/high-head safety injection or centrifugal charging pumps used in plants with a Westinghouse-designed emergency core cooling system (ECCS) or similar pumps. The loop is considered contaminated; therefore, only pumps intended for service in nuclear systems can be tested. A successful performance test was completed on September 17, 2016, for an intermediate-head safety injection pump (SIP) from Wolf Creek without incident. The pump was refurbished at another facility and shipped to Westinghouse for testing. Replacement of the currently installed pump was necessary due to reduced margin after revision of the plant's inservice test (IST) limits analysis to incorporate additional instrument uncertainties.

The measured performance data matched closely with what was expected and fell within the maximum and minimum safety analysis limit curves. These limit curves were recently revised to incorporate instrument and emergency diesel generator (EDG) frequency and voltage uncertainties using the methodology of WCAP-17308-NP, Revision 0, "Treatment of Diesel Generator (DG) Technical Specification Frequency and Voltage Tolerances," issued April 2012. Subsequent required net positive suction head ($NPSH_R$) testing revealed limitations associated with the test loop. Due to the nature of the refurbishment for this pump, the customer and pump original equipment manufacturer determined that it was not necessary to perform $NPSH_R$ testing. This paper describes the background and motivation for the pump refurbishment and testing and presents the test results and calculated pump performance curves required to meet safety analysis requirements.

Introduction

Safety-related pumps in nuclear power plants, included in engineered safety features, particularly ECCS pumps, must meet performance requirements assumed in plant safety analyses and are typically based on vendor shop performance curves. These pumps are required to be periodically tested to ensure that they are capable of performing their intended safety function. Periodic IST requirements are prescribed in American Society of Mechanical

Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code) subject to the conditions of U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 97-90, “Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests,” dated December 30, 1997. Test acceptance criteria (TAC) for each pump must use the most limiting criteria from either the ASME OM Code or plant safety analyses. When the pump performance assumed in the safety analyses is more limiting, the TAC must account for various measurement and operational uncertainties.

Recent component design-basis inspections have identified deficiencies in TAC that do not account for the impact on pump performance due to EDG operating ranges specified in plant technical specifications (TS). In some plants, the EDG TS surveillance requirements (SRs) have not been changed from those in the improved Standard TS (NUREG-1430 through NUREG-1434), which could allow performance to vary sufficiently from tested performance so as to not meet safety analysis requirements. WCAP-17308-NP was developed to provide standard methods to adjust TAC or to assess performance capabilities to account for the EDG uncertainties as well as instrument uncertainties. This methodology was applied to the Wolf Creek TAC for adjusting IST limits for the intermediate-head SIP and for shop TAC for the testing performed in the Waltz Mill test loop. The analysis was requested by Wolf Creek to investigate the possibility of margin recovery while still maintaining conservative limits compared to the methods that were previously used.

The pump that was tested is a 3-inch model JHF pump with 11 stages originally manufactured by the Pacific Pumps Division of Dresser Industries, Inc., now Flowserve Corporation. The pump was refurbished to provide an available spare for replacement of an underperforming pump. The original pump curve indicates that the rated diameter of the impellers is 8 and 9/16 inches, and the rated speed is 3,550 revolutions per minute (rpm). The pump was driven by a Westinghouse test motor. For reference, pictures of the pump and the loop along with a flow diagram are included in the appendix to this paper. Per customer request, the pump testing was to include head-flow performance testing, determination of pump power and efficiency, and confirmation of the $NPSH_R$. The pump test loop was previously operated jointly by Westinghouse and the pump vendor. This test was the first test conducted since Westinghouse assumed full ownership and responsibility for the test loop.

All analyses and tests were performed under the Westinghouse quality assurance program in full compliance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, “Domestic Licensing of Production and Utilization Facilities,” Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”

Test Loop Description and Test Performance Inputs

The test loop, located in the T-Building Annex at the Westinghouse Waltz Mill site, consists of a 5,000-gallon tank, two butterfly valves that are used for suction (16 inch) and discharge isolation (10 inch), a breaking (throttle) valve in the discharge piping to control the flow, interconnecting piping, and a venturi meter to measure the flow. Pressure and temperature measurement transducers are included for measurement of the process water, lubricating oil, and oil cooler water parameters. See appendix Figures 1 through 4 for photographs and Figure 5 for a flow diagram.

The test loop and instrumentation were configured to be in compliance with American National Standards Institute/Hydraulic Institute (ANSI/HI) 14.6-2011, "Rotodynamic Pumps, for Hydraulic Performance Acceptance Tests." New pressure measurement manifold rings were fabricated to ensure accurate suction and discharge pressure measurement. Piping configurations ensured proper length to diameter straight pipe ratios between instrumentation and bends, valves, and other flow disturbances. The venturi meter performance and uncertainty were determined using the methods of MFC-3M-2004, "Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi," with 2007 addenda.

Fluid Properties

Density (ρ) is a function of temperature and pressure and is calculated using the Westinghouse custom Microsoft® Excel®[1] steam table database function stVCL. This function returns the specific volume of the fluid in cubic feet per pounds mass (ft^3/lb_m), which is the inverse of density. For the purposes of this test report, density will be calculated using the suction temperature and pressure because the suction conditions are the closest measured conditions to the fluid in the pump and the fluid in the venturi. Although the temperature in the venturi was observed to be slightly higher, the difference in density is negligible.

The specific gravity of the fluid is the ratio of the density of the fluid and the density of water at standard temperature and pressure (68 degrees Fahrenheit (F) and 14.696 pounds per square inch absolute).

$$S.G. = \frac{\rho}{62.3233}$$ **Equation 1**

The acceleration due to gravity was corrected for location and elevation using the methodology available from http://www.sensorone.com. The international gravity formula (IGF) in meters per second squared (m/s^2) is calculated as a function of latitude (Φ).

$$IGF = 9.780327 * (1 + 0.0053024 * sin^2(\Phi) - 0.0000058 * sin^2(2 * \Phi)$$ **Equation 2**

The free air correction (FAC) in m/s^2 is calculated as a function of elevation in meters.

$$FAC = -3.086 * 10^{-6} * h$$ **Equation 3**

1 Microsoft and Excel are trademarks or registered trademarks of the Microsoft Corporation.

The local acceleration of gravity is the sum of IGF and FAC.

Venturi Meter Flow Rate

Beta (β) is the ratio of the venturi throat (d_2) and inlet (d_1) diameters.

$$\beta = \frac{d_2}{d_1} \quad \textbf{Equation 4}$$

The mass flow, q, in pounds mass per second (lb_m/s) is calculated as a function of the venturi discharge coefficient (C), throat area (A_2), diameter ratio (β), the fluid density, and the change in pressure between the inlet and the throat of the venturi (dp).

$$q = C * A_2 * \sqrt{\frac{2 * \rho * dp_{venturi}}{1 - \beta^4}} * 0.089799 \quad \textbf{Equation 5}$$

The volumetric flow rate, Q, in gallons per minute (gpm) is calculated as a function of the mass flow and the density of the fluid.

$$Q = \frac{q}{\rho} * 448.831169 \quad \textbf{Equation 6}$$

The conversion factors of 0.089799 and 448.831169 are included to convert the results from their measured units to lb_m/s and gpm.

Total Developed Head

The total developed head (TDH) in feet of water is calculated from Bernoulli's equation as a function of the suction (P_S) and discharge (P_D) pressures and includes corrections for the head lost due to system resistance ($CORR_D$ and $CORR_S$), the differences in the height of the pressure gauges (Z_D and Z_S), and the velocity head of the fluid (VH_{total}).

$$TDH = \frac{(P_D - Corr_D) - (P_S - Corr_S)}{S.G.} + (Z_D - Z_S) + VH_{total} \quad \textbf{Equation 7}$$

In order to account for friction losses, the suction and discharge pressures in feet of water need to be corrected as a function of flow rate. Piping head loss in feet of water is a function of the piping friction factor, the length and diameter of the pipe, and fluid speed.

$$h_L = f * \left(\frac{L}{D}\right) * \frac{U^2}{2 * g} \quad \textbf{Equation 8}$$

The suction and discharge values are shown in Table 6 in the appendix. The friction factors are taken from Crane Technical Paper No. 410, and the lengths are taken by measurements of the test loop.

The equivalent correction factor for the discharge and suction piping obtained by quadratic curve fit as are given below. Note that these correction factors may be combined algebraically into a single equivalent factor.

$$Corr_D = 3.017 * 10^{-6} * Q^2 \qquad \textbf{Equation 9}$$

$$Corr_S = 7.674 * 10^{-8} * Q^2 \qquad \textbf{Equation 10}$$

The total velocity head in feet of water developed by the pump is the difference between the discharge and suction velocity heads. The suction and discharge velocity heads are calculated as a function of the fluid velocity in feet per second (ft/s).

$$VH = \frac{U^2}{2 * g} \qquad \textbf{Equation 11}$$

Brake Horsepower and Hydraulic Efficiency

The hydraulic efficiency (η_{HYD}) is the ratio of the water horsepower (WHP) and the brake horsepower (BHP).

The WHP of the pump is calculated as a function of the TDH, the flow, and the specific gravity of the fluid.

$$WHP = \frac{TDH * S.G. * Q}{3960} \qquad \textbf{Equation 12}$$

The BHP is a function of the power into the motor and the efficiency (η) of the motor.

$$BHP = \frac{P_{motor} * \eta_{motor}}{0.746} \qquad \textbf{Equation 13}$$

There is power (P) lost between where it is measured at the control panel and the motor; this is calculated as:

$$P_{motor} = P_{panel} * \eta_{transmission} \qquad \textbf{Equation 14}$$

Field Speed

The site has indicated that the pump operates at 3,550 rpm at runout conditions and 3,577 rpm at minimum flow (recirculation) conditions, which is consistent for a motor with a synchronous speed of 3,600 rpm. The field speed is calculated by interpolating between these values at the tested flow rate.

RPM Corrections

The performance will be corrected from the test speed to the field speed using the pump affinity laws.

$$Q_2 = Q_1 * \frac{n_2}{n_1} \quad \textbf{Equation 15}$$

$$TDH_2 = TDH_1 * \left(\frac{n_2}{n_1}\right)^2 \quad \textbf{Equation 16}$$

$$BHP_2 = BHP_1 * \left(\frac{n_2}{n_1}\right)^3 \quad \textbf{Equation 17}$$

Pump-Specific and Test Loop Configuration Inputs

The values in appendix Table 2 were used when calculating the pump performance.

Discussion of Significant Assumptions

The motor voltage is measured at a remotely located motor control panel, and there is some power lost due to transmission. The transmission efficiency is assumed to be 97 percent based on the available records from previous tests. This value has been assumed in the past and is used here for consistency with the previous tests.

Test Results and Adjusted Performance Limits

The data points in appendix Table 3 used in calculating pump performance were collected during the test.

Pump Test Performance Calculations

The performance calculations were automated in Microsoft Excel and are summarized in appendix Table 4 for the tested performance, and the calculated values at the speed of the motor used at the plant (field speed) are summarized in Table 5.

The TDH, BHP, and pump efficiency (EFF) corrected for field speed are plotted in appendix Figure 6. The TDH versus flow for the replacement pump compares well with the Original Pump A data, also given in Figure 6. For reference, the performance curve is plotted against the upper and lower performance limits in appendix Figure 7, along with the previous lower limit, labeled as the “Original MOL” curve. The lower limit was calculated by Westinghouse as described in the following section, labeled as the “Revised Lower Limit” curve in Figure 7, and the upper limit was provided to Westinghouse by Wolf Creek.

Test Acceptance Criteria Adjustment Method

The purpose of these calculations is to generate revised minimum test curves that account for the effects of steady-state EDG frequency and voltage uncertainties and flow and pressure measurement uncertainties for the purpose of improving margin for use with the plant's comprehensive pump tests (CPTs). These adjustments may also be applied for the TS quarterly tests, assuming the instrument uncertainties are bounded by those used for the CPT.

The allowable steady-state variations in frequency and voltage that must be considered when evaluating the capability of equipment to meet intended safety performance are defined in TS SRs. The Wolf Creek steady-state EDG allowable operating tolerances defined in the Wolf Creek TS SRs are a frequency band of 59.4 to 60.6 Hertz (Hz) and a voltage band of 3,950 volts (V) to 4,320 V. These equate to tolerances of ±1.0 percent (±0.6 Hz based on nominal 60 Hz) for frequency and -5.0/+3.8 percent (-210/+ 160 V based on nominal 4,160 V) for voltage. In this analysis, only the minimum voltage operating limit is addressed; therefore, only the lower voltage tolerance of -5 percent is applicable.

The methodologies used in this calculation are based on WCAP-17308-NP, Revision 0, which is derived from the pump affinity laws and induction motor characteristics. The advantage of this methodology is that margin recovery is maximized while maintaining conservative limits. The speed uncertainty is a function of frequency and voltage and accounts for the relationship of the motor and pump torque-speed curves.

$$U_\omega = \left[\left[\frac{V_{Nom}\left(f_{Nom} + |U_f|\right)}{\left(V_{Nom} - |U_V|\right) f_{Nom}}\right]^2 - 1\right]\left(\omega_{Synch} - \omega_{Nom}\right) + \left[\frac{\left(f_{Nom} + |U_f|\right)}{f_{Nom}} - 1\right]\omega_{Nom}$$

Equation 18

The head uncertainty calculations described in WCAP-17308-NP, Revision 0, are in general based on the pump TDH form of Bernoulli's equation.

$$TDH = \Delta H = \frac{144}{\rho}\left(P_D - P_S\right) + \frac{V_D^2 - V_S^2}{2g} + \left(Z_D - Z_S\right)$$

Equation 19

Due to space constraints, the reader is referred to WCAP-17308-NP, Revision 0, for the remaining details. This calculation includes modifications to the base methodologies to apply corrections for friction head loss, velocity head, and elevation head between the suction and discharge pressure transducer locations.

Test Acceptance Criteria Curve Calculations

The inputs needed to determine the TAC curve adjustments, excluding the plant-provided pump curve data, are contained in appendix Tables 6 and 7. Several cases were evaluated to determine the maximum margin recovery available, using alternate flow measurement procedures, if necessary. These data are input to a spreadsheet that automates most calculations.

The friction head correction was obtained using plant piping take-off data. The velocity and elevation head corrections were determined in the same fashion as for the pump test.

The results of the calculations to adjust the minimum pump TAC curve for EDG and instrument uncertainties are given in appendix Table 8. This curve was plotted with the pump test data as the “Revised Lower Limit” curve in appendix Figure 7. Note the improved margin with the revised curve.

Test Parameter Measurement Uncertanties

Flow Tolerance (U_q)

The flow tolerance is derived from Equation 5. As shown in this equation, the flow rate is a function of the discharge coefficient, the Venturi dimensions, the fluid density, and the measured differential pressure; therefore, the tolerance of the flow rate can be calculated from the tolerances for each of these values. Due to space constraints, the detailed calculations for individual tolerances are omitted.

Venturi Discharge Coefficient Uncertainty (U_C) = 1.0 percent according to MFC-3M-2004, or ±0.12 percent based on the standard deviation of the original calibration records. The higher value was used for conservatism.

Venturi Differential Pressure Uncertainty (U_{dp}) = 0.4 percent full scale and a range of 750 inches H_2O.

Venturi Beta Ratio Uncertainty (U_β) = 0.25 percent, which is the square root sum of the squares (SRSS) of 0.15 percent (U_{d1}) and 0.20 percent (U_{d2}) based on the standard deviation of the original calibration records.

Density (U_ρ) Uncertainty = 0.10 percent based on the range of density and the temperature gauge range of 32–225 degrees F and a tolerance of ±4 degrees F.

Full-Scale Flow Uncertainty (U_Q)

MFC-3M-2004 outlines a method for calculating flow uncertainty based on the value of beta and the calculated uncertainties.

$$\sqrt{(U_C)^2 + \left(\frac{2*\beta^4}{1-\beta^4}\right)^2 (U_{d1})^2 + \left(\frac{2}{1-\beta^4}\right)^2 (U_{d2})^2 + 0.25\left(U_{dp}\right)^2 + 0.25\left(U_\rho\right)^2} = U_Q \qquad \textbf{Equation 20}$$

The tolerance is calculated using this method as 1.10 percent at full scale.

$$\sqrt{1.0^2 + \left(\frac{2*0.301^4}{1-0.301^4}\right)^2 * 0.15^2 + \left(\frac{2}{1-0.301^4}\right)^2 * 0.20^2 + 0.25*0.4^2 + 0.25*0.1^2} = 1.10\%$$

When the discharge coefficient is evaluated at the measured value of 0.12 percent instead of the code value of 1.0 percent, the combined tolerance is evaluated as 0.47 percent at full scale.

$$\sqrt{0.12^2 + \left(\frac{2*0.301^4}{1-0.301^4}\right)^2 * 0.15^2 + \left(\frac{2}{1-0.301^4}\right)^2 * 0.20^2 + 0.25*0.4^2 + 0.25*0.1^2} = 0.47\%$$

ASME OM-2015, Part 28, Nonmandatory Appendix C, outlines a method for calculating uncertainty similar to the SRSS method, but instead of multiplying the square of an uncertainty value by its exponent, each uncertainty should be multiplied by its exponent first, and the product should be squared. Note that the ASME OM-2015 methods are identical to those of ASME OM Standards and Guides 2000 through 2007, as well as ASME OM-2009 and ASME OM-2012. ASME OM-2015 does not include beta uncertainty, but for conservatism, it is included in the equation below.

$$\sqrt{{U_C}^2 + {U_\beta}^2 + \left(0.5*U_\rho\right)^2 + \left(0.5*U_{dp}\right)^2 + (2*U_{d2})^2} = U_Q \qquad \textbf{Equation 21}$$

Using this method along with the code value of 1.0 percent for the discharge coefficient, the result is a 1.13 percent uncertainty at full scale.

$$\sqrt{1.0^2 + 0.25^2 + (0.5*0.1)^2 + (0.5*0.4)^2 + (2*0.20)^2} = 1.13\%$$

When this method is used with the measured discharge coefficient value of 0.12 percent, the result is a 0.53 percent uncertainty at full scale.

$$\sqrt{0.12^2 + 0.25^2 + (0.5*0.1)^2 + (0.5*0.4)^2 + (2*0.20)^2} = 0.53\%$$

The uncertainty in flow rate will be taken as 1.13 percent for conservatism.

Total Developed Head Tolerance

ASME OM-2015 defines the TDH uncertainty as the combination of the suction pressure, discharge pressure, specific gravity, gauge height, flow, and pipe diameter uncertainties. These values are weighted as a function of their contribution to the TDH. Each of these weighted values were calculated, and the total uncertainty was calculated from the combination of the weighted uncertainties. The details are omitted due to space constraints.

Suction Pressure (U_{PS})

The ASME OM-2015 weighting factor is defined as follows:

$$X_{P_S} = \frac{\Delta H_P}{TDH} * \left(\frac{P_S}{P_D - P_S}\right)$$ **Equation 22**

The suction pressure gauge has a tolerance of 0.4 percent full scale of 180 feet, or 0.72 feet; thus, the uncertainty varies with suction pressure. The maximum weighted percent of the suction pressure uncertainty is 0.041 percent.

Discharge Pressure (U_{PD})

The ASME OM-2015 weighting factor is defined as follows:

$$X_{P_D} = \frac{\Delta H_P}{TDH} * \left(\frac{P_D}{P_D - P_S}\right)$$ **Equation 23**

The discharge pressure gauge has a tolerance of 0.4 percent full scale of 10,380 feet, or 41.52 feet; thus, the uncertainty varies with discharge pressure. The maximum uncertainty at the minimum discharge pressure is 2.36 percent. The maximum weighted percent of the discharge pressure uncertainty is 2.39 percent.

Specific Gravity (U_{SG})

The ASME OM-2015 weighting factor is defined as follows:

$$X_{\upsilon} = \frac{\Delta H_P}{TDH}$$ **Equation 24**

The maximum tolerance of the density is 0.10 percent. The tolerance of the specific gravity is identical to the tolerance of the density. The maximum weighted percent of the specific gravity uncertainty is 0.10 percent.

Gauge Height (U_Z)

The ASME OM-2015 weighting factor is defined as follows:

$$X_{\Delta \mathrm{Z}} = \frac{\Delta H_Z}{TDH} \qquad \textbf{Equation 25}$$

The gauge height uncertainty is 0.125 inches, which gives an equivalent tolerance of 0.026 feet. Applied to the difference in gauge heights of 0.16 feet for conservatism yields an uncertainty of 15.8 percent of the differential measurement. The maximum weighted gauge height uncertainty is 0.0015 percent for a weighting factor of 9.3E-05. If the height measurement uncertainty is assumed to apply per foot, the tolerance is 2.6 percent and the weighted gauge height uncertainty is 0.00024 percent. The impact is negligible.

Flow (U_Q)

The maximum weighted flow uncertainty is 0.019 percent for a maximum full-scale flow uncertainty of 1.13 percent.

The ASME OM-2015 weighting factor is defined as follows:

$$X_{\mathrm{Q}} = 2 * \frac{\Delta H_V}{TDH} \qquad \textbf{Equation 26}$$

Pipe Diameter (U_{DP})

As defined in ASME Specification SA-999, "Specification for General Requirements for Alloy and Stainless Steel Pipe," the tolerance of the pipe diameter is 0.0625 inches, which is equivalent to 1.5 percent of the suction and 3.0 percent of the discharge.

The ASME OM-2015 weighting factor is defined as follows:

$$X_{\mathrm{D}_P} = 4 * \frac{\Delta H_V}{TDH} \qquad \textbf{Equation 27}$$

The maximum weighted pipe diameter uncertainty is 0.075 percent.

Total Developed Head Uncertainty

As shown in ASME OM-2015, the weighted uncertainties are combined by the SRSS method to calculate the total TDH uncertainty.

$$U_{TDH} = \sqrt{{U_{PS}}^2 + {U_{PD}}^2 + {U_{SG}}^2 + {U_Z}^2 + {U_Q}^2 + {U_{DP}}^2} \qquad \textbf{Equation 28}$$

Evaluating Equation 28 using the weighted values calculated in the previous sections results in a TDH uncertainty of 2.4 percent of 1,746 feet, or 41.84 feet at 660 gpm.

The maximum uncertainty in feet of head using the weighted values is 42.24 feet at 377 gpm. For the TDH of 3,077 feet, the percent uncertainty is 1.37 percent of TDH. Based on the full-scale discharge pressure transducer, the uncertainty is 42.24/10,380 = 0.407 percent. This uncertainty in feet of head bounds the uncertainty at all flow rates. This demonstrates that the TDH uncertainty is dominated by the uncertainty of the discharge pressure gauge of 41.52 feet (0.4 percent of full scale) for the instrumentation used for the test.

Results and Conclusions

Test results met customer requirements for pump performance and were within safety analysis limits that were adjusted for EDG and instrument uncertainties, providing test margin to the minimum and maximum test acceptance criteria limits for plant IST, and also met the requirements of original specifications. The overall uncertainties also met customer requirements.

Test uncertainties were determined using methods from MFC-3M-2004 and ASME OM-2015, Part 28, Nonmandatory Appendix C. The flow is measured using a venturi meter, the pressure is measured using gauges with a tolerance of 0.4 percent of full scale, and the temperature is measured using gauges with a tolerance of 4 degrees F. The combined full scale, percent of range, and test loop uncertainties were calculated as 1.13 percent of flow and 2.4 percent of TDH. Based on the results of the testing, several upgrades have been identified to improve future tests.

The maximum tolerance for the venturi meter flow measurement, using the uncertainties specified in MFC-3M-2004, is 1.13 percent at full scale, while the maximum tolerance using the measured uncertainties is 0.53 percent at full scale.

The bounding tolerance of the TDH is calculated as 42.24 feet or 0.407 percent at full-scale discharge pressure of 10,380 feet. When applied to the test results, the point-specific uncertainty in TDH ranges from 1.15 percent to 2.40 percent.

The $NPSH_R$ test data collected were higher than expected and the time necessary to conduct the tests was much longer than expected due to loop cooling constraints. After review, it was determined that upgrades to the test loop configuration would be required to perform NPSH testing appropriately. These include but are not limited to the following:

- loop cooling and piping upgrades to allow for performance and NPSH testing in 1 day
- upgraded valves to improve control of the loop
- upgraded instrumentation, calibration, and test panel to reduce uncertainty and improve data recording

Testing of intermediate-head SIPs utilized in Westinghouse ECCSs was successfully completed in the recommissioned Westinghouse Waltz Mill pump test loop. The pump was shown to meet test limits that were modified to account for the impact of EDG frequency and voltage operating tolerances and instrument uncertainties. This loop can be used to determine performance characteristics for certain contaminated pumps that have been used in nuclear power plants and require radiological controls. Charging/high-head SIPs can also be tested at the facility, along with pumps of similar capacities in full compliance with 10 CFR Part 50, Appendix B, and industry standards and full radiological control.

References

(1) Westinghouse Report WCAP-17308-NP, Revision 0, "Treatment of Diesel Generator (DG) Technical Specification Frequency and Voltage Tolerances," April 2012.

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(4) ANSI/HI 14.6-2011, "Rotodynamic Pumps, for Hydraulic Performance Acceptance Tests."

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(6) SensorONE Measurement Instrumentation Products, http://www.sensorsone.com/local-gravity-calculator/, based on Geodetic Reference System 1980, *Bulletin Géodésique*, Vol. 54:3, 1980. Republished (with corrections) in Moritz, H., 2000, "Geodetic Reference System 1980," *J. Geod*, at http://geoweb.mit.edu/~tah/12.221_2005/grs80_corr.pdf

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(9) ASME Specification SA-999/SA-999M, "Specification for General Requirements for Alloy and Stainless Steel Pipe," 2015 Edition.

(10) NUREG-1430, "Standard Technical Specifications: Babcock and Wilcox Plants."

(11) NUREG-1431, "Standard Technical Specifications: Westinghouse Plants."

(12) NUREG-1432, "Standard Technical Specifications: Combustion Engineering Plants."

(13) NUREG-1433, "Standard Technical Specifications: General Electric Plants (BWR/4)."

(14) NUREG-1434, "Standard Technical Specifications: General Electric Plants (BWR/6)."

Appendix: Figures and Tables

TABLE 1. HEAD LOSS

Segment	Gauge to Flange Length (ft)	Friction Factor	Head Loss (ft) at Flow		
Flow Rate (gpm)	N/A	N/A	0	200	675
Suction	1.354	0.015	0	0.00307	0.03497
Discharge	1.104	0.018	0	0.12067	1.37447

TABLE 2. PUMP TEST INPUTS

Description	Variable	Value	Units
Suction Diameter	d_S	6.065	in.
Discharge Diameter	d_D	2.9	in.
Pump Stages	Stages	11	N/A
Motor Efficiency	η_M	92.7	%
Barometer Reading	P_{atm}	29.05	in Hg
Transmission Efficiency	η_T	97	%
Venturi Pipe Diameter	d_1	7.97	in.
Venturi Throat Diameter	d_2	2.402	in.
Venturi Discharge Coefficient	C	0.9901	N/A
Suction Transducer to Pump Centerline	Z_S	0.219	ft
Discharge Transducer to Pump Centerline	Z_D	0.057	ft
Latitude	Φ	40.22	deg
Elevation USGS	h	1000	ft

TABLE 3: PERFORMANCE INPUT

Test Point	1	2	3	4	5	6	7	8	9	10	11	12
Discharge Pressure (ft)	1762	2072	2330	2612	2768	2840	3074	3306	3468	3566	3618	3656
Suction Pressure (ft)	41.20	44.90	39.95	45.55	45.35	41.75	45.55	45.35	45.15	43.85	44.5	44.95
Venturi Pressure (in.)	409.2	334.8	280	219.2	189	176.2	132.4	93.8	59.6	32.2	11.0	2.0
Motor Power (kW)	370.5	364.4	362.5	351	344.5	342.1	325.9	309	286.9	256.4	219.0	191.8
Shaft Speed (rpm)	3544	3545	3546	3549	3550	3547	3552	3556	3561	3565	3569	3574
Suction Temperature (°F)	84	121	97	119	116	101	114	112	108	102	102	103
Discharge Temperature (°F)	85	120	102	122	121	107	121	118	116	107	109	112

TABLE 4: TESTED PERFORMANCE

Point Number	1	2	3	4	5	6	7	8	9	10	11	12
Total Developed Head (ft)	1741	2061	2311	2599	2754	2820	3059	3290	3449	3543	3594	3632
Flow (gpm)	659	598	546	484	449	433	376	316	252	185	108	46
Brake Horsepower (hp)	447	439	437	423	415	412	393	372	346	309	264	231
Pump Efficiency (%)	64.7	70.2	72.5	74.4	74.6	74.4	73.3	70.0	63.0	53.3	37.0	18.2
Shaft Speed (rpm)	3544	3545	3546	3549	3550	3547	3552	3556	3561	3565	3569	3574

TABLE 5: FIELD SPEED PERFORMANCE

Point Number	1	2	3	4	5	6	7	8	9	10	11	12
Field Speed (rpm)	3550	3553	3555	3558	3559	3560	3562	3565	3568	3571	3574	3577
Flow (gpm)	660	599	547	485	450	435	377	317	252	185	108	46
Total Developed Head (ft)	1747	2070	2323	2612	2768	2841	3077	3306	3462	3555	3604	3638
Brake Horsepower (hp)	449	442	440	426	418	417	396	375	348	311	265	232

TABLE 6: SIP CONSTANT INPUTS

Name	Variable	Value	Units
Frequency	F	60	Hz
Frequency Uncertainty	U_F	1.0	%
Pump Operating Voltage	V	4000	V
Voltage Uncertainty	U_{REG}	5	%
Flow Element FE-918/922 Range	Q_R	800	gpm
Flow Element FE-918/922 Uncertainty	U_Q	1.693	% FS
Flow Element FE-918/922 Alternate Uncertainty	$U_{Q\text{-}ALT}$	1.173	% FS
Flow Element FE-968 Range (TS)	$Q_{R\text{-}TS}$	100	gpm
Flow Element FE-968 Uncertainty (TS)	$U_{Q\text{-}TS}$	1.5	% FS
Flow Uncertainty CPT	$U_{Q\text{-}CPT}$	1.703	% FS
Flow Uncertainty Alternate CPT	$U_{Q\text{-}CPT\text{-}ALT}$	1.188	% FS
Test Discharge Pressure (AOR Head @ 650 gpm)	P_D	676	psig
Test Suction Pressure (Test Max)	P_S	30	psig
Max. Test Suction Temperature (RWST)	T_S	100	°F
Density—Average Test Pressure*	ρ	62.07	lb_m/ft^3
Dynamic Viscosity—Average Pressure*	μ	4.656E-04	lb_m/ft-sec
Dynamic Viscosity—Average Pressure*	μ	0.6923	cP
Discharge Pressure Gauge Range	$P_{D\text{-}R}$	3000	psig
Suction Pressure Gauge Range	$P_{S\text{-}R}$	300	psig
Pressure Gauge Accuracy (>20% Range)	PEA1	0.10	% reading
Pressure Gauge Accuracy (0–20% Range)	PEA2	0.02	% FS
Pressure Gauge Calibration Accuracy	SCA	0.025	% FS
DP Cell Gauge Uncertainty (for Flow Measurement)	$U_{Q\text{-}DP\ Cell}$	0.2	% FS
TDH Uncertainty	U_{PD}	0.103	% reading
Motor Synchronous Speed	$M_{\omega S}$	3600	rpm
Motor & Pump Running Speed	$M_{\omega Nom}$	3546	rpm

* Density and viscosity are determined from average of suction and discharge test pressures. Dynamic viscosity is determined in lb_m/ft-sec from Westinghouse Excel Custom Functions/ASME Steam Tables data and is converted to centipoise by cP = lb_m/ft-sec * 1487 (Crane Technical Paper No. 410, page B-2).

TABLE 7: VELOCITY, FRICTION, AND TOTAL HEAD CORRECTIONS

Flow (gpm)	Discharge V(ft/sec)	Suction V (ft/sec)	Diff Vel. Head (ft)	Friction Head (ft)	Total Correction (ft)
0	0.00	0.00	0.00	0.00	-0.51
50	1.39	0.55	0.03	0.11	-0.38
100	2.79	1.11	0.10	0.36	-0.04
200	5.57	2.22	0.41	1.34	1.24
300	8.36	3.33	0.91	2.93	3.34
400	11.15	4.44	1.62	5.14	6.25
440	12.26	4.88	1.97	6.19	7.65
500	13.94	5.55	2.54	7.95	9.98
650	18.12	7.21	4.29	13.33	17.11
670	18.67	7.43	4.56	14.15	18.20

TABLE 8: ADJUSTMENT TO SIP MINIMUM TAC PUMP CURVE—CPT—PLANT COMPUTER FLOW MEASUREMENT

Min AOR Curve		Rate of Change of Head/flow	Flow Measurement Uncertainty	Head Uncertainty	Head Uncertainty Due to Flow	Head Uncertainty Due to Speed	Overall Pump Head Uncertainty	Revised Min TAC	Revised TAC with Instrument Corrections	Equivalent Pump Differential Pressure
Q_{SA}	ΔH	d(ΔH)/dQ	U_Q	$U_{\Delta H}$	$U_{\Delta H\text{-}Q}$	$U_{\Delta H\text{-}w}$	$U_{\Delta H,Total}$	ΔH	ΔH	ΔP
(gpm)	(ft)	(ft/gpm)	(gpm)	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(psid)
0	3246	1.000	1.5	3.34	1.50	78.27	78.4	3324	3325	1439
50	3282	0.448	1.5	3.38	0.67	79.41	79.5	3362	3362	1455
100	3291	-0.105	13.54	3.39	1.42	79.47	79.6	3370	3370	1459
200	3225	-1.210	13.54	3.32	16.38	80.66	82.4	3307	3306	1431
300	3049	-2.314	13.54	3.14	31.35	81.84	87.7	3137	3133	1356
400	2762	-3.419	13.54	2.85	46.31	82.99	95.1	2857	2851	1234
440	2617	-3.861	13.54	2.70	52.30	83.45	98.5	2715	2707	1172
500	2365	-4.524	13.54	2.44	61.27	84.13	104.1	2469	2459	1065
650	1562	-6.181	13.63	1.61	84.23	85.82	120.3	1682	1665	721
670	1436	-6.402	13.63	1.48	87.24	86.04	122.5	1559	1541	667

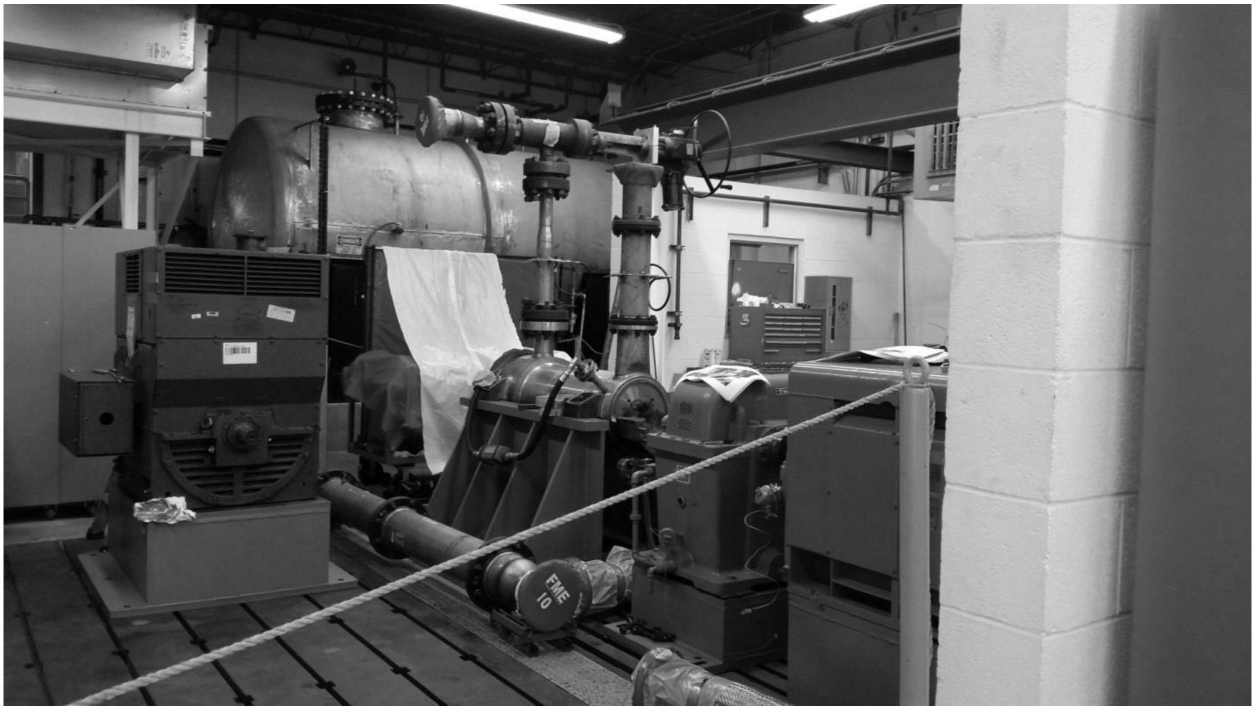

Figure 1. Loop without SIP Showing Tank, SIP Motor, and Centrifugal Charging Pump Casing

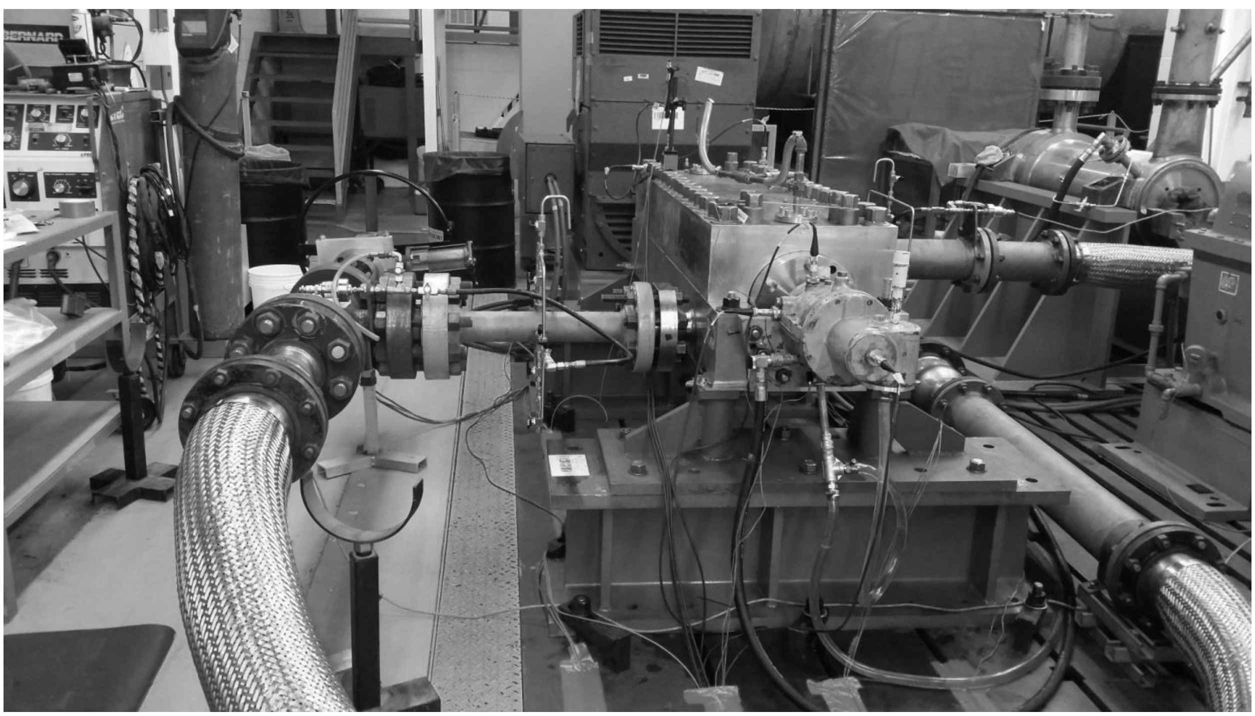

Figure 2. Pump in Test Loop—Discharge End

Figure 3. Pump in Test Loop View of Suction Side

Figure 4. Venturi Meter

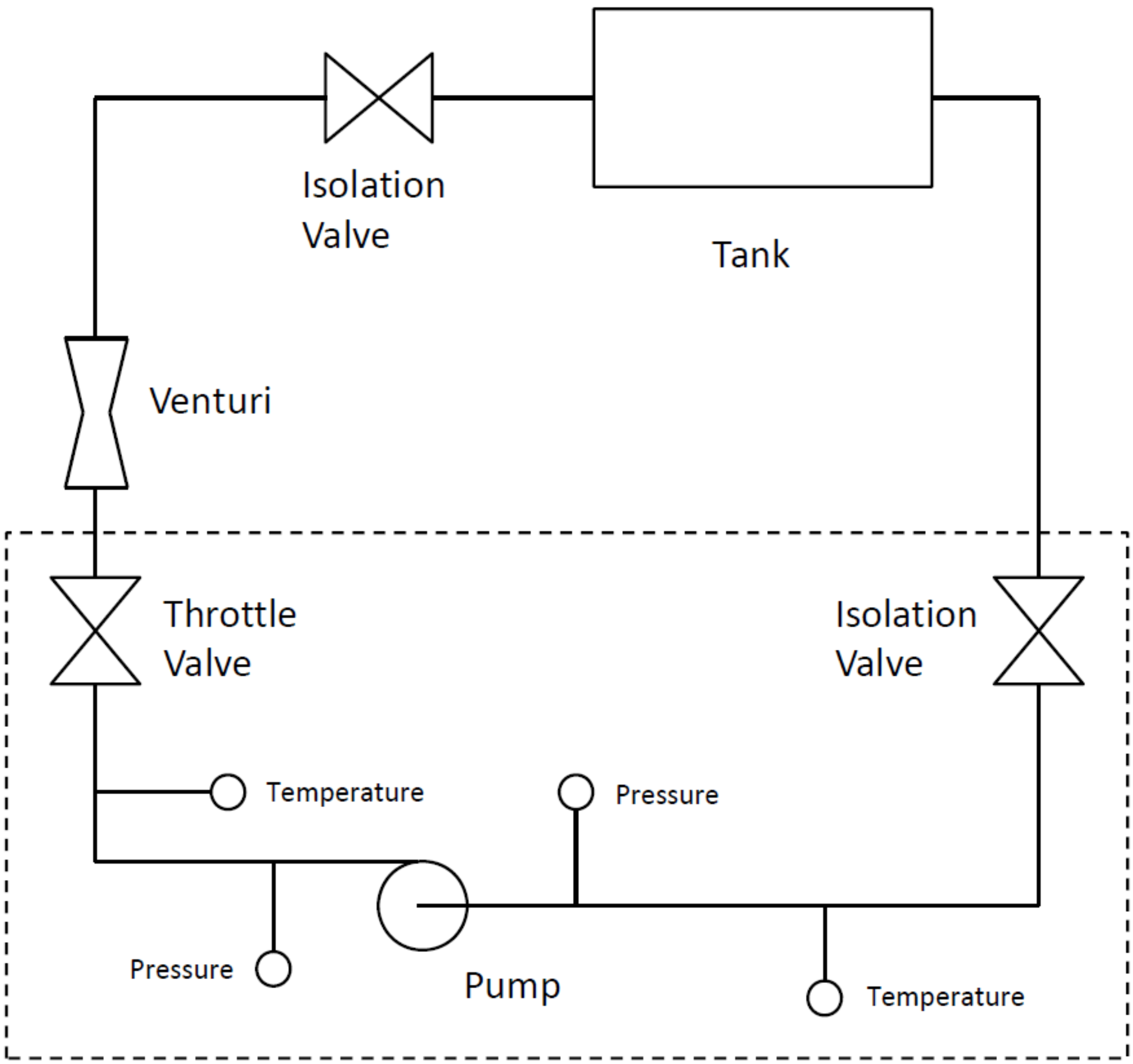

Figure 5. Flow Diagram—Dashed Line Indicates Contaminated Control Area

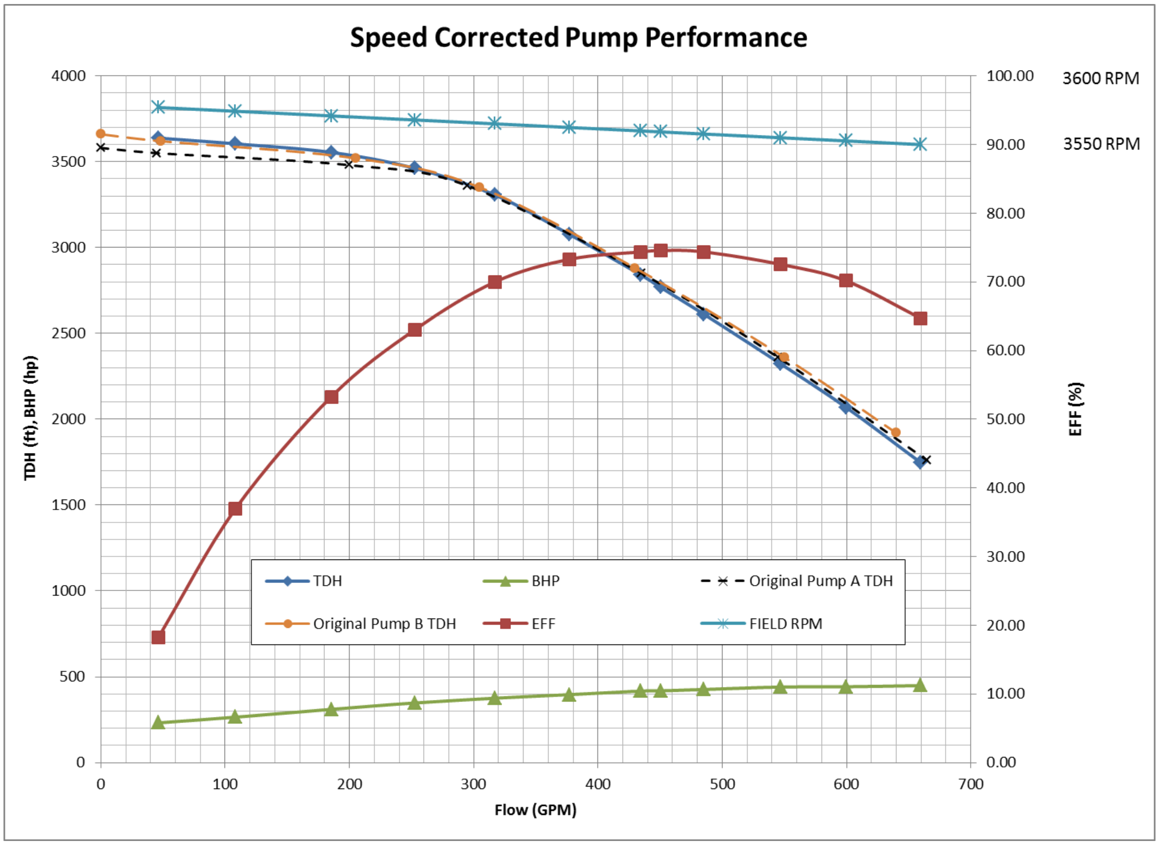

Figure 6. Speed Corrected Pump Performance

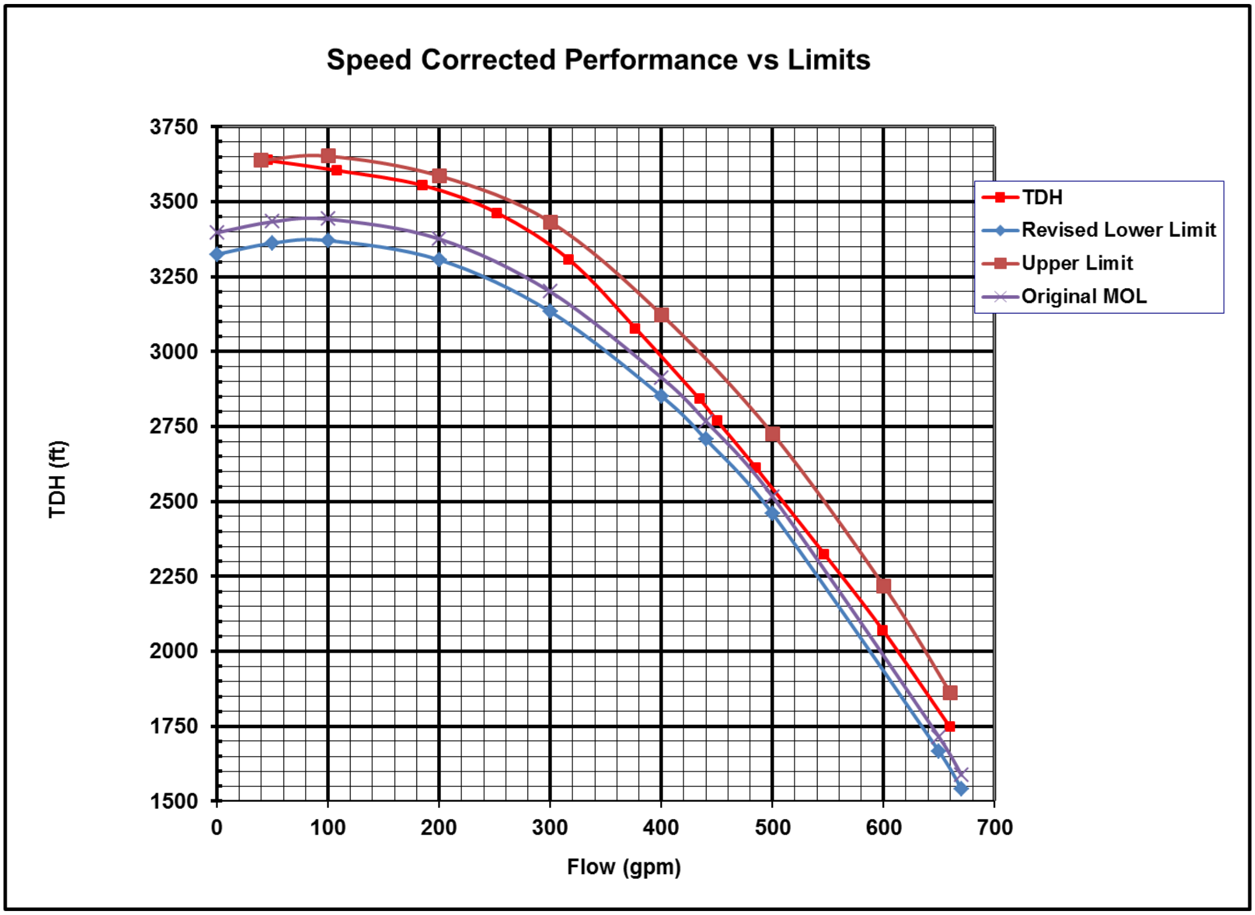

Figure 7. Test Performance vs. Limits

What Is Your Actual Pump Flow Rate?

Norman F. Perkins, P.E.
Alden Research Laboratory, Inc.
Holden, MA, USA

Philip S. Stacy
Alden Research Laboratory, Inc.
Holden, MA, USA

Abstract

What appears to be a simple question is often quite difficult to answer, depending on the quantity of flow and the size, type, and location of piping. Even the reason for asking the question can be varied and complex - ranging from environmental regulation, investment decisions, aging infrastructure improvement planning, and new equipment evaluation. Absolute field performance testing of power plant equipment yields valuable data that can be used in a variety of ways.

National and international codes list several methods to measure water flow in a performance application and provide realistic uncertainty estimates. Codes and standards exist for equipment evaluation and contractual performance tests. These codes, though, are sometimes viewed as costly or perceived to impose additional risk on suppliers. Herein, we will present how to obtain performance test data and how that data can be used.

In many rehabilitation or regulation-driven projects, an accurate representation of the state of the existing power plant is desired. Pump curves typically do not represent an accurate depiction of flow due to equipment degradation, changes in system components/geometry, and/or biofouling. While the testing may be considered costly, it can often be justified as part of a rehabilitation project. Absolute testing provides a lower uncertainty that can yield more definitive estimates of return on investment to justify projects that might be otherwise considered marginal.

Case studies will be discussed that illustrate these points, including the following:

- flow measurement feasibility and site testing at a nuclear thermal plant
- in situ flow testing to calibrate existing ultrasonic flow meters at a biomass thermal plant
- condenser performance testing at a nuclear thermal plant

Introduction

In situ pump performance testing is often a difficult and sometimes costly endeavor mostly due to the measurement of flow. The quantity of flow and the size, type, and location of piping all dictate the feasibility of measuring flow and the level of uncertainty that may be obtained. Numerous techniques and technologies exist that have been used successfully for decades, each having positive and negative aspects to their use and viability. Their cost varies significantly depending on the technology and intended use (i.e., permanent versus temporary).

The following information is intended to provide the reader with a sense of how pump performance can change over time, pump testing/flow measurement techniques, and budgetary prices associated with testing.

What's Wrong with Design Flow?

The simple answer to this question is "nothing." Facilities have been using pump curves and original design flow for decades. The design flow is often used for reporting water usage to environmental regulators, potential system modifications, and evaluating system performance.

However, over time all things change. Pump components wear, and pipe can change due to erosion and corrosion. In addition, environmental changes can occur that can change water levels, water chemistry, and flow approach conditions. Facilities sometimes replace flow-related equipment or change operations which can change the flow from the original design.

These changes can modify either the original pump curve or system curve. Pump wear can cause a pump curve to be lower than expected, and in the case of a pump rebuild with different components, higher than expected. Similarly, environmental and system changes may cause the system curve to be above or below the original design. See Figure 1 for an example of an original pump and system curve and Figure 2 for potential pump and system curves.

The data in Table 1 present the results of pump flow data recorded in the field versus original design. As shown, results can vary from slightly higher than design to as much as 27 percent below design. Note that pump 16 is 2 percent over design because of an incorrect impeller replacement during a rebuild. For reasons of confidentiality, the facility details cannot be presented.

In Situ Flow Measurement Techniques

The following is not an all-encompassing list of flow measurement techniques or technologies, but it is a list of methods frequently used for in situ flow measurement.

<u>Dye Dilution</u> - The dye dilution method for measuring flow allows an instantaneous flow to be measured by determining the dilution of a tracer injected into a flow. The dye dilution method is based on a mass balance calculation. A small quantity of fluorescent dye (typically Rhodamine WT) at high concentration is continuously injected at a measured, constant rate into the test flow. Concentration of the fully mixed flow is determined by fluorescence intensity

measurements. The ratio of the injected concentration to the final concentration, minus any background concentration in the incoming flow, multiplied by the injection flow equals the fully mixed test flow. See Figure 3 for an example dye injection setup and Figure 4 for an example dye sampling setup.

Area Velocity by Pitot - Flow can be determined by integrating point velocities measured by pitot probe, which measure velocity by simultaneously sensing impact and static pressure. This technique is typically feasible only if special pipe penetrations (see Figure 5) are installed in existing piping. The expense of adding wet-tap type fittings to existing piping is often cost prohibitive and sometimes physically infeasible. In addition to pipe access, this technique also requires a custom built and calibrated pitot probe, and an accurate measurement of the inside diameter of pipe. Once diameter measurements are obtained, careful calculation of equal areas and probe immersion depth are required. The velocities can be measured only along the axes of the ports.

Area-Velocity by Current Meters - For large pump intakes, velocity integration using current meters (see Figure 6) may be a viable flow measurement technology. Flow is measured by integrating velocities and the cross sectional area. Typically, a custom-built site-specific frame and meter racks are constructed for each application (see Figure 7). The meter rack is lowered into the intake gate slot. Current meter velocity integration is a relatively slow measurement with a single flow condition requiring 1.5 - 2 hours; however, there is no impact on plant operation (i.e., no dewatering to implement).

Ultrasonic - Ultrasonic flow meters have been used in both temporary (clamp on) and permanent (internal) installations. Ultrasonic pulse transit times are altered by the velocity of the flowing fluid. The effect on this transit time provides the velocity in the pipe at the axis of the meter transducers. Multiple transducer paths are employed to register the entire cross sectional velocity. Accurate measurements of the transducer locations and of the pipe or conduit dimensions are required. The measured velocities are integrated over the pipe area to calculate the fluid flow. Ultrasonic technology is suitable for long and short pipe runs and provides a relatively fast measurement. Permanent installations require site-specific installations and do impact plant operations (i.e., dewatering) to install. Once installed, future testing is fast and easy.

Additional Measurements - Collecting the following information is recommended. These data can be invaluable for use after the initial flow measurement; when correlated to the measured flow, they can be used for later indication of the flow performance:

- pump inlet pressure
- gauged or water level
- pump outlet pressure
- pump speed
- additional differential pressure measurements in the system
- power

Methods Applied

As shown in Table 1, the majority of the testing was performed using the dye dilution method (see Table 2). The method is favored due to its low cost, minimal disruption to facility operation, and brief testing time compared to the other methods described. The two techniques previously described (area velocity and ultrasonic), though not represented in Table 2, have been presented here because of their use predominately in the hydropower industry and their potential applicability in thermal power production.

Price of Testing

The associated price of testing for the pumps listed in Table 1 is presented in Table 3. The reader will notice that the pump tests on the upper half of the table are significantly higher priced than those on the lower half of the table. This disparity is due to the testing at nuclear facilities versus testing at fossil/biofuel facilities. Nuclear facilities require significantly more effort in the aspects of training, mobilization, demobilization, and paperwork.

Codes and Uncertainty

All of the flow measurement techniques/technologies listed in this paper have uncertainties on the order of 2 percent. Flow measurement uncertainties consist of bias and precision related to the following:

- mixing (dye dilution)
- dead zones (dye dilution)
- injection flow (dye dilution)
- calibration (all)
- data acquisition and reduction (all)
- length measurement (area velocity)

See the reference section at the end of this paper for the codes that are primarily used for pump testing and flow measurement.

Conclusion

Measuring pump flow rate is often a difficult task but not impossible. Multiple code-accepted techniques and technologies exist that have been in use for decades. Understanding flow conveyance system details and the limitations of measurement options are keys to determining the best approach. Historical flow data indicate that pump flow output may be off by as much as 27 percent due to either pump degradation, environmental or system changes, or a combination of these factors. The price of testing is not trivial, especially when dealing with the nuclear industry requirements.

References

American Society of Mechanical Engineers (ASME), 2002, ASME PTC 18-2002, “Hydraulic Turbines and Pump-Turbines Performance Test Codes,” 2002.

ASME, 2005, ASME PTC 19.1-2005, “Test Uncertainty,” 2005.

ASME, 2004, ASME PTC 19.5-2004, “Flow Measurement,” 2004.

International Electrotechnical Commission (IEC), 1991, “Field Acceptance Tests to Determine the Hydraulic Performance of Hydraulic Turbines, Storage Pumps, and Pump-Turbines,” International Standard IEC 41, Third Edition, 1991.

Table 1. Pump Data

Pump	Design Q (gpm)	Meas. Q	% diff
1	50,000	38,715	-22.6
2	50,000	50,292	0.6
3	137,200	122,723	-10.6
4	137,200	120,747	-12.0
5	137,200	132,326	-3.6
6	137,200	129,975	-5.3
7	152,000	138,575	-8.8
8	152,000	157,250	3.5
9	152,000	148,135	-2.5
10	152,000	152,001	0.0
11	152,000	152,504	0.3
12	152,000	150,003	-1.3
13	330,000	324,345	-1.7
14	330,000	317,589	-3.8
15	330,000	316,716	-4.0
16	330,000	335,570	1.7
17	22,000	20,243	-8.0
18	22,000	19,638	-10.7
19	44,000	39,580	-10.0
20	22,000	21,758	-1.1
21	38,200	36,845	-3.5
22	38,200	28,088	-26.5
23	7,000	5,530	-21.0
24	7,000	6,020	-14.0
25	10,000	7,900	-21.0
26	10,000	7,300	-27.0
27	9,500	7,220	-24.0
28	636,000	634,495	-0.2

Table 2. Pump Test Methods

- Pumps 1-2
  - *Dye-Dilution*
- Pumps 3-6
  - *Dye-Dilution*
- Pumps 7-12
  - *Dye-Dilution*
- Pumps 13-16
  - *Velocity distribution with pitot probe*
- Pumps 17-20
  - *Dye-Dilution*
- Pumps 21-22
  - *Dye-Dilution*
- Pump 23-27
  - *Dye-Dilution*
- Pump 28
  - *Dye-Dilution*

Table 3. Price of Testing

- Pumps 1-2
  - *$70,000 (2015)*
- Pumps 3-6
  - *$93,000 (2012, 2015)*
- Pumps 7-12
  - *$102,000 (2013, 2016)*
- Pumps 13-16
  - *$72,000 (2013)*
- Pumps 17-20
  - *$36,000 (2012, 2013)*
- Pumps 21-22
  - *$24,000 (2008)*
- Pump 23-27
  - *$19,000 (2004)*
- Pump 28
  - *$55,000 (2004)*

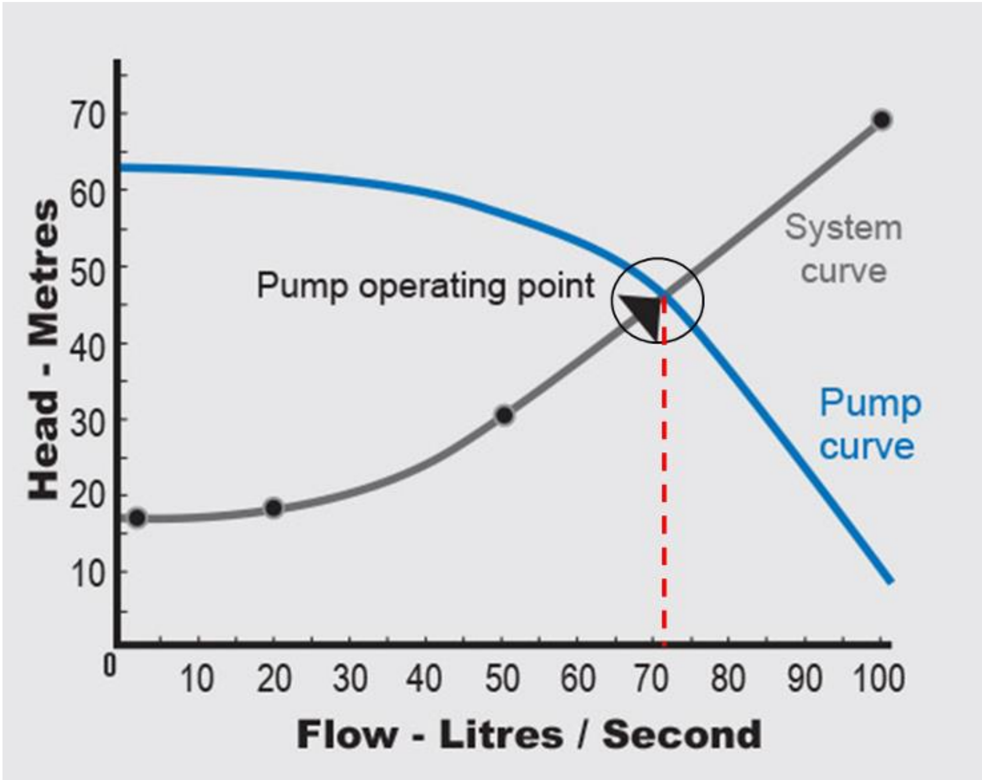

Figure 1. Example Original Pump and System Curve

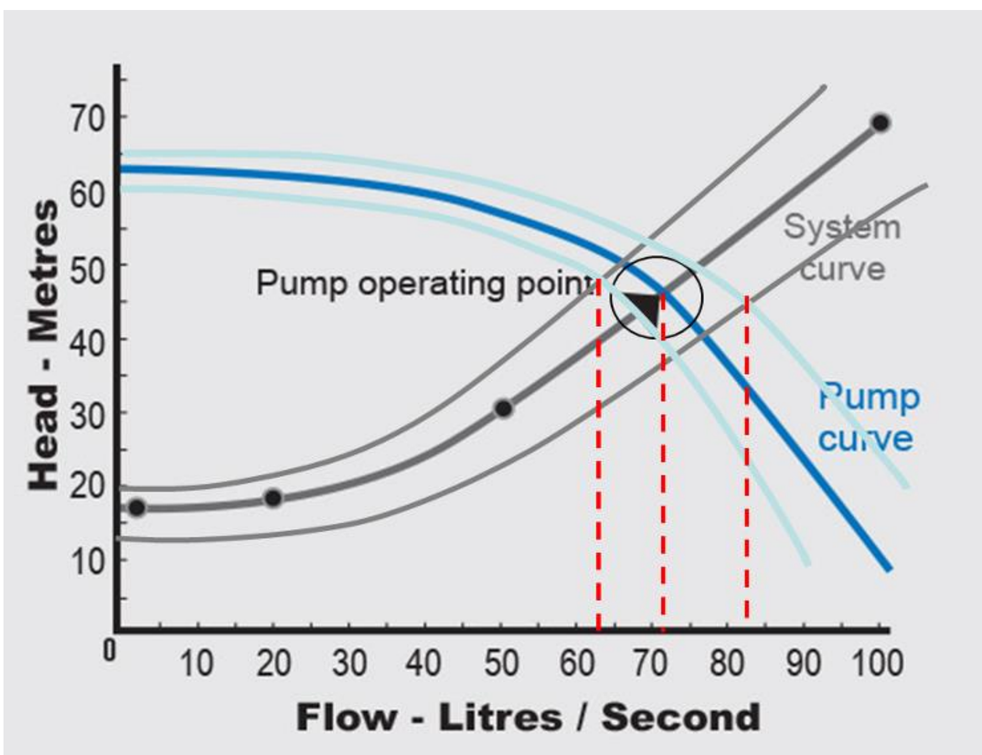

Figure 2. Example Potential Pump and System Curves

Figure 3. Dye Injection Equipment

Figure 4. Dye Sampling Equipment

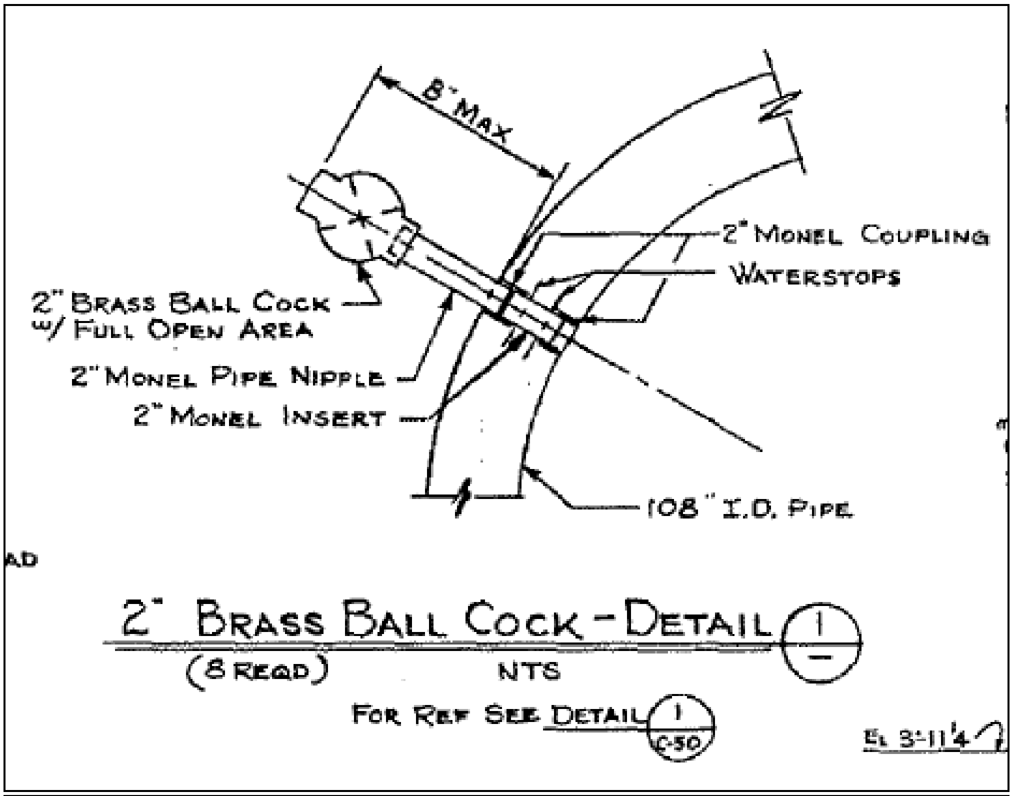

Figure 5. Typical Wet Tap Configuration

Figure 6. Typical Current Meter Suspended from a Rack

Figure 7. Typical Current Meter Rack

ISTB Pump Implementation Issues

Melvin L. McGaha and Tony Wayne Rogers
Iddeal Solutions, LLC

Abstract

Members of ISTB and ISTA have developed a list of issues regarding ISTB pump implementation that have been identified during inservice testing (IST) program reviews, day-to-day operation of IST programs, and site assessments of IST programs (including issues found during updates). Implementation of the ISTB requirements for pumps in commercial U.S. plants has presented challenges over the last few years with all the changes in ISTB since the issuance of the 1995 Edition of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code) through the 2006 Addenda. This paper discusses issues related to implementation and offers suggestions of good practices to enable the site IST engineers to interpret ASME OM Code requirements and develop subsequent implementation test requirements. Some projected issues with implementation of ASME OM Code, 2012 Edition, Mandatory Appendix V, "Pump Periodic Verification Test Program," are also discussed.

Introduction

This paper discusses various issues that challenge implementation of the ASME OM Code, 1995 Edition through the 2006 Addenda. Experience with IST 10-year updates indicates that most plants have the 2001 Edition through 2003 Addenda or 2004 Edition through 2006 Addenda as the Code of Record for their IST programs. In light of the upcoming plants implementing the 2012 Edition of the OM Code, changes for variance in reference values and test parameters, along with implementation of Appendix V, are also discussed.

- One of the issues was addressed during the Symposium and in 2017 with the issuance of ASME OM Code Case OMN-22, "Smooth Running Pumps," in which smooth running pump issues can be resolved by using the ASME OM Code approved Code Case. A relief request is still required until the OMN-22 is approved by the U.S. Nuclear Regulatory Commission (NRC) and is listed in Regulatory Guide (RG) 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code." Many nuclear plants currently have approved relief requests to implement similar positions (as shown in the OM Code Case) based on the IWP requirements from the 1986 Edition of the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, not being carried over to the OMa-1988 Part 6 requirements. Research indicates that the United States has approximately 12 sites with some form of relief for smooth running pumps.

- Some plants are not properly compensating for instrument uncertainty within their IST pump acceptance criteria for pump testing. The NRC has issued numerous documents requiring that instrument uncertainty be addressed in the accident analysis flow requirements. Design engineering at each site should be tasked with providing the IST acceptance criteria for pump testing where instrument uncertainties or inaccuracies are not accounted for in IST acceptance criteria.

- Previously approved 2004 Edition through 2006 Addenda ISTB Pump Test Acceptance Criteria listed in Tables ISTB-5121-1, ISTB-5221-1, ISTB-5321-1, and ISTB-5321-2 show greater than 1.03Qr (reference flow rate) for the required action range for comprehensive pump tests. The 2012 ISTB tables have revised these criteria to greater than 1.06*Qr*. Some plants had experienced a noticeable change in flow rates for comprehensive pump tests when using more accurate gauges (2-percent gauge versus ½-percent gauge). Some plants have created a separate comprehensive pump test procedure, and the Group A and B quarterly pump test data are not compared to the separate comprehensive pump test data, based on minimum flow lines being used for quarterly tests.

- In relation to fixed reference points, prior to the issuance of the 2012 Edition, there was no specified allowable range for the reference point. As an example, ISTB-5121(b) has been revised to state the following:

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

  Each plant needs to ensure that the requirements are split as written in ISTB and not simply ±2 percent for both. You could conclude that +2 percent is allowed for one and -2 percent is allowed for the other, but the requirements are slightly more restrictive, depending on flow rate or differential pressure.

- Some relief requests have been submitted for ASME OM Code Case OMN-18, “Alternate Testing Requirements for Pumps Tested Quarterly Within ±20% of Design Flow.” The NRC has proposed a condition within RG 1.192 that Group A Test Acceptable Ranges for flow and differential pressure (or discharge pressure) must be 1.06Qr and 1.06ΔPr (discharge pressure reference value), respectively.

OMN-18 (2012 Edition)	*Alternate Testing Requirements for Pumps Tested Quarterly Within ±20% of Design Flow*
	The upper end values of the Group A Test Acceptable Ranges for flow and differential pressure (or, discharge pressure) must be $1.06Q_r$ and $1.06\Delta P_r$ (or $1.06P_r$), respectively, as applicable to the pump type. The high values of the Required Action Ranges for flow and differential pressure (or discharge pressure) must be $>1.06Q_r$ and $>1.06\Delta P_r$ (or $1.06P_r$), respectively, as applicable to the pump type.

In some cases, plants requested use of OMN-19, "Alternative Upper Limit for the Comprehensive Pump Test," and in turn had to implement Appendix V.

OMN-19 (2012 Edition)	*Alternative Upper Limit for the Comprehensive Pump Test*
	Applicants or licensees who use this Code Case must implement a pump periodic verification test program. A pump periodic verification test is defined as a test that verifies a pump can meet the required (differential or discharge) pressure as applicable, at its highest design basis accident flow rate. The applicant or licensee must: (a) Identify those certain applicable pumps with specific design basis accident flow rates in the applicant's or licensee's credited safety analysis (e.g., technical specifications, technical requirements program, or updated safety analysis report) for inclusion in this program. (b) Perform the pump periodic verification test at least once every two years. (c) Determine whether the pump periodic verification test is required before declaring the pump operable following replacement, repair, or maintenance on the pump. (d) Declare the pump inoperable if the pump periodic verification test flow rate and associated differential pressure (or discharge pressure for positive displacement pumps) cannot be achieved. (e) Maintain the necessary records for the pump periodic verification tests, including the applicable test parameters (e.g., flow rate and associated differential pressure, or flow rate and associated discharge pressure, and speed for variable speed pumps) and their basis. (f) Account for the pump periodic verification test instrument accuracies in the test acceptance criteria. The applicant or licensee need not perform a pump periodic verification test if the design basis accident flow rate in the applicant's or licensee's safety analysis is bounded by the comprehensive pump test or Group A test.

At the time this paper was written, rulemaking for Revision 2 of RG 1.192 had not been issued (scheduled to be issued 30 days after rulemaking for the 2012 Edition of the OM Code).

- In the 2012 Edition, Appendix V establishes the requirements for implementing a pump periodic verification test. As discussed in ISTB-1400, the Owner shall establish a pump periodic verification test program for *certain* applicable pumps that are tested in accordance with paragraph ISTA-1100.

  If a plant applies verbatim compliance to that of Appendix V, there may be no exemption for any pumps due to the creation of design-basis flow rates for all comprehensive pump testing. A solid basis for inclusion or exclusion from Appendix V has to be developed, even if your current comprehensive testing is at design flow.

- ISTB is in the process of pushing a change through the Standards Committee to help clarify systematic error evaluation prior to determining if a pump is in alert range or required action range based on data obtained during a test. This paper will explain the background of changes from ASME BPV Code, Section XI, to the ASME OM Code that have created issues regarding systematic error in IST programs identified during component design basis inspections (CDBIs).

Discussion of Specific Implementation Changes and Associated Code Edition and Addenda

1. ASME OM Code Case OMN-22, "Smooth Running Pumps"

Smooth running pump issues can be resolved by using the ASME-approved Code Case. A relief request is still required because the OM Code Case (OMN-22) has not been approved by the NRC and is not listed in RG 1.192. Many nuclear plants currently have approved relief requests to implement similar positions (as shown in the OM Code Case) based on the IWP requirements from the 1986 Edition of ASME BPV Code, Section XI, not being carried over to the OMa-1988 Part 6 requirements. Research indicates we have approximately 12 sites with some form of relief for smooth running pumps in the United States. The Inquiry that pushed the OMN-22 Code Case through ISTB was a site in Europe looking for guidance on resolving its smooth running pump issues. All of the relief requests were not reviewed as part of this paper, but it is assumed that the NRC imposed the use of predictive maintenance (PdM) for monitoring the pump performance as a condition of the relief.

However, many of the sites with currently approved relief requests implemented today are monitoring their smooth-running pumps using the PdM program to monitor and trend the data for the smooth running pumps. OMN-22 stipulates that pumps that will use the "minimum reference" value for one or more vibration points shall be included in the Owner's PdM program. The PdM program shall apply predictive monitoring techniques and perform vibration analysis beyond the trending of vibration levels specified in the ASME OM Code to provide early detection of pump performance issues. The Owner shall determine which PdM supplemental monitoring activities will be utilized on the pump. The relief requests that have been reviewed by the author indicate the PdM requirement is required by these relief requests as a condition of the relief.

At a minimum, the Owner shall perform spectral analysis of measured vibration of the applicable pumps. The Owner shall document the conclusion of the PdM performance analysis on the pump test record prior to the subsequent test with a conclusion of acceptance, degrading but acceptable, or unacceptable. Corrective action shall be initiated when an unacceptable trend in performance is identified.

The OMN-22 Code Case has not been included in the 2017 Edition of the ASME OM Code (published this year), so basically it would be published in the next edition of the ASME OM Code and then it could be added to RG 1.192, for use without a relief request, pending no conditions imposed by the NRC through issuance of the RG 1.192 revision.

2. Some Plants Are Not Properly Compensating for Instrument Uncertainty

Within their IST pump acceptance criteria for pump testing, plants must compensate for instrument uncertainty. The NRC has issued numerous documents requiring that instrument uncertainty be addressed in the accident analysis flow requirements. Design engineering at each site should be tasked with providing the IST acceptance criteria for pump testing.

In most cases the uncertainty is rolled into the IST pump acceptance criteria. The NRC issued Information Notice (IN) 2008-02, “Findings Identified During Component Design Bases Inspections,” on March 19, 2008, which, in part, identified issues related to instrument uncertainty. In one case, a level setpoint issue was identified that involved the failure to account for instrument uncertainty, resulting in potentially inadequate vortexing margin for the residual heat removal (RHR) pumps during reactor coolant system mid-loop operation. Another case involved failure to account for the potential effect of air entrainment on the level instrument sensing lines (another potential problem for pump testing). As part of this IN, the NRC noted that NRC inspectors identified instances during CDBIs in which test acceptance criteria failed to ensure capability of the equipment to perform its function under the most limiting conditions. Examples included the acceptance criteria for valve and pump surveillance tests as well as design requirements. Some additional test deficiencies included failure to appropriately account for instrument uncertainties.

In many cases, where pump margins are low, plants may actually be below operability requirements, as applied to this margin, without including instrument uncertainty. In all cases, each licensee should ensure that the IST testing acceptance criteria account for instrument uncertainty.

The basis for instrument calibration intervals in Branch Technical Position 7-12, “Guidance on Establishing and Maintaining Instrument Setpoints,” indicates that the licensee should evaluate the effects of extended calibration intervals on instrument uncertainties, equipment qualification, and vendor maintenance provisions to ensure that an extended surveillance interval does not result in exceeding the assumptions stated in the accident analysis.

Another issue related to allowable variance reference points, from Section 5.3, “Allowable Variance from Reference Points and Fixed-Resistance Systems,” of NUREG-1482, Revision 2, “Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants, Final Report,” issued October 2013, is that certain designs do not allow for the licensee to set the flow at an exact value because of limitations in the instruments and controls for maintaining steady flow. Licensees have requested relief to establish a range of values using a pump curve, but with a very narrow band. For a tolerance greater than the allowed percent (which may be necessary depending on the precision of the instrument), the licensee may make a corresponding adjustment to acceptance criteria to compensate for the uncertainty. The same principle applies to the uncertainties associated with the instruments used for IST. If the instrument uncertainty is not compensated for in the accident analysis values used for pump testing, the licensee can take away a certain percentage of the requirement to apply to the acceptance criteria so that the uncertainty is rolled into the IST acceptance criteria, essentially compensating for the instrument uncertain in the test.

NUREG-1482, Revision 2, Section 5.8, “Adjustments for Instrument Inaccuracies,” states the following:

> If the accuracy of plant instrumentation used for IST is not well understood, the test results may not be adequate to meet the licensee’s safety analysis, even if they meet Code requirements. For example, TS or the safety analysis report require a pump to produce 1,000 gpm at 500 pounds per square inch differential (psid), but the IST reference values are 1,000 gpm (fixed) and 550 psid. The low end of the acceptable range for differential pressure from ISTB Table ISTB Table ISTB-5121-1 for Group A and Group B tests (0.90) would be 495 psid, although conservatively set at 500 psid. If this test is also to prove operability of the pump in addition to meeting IST requirements, and the ±2 percent instrument inaccuracies were taken into account for flow rate and differential pressure, there is a possibility that the pump is putting out less than the required values. In this example, the instrument inaccuracies would need to be taken into account if they were not already considered when the design parameters were developed.

When pump test procedures are developed, limits in the safety analysis or technical specifications (TS) cannot be ignored. If specific plant requirements are more restrictive or conservative, especially with the emphasis the ASME OM Code places on design flow requirements from previous comprehensive testing and now with Appendix V, such limits must be clearly indicated as the “operability” limits and used for acceptance criteria in IST.

3. Variance in Reference Points

In relation to fixed reference points, prior to the issuance of the 2012 Edition, there was no specified allowable range for the reference point. As an example, ISTB-5121(b) has been revised to state the following:

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

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

Assessments performed at some plants indicate the licensees are using ±2 percent for both flow and differential pressure, which is not in accordance with the ASME OM-2012 Code requirements.

NUREG-1482, Revision 2, Section 5.3, states the following:

> Certain designs do not allow for the licensee to set the flow at an exact value because of limitations in the instruments and controls for maintaining steady flow. The characteristics of piping systems in other designs do not allow for the licensee to adjust the flow to exact values.

As part of the recommendation the NRC stated:

> The allowed tolerance for setting the fixed parameter must be established for each case individually, including the accuracy of the instrument and precision of the display….For Group A and Group B tests, a total tolerance of ±2 percent of the reference value (including instrument accuracy) is allowed without prior NRC approval; for Preservice and Comprehensive tests, the allowable total tolerance is ±1/2 percent (including instrument accuracy) for pressure and differential pressure, ±2 percent (including instrument accuracy) for flow.

If your plant has established ±2 percent for all readings and has not taken into account instrument accuracy or the difference between preservice and comprehensive being more restrictive for pressure and differential pressure, you may be outside the NRC guidance on this issue. Review your program documents and ensure you are in compliance with Section 5.3 of NUREG-1482 for the 2001 Edition through the 2006 Addenda, or implement the guidance of the 2012 Edition of the ASME OM Code as written and reconcile your program documents. Regulatory approval may be required if your Code of Record is not the 2012 Edition.

4. Differences between Group A Quarterly and Comprehensive Pump Table Requirements between Codes of Record

For previously approved 2004 Edition through 2006 Addenda, ISTB pump test acceptance criteria listed in Tables ISTB-5121-1, ISTB-5221-1, ISTB-5321-1, and ISTB-5321-2 show greater than 1.03*Qr* as the required action range for comprehensive pump tests. The 2012 ISTB tables have revised these criteria to greater than 1.06*Qr*. Some plants had experienced challenges to the 3-percent change in flow rates for comprehensive pump tests when using more accurate gauges. Some plants have created a separate comprehensive pump test procedure, and the Group A and B quarterly pump test data are not compared to the separate comprehensive pump test data (some Group A and Group B tests are performed on minimum flow lines). In an attempt to obtain the 1.06 percent for comprehensive pump tests, plants submitted relief requests asking to use ASME OM Code Case OMN-19. The conditions imposed by the NRC as part of the approval of these relief requests are discussed in this section.

As the 2004 Edition through the 2006 Addenda of the ASME OM Code were being evaluated, ISTB initiated a change to the tables for the 2012 Edition through ASME OM Code Cases OMN-18 and OMN-19. As part of implementing these ASME OM Code Cases for the 2004 Edition through the 2006 Addenda, plants could ask for relief to implement full flow testing quarterly (OMN-18) or apply the 1.06 percent to the comprehensive pump testing acceptance criteria. Some plants had experienced a change beyond or close to the 1.03 percent while performing comprehensive pump testing and wanted to add an additional 3 percent to their test acceptance criteria.

Some plants had previous relief requests for performing full flow testing quarterly to ±20 percent of the design flow rate. Most of these plants were of boiling-water reactor design where full flow testing could be performed quarterly. This relief allowed for comprehensive pump testing to be performed quarterly, so no biennial comprehensive pump test is required. These plants were updated to request relief based on the previous request and, in some cases, the NRC allowed or imposed the 1.06 multiplier for the upper range for acceptance criteria. In some reported cases, this relief was allowed for the 2001 Edition through the 2003 Addenda, after the 2012 Edition of the OM Code was published (April 8, 2013). Also, when the NRC issued the proposed Revision 2 to RG 1.192 in March 2016 (Draft Regulatory Guide DG-1297, “Operation and Maintenance Code Case Acceptability, ASME OM Code” (Agencywide Documents Access and Management System (ADAMS) Accession No. ML15027A330), OMN-18 was listed in Table 2, “Conditionally Acceptable OM Code Cases,” with this “condition”:

> The upper end values of the Group A Test Acceptable Ranges for flow and differential pressure (or discharge pressure) must be $1.06Q_r$ and $106\Delta P_r$ (or $1.06P_r$), respectively, as applicable to the pump type. The high values of the Required Action Ranges for flow and differential pressure (or discharge pressure) must be $>1.06Q_r$ and $106\Delta P_r$ (or $1.06P_r$), respectively, as applicable to the pump type.

Without speaking for the NRC, it is believed this condition was imposed to reconcile the Group A Test Allowance of a 1.10 multiplier and the 1.03 multiplier for comprehensive pump Testing from the 2001 Edition through 2006 Addenda. This change will allow a boiling-water reactor implementing the OMN-18 Code Case to use the 1.06 multiplier without having to request the use of OMN-19 to obtain the 1.06 multiplier (it is believed the original intention of requesting relief to obtain the 1.06 multiplier per OMN-19 was just that - to obtain the multiplier).

For plants that submitted relief requests for the use of ASME OM Code Case OMN-19, the NRC imposed conditions on these relief requests. In the proposed revision to RG 1.192 (DG-1297), OMN-19 was listed in Table 2 with the following conditions:

> The applicant or licensee must:
>
> a) Identify those certain applicable pumps with specific design basis accident flow rates in the applicant's or licensee's credited safety analysis (e.g., TS, technical requirements program, or updated safety analysis report) for inclusion in this program.
>
> b) Perform the pump periodic verification test at least once every two years.
>
> c) Determine whether the pump periodic verification test is required before declaring the pump operable following replacement, repair, or maintenance on the pump.
>
> d) Declare the pump inoperable if the pump periodic verification test flow rate and associated differential pressure (or discharge pressure for positive displacement pumps) cannot be achieved.
>
> e) Maintain the necessary records for the pump periodic verification tests, including the applicable test parameters (e.g., flow rate and associated differential pressure, or flow rate and associated discharge pressure, and speed for variable speed pumps) and their basis.
>
> f) Account for the pump periodic verification test instrument accuracies in the test acceptance criteria.
>
> The applicant or licensee need not perform a pump periodic verification test if the design basis accident flow rate in the applicant's or licensee's safety analysis is bounded by the comprehensive test or Group A test.

The conditions listed in proposed Revision 2 of RG 1.192 specify that the applicant implement Appendix V of the 2012 Edition of the ASME OM Code as part of approval for use. The conditions imposed by RG 1.192 are essentially the requirements of Appendix V of the 2012 Edition of the ASME OM Code.

Code Case OMN-19
Alternative Upper Limit for the Comprehensive Pump Test

Background: Owners are having difficulties based on normal data scatter with implementation of the comprehensive pump test's current "Required Action Range" upper limit of 3% above the established reference value for the measured hydraulic value of differential pressure, discharge pressure, or flow. Owners have had to declare pumps inoperable for reasons other than a pump degradation issue. A "Required Action Range" upper limit of 6% above the reference value is a realistic value that should allow any true degradation issues to be captured and should alleviate unnecessarily declaring pumps inoperable.

This issue was also discussed at the ASME/NRC special meeting on June 4, 2007. The basis for the 1.06 upper limit is established in the white paper for the Code change that was approved under Standards Committee Ballot 09-610, record 09-657. This white paper discussed the impact of instrument inaccuracies, human factors involved with setting and measuring test parameters, readability of gauges, and other miscellaneous factors on the ability to meet the 1.03 criteria. Operating experience was also discussed in the white paper.

Inquiry: What alternative acceptance criteria may be used in place of the 1.03 reference value multiplier for the comprehensive pump test's upper "Acceptable Range" criteria and "Required Action Range, High" criteria referenced in the applicable ISTB test acceptance criteria tables?

Reply: It is the opinion of the Committee that a multiplier of 1.06 times the reference value may be used in lieu of the 1.03 multiplier for the comprehensive pump test's upper "Acceptable Range" criteria and "Required Action Range, High" criteria referenced in the ISTB test acceptance criteria tables listed in Table 1.

Applicability: ASME OMc Code-1994 Addenda through the ASME OM-2009 Edition.

Table 1 Test Acceptance Criteria Tables Affected by Alternative Upper Limit for the Comprehensive Pump Test

Applicable Code	Applicable ISTB Test Acceptance Criteria Table(s)
ASME OMc Code-1994 Addenda, ASME OM Code-1995 Edition, ASME OMa Code-1996 Addenda, ASME OMb Code-1997 Addenda	Table ISTB 5.2.3-1, Comprehensive Test Hydraulic Acceptance Criteria
ASME OM Code-1998, ASME OMa-1999 Addenda, ASME OMb Code-2000 Addenda, ASME OM Code-2001 Edition, ASME OMa Code-2002 Addenda, ASME OMb Code-2003 Addenda	Table ISTB-5100-1, Centrifugal Pump Test Acceptance Criteria Table ISTB-5200-1, Vertical Line Shaft and Centrifugal Pumps Test Acceptance Criteria Table ISTB-5300-1, Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria Table ISTB-5300-2, Reciprocating Positive Displacement Pump Test Acceptance Criteria
ASME OM Code-2004, ASME OMa Code-2005, ASME OMb Code-2006, ASME OM-2009	Table ISTB-5121-1, Centrifugal Pump Test Acceptance Criteria Table ISTB-5221-1, Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria Table ISTB-5321-1, Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria Table ISTB-5321-2, Reciprocating Positive Displacement Pump Test Acceptance Criteria

As part of this report, the challenges associated with implementation of Appendix V are discussed below, but the authors are uncertain why the NRC imposed the Appendix V requirements as part of approval of a relief request for OMN-19, when the Code Case has no ties to Appendix V.

For plants implementing the 2004 Edition through the 2006 Addenda of the ASME OM Code, use of the OMN-18 Code Case and the associated conditions with RG 1.192 will allow the applicant or licensee to implement the 1.06 multiplier for the comprehensive pump test when performed quarterly.

5. 2012 Edition Implementation of Appendix V

Appendix V implementation related to the 2012 Edition requires some analysis for each licensee. Appendix V establishes the requirements for implementing a pump periodic verification test. As discussed in ISTB-1400, the Owner shall establish a pump periodic verification test program for <u>certain</u> applicable pumps that are tested in accordance with paragraph ISTA-1100.

This mandatory appendix contains requirements to augment the rules of Subsection ISTB, “Inservice Testing of Pumps in Light Water Reactor Nuclear Power Plants.” The Owner is not required to perform a pump periodic verification test if the design-basis accident flow rate in the Owner’s safety analysis is bounded by the comprehensive pump test or Group A test.

Paragraph V-3000, “General Requirements,” in Appendix V states that the Owner shall:

a) Identify those certain applicable pumps with specific design basis accident flow rates in the Owner’s credited safety analysis (e.g., TS, technical requirements program, or updated safety analysis report) for inclusion in this program.

The issue here is identifying which pumps are included and excluded from this requirement.

The NRC safety evaluation report (SER) that evaluates the use of OMN-19 will outline the methodology of including or excluding specific pumps. The design aspects applied to this relief request and subsequent SER are explained based on the table below. The question that remains from the approach used in this relief request is how you would exclude cooling water pumps or service water pumps if there are design-basis flow requirements for flow for these pumps. In most cases, each site should already have the design-basis flow requirements established for comprehensive pump testing (i.e., ±20 percent). For this plant site, the RHR pumps were excluded, but the low head safety injection pumps were included. It is believed the RHR pumps were beyond licensing basis and only used for cold shutdown operations, with the plant possibly being licensed to hot standby (unknown related to this paper). There were control room heating, ventilation, and air conditioning pumps not included, while the service water pumps were included and the component cooling water pumps were not included. The component cooling water pumps may be related to British thermal unit heat removal capability and are not shown with a design flow rate.

Table 2: Pumps Affected by Alternative Request P-6, Unit 1

Pump Group	System	Code Class	Pump Type	Description	Design Basis Flow Rate (gpm)	PPV Test Required
1-CC-P-1A 1-CC-P-1B	Component Cooling	3	Centrifugal	Component Cooling Water Pump	None	No
1-CC-P-2A 1-CC-P-2B	Component Cooling	3	Centrifugal	Component Cooling Water Pump to Charging Pump	30	Yes
1-CH-P-1A 1-CH-P-1B 1-CH-P-1C	Chemical and Volume Control / Safety Injection	2	Centrifugal	High Head Safety Injection / Charging Pump	436	Yes
1-CH-P-2A 1-CH-P-2B	Chemical and Volume Control	2	Centrifugal	Boric Acid Transfer Pump	None	No
1-FW-P-2	Auxiliary Feedwater	3	Centrifugal	Auxiliary Feedwater Motor Driven Pump	400	Yes
1-FW-P-3A 1-FW-P-3B	Auxiliary Feedwater	3	Centrifugal	Auxiliary Feedwater Motor Driven Pump	300	Yes
1-RH-P-1A 1-RH-P-1B	Residual Heat Removal	2	Centrifugal	Residual Heat Removal Pump	None	No
1-RS-P-1A 1-RS-P-1B	Recirculation Spray	3	Vertical Line Shaft Centrifugal	Inside Containment Recirculation Spray Pump	3100	Yes
1-RS-P-2A 1-RS-P-2B	Recirculation Spray	3	Vertical Line Shaft Centrifugal	Outside Containment Recirculation Spray Pump	2900	Yes
1-SI-P-1A 1-SI-P-1B	Safety Injection	3	Vertical Line Shaft Centrifugal	Low Head Safety Injection Pump	2901	Yes
1-SW-P-1A 1-SW-P-1B 1-SW-P-1C	Service Water	3	Vertical Line Shaft Centrifugal	Emergency Service Water Pump	14550	Yes
1-SW-P-10A 1-SW-P-10B	Service Water	3	Centrifugal	Service Water Pump to Charging Pump	42	Yes
1-VS-P-1A 1-VS-P-1B 1-VS-P-1C	Ventilation	3	Centrifugal	Main Control Room Air Conditioning System Condenser Water Pump	None	No
1-VS-P-1D 1-VS-P-1E	Ventilation	3	Centrifugal	Main Control Room Air Conditioning System Condenser Water Pump	None	No
1-VS-P-2A 1-VS-P-2B 1-VS-P-2C	Ventilation	3	Centrifugal	Main Control Room Air Conditioning System Chilled Water Pump	None	No
1-VS-P-2D 1-VS-P-2E	Ventilation	3	Centrifugal	Main Control Room Air Conditioning System Chilled Water Pump	None	No

(Source: Author)

The pumps listed here as not having a design-basis flow rate (none) were excluded from the conditions imposed by the NRC for a pump periodic verification test program. By submitting this relief request to implement OMN-19 in order to establish the required action range at greater than 1.06Qr, the applicant was required to implement Appendix V of the 2012 Edition. This information is provided to outline some of the challenges in implementing Appendix V for licensees, as part of the new intervals being developed. A solid basis for inclusion or exclusion from the Appendix V pump periodic verification test program would be required, at a minimum.

The authors have questions concerning the implementation of this appendix as it relates to how you would exclude those pumps in the current IST program, when many pumps have calculations or analyses that have determined the comprehensive pump test flow rate(s). One question is whether the flow rates developed for the comprehensive pump test are considered where Footnote 1 of Appendix V states:

> This Mandatory Appendix contains requirements to augment the rules of Subsection ISTB, “Inservice Testing of Pumps in Light Water Reactor Nuclear Power Plants.” The Owner is not required to perform a pump periodic verification test, if the design basis accident flow rate in the Owner’s safety analysis is bounded by the comprehensive pump test or Group A test.

Also, Footnote 2 states:

> A pump may have several design basis postaccident operating points due to different system configurations or single vs. parallel pump operation. Reference ASME OM Standard Part 28, Standard for Performance Testing of Systems in Light-Water Reactor Power Plants, for additional information on testing of power plant systems.

First, we look at the Footnote 1 requirements. Keep in mind that for the comprehensive pump test requirements listed in ASME OM Code-2004, ISTB-3300(e)(1), “Reference values shall be established within ±20% of pump design flow rate for the comprehensive test.” This requirement is not listed in ASME OM-2012 (Code) ISTB-3300(e)(1) and has been revised to state, “Reference values shall be established at the comprehensive pump test flow rate for the comprehensive test.” From the OM-2012, ISTB-2000, “Supplemental Definitions,” comprehensive pump test flow rate is defined as “the flow rate established by the Owner that is effective for detecting mechanical and hydraulic degradation during subsequent testing. The best efficiency point, system flow rates, and any other plant-specific flow rates shall be considered.”

It appears your comprehensive pump flow rate could be relaxed to the best efficiency point on the pump curve rather than within ±20 percent of design accident flow rate, which may benefit some plants. However, after identifying the pumps required per V-3000(a) shown above, the plant has to determine whether the pump periodic verification test is required before declaring the pump operable following replacement, repair or maintenance on the pump according to paragraph V-3000(c) in Appendix V. Also, if the comprehensive pump flow rate is lowered from the previous interval's ±20 percent of design flow, the periodic verification test will be required for the accident flow rate.

Also, is it acceptable to lower the comprehensive pump test flow rate to the best efficiency point, and then as part of the same test, only increase flow to the accident flow rate prior to terminating the test after all the flow, differential pressure, and vibration measurements have been taken? From review of ISTB for OM-2012 and Appendix V, this appears to be acceptable and may help minimize wear on any pump that may be challenged at accident analysis design flow rates, since in many cases, this could mean pumping water to an open-ended pipe inside containment during an actual large-break loss-of-coolant accident (LOCA).

Now, we look at Footnote 2, and the reference to Part 28. The Scope statement (Section 1.1) within Part 28 indicates it is used for the following:

> [to] assess the operational readiness of certain safety-related systems and systems important to safety used in light-water reactor power plants. The systems covered are those required to perform or support a specific function in shutting down a reactor to safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident.

This scope statement is similar to ISTA-1100 for components required to be part of an IST program. While this part is designed to provide guidance for testing, many of the systems listed in Section 5, "Specific Testing Requirements," of Part 28 may not be within the scope of V-3000(a) (pumps with specific design-basis accident flow rates in technical specifications, technical requirements manual (TRM), or the final safety analysis report). Section 5 has a number of systems listed, such as "Closed Cooling Water Systems" (5.3) and "Instrument Air Systems" (5.5), which are unlikely candidates for pumps with specific design-basis accident flow requirements. Other sections, such as 5.1, "Emergency Core Cooling Systems"; 5.2, "Auxiliary or Emergency Feedwater Systems"; and 5.4, "Emergency Service Water Systems," may in fact have some of the pumps requiring pump periodic verification testing. Since ASME subcommittees are not supposed to provide consulting, it may be up to you as the IST engineer, or your IST services vendor, to answer these questions regarding implementation of Appendix V of the OM-2012 Code.

6. Changes Associated with ISTB-6200 and ISTB-6300 as They Apply to Systematic Error

ISTB is in the process of pushing a change through the Standards Committee to help clarify systematic error evaluation prior to determining if a pump is in the alert range or required action range based on data obtained during a test. This paper will attempt to explain the background of changes through the years where this is another change from ASME BPV Code, Section XI, to the ASME OM Code where systematic error was moved to a separate paragraph from Corrective Action and which may have created issues for programs identified during CDBI assessments.

A change was proposed for ISTB-6200 and ISTB-6300 under OM Ballot 16-1276. A detailed white paper was written after the initial general ballot went out to OM members. The change was based on some issues resulting in questions and a violation (CDBI) based on pumps having systematic errors that were undetected as part of the initial comprehensive pump tests performed at two different sites (two known sites—there may be others that are unknown). Research was provided to ISTB showing that systematic error, as it is known today (2015 ISTB-6300) and within IWP-3230 of the 1986 Edition of ASME Section XI. You can see from the examples that within the IWP Section XI Code, IWP-3230(d) is what ISTB-6300 systematic error is today.

IWP-3230 CORRECTIVE ACTION

(a) If deviations fall within the Alert Range of Table IWP-3100-2, the frequency of testing specified in IWP-3400 shall be doubled until the cause of the deviation is determined and the condition corrected.

(b) If deviations fall within the Required Action Range of Table IWP-3100-2, the pump shall be declared inoperative and not returned to service until the cause of the deviation has been determined and the condition corrected.

(c) Correction shall be either replacement or repair per IWP-3111, or shall be an analysis to demonstrate that the condition does not impair pump operability

and that the pump will still fulfill its function. A new set of reference values shall be established after such analysis.

(d) When test shows deviations greater than allowed (see Table IWP-3100-2), the instruments involved may be recalibrated and the test rerun.

Requirements for alert range, required action range, corrective action, and systematic error were all part of the same section of the Subsection IWP IST of pumps in nuclear power plants.

As part of the discussion for the June 2016 ISTB Subcommittee Meeting and the December 2016 meeting, it was determined that, rather than adding a subsection and having to renumber the sections (which may have affected many licensee procedures), a compromise was reached to add a note that, prior to declaring a pump in the alert or required action range, licensees should ensure that no systematic error occurred.

The two plants that had issues with systematic errors either declared the pumps within alert range and shortened the frequency of the comprehensive pump test to 1 year, or had a pump with required action range data that was not tested for another 2 weeks, since a gauge was found broken. The gauge could not be swapped without making the other divisional pump inoperable. For critical comprehensive pump tests, it is suggested that pretest and posttest calibration of gauges be performed to eliminate systematic error concerns.

OM-2015 ISTB-6300

ISTB-6300 Systematic Error

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

Conclusion

Members of ISTB and ISTA developed a list of issues regarding ISTB pump implementation that have been identified during IST program reviews, day-to-day operation of IST programs, and site assessments of IST programs (including issues found during updates).

Smooth running pumps will have an ASME OM Code Case and PdM program monitoring to address the lower range(s) needed to address these pumps without relief (long term).

Instrument uncertainty has to be addressed as part of your design basis or your IST program.

The 1.06 multiplier can now be used in a variety of applications for various Codes of Record and is now part of the newly approved 2012 Edition of the ASME OM Code.

Variance in reference points should be addressed by compliance with NUREG-1482, Revision 2, or implementation of the OM-2012 ISTB requirements.

ASME OM Code Case OMN-18 can be requested to perform comprehensive pump testing quarterly and use the 1.06 multiplier for the upper end for acceptance criteria.

Appendix V to OM-2012 presents challenges that should be addressed as part of your 10-year interval update. If your plant is performing design flow testing quarterly in lieu of comprehensive pump testing, your plant should transition to Appendix V without any issues, as long as you have a solid basis for exclusion of those pumps not meeting V-3000(a).

Changes are coming to ensure that systematic error is addressed prior to declaring a pump in the alert or required action range. Each IST engineer should ensure that the implementation procedures address this action.

References

(1) ASME, *Boiler and Pressure Vessel Code*, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Subsection IWP, "Inservice Testing of Pumps in Nuclear Power Plants," 1986.

(2) ASME, OM-2015, *Operation and Maintenance of Nuclear Power Plants.*

(3) ASME, OM-2012, *Operation and Maintenance of Nuclear Power Plants.*

(4) ASME, OM Code-2004, *Code for Operation and Maintenance of Nuclear Power Plants.*

(5) ASME, OMa Code-2005, Addenda to ASME OM Code-2004, *Code for Operation and Maintenance of Nuclear Power Plants.*

(6) ASME, OMb Code-2006, Addenda to ASME OM Code-2004, *Code for Operation and Maintenance of Nuclear Power Plants.*

(7) ASME, OM Code-2001, *Code for Operation and Maintenance of Nuclear Power Plants.*

(8) ASME, OMa Code-2002, Addenda to ASME OM Code-2001, *Code for Operation and Maintenance of Nuclear Power Plants.*

(9) ASME, OMb Code-2003, Addenda to ASME OM Code-2001, *Code for Operations and Maintenance of Nuclear Power Plants.*

(10) ASME, OM Code Case OMN-22, "Smooth Running Pumps."

(11) ASME, OM Code Case OMN-18, "Alternate Testing Requirements for Pumps Tested Quarterly Within ±20% of Design Flow."

(12) ASME, OM Code Case OMN-19, "Alternate Upper Limit for the Comprehensive Pump Test."

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Component Cooling Water Pump Assessment Report

Watson Tomlinson, Power Industry Specialist, Flowserve Corp.

Steven Kochaniec, Supervisor, Assessment Engineering, Flowserve Corp.

Abstract

Three component cooling water (CCW) pumps, IR 8X18SE, appeared to have been operated beyond their original manufacturer pump curves without proper justification and analysis. The testing was performed to determine exactly where the pumps were operating relative to the original head-capacity curve, at different system demands. Additionally, the results would be compared to the customer's flow and pressure measuring capabilities.

Introduction

The customer utilizes three IR 8X18SE (Flowserve heritage) pumps as the main fluid driver for its CCW system. The pumps are single stage, between bearing, horizontally split volute pumps, with two of the three pumps online during normal operation. Due to suspected inaccuracies in the annubar used for the system flow measurement, the CCW system appears to have been operated at a higher capacity than the original design requirements without proper justification and analysis, thus resulting in the CCW pumps operating at flow greater than the best efficiency point. Testing was performed to determine exactly where the pumps were operating relative to the original head-capacity curve, at different system demands.

Original Equipment Manufacturer (OEM) Pump Data:

- Make: Ingersoll-Rand
- Model: 8X18 SE
- Number Stages: 1
- Style: Horizontally split volute type
- Driver: Motor (250 horsepower (hp))
- Design Head: 210 feet
- Design Flow: 3,425 gallons per minute (gpm)
- Design Speed: 1,750 revolutions per minute (rpm)
- Impeller Diameter: 15 7/8 inches
- The original bronze impeller/casing ring clearance tolerance was 0.010 - 0.014 inches.
- The newer stainless steel impeller/casing ring clearance tolerance is 0.015 - 0.023 inches.

A performance curve of the CCW pump can be seen in Figure 1, followed by a sectional assembly drawing in Figure 2. The original curves are based on 1,750 rpm. These pumps utilize 15-7/8 inch diameter impellers and operate at 1,785 rpm. It should be noted that the sectional of this pump is only typical of this product line and not exact.

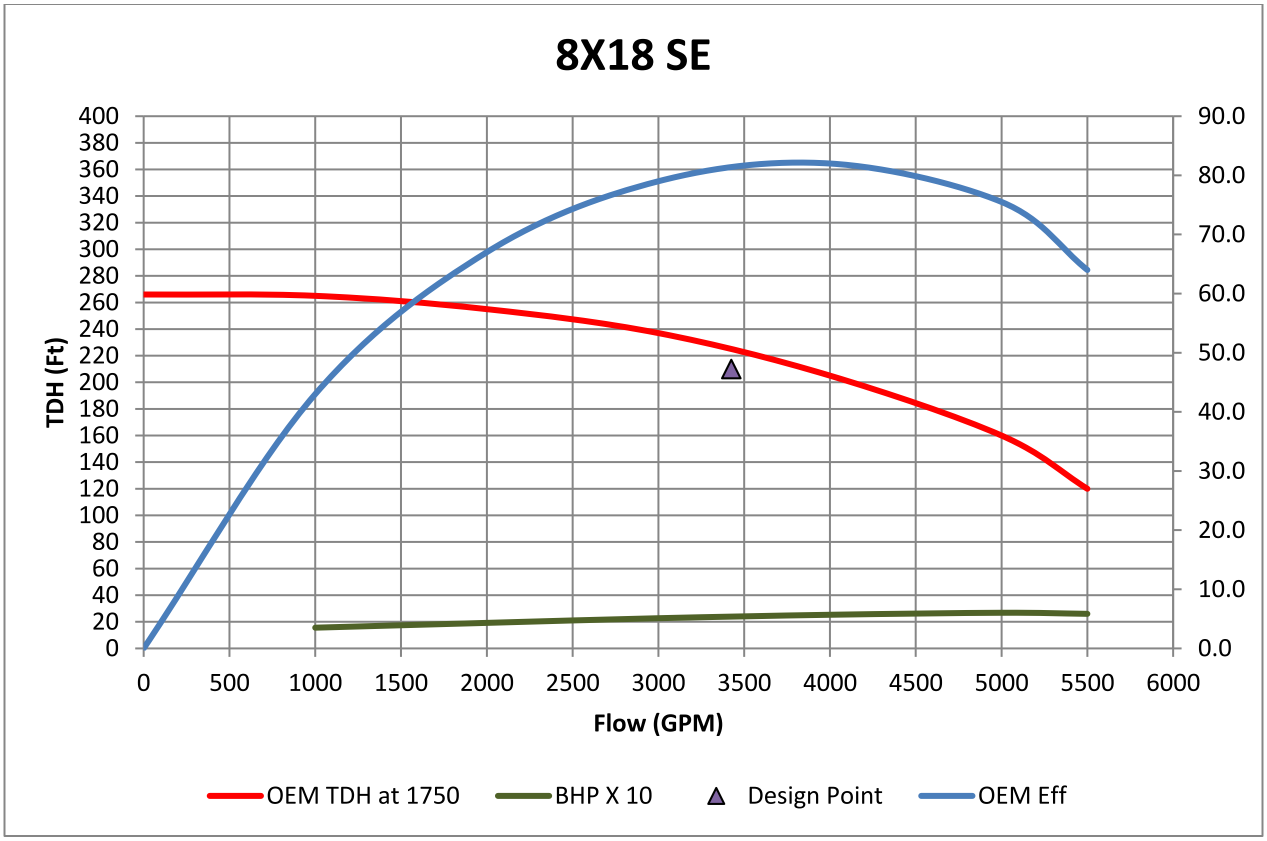

Figure 1. OEM CCW Performance Curve
(Source: Author)

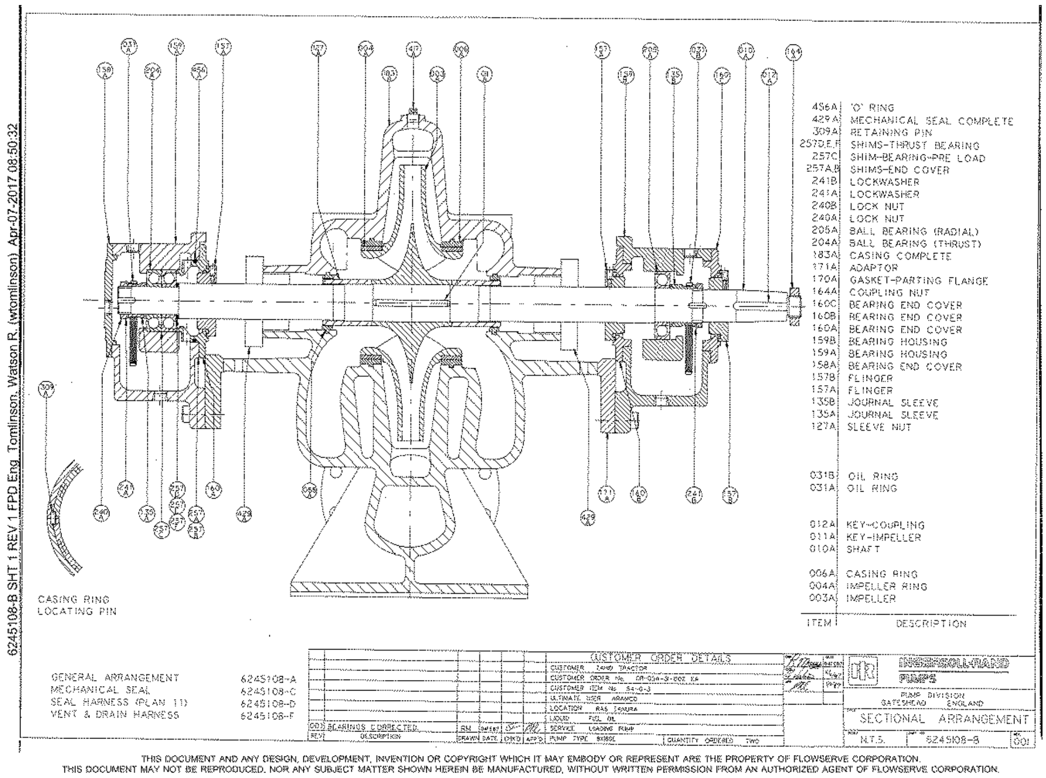

Figure 2. Typical Sectional Assembly of 8X18 SE
(Source: Author)

Test Methodology

Pump performance was measured by operating each pump individually during a period when the CCW system demand was minimal. During the test, the nonoperating pumps were isolated from the system by closing the associated suction and discharge isolation valves. This minimized errors in the flow reading by preventing back-leakage through nonoperating pumps. The discharge isolation valve for the tested pump was throttled to control the pumps' output at various points.

The following points were monitored during the assessment.

Pump Flow

To measure pump flow, Flowserve utilized Panametrics ultrasonic flow meters. Two independent flow channels and transducer setups were installed on the 16-inch suction header with 10+ pipe diameters of straight pipe upstream of the transducers and four diameters of straight pipe downstream. The transducer setups were 90 degrees apart radially and 6 inches offset axially. An additional transducer setup was installed on the discharge of the nonrunning pumps to check for back leakage. After the flow meter has calculated fluid flow, it generates a 4 - 20 milliamp output for each flow measurement. The 4 - 20 milliamp signal is broadcast by an intelligent process system wireless transmitter to a receiver. According to the calibration sheets, the meters read within 2 percent of the reference flows across the calibration range.

Total Developed Head

Total developed head (TDH) is found by determining the difference between the total discharge and suction pressures and converting to head. To measure CCW pump suction and discharge pressures, intelligence process system wireless pressure transducers were installed at the suction and discharge of the pumps. The transducers have a built-in wireless transmitter that sends a signal to the receiver. For the 0 - 1,000 sensors (discharge), the accuracy is 0.01 percent full scale with a resolution of 0.3 pounds per square inch (psi). For the -30 inch mercury (Hg) to 30 psi sensors (suction), the accuracy is 0.01 percent of full scale with a resolution of 0.026 psi.

Installation of Pressure Gauges on the CCW "A" Pump to Measure Suction (right), Discharge (left) Pressures
(Source: Author)

System Temperature

The system temperature was checked with a handheld pyrometer. The piping temperature varied from 79 to 83 degrees Fahrenheit (F) during the course of the testing.

Vibration Data

Vibration data were collected using a CSI 2130 handheld vibration analyzer. Data were collected at the lowest flow point, an intermediate flow point, and the highest flow point.

Motor Power

Motor power was measured using a Fluke 1735 Three Phase Power Logger and a site supplied Fluke 43B Power Analyzer. Voltage and current measurements were collected on each phase, and an accurate power factor was calculated for each phase. Brake horsepower (BHP) was calculated based on data collected for the Fluke 1735 and an OEM motor efficiency of 94.1 percent.

Data Collection

All wireless signals were transmitted to a receiver, which stored the data on a memory stick. Data were viewed in real-time by connecting a laptop to the receiver. Data were also collected manually to ensure that the readings coming into the receiver were good data in the ranges that would be expected.

Test Procedure

The test was controlled by one of the plant's operations procedures. One pump was operated at a time with a starting system pressure of 140 pounds per square inch gauge (psig). The system pressure was dropped in 10 psi increments to obtain additional flow data. The maximum flow allowed per the procedure was 6,300 gpm based on the station annubar. At least six flow points were captured for each of the pumps.

Pump Performance

Component Cooling Water Pumps 3A, 3B, and 3C Performance

Figure 3 shows three curves: the original performance curve based on 1,750 rpm, the original curve stepped up to 1,785 rpm to match the present operating speed, and the stepped-up curve (1,785 rpm) compensated for the increased clearance with the new stainless steel impellers and rings. The performance of the three pumps was compared to the later curve. Test versus OEM performance of the CCW 3B is shown in Figures 4 - 6.[1] There are three graphs for the pump: tested total developed head (TDH) and efficiency, tested TDH and BHP, and tested TDH average of data points curve. The graph in Figure 7 shows how the three pumps relate to one another in TDH.

All three pumps were low in head, flow, and efficiency as compared to the corrected original curve. The 3C pump was the best in performance, and the 3A and 3B pumps were nearly equal in performance. All of the pumps exhibit what is expected as normal wear ring clearance opening and possibly some erosion of the flow passages in the casing. The performance calculations for each pump include corrections for velocity head. The 3A pump was the only

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[1] For this presentation, only the data for one of the pumps will be shown.

pump for which the discharge check valve indicated back leakage. The indicated backflow was 25 to 35 gpm at a system pressure of 140 psig, and 15 to 25 gpm at a system pressure of 80 psig.

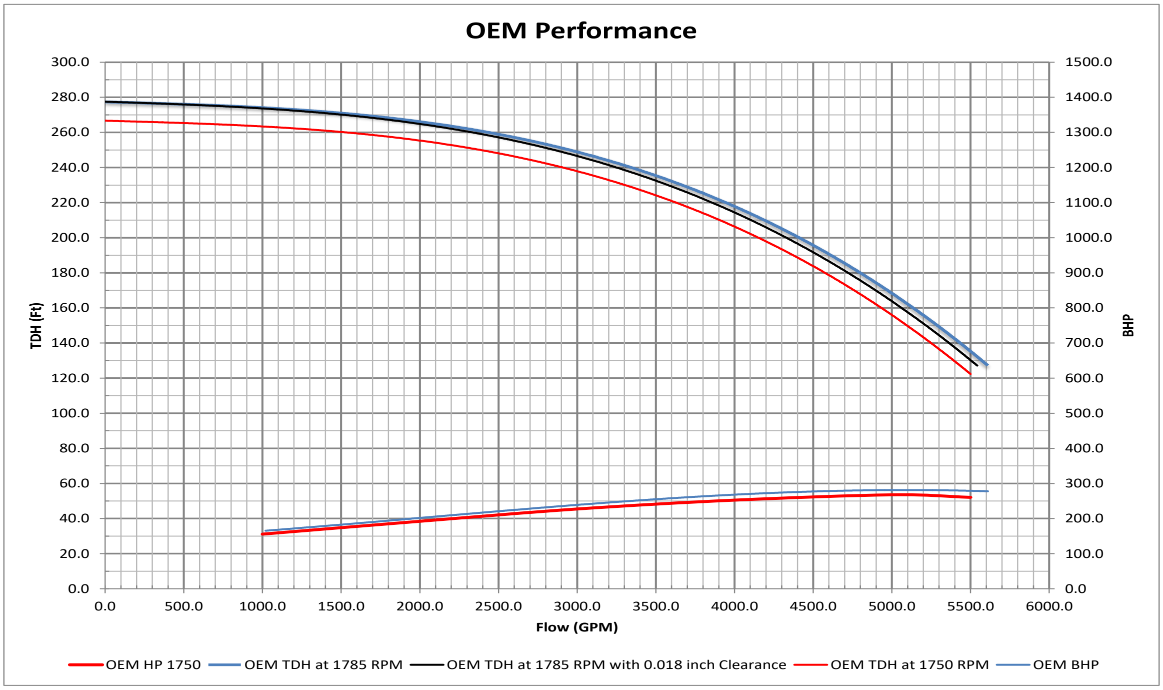


Figure 3. CCW Pump 1 Test Performance
(Source: Author)

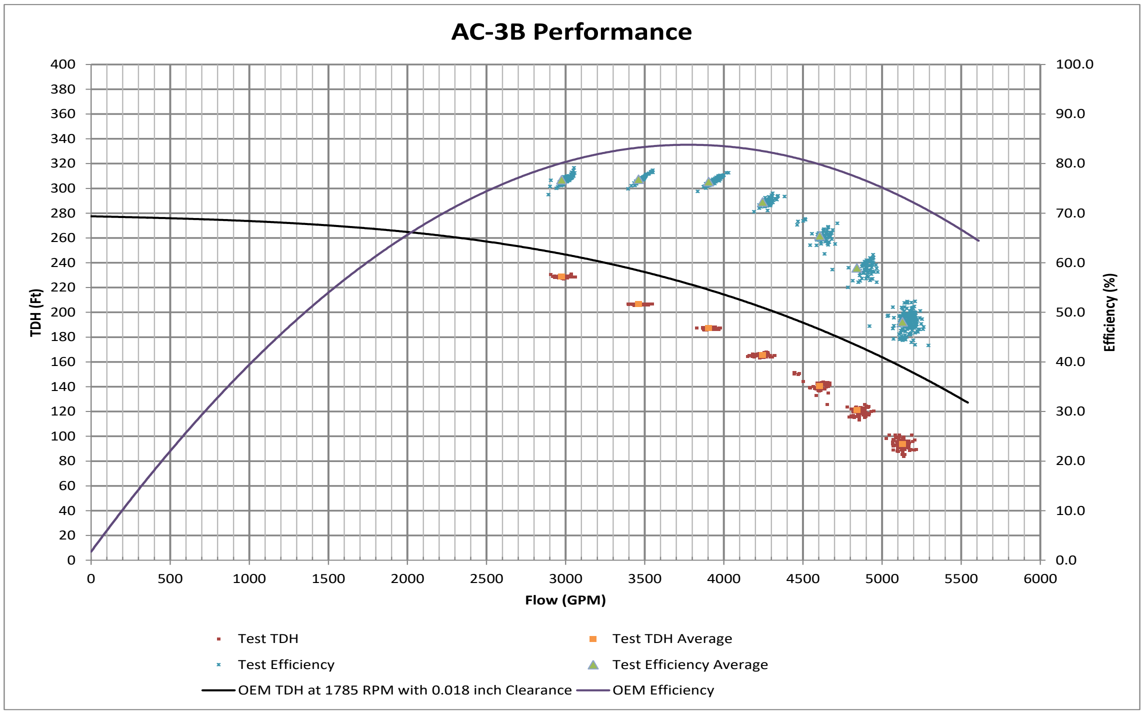


Figure 4. CCW 3B Pump Test Performance and Efficiency
(Source: Author)

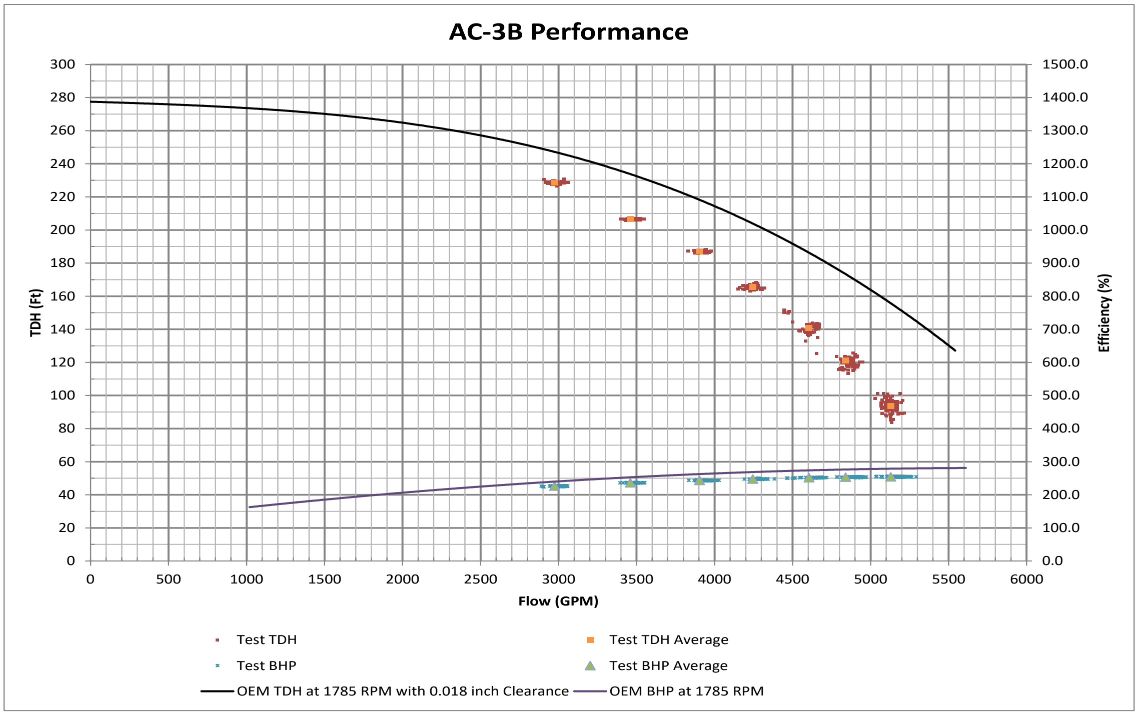


Figure 5. CCW 3B Pump Test Performance and BHP
(Source: Author)

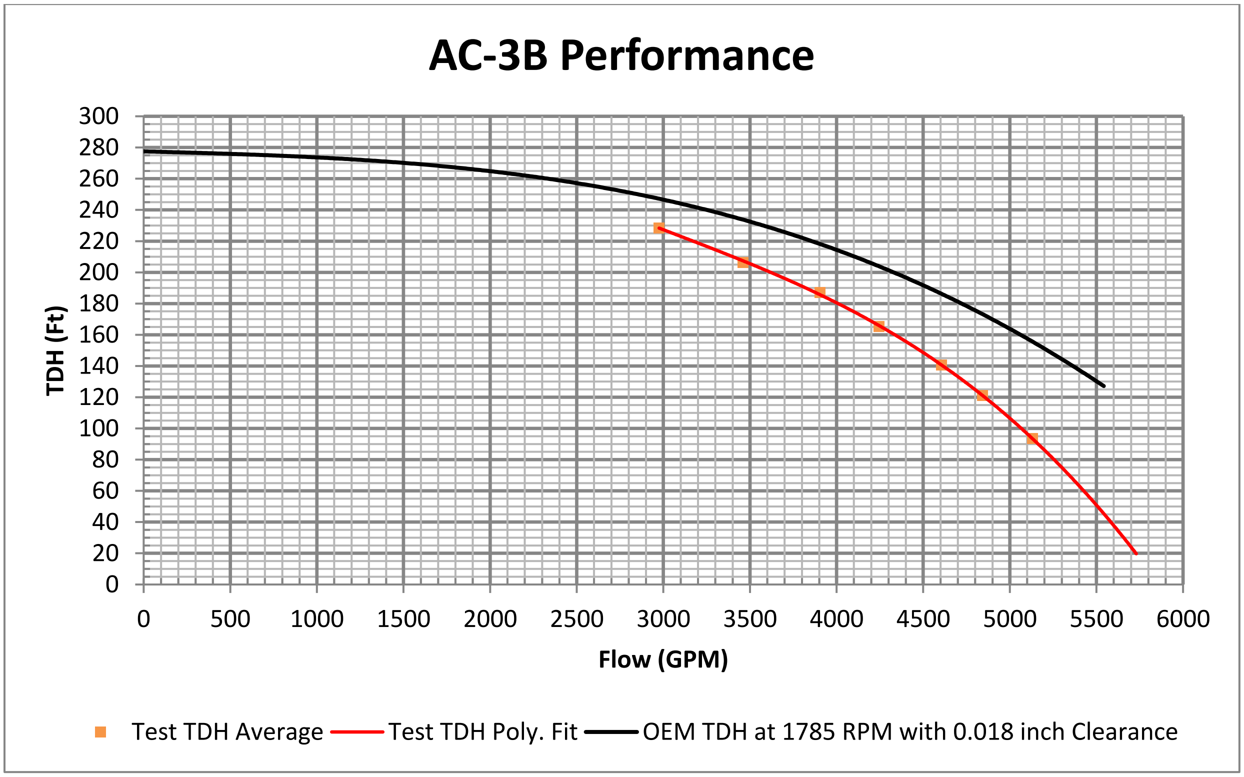


Figure 6: CCW 3B Pump Test Performance Average of Data Points
(Source: Author)

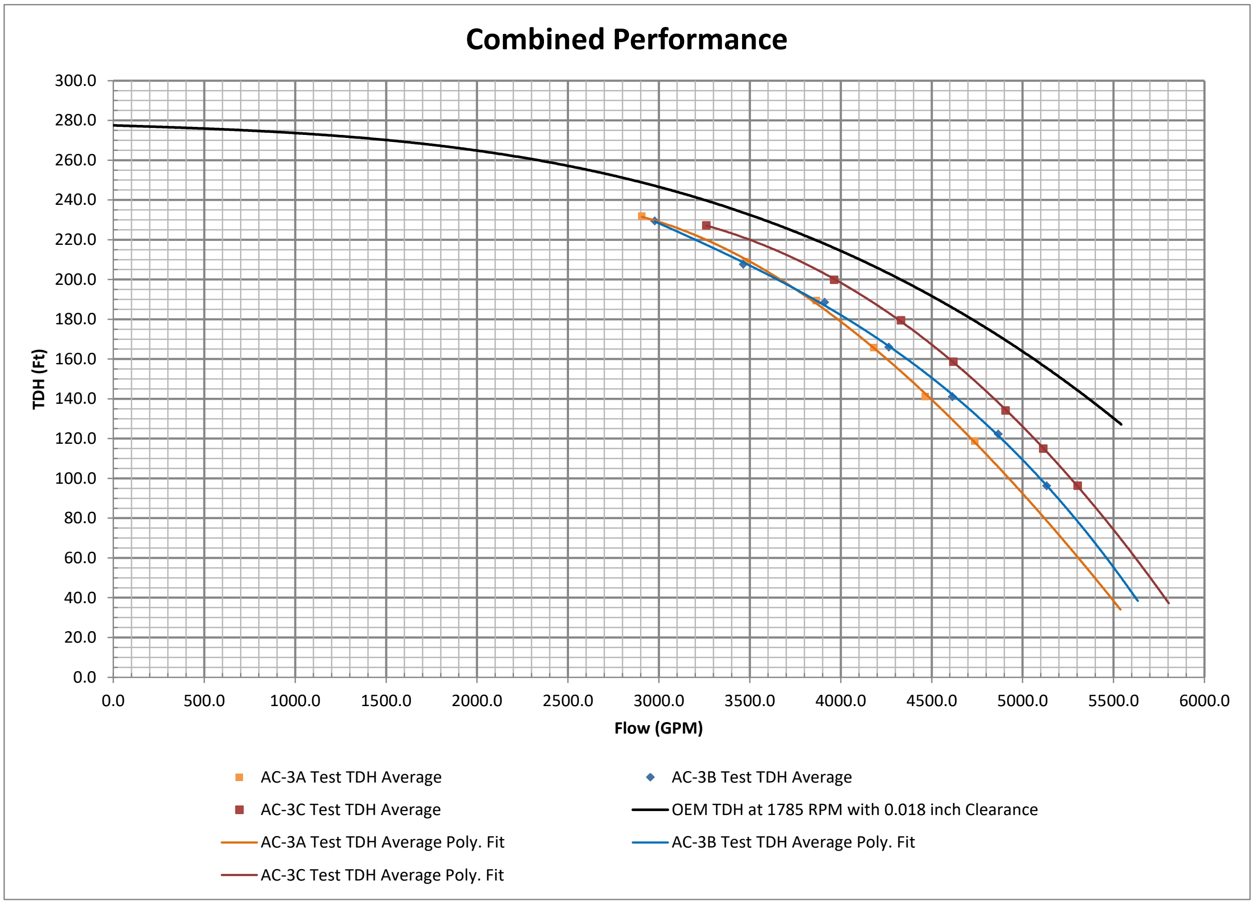


Figure 7: CCW Combined Performance of All Three Pumps
(Source: Author)

Immediate Recommendation from the Performance Testing

The hydraulic performance of the pumps was found to be slightly degraded near the rated point of the pumps (12 percent low in head or less); however, the hydraulic performance degraded more rapidly as the pump flow was increased. At the highest flow point measured for each pump, all three pumps were at least 30 percent low in head. This is an indication that, as well as internal clearances enlarging, there may be some casing wear that is affecting the pump performance. Due to the system pressure limitations, approximately 2,900 gpm was the lowest flow point obtained on any of the pumps and, due to operations procedure limits, approximately 5,300 gpm was the highest flow obtained. When a pump is 10 to 15 percent low in head, it can normally be attributed to wear of the internal wear parts; however, above 20 percent low in head can indicate wear in the casing flow passage ways or sealing surfaces. It was recommended that at least one of the pumps be disassembled and inspected to determine the cause of the loss of performance. This inspection was recommended to include measuring the exit areas of the impeller to verify correct hydraulics.

Followup Performance Testing

As a result of the performance testing, CCW pump 3B was removed from service, and a "disassemble, clean, and inspection" was performed. As a result of this procedure, a new impeller and case rings were installed in the pump, though no modifications were performed to mitigate/restore casing wear.

Following the repair and installation of CCW pump 3B, the performance test was repeated for the CCW pump 3B only, using the same procedure and instrumentation. As in the previous test, the pump was operating at 1,785 rpm, and the OEM performance curve was corrected to account for the speed change and increased clearance with the stainless steel impeller and rings. Test versus OEM performance of the CCW 3B is shown in Figures 8 - 10. There are three graphs for the pump: TDH and efficiency, tested TDH and BHP, and tested TDH average of data points curve. Additionally, Figure 10 shows the comparison of the pre-repair versus post-repair performance test data.

The 3B pump performance showed significant improvement after the rebuild. At the test point nearest the rated point, the pump is now 4 percent low in head as compared to the original test performance, but is now above the rated head (see Figure 10). This is an 8-percent increase in head at this data point. At the highest flow point achieved (4,593 gpm), the pump is now 14 percent low in head. This is a 13-percent increase in head at this data point. The performance calculations for the CCW pump 3B pump include corrections for velocity head.

The deviation from the OEM performance curve after the rebuild is attributed to washout of the casing not being repaired.

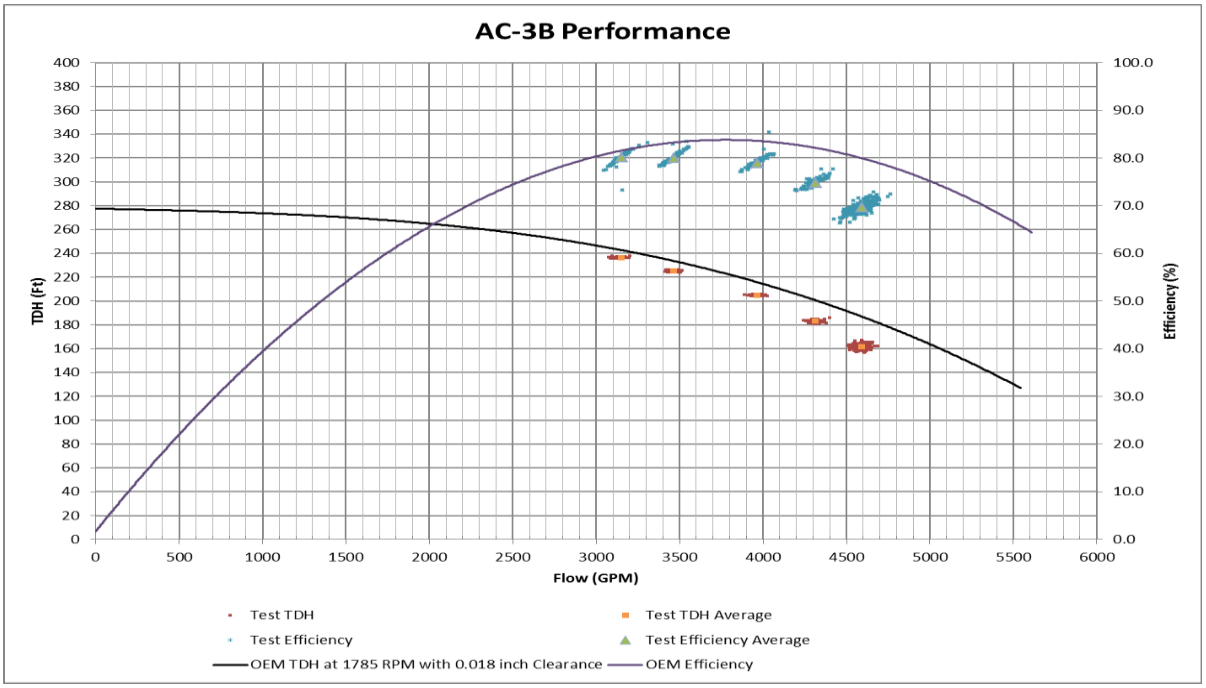


Figure 8: CCW 3B Pump Test Performance and Efficiency
(Source: Author)

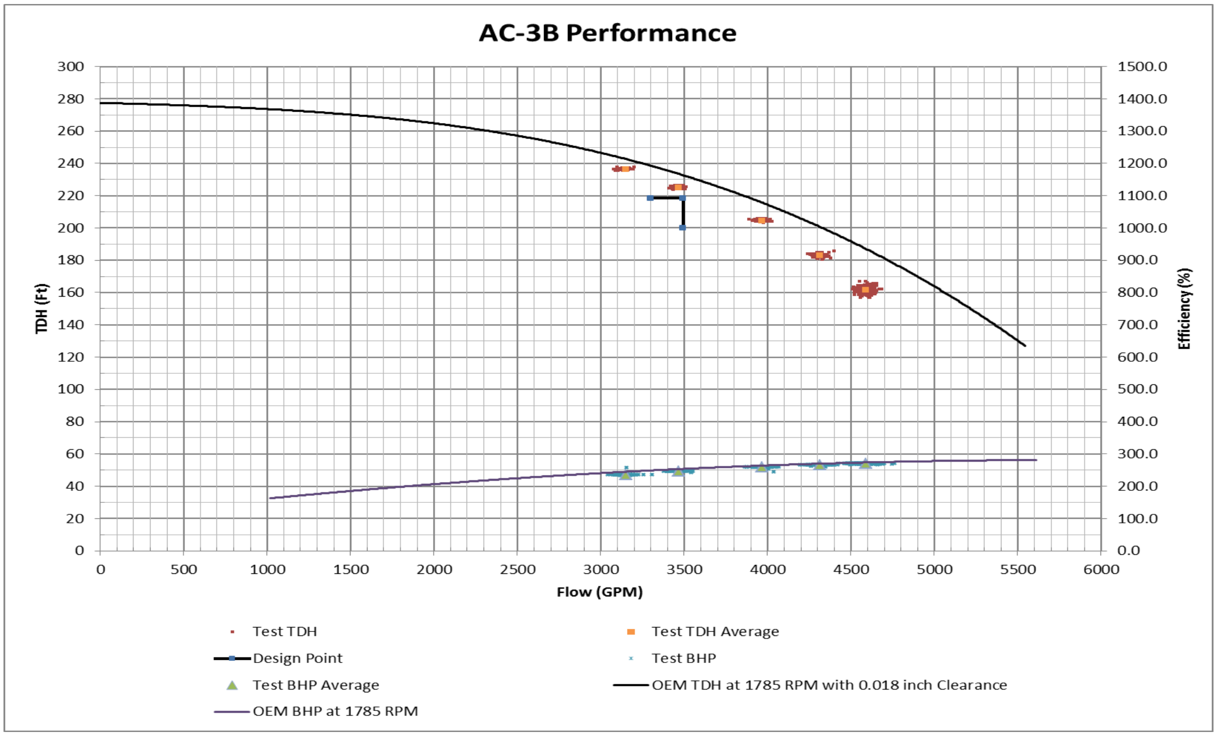


Figure 9: CCW 3B Pump Test Performance and BHP
(Source: Author)

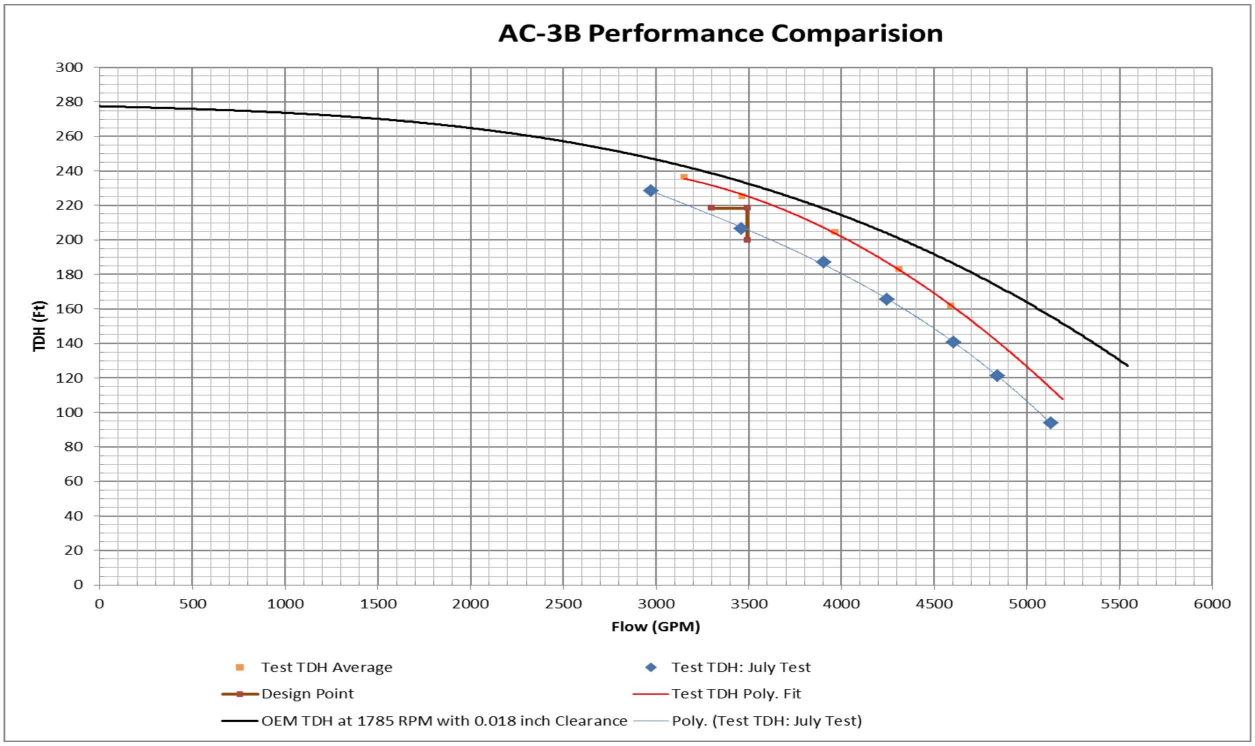


Figure 10: CCW 3B Pump Test Performance Average of Data Points
(Source: Author)

Conclusions

The CCW pumps have been in service for nearly 40 years. The pumps have been upgraded to stainless steel impellers during that time. No other upgrades were documented.

As verified during the onsite testing, the normal system flow was approximately 4,400 gpm at 162 feet. This is within 15 percent of the best efficiency point of the pumps and is acceptable for long-term operations. As a result of the initial and followup performance testing, it was recommended that the remaining two pumps be disassembled and inspected and have clearances and casing dimensions restored to OEM specifications.

The vibration data collected for all three pumps indicated that the pumps/motors are all operating within acceptable industry standards. The 3B motor started with axial vibration levels on the high end of acceptable but, through the course of the testing, the levels dropped. All of the pumps/motors have low-level indications of imbalance, misalignment, and vane pass frequencies, which all are expected in these pumps.

The motor data collected showed that the motors are operating in their service factor at the higher flow rates. This is not a cause for immediate concern, but it will shorten the life of the motors. It appears that the motors were sized based on the pump hp requirements at 1,750 rpm. However, the motors operate at 1,785 rpm, which increases the hp requirements of the pumps. It was recommended that the station consider replacing the current motors with 300-hp motors in the future.

Additionally, the ultrasonic flow data were compared to the system annubar data. There was a noticeable difference between the ultrasonic flow readings and the readings from the station-installed annubar, which read higher. The readings differed by as much as 1,400 gpm during the 3A pump test and approximately 600 gpm for the 3B and 3C pumps. The calibrated meters had a good location of stable flow on the suction piping to the pumps, whereas the station annubar is installed in an unstable location near the discharge of the pumps. It is believed that the annubar readings are in error. This would provide the basis for the station to believe that the pumps were performing above their performance curves. The station was pursuing the replacement of the annubar with a more reliable flow-measuring device.

An Investigation of Turbine-Driven Auxiliary Feedwater Pump Malfunctions

Chang Seog Ko
Korea Institute of Nuclear Safety

Abstract

Auxiliary feedwater pump (AFWP) performance in operating pressurized-water reactors (PWRs) shall be verified at accident conditions. However, some turbine-driven pumps appeared to have trouble with the steam supply to the turbine, which was caused by steam isolation valve malfunctions. In new plants, the hydro amplification device of the steam flow control valve to control the pump speed has also had malfunctions caused by rust.

Modification of the reference pump speed (e.g., 3,550 revolutions per minute (rpm) ->3,750 rpm), in order to meet design-bases pump hydraulic performance, might be allowable, but the gap between increased speed and overspeed protection setpoint (e.g., 3,905 rpm) was so close to tripping the turbine that the pump could not perform its safety function of auxiliary feedwater (AFW) supply to steam generators (SGs). Also, the gate-type valve in the air-operated valve (AOV) did not act smoothly due to resistance between the valve disk and guide. ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants," issued a warning that there might be problems with some gate valves at harsh conditions. The old plants should be careful using this type of valve assembly.

Another problem of turbine-driven auxiliary feedwater pumps (TD-AFWPs) came from the hydro amplification device of the steam control hydraulic-operated valves in new plants, which control the turbine speed. Rust in the oil caused issues with the device movement because the plug of the device is vulnerable to interference of microparticles. The rust had formed during the construction stage of the plants since the oil tank is made from carbon steel. The rust had deposited deeply into the oil route to the plug until the plant was started for commercial operation. New plants experienced several trips of the TD-AFWPs during inservice testing (IST). It might be useful if there was a rule to allow the corrective actions for these types of recurrent test failures.

Introduction

There were several IST failures of TD-AFWPs both in operating plants (old plants) and new plants as follows.

(1) Old Plants

There was a reactor trip following turbine-generator trip in an old PWR after a loss of condenser vacuum which resulted from a crack in the expansion joint connection between the low-pressure turbine and condenser in 2016. The reactor was at 100-percent power operation when the event occurred, and the main feedwater pumps (MFWPs) were in operation. After the incident, the SG level decreased below the AFWP start setpoint, and all of the AFWPs (two motor-driven pumps and one turbine-driven pump) started to deliver water into the SG secondary, but the TD-AFWP tripped by the overspeed protection device as soon as it started. The AFWP is important in a PWR plant because it is safety equipment to replace the MFWP when the main feedwater is not available and when reactor coolant system heat removal through the SG is required, as in this incident.

(2) New Plants

There were several occurrences of test failures in TD-AFWPs in new plants that started commercial operation during 2012 - 2013. The pilot valve plunger of the hydro amplifier of the TD-AFWP turbine driver in new plants had malfunctions from some foreign obstacles (i.e., rust and solid particles). Therefore, the TD-AFWPs had a delayed response to the speed control demand and rapid speed increase. Also, those malfunctions caused trip latch dislocation, which resulted in additional pump trips.

Malfunctions of the Steam Supply and Control to the TD-AFWPs

(1) Old Plants

Figure 1 shows a typical diagram of the TD-AFWP steam supply piping and schematics of AOV opening in old plants. The AOV malfunctions had occurred several times during the Group B pump IST, especially at high SG pressure. Unstable steam supply has been identified to result in a turbine trip by overspeed protection gear. It was found that the AOV gate valve had a nonuniform friction force, which caused an unexpected increase in unwedging thrust on the disk and guide of the valve at opening.

Another fact affecting fail to start was that the normal operation speed of the TD-AFWP had been changed from 3,550 rpm of the reference speed to 3,750 rpm at that time in order to meet design-basis pump hydraulic performance, and in turn, the lower margin (gap between increased speed and overspeed protection setpoint, 3,905 rpm) was close to tripping the turbine; therefore, the pump could not perform its safety function of AFW supply to SGs. The licensee restored the normal operation speed setpoint and verified that with reduced speed (original design value), the AFW flow rate was enough to meet the final safety analysis report design basis (accident analysis) (i.e., minimum flow rate into SGs at no load secondary pressure condition).

The licensee reported that the TD-AFWP can be operable by correctly maintaining AOV functions (i.e., valve disk and guide lapping, spring force adjustment for the valve air operator, and, finally, verifying valve opening by measuring operation time after maintenance).

When an AFWP is not available, reactor operation shall be limited by the plant technical specifications (TS). The TS limiting conditions for operation prescribe that all AFW trains be available at reactor power operation and also hot standby or, if one of those is not available, restore the failed train (pump) within 72 hours. After the event, the unit had been in the course of shutting down and did not violate action time, but the operator did not declare violation of the limiting condition for operation and did not implement corrective actions.

(2) New Plants

TD-AFWP test failures at new plants were caused by a trip latch separation of overspeed protection gear, malfunction of the hydro amplifier of the pump speed controller, etc. Major and recurrent failures had come out from the hydro amplifier malfunction. Those new plants that started for commercial operation around 2012 - 2013 had several test failures of TD-AFWPs as shown in Table 1.

The hydro amplifier controls oil supply to the servo-piston by moving the pilot valve plunger to make the bushing and hole of oil route close or open. The plunger is vulnerable to attack by crust, gasket chips, and solid particles. For those reasons, the turbine speed controller did not work properly in response to the demand for speed increasing and decreasing. The new plants have three 200-mesh filters per unit in the steam control valve to the TD-AFWP, but there are no filters between the pressurized oil tank and hydraulic amplifier, and there is a possibility of penetration of fine foreign solid material into the amplifier.

Considering that the major piping of this hydro amplifier consists of carbon steel piping and a tank and gasket, and also considering the long-term construction period of a nuclear plant, it is clear that there had been some adverse environmental conditions generating foreign materials, (i.e., rust and chips in the oil piping and tank). Although the tank, strainer, and amplifier of the hydraulic valve were cleaned thoroughly before startup, the rust and foreign material could not be removed since those particles had been deeply stuck into the oil route to the valve.

For the corrective actions, the licensee installed new fine filters, flushed the piping, checked the oil chemistry, and finally, made prescriptions for refining the oil every refueling outage. However, there was no rule to accept (or request) corrective actions to those repetitive and similar types of test failures, especially failure to meet TS and IST requirements. The high frequency of test failures in the AFWP should be prevented by some specific prescriptions.

Conclusion

Based on lessons learned, we need some specific rules to prevent repetitive and similar types of test failure. For the steam isolation AOV for the TD-AFWP, ASME Standard QME-1 describes gate valve problems and also the standard recommends monitoring of the significant aging mechanism for the valve obturator. It is recommended that we study matching QME-1 to

IST rules. For the hydraulic steam control valve of TD-AFWP, it has been typically recommended that the oil filter elements shall be replaced and their housings shall be cleaned every refueling outage. Also, looking into the IST rules for the safety valve test, if a valve in a group fails its as-found test, two more valves in a group shall be tested. The ASME OM Code prescribes that if a pump does not meet the acceptance criteria, the test interval shall be reduced by half until the unacceptable conditions are cleared. Therefore, it should be helpful to have a rule for the corrective actions for those recurrent and repetitive failures of similar type components (i.e., reducing the test interval of TD-AFWPs and testing all of the same type pumps or valves until the cause of malfunctions is cleared).

References

ASME OM Code 2015, *Operation and Maintenance of Nuclear Power Plants*.

ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants."

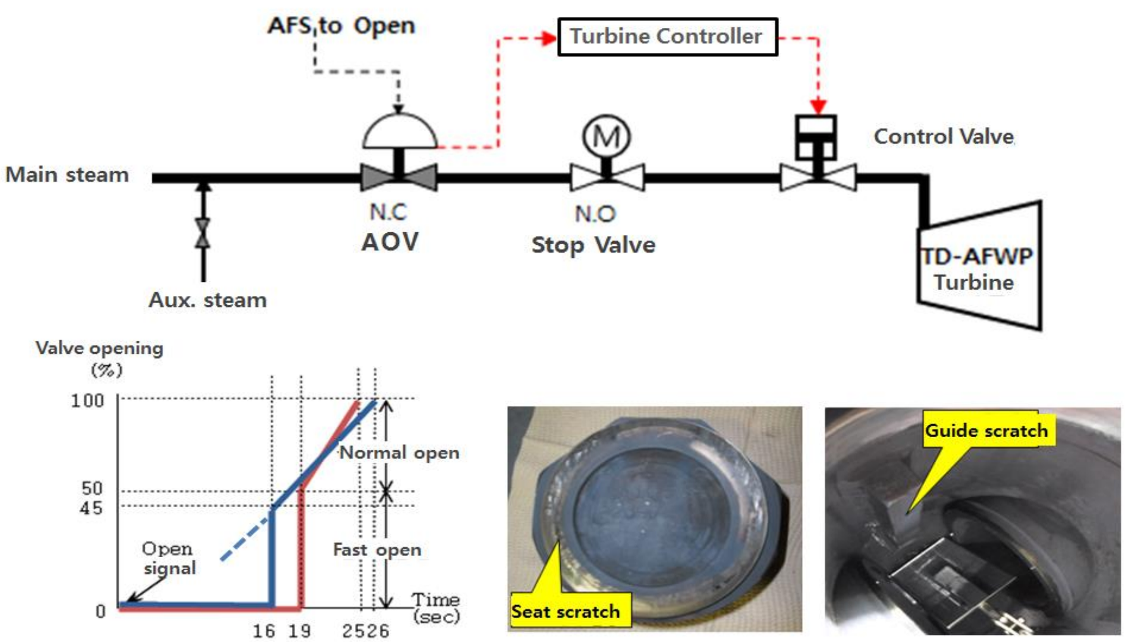


Figure 1. Typical Diagram of the Steam Supply and AOV Schematics for TD-AFWP
(Source: Author)

Table 1. Test Failures of TD-AFWPs at New Plants

No.	Fail Cause	Results	Corrective Actions
1	N2 overcharge in pressure tank	Overspeed trip	Adjust N2 pressure ($9 \rightarrow 5 kg/cm^2$)
2	Trip latch dislocation (groove over machining)	Turbine stop	Replace trip latch, check settling
3	Hydro amplifier malfunction	Fail to reach normal speed	Enhance oil management (Check oil chemistry every refueling outage) Clean(flush) oil line Change gasket type
4		Manual trip due to overspeed	
5		Fail to reach normal speed	
6 ~ 9	Hydro amplifier malfunction + trip latch dislocation	Uncontrolled speed increase, trip	Trip latch change Adjust spring keeper gap

Track 3: Motor-Operated Valves

Track Chair: Domingo Cruz, Arizona Power Service

Evaluating AOV and MOV Performance

Tom Walker
Electric Power Research Institute
Charlotte, NC, USA

Nick Camilli
Electric Power Research Institute
Charlotte, NC, USA

Abstract

Calculating margin for valve operation under design-basis conditions requires evaluation of the stem loads required to operate the valve and the load capability of the actuator. These evaluations require justified and validated methodologies with verified inputs to implement the methodologies. The lack of validated methodologies in the past led to plant events and issues that prompted three U.S. Nuclear Regulatory Commission (NRC) generic letters for motor-operated valves (MOVs) and numerous generic correspondence documents from the NRC on air-operated valve (AOV) and MOV performance. Over the past 25 years, the Electric Power Research Institute (EPRI) has performed extensive research to better understand the performance of valves and power operators. This research has been used to develop predictive methods for the evaluation of valve required operating loads and actuator output capability.

This paper summarizes EPRI's research related to the development of predictive methodologies for valves and power operators and methods that are available, specifically methods for the following:

- predicting required operating loads under design-basis conditions
- predicting actuator output capability
- addressing thermal binding of gate valves
- addressing the rate-of-loading phenomenon for MOVs

This paper also describes a recent project to develop and validate a method for predicting the required thrust to overcome friction between the valve disk and body due to disk side-loading in cage-guided balanced disk globe valves.

Introduction

This paper summarizes EPRI's research related to the development of predictive methodologies for valves and power operators and summarizes the methods that are available. This paper also describes a recent project to develop and validate a method for predicting the required thrust to overcome friction between the valve disk and body due to disk side-loading in cage-guided globe valves.

EPRI MOV Performance Prediction Program

In the mid-1990s, EPRI carried out the MOV Performance Prediction Program (PPP) to investigate the performance of MOVs and to develop improved methods for evaluating MOVs. Some of the key lessons learned from the PPP include the following:

- Gate valve friction coefficients can be much higher than typically assumed in the original sizing calculations (0.6 - 0.7 versus 0.2 - 0.3) and can be affected by the material combination, the fluid temperature, the contact stress, and the contact configuration (e.g., flat versus tipped contact between the two surfaces in contact).

- The gate valve seat friction coefficient (self-mated Stellite) generally increases with valve stroking from an initially low value to a "plateau" value, for cold water conditions (see Figure 1). Because of this "preconditioning effect," results from a single dynamic flow test of a gate valve may not be indicative of future valve performance.

- Gate valves may exhibit unpredictable, or anomalous, behavior if the disk tips during the stroke (see Figure 2.), there are sharp Stellite edges, and the loads exceed certain damage threshold values. This unpredictable behavior is expected to be a concern only at high flow rates (greater than about 15 feet/second). To properly evaluate the potential for unpredictable behavior, the differential pressure versus stroke position profile is needed.

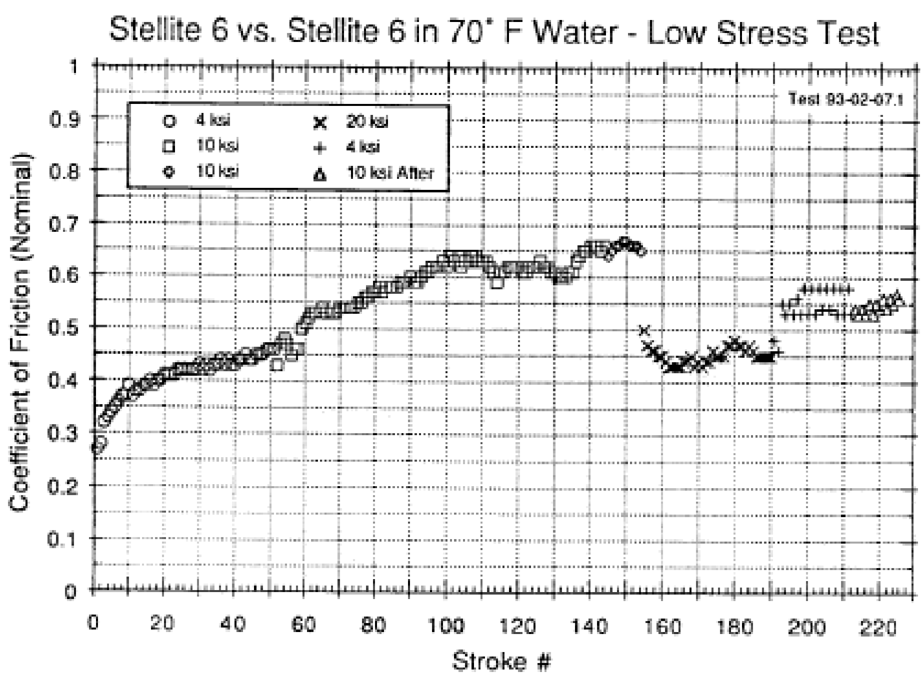


Figure 1. Gate Valve Preconditioning Effect
(Source: Author)

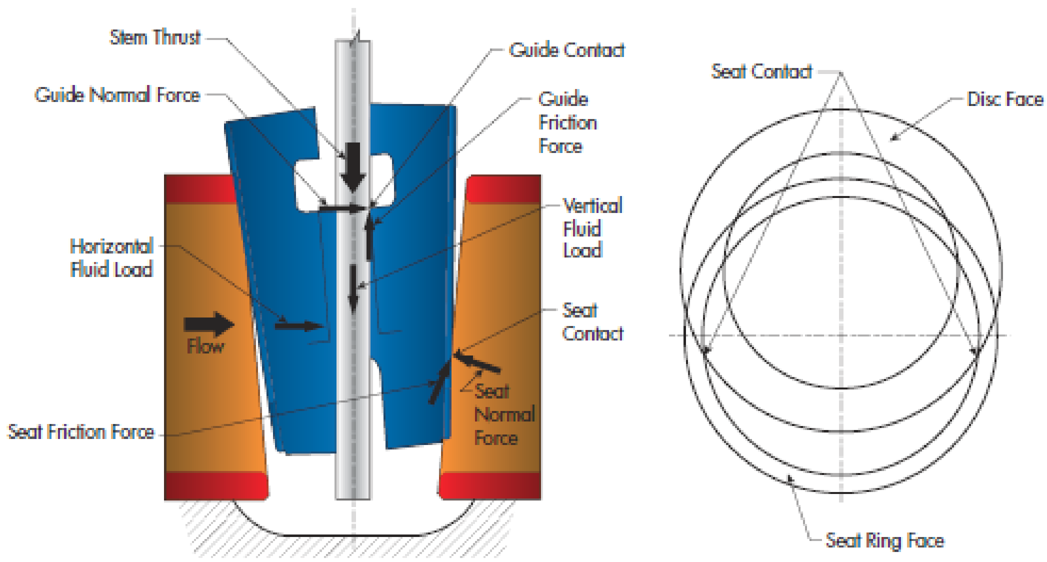


Figure 2. Gate Valve Disk Tipping
(Source: Author)

- For some globe valve designs, the differential pressure load may act on the guide area (guide-based), rather than the smaller seat area (seat-based), as is typically assumed (see Figure 3). Accordingly, thrust requirements may be higher than originally assumed for operator sizing.

- For some globe valve applications, a significant side load may be applied to the valve disk due to flow around (rather than over or under) the disk. Such side loading results in friction between the valve disk and the body, which affects the thrust required to stroke the valve.

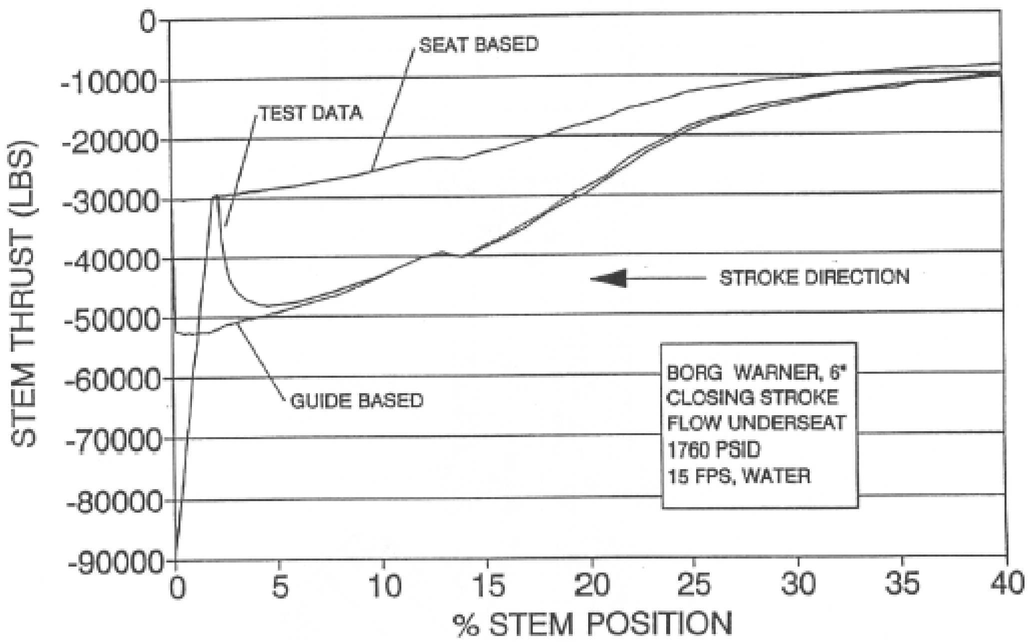


Figure 3. Globe Valve Guide-Based Behavior
(Source: Author)

- For butterfly valves, the limiting torque requirement typically occurs at the seating/unseating region for low-flow applications (less than about 15 feet/second); however, for higher flow applications, the limiting torque requirement may occur at a midstroke position, including at stroke positions as high as 60-70° open. Such midstroke effects are important for MOVs, which have essentially constant operator output capability, and even more important for AOVs, which have a variable operator output capability. To properly evaluate these midstroke effects, the differential pressure versus stroke position profile is needed.

- The rate-of-loading (ROL) effect, which can cause the thrust at torque switch trip (TST) for an MOV to be lower under dynamic conditions (with differential pressure (DP) and flow) than under static conditions (zero DP and zero flow), is likely due to lubrication effects at the stem-to-stem nut connection and cannot be predicted based on first principles. The ROL effect is discussed in more detail later in this paper.

The key product of the PPP was the EPRI MOV Performance Prediction Methodology (PPM) software, which provides the nuclear industry with a validated analytical approach for evaluating the design-basis thrust and torque requirements of safety-related MOV applications. The PPM software covers gate, globe, and butterfly valve designs commonly used in nuclear power plants and has been reviewed and accepted by the NRC (with some limitations and conditions) as an alternative to DP testing. As part of the PPP, EPRI also developed and validated hand calculation methods for evaluating the following unique gate valve designs:

- Anchor/Darling Double Disk Gate Valves
- Aloyco Split Wedge Gate Valves
- Westinghouse Gate Valves
- WKM Expanding Parallel Gate Valves

These PPM methods are prescriptive methodologies. Dimensional inputs must be obtained from the valve vendor using the included specifications (or measured). Other key inputs (such as packing load) must be determined or validated as specified by the methodologies. In addition, for gate valves, the most important inputs - the seat and guide friction coefficients - are built into the methodology. The PPM addresses the key lessons learned from the PPP as follows:

- The built-in gate valve friction coefficients account for the sliding materials, fluid temperature, contact stress, and contact configuration and reflect fully preconditioned values, such that they are expected to bound valve performance for the life of the plant.

- For gate valves, the PPM software evaluates the potential for unpredictable behavior due to disk tipping. The PPM includes a System Flow Model to calculate the differential pressure versus stroke position profile for the valve stroke.

- The PPM documentation provides guidance for determining whether a globe valve is seat based or guide based. The user makes this determination, and the PPM calculates the required thrust accordingly.

- A side-loading correlation is provided for some globe valve applications; however, the applicability of the PPM to globe valve applications is limited because of the potential for high side loading.

- The PPM has built-in flow and torque coefficients for butterfly valves, and the differential pressure versus stroke position profile from the System Flow Model is used with these coefficients to evaluate potential midstroke effects.

The key advantages of the PPM methods are as follows:

- They are validated against MOV dynamic test data.

- They were developed under a quality assurance (QA) program in accordance with the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, “Domestic Licensing of Production and Utilization Facilities,” Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and 10 CFR Part 21, “Reporting of Defects and Noncompliance.”

- They have been reviewed and accepted by the NRC (with some limitations and conditions) in a safety evaluation as an alternative to DP testing and MOV grouping.

- MOVs evaluated using the PPM are automatically classified as Class A valves in the Joint Owners' Group Periodic Verification Program, if all PPM applicability requirements are met and default friction coefficients are used, potentially reducing the frequency of required diagnostic testing to meet NRC Generic Letter 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996.

- The methods can be used as "test-based methodologies" to meet ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants."

These methods were used extensively for MOVs in the 1990s and 2000s to meet the requirements of Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989. In the last decade, the PPM methods have been used primarily for new MOVs and for MOVs that have undergone a modification that invalidated its design-basis verification. For example, replacement of the valve disk for a gate valve would typically invalidate the design-basis verification for that valve if the basis was a single DP test of the valve.

The PPM Guidebook is a complement to the PPM software user manual and the various technical reports and includes lessons learned, improved analysis techniques and methods, and potential applicability extensions of the PPM methods based on nearly two decades of use of the PPM in the nuclear industry. It covers the applicability of the PPM methods for use in safety-related applications and identifies key factors and general techniques for justifying the use of the PPM outside the nominal applicability. It also provides example justifications for extension of PPM applicability for select applications.

Although the PPM methods were originally developed to evaluate MOVs, they can be adapted for use on AOVs and hydraulically operated valves. In the late 1990s, EPRI carried out pilot programs to apply the PPM methods to AOVs at four nuclear power plants, and the PPM software was subsequently modified to allow evaluation of AOVs and hydraulically operated valves.

Valve Application and Evaluation Guides

To address key elements of valve design and setup not specifically covered by the PPM methods, EPRI developed application guides for MOVs and AOVs. These application guides focus on actuator design and evaluation. Valve design and evaluation are covered in a separate evaluation guide (discussed below). The application guides provide methods for the following:

- defining valve functional and design requirements
- assessing valve and piping system design features that can affect valve operation
- evaluating rated and survivable stem thrusts and torques
- evaluating operator output and design features that affect valve operation

- evaluating the margin for operation
- evaluating the structural margin
- calculating test acceptance criteria
- evaluating test data

Whereas the PPM methods are prescriptive methodologies that are covered by an NRC safety evaluation, the application guides, although developed under EPRI's QA program, either reference methods developed by others or document first-principles methods for which users must determine and justify key inputs. For motor-operators, the methods to evaluate operator output are based primarily on guidance from Limitorque for alternating current MOVs and guidance from the Boiling-Water Reactor Owners' Group for direct current MOVs. These methods have been evaluated and shown to provide bounding results. For AOVs, the methods to evaluate operator output are based on first principles and include some key inputs that must be provided by the user; for example, effective diaphragm area and quarter-turn actuator efficiency. Some of these inputs are currently being researched and evaluated by the nuclear industry.

As a complement to the application guides, which focus on the valve operators, the *EPRI Evaluation Guide for Valve Thrust and Torque Requirements* is a comprehensive guide for evaluating thrust and torque requirements for a wide range of valve types. This evaluation guide references the PPM methods where applicable but provides methods for valve types not covered by the PPM (for example, ball, plug, and diaphragm valves) and simplified methods for some valve types that are covered by the PPM methods. These simplified methods can be used for those valve applications for which a method generically approved by the NRC is not needed.

The evaluation guide was developed in 2016 primarily based on the methods and equations previously included in the AOV and MOV application guides. However, some new content was added. For example, for cage-guided, balanced disk globe valves, a new method for evaluating potential side load effects was added (discussed later in this paper). For unbalanced disk globe valves, the guide includes screening criteria to determine whether midstroke effects due to potential side loading and trim effects need to be considered.

Similar to the application guides, this evaluation guide was developed under EPRI's QA program and provides first-principles methods that require the user to determine and justify some key inputs. Examples of key inputs that must be provided by the user are torque coefficients and bearing friction coefficients for quarter-turn valves.

Together, the application guides and the evaluation guide provide nuclear utilities with important methods for ensuring valves are properly designed and set up to perform their required functions and to meet the requirements of Appendices III and IV of the ASME Operation and Maintenance (OM) Code (see Figure 4).

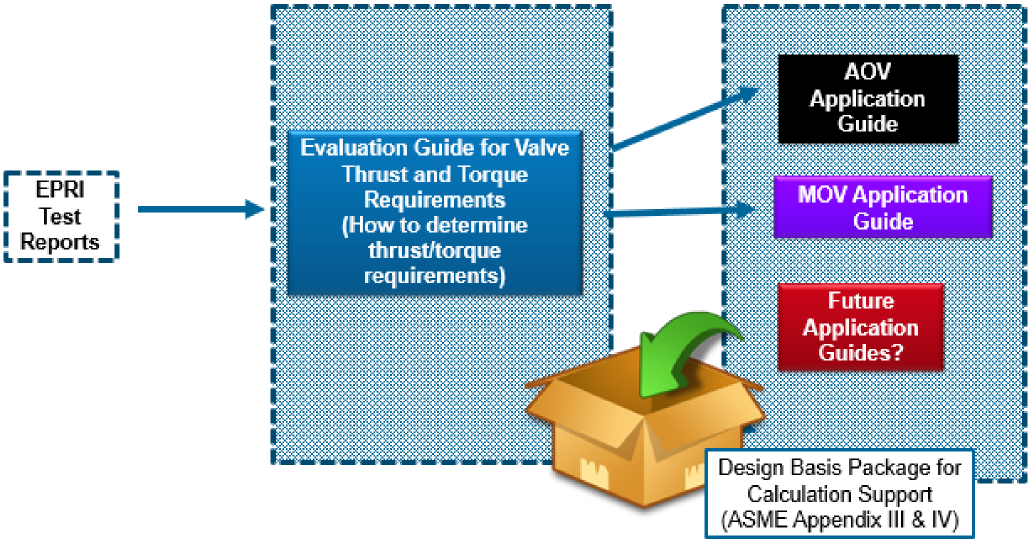


Figure 4. EPRI Application and Evaluation Guides
(Source: Author)

Thermal Binding

Thermal binding occurs when the thrust required to unwedge a gate valve is increased due to temperature changes between the time the valve was closed and the time it is opened. The combination of temperature changes and the difference in the coefficients of thermal expansion of the body material and the disk material might cause disk pinching or further wedging of the disk, which can cause a significant increase in the seat-to-disk contact loads. Both solid and flexible wedge gate valves are potentially susceptible to thermal binding, and the severity of binding depends on the specific design of the valve and the magnitude of the change in operating temperature.

Thermal binding concerns can be mitigated by several approaches, including reducing the wedging loads during closure and cycling the valve open and closed during temperature transients to prevent excessive binding. However, for some applications, thermal binding cannot be mitigated, and the thrust required to unwedge a gate valve under thermal binding conditions needs to be predicted. To address this issue, EPRI developed and validated an analytical methodology based on first principles for predicting the increase in unwedging thrust under various thermal binding scenarios. The methodology covers the following operating sequences that can lead to thermal binding.

- The valve is closed hot and allowed to cool down before unwedging.
- The valve is closed cold and exposed to high temperature on one side before unwedging.

- The valve is subjected to changes in upstream and downstream pressures (which can cause pressure-induced disk pinching) either apart from or in conjunction with the temperature changes.

The thermal binding phenomenon involves complex interactions between mechanical and thermo-fluid mechanisms that affect temperature distributions, differential expansions/contractions resulting in changes in interferences and loads between valve components, and changes in friction coefficients due to changes in fluid temperatures. The first-principles model accounts for all these mechanisms and predicts the unwedging thrust based on valve design parameters, operating parameters (fluid, temperature, pressure), and thermal binding scenarios (for example, closed hot/opened cold or closed cold/opened hot).

To calculate the required unwedging thrust for a gate valve, the following are required: the stiffnesses of the disk, body, and valve topworks; average temperatures of these components; the closing/wedging load during the preceding closing stroke; and disk-to-seat friction coefficients. Stiffnesses of the disk and body for a specific valve are calculated by closed-form equations provided by the methodology. These equations for body and disk stiffnesses are based on a matrix of finite element analyses that covered variations in the dimensions and proportions due to valve size, pressure class, and manufacturer. Stiffness of the valve topworks is calculated by using an equivalent stem length approach that uses the static thrust trace from valve closure. Average temperatures of these components are calculated using a simplified closed-form temperature algorithm provided in the methodology. The temperature algorithm is based on exercising a lumped parameter thermal model. This model was successfully compared against detailed computational fluid dynamics (CFD) analyses to cover a wide range of variations in valve geometrical, fluid, and operating condition parameters. Disk-to-seat friction coefficients, which depend on fluid temperatures under closing and opening conditions, are provided in the methodology based on extensive separate effects tests performed by EPRI under the MOV PPP.

The methodology was validated by comparing predictions to data from flow loop tests performed on flexible and solid wedge disk valves over a wide range of operating conditions with steam at temperatures up to 650 degrees Fahrenheit (F). Test valves were instrumented to provide detailed external and internal temperature measurements, in addition to thrust, torque, and stem position measurements. The test matrix included three disk stiffnesses, two valve designs, different heating/cooling scenarios and pressure sequences, tests with and without bonnet fluid communication to the upstream pipe, and tests with and without thermal insulation.

The methodology predictions bound results for all tests, with overall ratios of measured thrust/predicted thrust ranging from 0.34 to 0.96. The methodology can be used to assess the potential for thermal binding in gate valves using input information that is relatively easy to obtain.

Globe Valve Side Loading

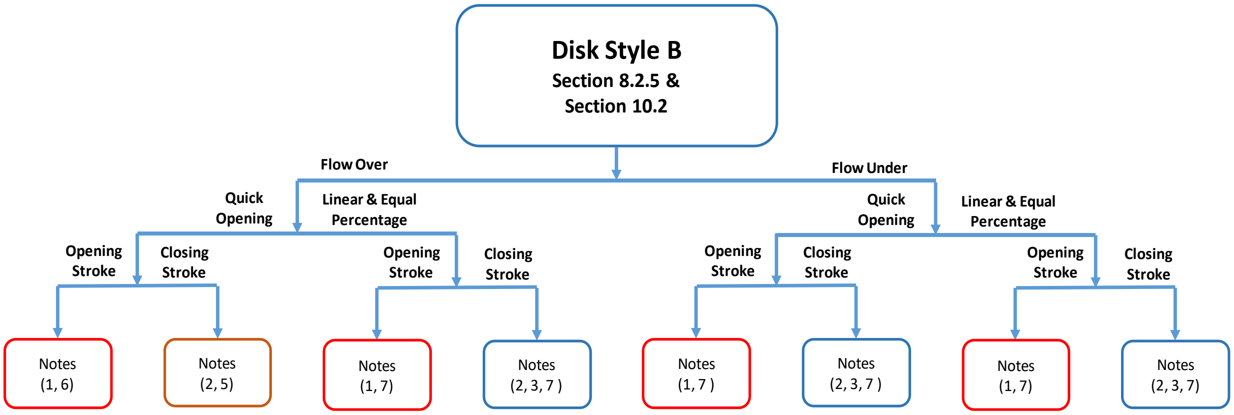
As mentioned previously, the PPM includes a side-load correlation for some globe valve applications; however, the applicability of the PPM to globe valve applications is limited because of the potential for high side loading, particularly for high-flow applications and applications with elevated fluid temperatures (above 150 degrees F). To address this issue, additional research has been performed to develop and validate a method for predicting the required thrust to overcome friction between the valve disk and body due to disk side-loading in cage-guided balanced disk globe valves.

This project leveraged CFD modeling to minimize the number of valves to be flow-tested to justify the methodology. A CFD model of a specific cage-guided balanced disk globe valve commonly used in the nuclear industry was developed and used to predict side loading under specific flow conditions. Flow testing of the valve was then performed to validate that the CFD model provided bounding, but reasonable, predictions of side load and the stem thrust required to overcome those side loads.

Once the CFD model was validated, it was used to perform extensive parametric studies. The purpose of the parametric studies was to evaluate the effect of specific parameters, such as valve dimensions and flow conditions, on the predicted side load. In all, about 150 CFD analyses were performed. Based on the results of the parametric studies, a methodology was developed to predict side load for specific valve applications.

To validate the methodology, valve flow loop testing was performed, including over 400 flow loop tests of two of the most common valve types in the nuclear industry—a 4-inch Fisher ED globe valve and a Masoneilan 4100 globe valve. Valve inlet flow velocities for the flow loop tests ranged from 15 feet per second (ft/s) to 45 ft/s, inlet pressure and maximum valve differential pressure ranged from 100 pounds per square inch (psi) to 230 psi, and water temperature ranged from 70 degrees F to 160 degrees F. Testing included quick opening and linear trims in the flow-over and flow-under orientations.

The methodology, which is documented in the EPRI Evaluation Guide, is implemented using hand calculations and includes a flowchart-based screening method (see Figure 5) to determine whether side loading is a potential issue, simple equations for calculating the stem thrust required to overcome side loads for potentially susceptible valve applications, and side load coefficients needed to implement the equations. One of the key results of the CFD analyses was that there is a flow-induced DP effect that tends to assist the closing stroke, regardless of the direction of flow through the valve. This DP effect offsets the stem thrust due to side loading for closing strokes. Because of this flow-induced DP effect, side loading is generally not a potential issue for closing strokes, thus simplifying implementation of the methodology for closing strokes.



Notes:

1. Evaluation requires multi-point model (effective area band model)
2. Evaluation using two-point method is generallly acceptable for the closing stroke. The two-point model is non-conservative at the full open position; however, the actuator output is much greater at the start of trave (at the open position) and the non-conservatism in the model does not affect margin predictions.
3. The most conservative evaluation is based on static running friction with line pressure and no DP (if this condition is applicable).
4. Acceptable evaluation method depends on normalized velocity.
5. The most conservative analysis is based on two-phase conditions. Two-phase conditions decreases the self-closing F_{DP} just off the seat (5% to 25%). If sufficient back pressure is not present to suppress cavitation, the most conservative evaluation is based on static running friction with line pressure only unless (if this condition is applicable).
6. The most conservative analysis is based on Single-phase conditions. Single-Phase conditions increases the self-closing F_{DP} just off the seat (5% to 25%).
7. Validation performed against test data over a range of Vp numbers

Figure 5. Flowchart for Side Load Screening
(Source: Author)

The method is applicable to cage-guided, T-pattern balanced disk globe valves with cage-to-body clearances within a certain range, and valve applications with incompressible (cavitating and noncavitating) flow up to 45 ft/second. Importantly, there are no limitations related to temperature. Many safety-related, air-operated globe valves are cage-guided, balanced disk valves, and this methodology is expected to be applicable to most of those valves.

Rate-of-Loading

ROL is a phenomenon that can cause the thrust at TST for an MOV to be lower under dynamic conditions (with DP and flow) than under static conditions (zero DP and zero flow), as shown in Figure 6 and Figure 7.

ROL effects must be considered when defining setpoints for torque switch-controlled MOVs (i.e., the minimum allowable thrust at TST) because MOVs are typically set up under static conditions but must be able to operate under dynamic conditions.

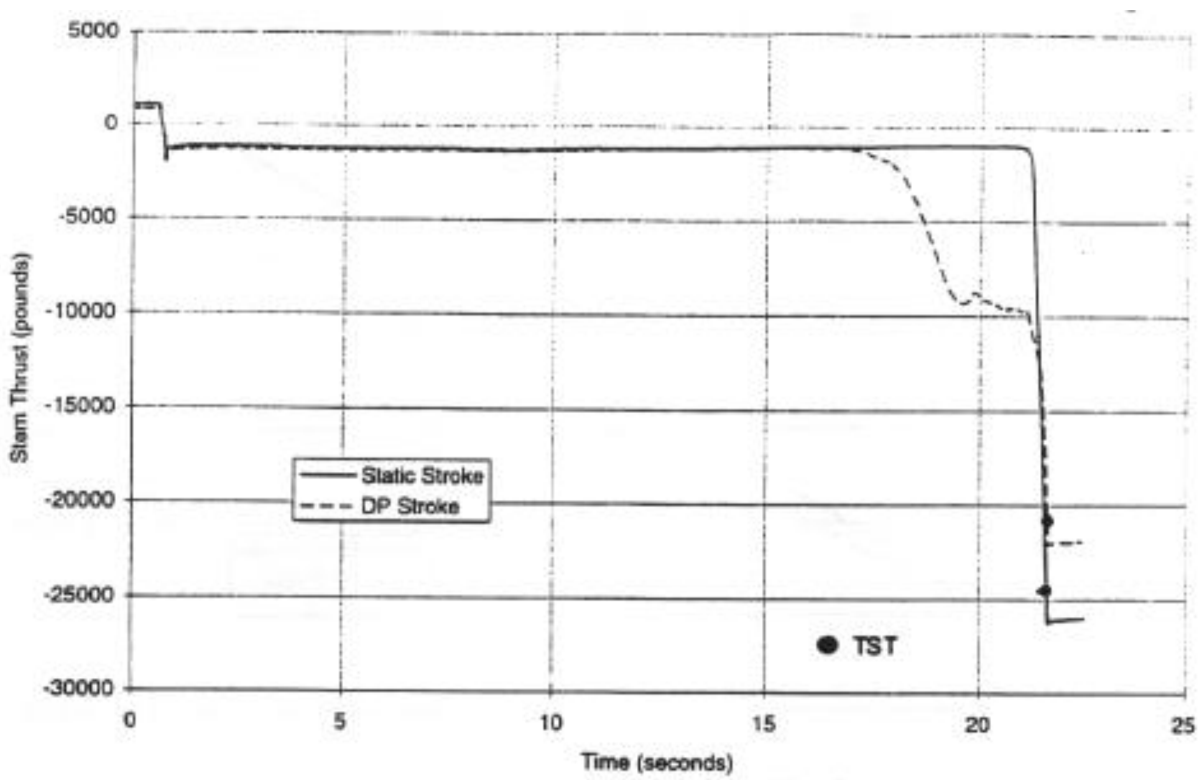


Figure 6. Load/Time History Illustrating ROL Effect
(Source: Author)

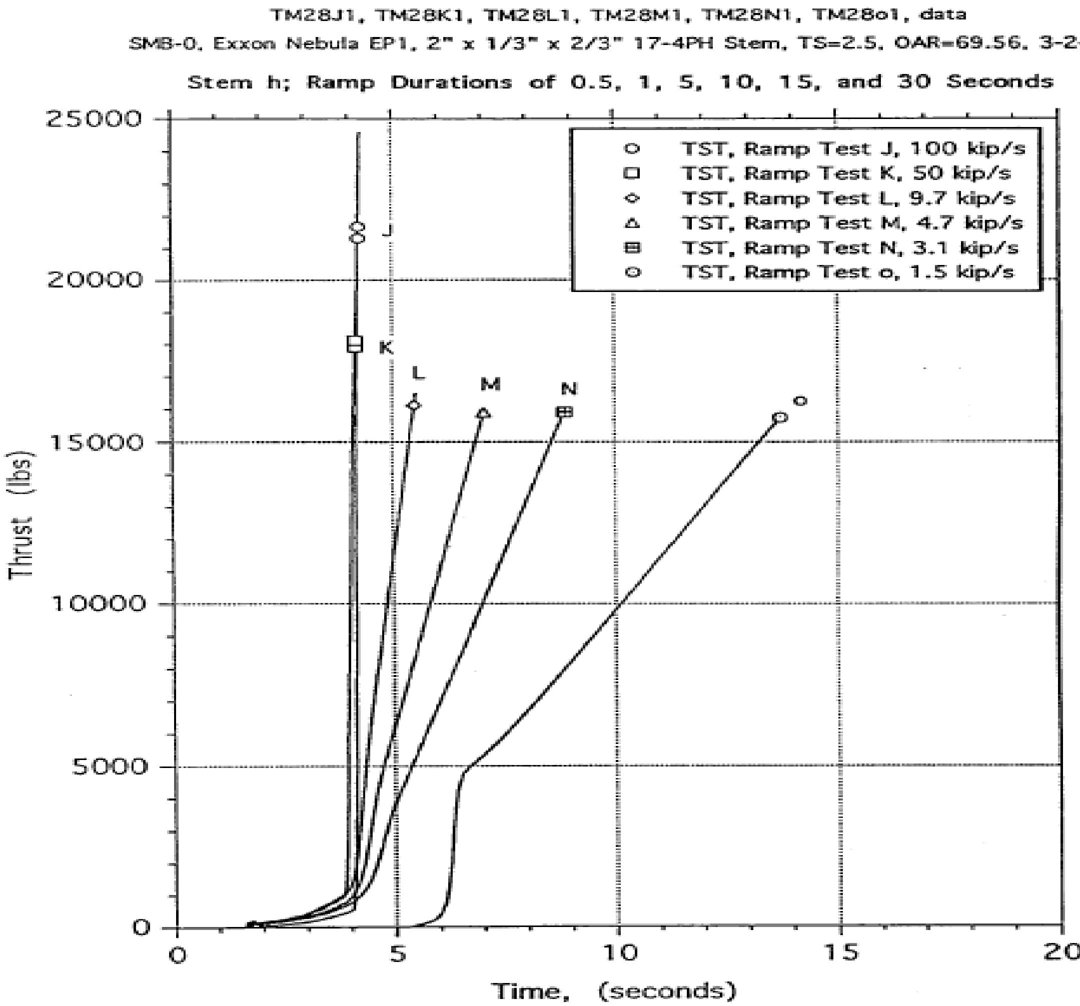


Figure 7. Effect of Loading Rate on Thrust at TST
(Source: Author)

Work performed by EPRI in the 1990s showed that ROL is most likely due to a “squeeze film” effect associated with the stem-to-stem nut threaded connection, which is lubricated. The theory is that the stem-to-stem nut connection operates in a mixed lubrication regime, demonstrating both boundary lubrication (with a typical friction coefficient of 0.1 - 0.5) and/or fluid film lubrication (with a typical friction coefficient much less than 0.1). Under dynamic conditions, the stem load increases gradually throughout a closing stroke as the DP across the valve increases. As a result, the stem thread lubricant flows away from the thread contact areas, and boundary lubrication effects dominate when the torque switch trips. Under static conditions, the stem load is low throughout the stroke and increases rapidly at seating. As a result, the lubricant does not have time to flow away from the thread contact areas, and the stem threads are supported on a pressurized film of lubricant at TST (“squeeze film effect”). The lubricant is trapped in “pockets” created by irregularities in the thread surfaces. The low friction coefficient under these conditions results in a higher thrust at TST for the same operator torque output.

EPRI concluded that ROL for a particular MOV could not be predicted based on first principles but must be determined experimentally. EPRI developed six test methods that can be used to account for ROL for a specific MOV application; these methods were reviewed and accepted by the NRC, with some limitations and conditions. The most straightforward test method is to perform a static diagnostic test of the MOV and apply an adjustment factor to the measured thrust at TST to account for ROL. EPRI conducted a statistical evaluation of the results of valve flow loop testing performed as part of the EPRI MOV PPP (see Figure 8) and determined adjustment factors that could be applied to account for ROL. These adjustment factors can be applied to the thrust at TST measured during a static test or to the MOV's required thrust to determine the minimum allowable thrust at TST. Other test methods allow the adjustment factor to be reduced if certain conditions, such as increased stem loading, can be achieved during the static diagnostic test.

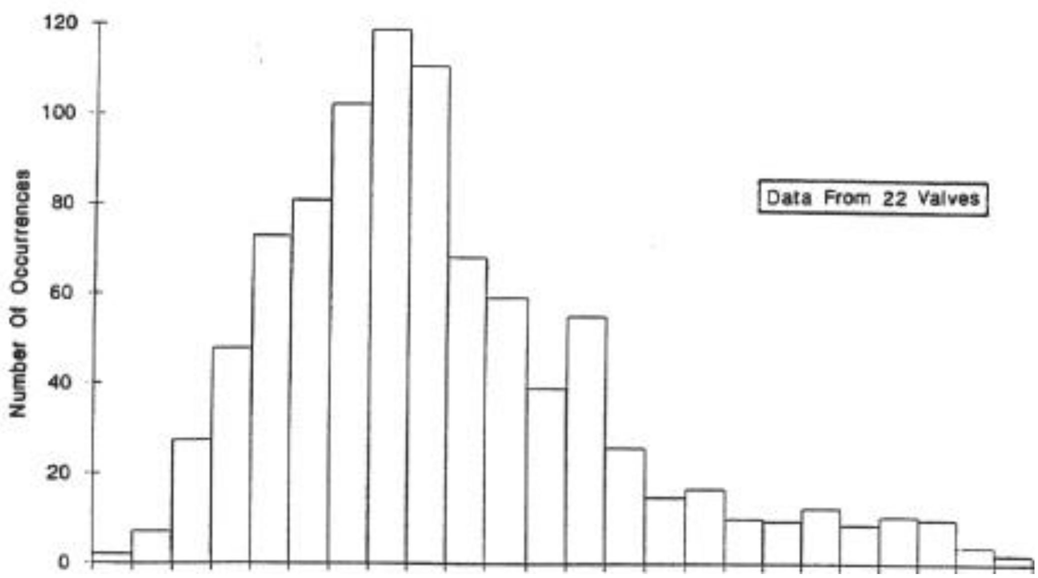


Figure 8. Distribution of Calculated ROL Values
(Source: Author)

Summary

EPRI has performed a significant amount of research over the last 25 years that has contributed to an improved understanding of valve and operator performance. Based on this research, EPRI has developed improved methods for predicting valve and operator performance. The key EPRI products in this area are:

- the PPM software and hand calculation methods
- the AOV and MOV Application Guides and the companion Evaluation Guide for Valve Thrust and Torque Requirements
- the gate valve thermal binding methodology
- globe valve side loading predictive methods
- methods to address ROL

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(17) Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989.

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Design-Basis Verification and Preservice Testing Considerations for OM Code Mandatory Appendix III

Neal E. Estep, P.E.
Kalsi Engineering, Inc.

Abstract

The American Society of Mechanical Engineers (ASME) OM Code, Mandatory Appendix III for inservice testing (IST) of motor-operated valves (MOVs), contains prerequisites for a design-basis verification test (DBVT) and preservice test prior to initiating IST. The DBVT has specific requirements that depend on valve type and operational experience, and the preservice test must adequately bridge the DBVT and inservice test. In addition, certain replacement, repair, or maintenance activities require an evaluation to determine what aspects (if any) of the DBVT or preservice test require repeat testing and/or engineering analysis to either confirm existing reference values or establish new reference values. Finally, existing testing performed under legacy NRC Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989, and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996, MOV Programs or ASME QME-1 functional qualification standard may be credited to satisfy all or a portion of the DBVT and preservice test.

The purpose of this paper is to describe the following, by valve type:

- the specific requirements for the DBVT and preservice test
- the use of previous qualification testing (e.g., GL 89-10/GL 96-05 and ASME QME-1) to satisfy the DBVT and preservice test requirements
- the activities that may require analysis and/or repeating portions of the DBVT and preservice testing and applicability to legacy MOV programs

Introduction

ASME OM Code, Appendix III, specifies the requirements for DBVT, preservice testing, IST, and exercise testing for MOVs. Under paragraph III-3100, it states that the requirements for a DBVT are specified in applicable regulatory documents. A review of MOV testing history shows that the following regulatory documents have identified various aspects of the DBVT:

- GL 89-10 and supplements for safety-related MOV testing and surveillance
- GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated August 17,1995, for pressure locking and thermal binding
- GL 96-05 for periodic verification testing of MOVs

- Regulatory Issue Summary (RIS) 2000-03, “Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves under Design Basis Conditions,” for performance of power-operated valves under design basis conditions

- NRC Information Notice (IN) 2012-14, “Motor-Operated Valve Inoperable Due to Stem-Disc Separation,” dated July 24, 2012, for acceptable design-basis verification test methods

- Regulatory Guide (RG) 1.100, Revision 3, “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants,” issued September 2009, for qualification testing of MOVs under ASME Standard QME-1

The following are the fundamental elements of the regulatory guidance:

- Comprehensively review and document the design-basis requirements that have an effect on actuator output capability or the valve required thrust or torque. These include system, environmental, and operational/age-related items that affect the valve required thrust or torque and actuator output capability.

- Perform flow and differential pressure (DP) testing or use test-based methods to validate the valve required thrust or torque under the most limiting design basis conditions.

- Perform flow and DP testing or use test-based methods to determine the dynamic stem thread coefficient of friction (COF) for rising stem valves.

- Use industry-accepted methods to determine the actuator output capability and stroke time under the most limiting design-basis conditions for actuators with alternating current (ac) and direct current (dc) motors.

- Develop open and close stroke direction switch-setting methods and test acceptance criteria for each MOV to provide functional margin and adequately account for degradation over the diagnostic test interval.

- Use diagnostic testing to implement and verify the switch settings and satisfaction of test acceptance criteria. Test parameters must be sufficient to verify functional margin and functional margin degradation.

- Perform evaluation of the test data to verify setup criteria assumptions, establish trends, determine functional margin, identify performance-related degradation, and perform a qualitative review of the data.

- Use configuration management and change controls to ensure the correct switch settings are determined and maintained throughout the life of the plant.

- Assess MOV failures and maintenance activities.

The following sections in this paper describe the relationship of the DBVT, preservice test, and inservice test from a system perspective. Use of a system perspective helps define the interactions between the various tests, impact of repair/replacement/maintenance, test data analysis, and test data evaluation.

Test Inputs and Outputs

The following sections define the significant inputs and outputs for the DBVT, preservice, and inservice tests. An understanding of the inputs and outputs identifies the relationship between tests and the specific changes that can affect each of these tests.

Design-Basis Verification Test

Inputs to the DBVT include the following items:

- system, environmental, and operational (i.e., design-basis) requirements and conditions: operating scenarios, open/close safety function requirements, limiting stroke time, seat leakage, seismic loading, available voltage, environmental temperature, equipment qualification requirements, line pressure, DP, flow rate, fluid conditions, upstream and downstream flow resistances (including requirements for line-break isolation), inservice operating conditions, and upstream flow disturbances within eight pipe diameters for quarter-turn valves
- actuator characteristics: manufacturer, model, motor data (speed start torque, voltage, current draw, heatup rate, temperature effects on torque/speed), gear ratio, torque switch spring pack, hand-wheel ratio, gear efficiencies, lubricant, available limit switches, and environmental qualification conditions and requirements
- valve characteristics: manufacturer, type, sealing and sliding contact surface materials, trim characteristics, critical dimensions for calculation inputs, disk and stem orientation effects, and upstream flow disturbance effects
- actuator to valve interface (rising stem only) characteristics: stem thread lubricant, thread geometry, thread friction, rate-of-loading, stem thread friction degradation

DBVT outputs include the following:

- Limiting system, environmental, and operational (i.e., design-basis) conditions, such as maximum upstream pressure, maximum DP, maximum environmental temperature, minimum supply voltage, limiting stroke time, safety-related stroke directions, inservice operating conditions used to establish classification and degradation allowances under the Joint Owners' Group (JOG) MOV Periodic Verification (PV) program.

- Valve required thrust or torque for the most limiting open and close stroke operating scenarios, including mitigation or calculation methods to address thermal binding and pressure locking for certain gate valves. Allowance for age and service-related degradation that could increase the valve required thrust or torque. Limiting values for running load, unseating and/or seating loads, disk and stem orientation, and proximity of upstream flow disturbances.

- Actuator output capability and switch-setting configuration for the most limiting open and close stroke operating scenarios. Output capability is typically determined using industry-accepted practices such as the Limitorque or ComEd method for ac motors and the dc Motor Method (DCMM) for dc motors. Limiting values for control switch repeatability, spring pack degradation, motor terminal voltage, and structural strength.

- For rising stem valves, the limiting static and dynamic thread friction coefficient and allowances for rate-of-loading and thread friction degradation. Criteria may also be provided for the required stem lubricant and maximum allowed stem nut thread wear.

- Preservice and inservice test acceptance criteria based on the valve required thrust or torque and actuator output capability, including assumptions for uncertainties (measurement and other), and required system conditions during the test (static or DP test).

Determination of valve operating requirements is specified in Appendix III, paragraphs III-3100 and III-6410. These paragraphs specify the following methods to determine or verify the valve required thrust and/or torque for DBVT purposes:

(1) measurements from dynamic (flow and DP) testing in situ or in a flow loop, along with justification for testing at conditions other than design-basis conditions

(2) justified (or validated) analytical techniques or methods using valve parameters that allow extrapolation to the design-basis conditions

(3) grouping with an engineering evaluation, alternative testing technique, or both, to justify the grouping approach

(4) engineering evaluation of operating experience for valve types (i.e., ball, plug, and diaphragm valves) where the need for DBVT has not been previously identified

With the exception of item 4, these methods are consistent with those previously identified in applicable regulatory documents, such as GL 89-10 (and supplements), IN 2012-14, and RG 1.100 (which references ASME QME-1 qualification testing). IN 2012-14 states that the most preferred methods are in situ testing at or near design-basis conditions and validated analytical techniques, such as the EPRI MOV Performance Prediction Method (PPM). The least preferred method is using grouping data from other plants or research programs since such data are typically obtained without the reporting requirements of Title 10 of the *Code of Federal Regulations* Part 21, "Reporting of Defects and Noncompliance" (i.e., obtained as nonquality assurance (non-QA)).

Key inputs that define the thrust or torque requirements by valve type are the following:

- Gate valve: Pressure locking effect, thermal binding effect, unwedging thrust, packing load, stem rejection thrust, DP thrust, and torque reaction thrust. Degradation considerations are needed for the DP thrust and stem thread COF.

- Globe valve: Unwedging thrust (for steep plug angles only), packing load, stem rejection thrust, DP thrust, seating load, side loading thrust, identification of the balanced or unbalanced area over which the DP acts, and torque reaction thrust. Degradation allowances are needed for the stem thread COF and side loading thrust, if applicable.

- Quarter-turn valve: Seating/unseating torque, running torque, hydrodynamic torque, bearing torque, hydrostatic torque, effect of upstream disturbances on hydrodynamic torque, fluid type, and disk orientation effects. Degradation allowances are needed for the bearing torque and seating/unseating torque.

- Diaphragm valve: Pressure force, running thrust, diaphragm flexure force. Degradation allowances may be needed for the diaphragm if maintenance does not preclude elastomer hardening.

MOVs in most legacy GL 89-10/GL 96-05 programs have satisfied the DBVT requirements. Under Appendix III, it will be important to ensure that the elements of the DBVT are available and defined for each MOV. In addition, there may be “new scope” Appendix III MOVs that were not in the legacy MOV programs that will require DBVT.

Preservice Test

Inputs to the preservice test include the following items:

- Test acceptance criteria, including limiting assumptions that were used to establish the valve required thrust or torque and the actuator output capability.

- Whether static or DP testing is required. DP testing may be required for certain MOVs where age and service-related degradation has not been quantified (see GL 96-05).

Outputs from the preservice test include the following:

- Test conditions, including ambient temperature, system pressure, DP, fluid temperature, and flow rate. These items are needed to ensure that the inservice test is conducted under similar conditions.

- Test data and test results, which are referred to in Appendix III as IST values or performance test data.

- Recording or verification of MOV configuration, such as the items identified in paragraph III-9100.

- Test analysis and evaluation results as described in paragraphs III-6200, III-6300, and III-6400.
- Independent review and final records.

MOVs in most legacy GL 89-10/GL 96-05 programs have a “baseline” test that will satisfy most requirements of the Appendix III preservice test. Exceptions include “new scope” MOVs and certain items such as record of test conditions, recording or verification of MOV configuration, and certain aspects of the test analysis and evaluation requirements, which include determination of functional margin and functional margin degradation.

Inservice Test

Inputs to the inservice test include the following items:

- test acceptance criteria, including limiting assumptions used to establish the valve required thrust/torque and the actuator output capability, from the most recent preservice test.
- work activity sequencing to ensure that no unacceptable preconditioning is done since the inservice test is to be performed in the as-found condition
- required test conditions from the preservice test

Outputs from the preservice test include the following items:

- Test conditions, including ambient temperature, system pressure, DP, fluid temperature, and flow rate. These items are needed to ensure that the inservice test is conducted under similar conditions.
- Test data and test results, which are referred to in Appendix III as IST values or performance test data.
- Recording or verification of MOV configuration, such as the items identified in paragraph III-9100.
- Test analysis and evaluation results per paragraphs III-6200, III-6300, and III-6400.
- Independent review and final records.

Similar to the preservice test, MOVs in most legacy GL 89-10/GL 96-05 programs have “periodic verification” tests that will satisfy most requirements of the Appendix III inservice test. Exceptions include “new scope” MOVs and certain items such as record of test conditions, recording or verification of MOV configuration, and certain aspects of the test analysis and evaluation requirements, which include determination of functional margin and functional margin degradation.

Effect of Replacement, Repair, or Maintenance

Changes to any of the inputs that are used to determine the valve required thrust or torque or actuator output capability need to be evaluated for impact on the DBVT or preservice test. Repair, replacement, and modification activities all have the potential to impact one or more of the critical inputs to varying degrees. For example, routine gate valve maintenance to correct excessive seat leakage can have little effect on the valve required thrust if minor lapping is performed. However, if the disk were replaced, or reoriented for certain gate valves, then a more extensive evaluation is required to ensure that any critical inputs to the thrust calculation are identified and addressed. Depending on the new sealing or wear surface material, disk orientation, and changes to critical dimensions and tolerances, followup actions can include documenting that there was no effect on the required thrust, revising an EPRI PPM calculation, or performing an in situ DP test. For additional guidance, the JOG MOV PV program identifies "disallowing modifications" that can invalidate a prior valve qualifying basis established based on in situ DP testing and due to changes to inservice operating conditions.

Examples of other, less obvious activities that may be of significance include (1) revisions to an emergency operating procedure that change the sequence of operating valves in series which increases the DP requirements of an MOV, (2) adding electrical loads or resequencing the emergency diesel generator loads can reduce the motor terminal voltage, and (3) power uprate conditions may result in an increase in the MOV ambient temperature used to determine the available motor torque.

Comprehensive guidance is required to address replacement, repair, or maintenance activities. Defining routine maintenance activities that have no or minor impact on the DBVT inputs is a significant first step. Other maintenance activities will need to be evaluated if they potentially impact one of the following DBVT inputs or outputs:

- system, environmental, or operational requirements and conditions
- actuator characteristics that are used to determine the actuator output capability
- valve characteristics that are used to determine the valve required thrust/torque
- actuator-to-valve interface characteristics that are used to determine the torque-to-thrust conversion efficiency for rising stem valves

Under legacy MOV programs, most plants developed change management controls and guidance to address revisions to operating procedures, system modifications, and MOV work activities to assess impact on the valve required thrust or torque and actuator output capability. The level of evaluation and/or post-activity testing is defined for most common MOV maintenance activities. However, under Appendix III, plants will be required to more exactly identify which performance parameter is expected to be affected by the activity to support observed deviations between new and previously established reference test values. Appendix III also specifies requirements to more formally document these evaluations.

Summary

An understanding of the various DBVT, preservice test, and inservice test inputs and outputs provides a framework to identify the dependencies among these Appendix III testing activities and the impact of replacement, repair, or maintenance. In addition, gaps between legacy MOV programs and Appendix III requirements can be more easily identified and addressed.

Figure 1 summarizes the various inputs and outputs presented in this paper.

References

(1) ASME *Operation and Maintenance of Nuclear Power Plants*, ASME OM-2009 and OM-2012.

(2) NRC Generic Letter 89-10 (and supplements), “Safety-Related Motor-Operated Valve Testing and Surveillance,” June 28, 1989.

(3) NRC Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves,” August 17, 1995.

(4) NRC Generic Letter 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” September 18, 1996.

(5) NRC Regulatory Issue Summary 2000-03, “Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves under Design Basis Conditions,” March 15, 2000.

(6) NRC Information Notice 2012-14, “Motor-Operated Valve Inoperable Due to Stem-Disc Separation,” July 24, 2012.

(7) NRC Regulatory Guide 1.100, Rev. 3, “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants,” September 2009.

(8) MPR 2524A, Rev. 1, “Joint Owners’ Group Motor Operated Valve Periodic Verification Program Summary,” September 2010.

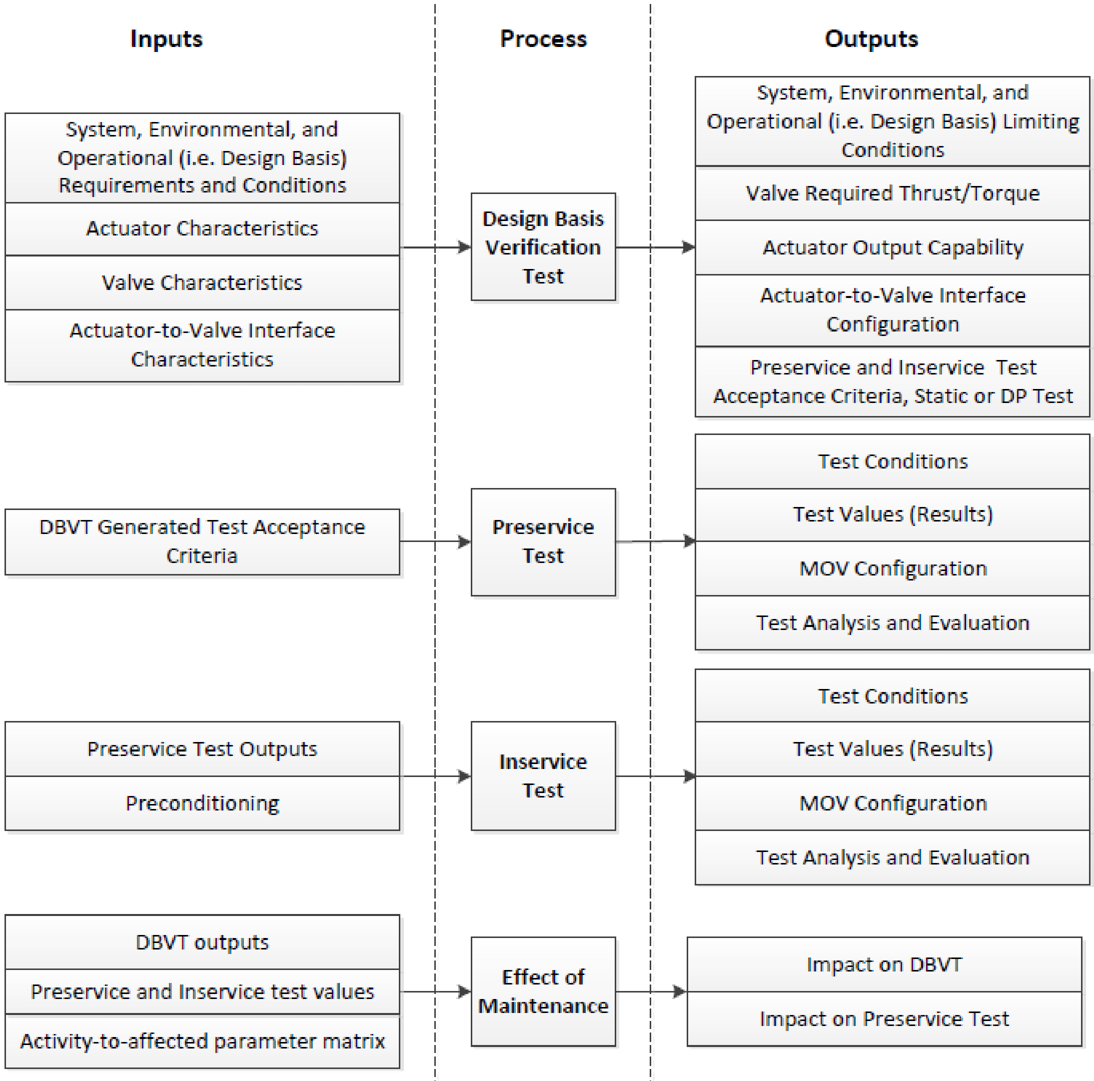

Figure 1: Appendix III Test Process Flows
(Source: Author)

TVA OM Code Mandatory Appendix III Readiness Assessment

Bob H. Thacker
Tennessee Valley Authority 1101
1101 Market Street
Chattanooga, TN, USA 37402

Jerry V. Mills
Tennessee Valley Authority
1101 Market Street
Chattanooga, TN, USA 37402

Neal E. Estep, P.E.
Kalsi Engineering, Inc.
745 Park Two Drive
Sugar Land, TX, USA 77478

Abstract

To prepare for implementation of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code), Mandatory Appendix III for inservice testing (IST) of motor-operated valves (MOVs), Tennessee Valley Authority (TVA) performed a comprehensive assessment at all three of its nuclear sites to identify gaps between its legacy IST and MOV programs and an IST program that meets the requirements of Appendix III. This assessment reviewed each paragraph of Appendix III and TVA governing documents to determine how the requirements are already being met or are missing in the legacy MOV program(s). Secondly, the assessment performed a high-level overview of TVA's MOV programs in response to the U.S. Nuclear Regulatory Commission's (NRC's) Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989, and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996, and identifies areas for improvement for TVA consideration. This paper presents the assessment purpose and objectives, scope, approach and methods, references, summary of significant gaps, and proposed actions to resolve these gaps prior to Appendix III implementation.

Introduction

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(b)(ii) specifies the use of Subsection ISTC of the OM Code for IST of MOVs in Quality Group A, B, and C systems. Subsection ISTC has historically used stroke-time testing to demonstrate operational readiness of MOVs. However, during the 1980s, it was discovered through a series of industry events and testing programs that stroke-time testing is not sufficient to provide assurance of MOV operability under design-basis conditions. NRC Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," dated November 15, 1985, and GLs 89-10 and 96-05 defined supplemental measures required to initially demonstrate MOV design-basis operability and to periodically verify MOV operational readiness. As a result of the NRC regulatory-driven MOV programs, there soon emerged both legacy IST stroke-time testing in addition to more extensive regulatory-driven MOV diagnostic testing. In 1989, the ASME OM Subgroup on MOVs began working on ASME OM Code

Case OMN-1 in an effort to address MOV operational readiness under the OM Code to supplant the need for both Code and regulatory-driven MOV programs. Code Case OMN-1 is approved for use in Regulatory Guide 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code." In the 2009 OM Code, Code Case OMN-1 is now Mandatory Appendix III, which is referenced in Subsection ISTC-5120 for active MOVs.

Currently, TVA nuclear plants have separate MOV and IST programs, with the legacy MOV programs governed by GLs 89-10 and 96-05 and the legacy IST programs governed by Subsection ISTC of the ASME OM Code. When TVA stations perform their next ASME 10-year IST updates, they will be required to have implemented the requirements of ASME OM Code, Mandatory Appendix III.

Purpose and Objectives

The main purpose of this project was to identify gaps between TVA's legacy MOV programs and the new requirements of Appendix III and identify specific actions to close the gaps. A secondary purpose is to identify improvement items for TVA's legacy MOV programs.

As illustrated in Figure 1, regulatory-driven GL 89-10 and GL 96-05 MOV programs will eventually fall entirely under ASME OM Code activities with the implementation of Appendix III.

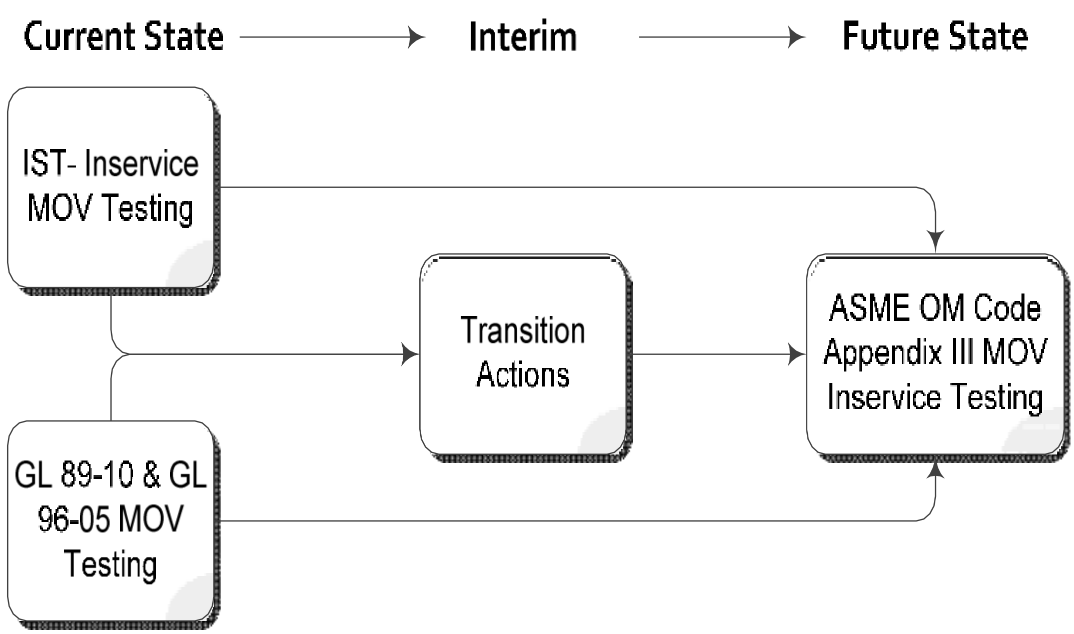

Figure 1: MOV Testing Transition Process
(Source: Author)

Scope

The assessment covered all of TVA's nuclear locations—Corporate, Browns Ferry Nuclear Station, Sequoyah Nuclear Station, and Watts Bar Nuclear Station. It included all legacy GL 89-10/GL 96-05 and IST program "active" MOVs.

Approach and Methods

Appendix III is divided into the following major paragraphs:

III-1000	Introduction
III-2000	Supplemental Definitions
III-3000	General Testing Requirements
III-5000	Test Methods
III-6000	Analysis and Evaluation of Data
III-9000	Records and Reports

The approach used for the readiness assessment was to develop a checklist of specific requirements from each of these major paragraphs. Common gaps identified in the Boiling-Water Reactor Owners' Group Appendix III Implementation Guide were also listed in the checklist under each major paragraph topic. Next, TVA-specific procedures and controlling documents that define MOV program actions and requirements were identified. For each nuclear site, a sample group of MOVs was selected. Selection priority was placed on the Joint Owners' Group MOV Periodic Verification Program (JOG MOV PV) classification, MOV modification history, and a desire to include at least one gate, globe, and butterfly valve, if possible.

Checklist items were then compared to legacy MOV program actions to identify gaps. TVA-Corporate was assessed first to identify potential generic and cross-cutting gaps. Assessments were then conducted at the Browns Ferry, Watts Bar, and Sequoyah nuclear plants.

For example, MOV population scope as defined by Appendix III, paragraph III-1200, involved the following three checklist items:

(1) Ensure that the legacy regulatory-driven MOV program scope is congruent with specified requirements.

(2) Verify that the basis for program scope (inclusion/exclusion) is documented and readily retrievable.

(3) Compare the current MOV program scope to the IST-active scope and identify gaps between the current GL 89-10 and Appendix III scope.

TVA-specific references included the MOV program scope document and IST program bases document.

Summary of Significant Gaps

Identified gaps were classified based on processes, procedures and documentation, training, and roles and responsibilities.

Process Gaps

(1) Revise the program scope to be those MOVs defined per ASME OM Code paragraph ISTC-1200.

(2) Develop design-basis verification testing (III-3100) methods for the new scope valve types that were not included in the legacy MOV program, such as ball valves.

(3) Ensure that a particular design-basis verification test method identified under paragraph III-3100 can be associated with each applicable MOV.

(4) Ensure that inservice test (III-3300) methods address requirements for remote position indication verification testing and preclude unacceptable preconditioning.

(5) Address how medium-risk MOVs will be mapped to either high safety-significant component (HSSC) or low safety-significant component (LSSC) rankings under Appendix III, paragraph III-3700.

(6) Ensure specific acceptance criteria are provided for each MOV to ensure that positive functional margin is available and that it is sufficient to support the existing inservice test interval (III-6100).

(7) Ensure that inservice test values for MOVs not removed from service for maintenance are immediately determined or confirmed (III-3400).

(8) Ensure that data evaluation occurs within a reasonable time period following IST in the event that adverse functional margin trends are identified such that the functional margin may become unacceptable prior to the next inservice test.

(9) Ensure the specific test information defined by Appendix III, paragraph III-9100, is verified or recorded as part of the preservice and IST processes.

(10) Ensure that controlling procedures address the specific documentation and signature requirements of Appendix III, paragraph III-9200 (i.e., preparer and independent reviewer).

Procedure and Documentation Gaps

(1) Develop new crosscutting procedures and standards for the following:

a. MOV IST and test data analysis and evaluation

b. interfaces with IST program

c. procedure (temporary) to review past MOV diagnostic testing to credit it as a qualified preservice or inservice test under Appendix III

(2) Revise MOV program scope to conform to Appendix III requirements and reconcile differences with past regulatory commitments.

(3) Update procedures to include Appendix III testing requirements (design-basis verification, preservice, and inservice) for new valve types (e.g., ball valves) that will be in the scope of Appendix III.

(4) Document effect of changing stem lubricant on assumed stem thread friction coefficient and rate-of-loading values.

(5) Clarify that the inservice test interval will be based on the JOG MOV PV criteria, but adjusted for degradation rate. Both inservice and exercise test intervals will need to be maintained in the IST program documents.

(6) Update the post-maintenance/modification matrix to provide a clear tie to the effect on design-basis verification testing and preservice testing and what test parameters are expected to change as a result of the maintenance activity.

(7) Revise MOV procurement specifications to ensure that new valves have design features and testing to minimize their impact on the Appendix III program. For example, a new valve that conforms to JOG MOV PV Class A and is supplied with a design-basis verification test would require minimum effort to integrate into the Appendix III program.

(8) IST stroke time will need to be replaced with Appendix III exercise testing. Stroke time will still need to be verified for MOVs that have licensing-basis stroke requirements.

(9) Ensure test acceptance criterion include all items that affect MOV functional margin. These include items that can decrease actuator output capability, increase the valve requirement, or degrade the actuator-to-valve interface efficiency.

(10) Ensure inservice test procedures are clear that an MOV is to be immediately declared “inoperable” if the test acceptance criterion is not met.

Training Gaps

(1) Ensure that additional personnel (other than MOV engineers) are trained and qualified to operate MOV diagnostic test equipment and perform the Appendix III analysis functions (i.e., verification of test acceptance criteria).

(2) Ensure that training is provided for all stakeholders regarding the effect of maintenance, test analysis and evaluation, and interfaces between MOV testing and IST.

Roles and Responsibilities Gaps

(1) Ensure clear definition of roles and responsibilities between the IST and MOV engineer.

(2) Ensure clear definition of roles and responsibilities between maintenance and the operations test group.

Proposed Actions

Most Appendix III actions need to be completed by the time conformance to Appendix III is required. These include design-basis verification testing, determination of test acceptance criteria, determination of inservice test interval, performance of a preservice test to determine inservice test values, test data analysis, test data evaluation, and applicable records and reports. To ensure these actions are accomplished prior to Appendix III implementation, TVA has outlined the following steps. Steps 1 and 2 should be completed within 6 months to 1 year, Steps 3 and 4 should be completed within 1 to 2 years, and Step 5 should be completed prior to the 10-year update.

Step 1—Scope

Perform scope comparisons between the IST program active (and possibly safety-related active augmented IST) MOVs and the GL 89-10/96-05 MOV program scope. For new scope MOVs:

(1) Identify and document new scope MOVs.

(2) Initiate action to perform risk ranking and expert panel review.

(3) Schedule preservice testing and establish inservice test interval.

(4) Evaluate licensing commitment changes.

(5) For active MOV with a skid-mounted IST test exemption document the basis that the integrated testing adequately demonstrates operational readiness.

Step 2—Update Documentation, Roles and Responsibilities

Since two very significant testing programs will merge under Appendix III, it will be necessary to update program documents and controlling procedures, personnel training requirements, and roles and responsibilities to conform to the new state. In the interim, generic procedures will need to maintain separate items in some sections to address separate actions under Appendix III versus those under the legacy GL 89-10/GL 96-05 program. Specific gaps in this area were identified previously.

Step 3—Design-Basis Verification and Preservice Testing

The design-basis verification approach for existing GL 89-10 MOVs will need to be formally documented to show that it meets the intent of Appendix III. Adding new valves to the MOV program under Appendix III will require a design-basis verification test and preservice test.

Step 4—Establish Testing Frequency

(1) Establish frequencies for IST. In general, these can correspond to the JOG MOV PV test frequency unless trending data show that a reduced test interval is required.

(2) Establish a method to determine inservice test intervals for new or modified MOVs. Appendix III specifies an initial functional margin verification test interval of two refueling outages or 3 years for HSSC MOVs and three refueling outages or 5 years for LSSC MOVs.

(3) Establish a process to reset the surveillance test due date if IST is performed early due to a modification, maintenance, or other activity.

(4) The IST program will need to transition from stroke-time testing to just exercising. However, stroke-time verification will be required for MOVs that have a licensing basis stroke-time requirement. The initial exercising intervals can correspond to the stroke-time testing intervals.

Step 5—IST Program Changes for Next 10-Year Update

(1) Update IST plan to remove stroke-time verification requirement for MOVs that do not have a licensing basis stroke-time requirement. Stroke time does not need to be trended.

(2) Update IST plan to identify the Appendix III requirements for exercise testing, including a “full cycle” test and the required test frequency.

(3) Update IST plan to identify that the exercise test interval for HSSC MOVs can be extended beyond quarterly by using risk-informed criteria, even if quarterly exercise testing is possible.

(4) Develop new site Appendix III program document: IST subtier document owned by MOV engineer.

(5) If required by NRC rulemaking, initiate an action for the IST program to develop the guidance required to satisfy obturator verification in conjunction with remote position indication verification test.

(6) Initiate action for IST program to identify any limitations regarding setting the obturator verification frequency to coincide with the inservice test frequency. Examples of exceptions may be certain containment isolation valves.

Acknowledgments

The authors would like to acknowledge those persons who contributed to the recent commercial operation of Watts Bar Unit 2.

References

(1) ASME *Operation and Maintenance of Nuclear Power Plants*, ASME OM-2009 and OM-2012.

(2) *Code of Federal Regulations*, Title 10, Section 50.55a, “Codes and standards.”

(3) MPR 2524A, Rev. 1, “Joint Owners’ Group (JOG) Motor Operated Valve Periodic Verification Program Summary,” September 2010.

(4) NRC Regulatory Guide 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code.”

(5) NRC IE Bulletin 85-03, “Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings,” November 15, 1985.

(6) NRC Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” June 28, 1989.

(7) NRC Generic Letter 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” September 18, 1996.

(8) NRC Generic Letter 89-04, “Guidance on Developing Acceptable Inservice Testing Programs,” April 3, 1989.

(9) BWROG-TP-15-010, “ASME Operation and Maintenance Code, Mandatory Appendix III Implementation Guide.”

(10) NUREG-1482, Rev. 2, “Guidelines for Inservice Testing at Nuclear Power Plants,” October 2013.

Track 4: Air-Operated Valves

Track Chair: Steven Unikewicz, NuScale

New Validated Methodology for the Required Force to Operate Balanced Disk Globe Valves

Zachary Leutwyler

Kenneth Beasley

Emil Leutwyler
Kalsi Engineering, Inc.

Abstract

In 2016, Kalsi Engineering, Inc., developed a new validated methodology to predict the required force to operate balanced disk globe valves for the Electric Power Research Institute. This methodology was developed based on flow loop testing and computational fluid dynamic analyses. The development of this methodology focused on quantifying the effect of side load on the disk and differential pressure between the top and bottom of the disk due to flow effects. Previous industry methodologies had not accounted for the differential pressure between the top and bottom of the disk and the offsetting benefit of this force for some configurations. This methodology will be vital for establishing test acceptance criteria for performance assessment testing of balanced disk globe valves in the plant's American Society of Mechanical Engineers *Operation and Maintenance of Nuclear Power Plants*, Mandatory Appendix IV program scope.

The purpose of this presentation is to describe the development, theory, applicability, and implementation procedure for this methodology. In addition, useful examples are provided to aid the power plant engineer in understanding how to screen valve applications for possible concerns.

Gauging the Force Effects of Valve Stem Packing on Valve Stem Actuation

James Drago, P.E.
Principal Applications Engineer
Garlock Sealing Technologies

Wayne Evans
Product Engineer
Garlock Sealing Technologies

Abstract

Stem friction in an operating valve is a function of the dynamic interaction of a number of variables—packing material of construction, number of packing rings, compressive load, lubrication, stem surface finish, temperature, cycling, etc. Forces due to friction can be reduced by modifying these factors. Attaining low actuation force and good sealing requires a balanced approach. Packing manufacturers have their own procedures for determining the frictional properties of different packing materials. This paper will show one such procedure and how varying materials and packing set configurations affect actuation force. The focus will be on linear reciprocating valve stems.

The equation $F = \pi \times d \times H \times GS \times \mu \times Y$ can be used to calculate the force of the packing on the valve stem, where F is the force needed to overcome packing friction; d is the stem diameter; H is the packing set height; GS is the compressive stress on the packing; μ is the packing coefficient of friction; and Y is the ratio of radial to axial load transference, commonly equal to 0.50. Knowing the force, F, by test allows the calculation of the packing set's frictional characteristics. This knowledge can guide valve designers and builders to properly size actuating units for consistent and reliable valve performance.

Introduction

Compression packing is one of the most common types of sealing technologies used by industry. Packing can be found in applications ranging from transmission of natural gas and water to chemicals and high-temperature steam. It is a cost-effective, high-performance means of sealing when used properly. Compression packing inherently creates a frictional force resisting actuation. This can pose major issues for certain applications and valve types, like air-operated valves. Friction reduction strategies involve modifying packing materials, configurations, and installation procedures to attain target frictional loads while balancing sealing performance. Effectively sealing one application may call for graphite, while another may require a polytetrafluoroethylene (PTFE)-based packing to reduce friction. Users may also have preferences based on cost, logistics, or historical performance. It is important to note there is no single solution to all sealing applications; this is why sealing companies possess a portfolio of sealing products. The strategies discussed will conceptually apply to most applications, but need to be evaluated before implementation. Each application has an optimal solution within currently available sealing technologies and strategies.

Compression packing controls the loss of media by blocking fluid migration from a higher pressure system to a lower pressure external environment. The sealing mechanism of compression packing is based on a tight fit between the packing and sealing surfaces. Packing commonly seals pumps, valves, and other equipment through axial compression that causes radial expansion of the packing against a dynamic sealing surface like a valve stem (Figure 1).

Nomenclature

AECL	Atomic Energy of Canada Ltd.
AOV	Air-operated valve
API	American Petroleum Institute
Bore or gland	Inside diameter of the valve packing chamber
EPRI	Electric Power Research Institute
FME	Foreign material exclusion
ISO	International Standards Organization
Packing contact area	Stem circumference multiplied by the height of the packing set
Packing stress	The compressive stress applied to the packing material. Based on the force exerted by the gland bolts via the gland follower.
PTFE	Polytetrafluoroethylene. Trade name of EI DuPont: Teflon®
Radial	Directional notation for perpendicular to the axis of the valve stem
Runout	Variation of the stem centerline with relation to the bore centerline as the stem is moved
Stiction	Actuating stem catching periodically on the packing set and causing erratic movement. Most common where static and dynamic friction vary greatly.

Importance of Stem Friction

There are multiple reasons end users should be mindful of the force exerted by the packing on the stem of a valve.

- If the valve is too difficult to actuate or lags due to a high breakaway force, the valve will not move as needed and will affect the process flow.

- Process flow control requiring constant motion of the valve stem can be stymied by stiction.
- Extreme ease of valve stem motion indicates that the packing may not be properly compressed, allowing leakage of critical fluids.

Smooth, reliable valve movement contributes to a process flow without system upsets, limiting unplanned downtime and process inefficiencies.

Actuation Force, Friction, and Packing Compression

Various theoretical models exist that describe friction in valve systems. While these models diverge in their implementation, the basis remains constant with the concept of normal force and the coefficient of friction.

Figure 2 shows the classic approach to friction in a reciprocating system. To apply this to our subject of linear valve stem actuation, the above is written as follows:

$$F = N \cdot \mu \qquad \text{(Eq. 1)}$$

where:

> F is the actuation force. It is always greater than the force caused by friction. This is found from testing.
>
> N is the force the packing exerts on the stem. The normal force N is dependent on the packing axial to radial load transfer ratio.
>
> μ is the coefficient of friction found by testing.

N is calculated using the equation below:

$$N = Y \cdot \pi \cdot GS \cdot H \cdot d \qquad \text{(Eq. 2)}$$

where:

> GS is the axial gland stress on the packing
> Y is the ratio of radial stress on the stem to axial stress on the packing
> H is the height of the packing
> d is the stem diameter

$$GS = \frac{\left(\frac{T \cdot n}{0.2 \cdot b}\right)}{\frac{\pi(D^2 - d^2)}{4}} \qquad \text{(Eq. 3)}$$

where:

T is the torque applied to the bolts
n is the number of bolts
b is the nominal bolt diameter
0.2 is the nut factor accounting for the losses in torque to axial bolt force (can vary)
D is the packing box diameter
d is the stem diameter

After combining the equations for normal force (N) and gland stress (GS):

$$N = \frac{Y \cdot \pi \cdot H \cdot d\left(\frac{T \cdot n}{.2 \cdot b}\right)}{\frac{\pi(D^2 - d^2)}{4}} \qquad \text{(Eq. 4)}$$

$$N = \frac{20 \cdot Y \cdot H \cdot d \cdot T \cdot n}{b\left(D^2 - d^2\right)} \qquad \text{(Eq. 5)}$$

Substituting into Equation 1:

$$F = \frac{\mu \cdot 20 \cdot Y \cdot H \cdot d \cdot T \cdot n}{b\left(D^2 - d^2\right)} \qquad \text{(Eq. 6)}$$

These equations reflect the classic approach we commonly refer to in textbook literature. The simplified form of friction in Equation 1 effectively describes material combinations like dry steel on lubricated steel, PTFE (a flat block) on steel, lubricated steel on steel, etc. The textures of the surfaces of these materials do not change radically when under stress. This is not the case with compression packing. Figure 3 shows braided packing before compression, and Figure 4 after compression. These are notably different. After compression, the packing is smoother with a slicker appearance. Because of this changing surface during compression, the coefficient of friction is a moving target which is changing in a nonlinear fashion as the packing is compressed. The Atomic Energy of Canada, Ltd. (AECL) report handles this by quantifying friction as the product of the coefficient of friction and Y (the ratio of radial to axial stress). Y can vary as the packing is compressed. Higher and higher GS will compress the packing more and change Y. The packing responds less and less as the compressive stress increases to a critical point, after which the response of the packing set is negligible. As GS increases, the packing surface conforms and smooths to mate with the stem surface. As the packing becomes denser, the load transfer characteristics change. At low GS, the packing is transferring little load to the stem, increasing through moderately high GS, and finally decreasing as the packing becomes so dense that it will not respond to additional compressive stress from the gland. These statements do not include packing sets capable of extrusion. Packing sets capable of extrusion will reach equilibrium of load where additional compression of the gland follower will have negligible effects as the packing extrudes through clearances at the top and bottom of the bore.

In Equation 1, μ quantifies how the packing material resists movement on a surface. A friction factor such as $Y\mu$ is not the same as a coefficient of friction. Friction factors are lumped variables describing friction for specific packing types and system configurations. The coefficient of friction describes an inherent material property. Friction factors vary for different types of compression packing and system parameters. Some manufacturers may have a factor of safety built into their friction factor values to accommodate variability of application parameters. This friction factor is of critical importance for valve designers to size actuators.

Some Key Points from AECL's Friction Investigation

The 1978 AECL report's primary objective with regards to sealing was to evaluate packing (mostly the PTFE and asbestos types of that day) with regards to leakage, packing consolidation (compression), friction, and corrosion. A key finding was that, in many cases, the friction factor and the coefficient of friction are the same order of magnitude. Where the coefficient of friction was available, Y values for some packing were found to range from 0.4 to 0.5. This supports the common assumption of $Y = 0.5$. Extreme values were calculated; the greatest outlier had a Y value of 0.27.

Friction Factor versus Load

Beyond the theoretical variances in calculating friction, the friction test methodology associated with reciprocating valve stems varies. Friction testing does not currently have a standardized procedure. Some tests, the Chevron Texaco packing specification standard for example, establish a maximum turning torque of a hand-wheel. There exists a need for a robust friction test standard. For this reason, packing and valve manufacturers, end users, and test facilities have developed varying test procedures to address friction in valves. One such test procedure is outlined below.

Testing Equipment and Protocol Method for a Four-Ring Set of Braided Packing

See Table 1 and figures at the end of this paper.

(1) Use appropriate solvent and/or abrasive to clean system.

(2) Install two rings. Compress to target gland stress.

- (a) Remove gland follower

(3) Install two rings. Compress to target gland stress.

- (a) Measure gap on left and right stud to ensure alignment within .032 inches. Record heights

(4) Actuate 25 times while recording axial force.

(5) Record gap on left and right studs. This is used to calculate the packing set's consolidation.

(6) Increase to target gland stress 2 (Table 2).

(7) Repeat steps 4 and 5.

(8) Increase to gland stress 3.

(9) Repeat steps 4 and 5.

(10) Increase to gland stress 4.

(11) Repeat steps 4 and 5.

(12) Remove gland follower.

(13) Record thickness of each ring. Note condition of rings.

Notes:

- Typically, ⅜-inch or ¼-inch square braid is tested.
- Properly sized and calibrated torque wrenches are used to tighten gland bolts.
- There are two hardened washers per stud.
- Properly sized and calibrated load cell is required.
- No internal pressure.
- Use manufacturer's installation instructions.
- For taller sets, compress every two rings.
- Document physical dimensions of system to calculate percent compression.

Load Cell Requirements

The load cell is a critical component in this testing. The force required to move the stem is key information in factor calculation. The load cell measurement frequency needs to be appropriately high to capture frictional spikes. Actuation force typically spikes as the reciprocating stem stops momentarily and changes direction. The load cell resolution must be capable of capturing these spikes. Figure 8 below shows two sets with different start/stop characteristics. One set is consistent with its force requirements through its stroke and change of direction, while the other has uneven force requirements that peak during direction change. Note that this spike is most prevalent in the first 100 cycles of a nonlubricated packing set. End users should be interested in both the peak spikes, as well as plateau force requirements to properly size a valve's actuator.

End users are continually interested in plant efficiency and reducing downtime. Friction is important to these end users, as reduced actuation force equates to reduced actuator cost and more efficient plant performance. Air-operated valves in particular are of concern due to their prevalence in industry.

Friction Reduction Strategies

To reduce the actuation force (F), compressive stress (GS) can be decreased (Equation 2). This is typically accomplished through reducing torque on gland studs, but other valve configurations exist in which packing load is applied through a packing nut. Reducing the axial compressive stress reduces the radial stress exerted by the packing sets on the stem, regardless of the axial to radial conversion ratio. Figure 9 depicts a packing set tested at four different loads. The relationship between compressive stress and friction is shown to be approximately linear for this specific set.

For a variety of reasons, many systems in a wide range of applications are overtightened during installation. Figure 10 describes a typical compressive stress range for effective performance. Beyond these loading conditions, extrusion may occur, and under these conditions, sealing effectiveness may be compromised.

There are various reasons additional load would be applied. These may include obtaining minimum bolt stress, live loading, emission compliance, or factor of safety. Typically, higher compressive loads equate to a tighter seal at the expense of required actuation force. The target stress for effective performance can typically be provided by the manufacturer, based on experience with the product, or by consulting the maintenance team. Assuming that well-lubricated alloy steel bolts are used, Equations 2 and 3 are commonly used to determine loading conditions.

The bolt torque to attain the target compressive stress is found by the following:

$$T = \frac{k \cdot FB \cdot b}{12 \cdot n} \qquad \text{(Eq. 7)}$$

where T is required bolt torque (ft-lb); k is the nut factor for machine oiled bolts and typically 0.2, FB is bolt force (pounds); b is nominal bolt diameter (inches); 12 is the conversion from inches to feet; and n is the number of gland bolts.

Material of Construction/Product Types

Nuclear end user requirements vary with respect to materials of manufacture, specifically for PTFE and metal filament. PTFE exposed to radiation suffers material property changes, leading to potential risks in sealing that some end users will accept to varying degrees. The metal wire commonly used in wire reinforced packing has become a focus of foreign material exclusion (FME) programs and is generally avoided.

When selecting the appropriate packing, the customer and application requirements typically point at one of the following packing types:

- pure PTFE—machined or braided
- hybrid—PTFE fiber over carbon braid
- non-PTFE—die-formed flexible graphite, carbon, or graphite yarns, engineered composite packing sets

End user material requirements need to be understood early. Typically, reducing friction focuses on changing the packing material to one with a lower coefficient of friction, which reduces the force required to move the stem through that packing set. Figure 11 shows five valve packing sets tested under the same load conditions. The force observed to move the stem ranged from 50 to 1,000 pounds.

Varying the packing is often the simplest method to reduce friction. For example, a PTFE-based braid may have a published friction factor of 0.08, a graphite braid with lubrication about 0.09, and a die-formed graphite set near 0.1. These published friction factors differ from actual values due to manufacturer's safety factors, consideration of worst-case scenarios, and averages over different sizes and styles of braids. Often, the published values have a 2:1 factor of safety. The ideal friction test uses the same packing, loading conditions, and stem finish. These empirical tests often result in measured values far lower than calculated force requirements (Table 3).

Figure 11 shows the actuation force required for a range of existing products from various manufacturers used for sealing low-friction applications. The families of braids utilizing lubricated PTFE display the lowest friction. Thermal cycling, abrasives, and emissions requirements are typically the issues associated with polymer packing choices due to the higher coefficient of thermal expansion and load retention characteristics.

Graphite and PTFE are the predominant low-friction materials for compression packing. PTFE is a highly lubricious material, but is limited by its 500-degree Fahrenheit (F) (260-degree Celsius (C)) temperature rating, as well as high creep and flow characteristics. Graphite can withstand temperatures of up to 850 degrees F (454 degrees C) in oxidizing atmospheres, and 1,200 degrees F (649 degrees C) in steam atmospheres. Both of these materials can be used as the dominant material of construction or can be added to reduce friction. Graphite, PTFE, and other polymers and lubricants are commonly added through a dip or dispersion to reduce friction during operation, or they can be manufactured into a pure PTFE or graphite sealing product.

Typically, graphite is formed into a sealing product by die-forming flexible graphite foil into solid rings. PTFE can be formed into fibers and braided, can be machined into sealing elements, or paste can be extruded into films that can be formed into yarns and braided. PTFE and graphite materials can be processed with other fibers and fillers to optimize desired characteristics such as lower friction and resistance to extrusion. For example, a thin coating of PTFE on carbon or graphite braid can significantly reduce friction, while the carbon core maintains the structural integrity and creep resistance of the braid. Another solution is to use die-formed graphite sets with angular planes that encourage radial movement to minimize the compressive load required to seal effectively. This decrease in compressive load in turn corresponds to decreased friction. PTFE braided over carbon exhibited the lowest friction factor of the products tested in Figure 11.

Number of Rings

Conceptually, the number of rings in a packing set should be the minimum to effectively seal, but in practice, more rings are typically used. Five rings is the typical target in industry as API 600/ISO 10434 states depth requirements of five uncompressed rings. Removing rings can pose potential issues with sealing effectiveness. Box depth can be adjusted by installing carbon or steel bushings to match the reduced height of the packing set. Introducing machined bushings means the sealing set is now an engineered set versus a spool of packing. This impacts both cost and logistic complexity. Figure 12 shows the impact that varying the number of rings has on the required actuation force. Note in Figure 12 that the number of rings is not directly related to increased actuation force; this disagrees with current friction prediction equations.

Interestingly, PVP-2009-77467 reports that once a minimum seating stress was applied, the seal tightness of two rings performed equivalently to four-, five-, and seven-ring sets. The reliability of two rings versus the standard five-ring sets was not evaluated. Optimizing the number of rings is an effective strategy for reducing friction, but application requirements take precedent. Stack height impacts the following:

- friction force
- seal tightness
- installation method
- set consolidation
- set relaxation

Friction Force versus Temperature

Typically, friction decreases as temperature increases. The friction factor decrease is a function of lubrication in the set, braid type, and valve design. There are often mechanical issues associated with valve operation at temperature extremes. Testing at service thermal extremes is recommended if friction is an issue.

- Valve mechanical lubrication may be become less viscous and run out of valve components onto packing sets.
- Impregnated (oil or other dispersions) packing sets may have increased load loss.
- Metal expansion may cause interference issues on close tolerance components.

Conclusions

The force effects of packing on the valve stem vary with respect to the materials of construction, operational parameters like temperature extremes, and installation parameters. General guidelines have been established to roughly estimate friction, but empirical testing is recommended with the system in question if more precision is required. Key points include the following:

- Various methods exist in industry to describe the frictional force from a compression packing set. These methods vary. There is limited standardized testing for packing friction.
- End users need to communicate closely with their sealing provider to develop optimal actuator designs.
- Conservative calculation of the friction factor should be derived from the breakaway force measurements occurring when the valve motion changes direction.
- End users should assume testing is performed at ambient temperatures and not assume these conditions hold true at the extremes of the product temperature range.
- Friction factors used for valve design should be calculated from similar, ideally the same, operational conditions and packing configuration.
- Allowing PTFE in the construction of a braid means dramatic decreases of friction factor and stiction.
- Customer requirements take precedent. Metal filament-reinforced flexible graphite and PTFE are two common materials of construction that various end users limit, particularly in the nuclear industry.

References

(1) Atomic Energy of Canada Limited, “Valve Stem Packing Seal Test Results for Primary Heat Transport System Conditions in Canadian Nuclear Generating Stations,” D.F. Dixon, J.M. Farrell, and R.F. Coutinho, Publication AECL-6183, Chalk River Nuclear Laboratories, Chalk River, Ontario, June 1978.

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(3) EPRI, “Performance Characterization of Bolt Torquing Techniques: Sealing Technology and Plant Leakage Reduction Series,” March 26, 2002.

(4) J.C. Blake and H.J Kurtz, “The Uncertainties of Measuring Fastener Preload,” *Machine Design*, Volume 37, September 30, 1965, pp. 128–131.

(5) API 600/ISO 10434, Steel Gate Valves – Flanged and Butt-welding Ends, Bolted Bonnets.

Figures

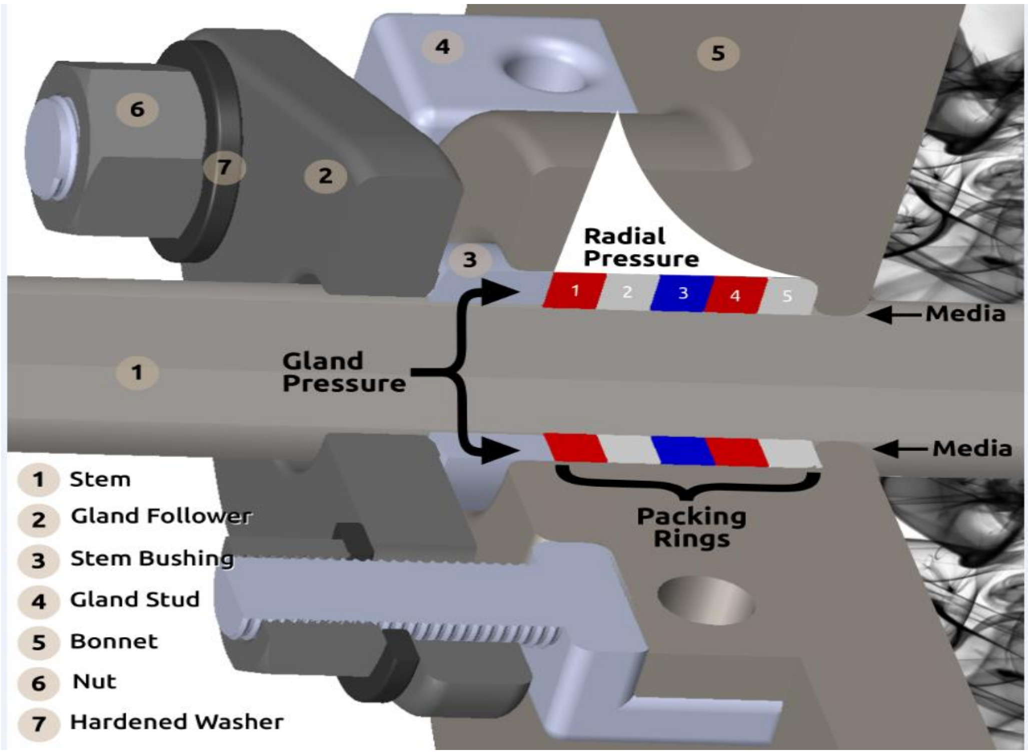

Figure 1. Typical Packing Box, Gland Follower, and Packing
(Source: Author)

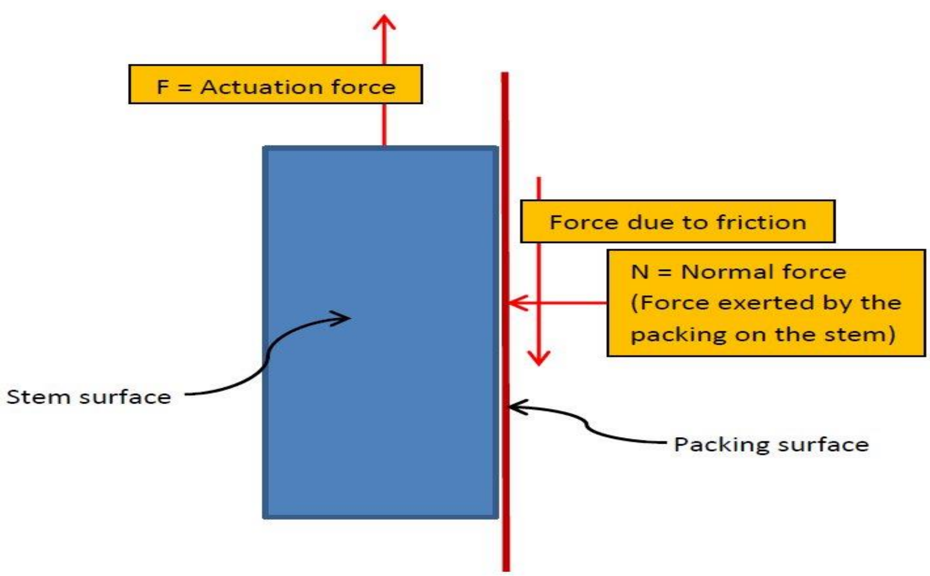

Figure 2. Basic Force and Friction Components
(Source: Author)

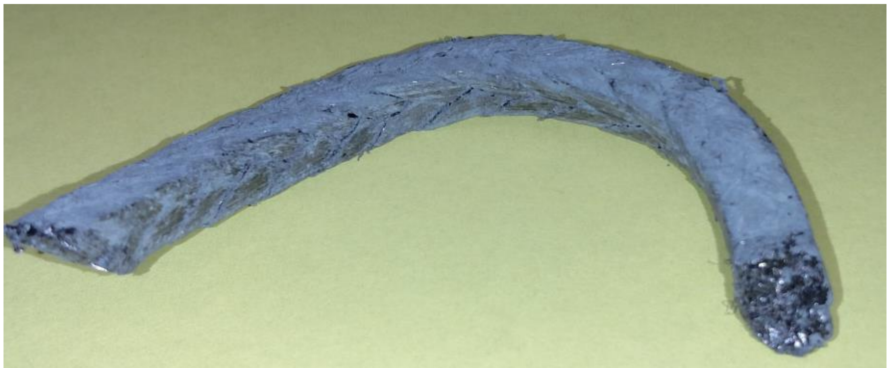

Figure 3. Before Compression—Wire-Reinforced Flexible Graphite Braid
(Source: Author)

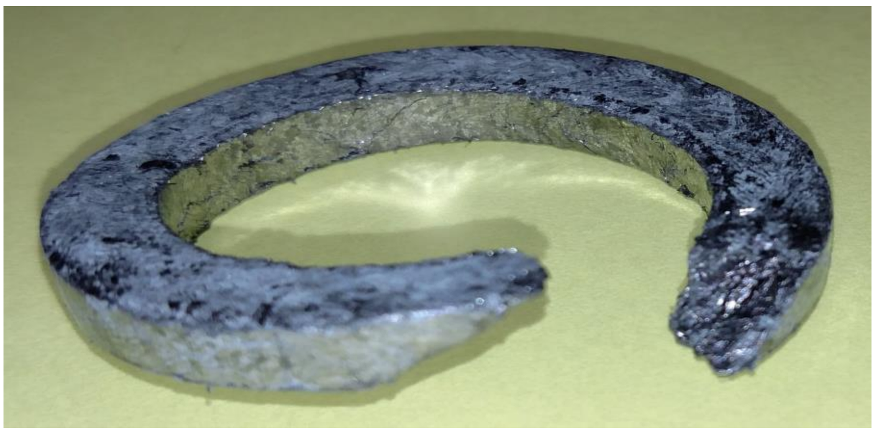

Figure 4. After Compression—Wire-Reinforced Flexible Graphite Braid
(Source: Author)

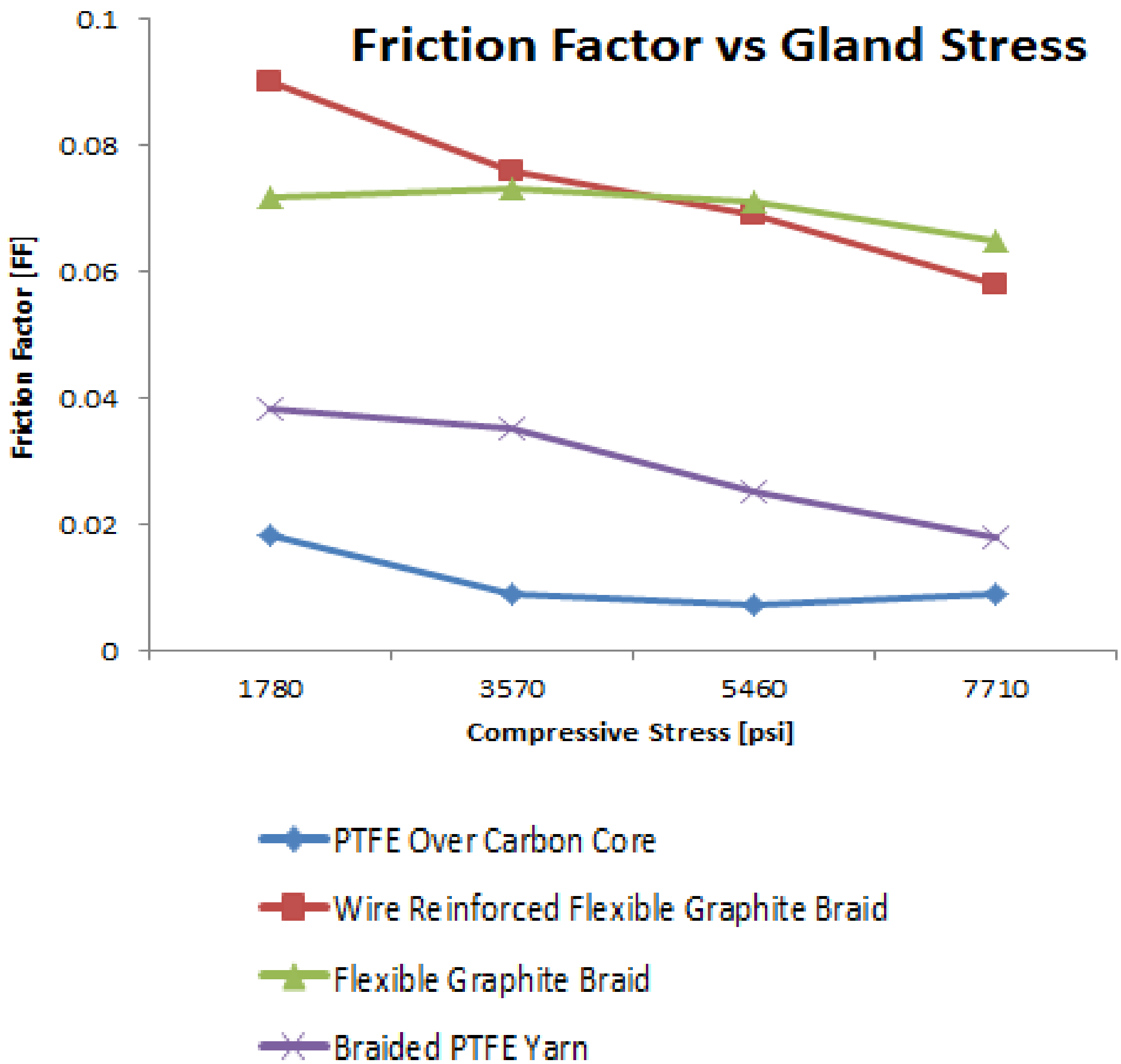

Figure 5. Friction Factor versus Stress for Various Packing Products
(Source: Author)

Figure 6. Valve Test Stand
(Source: Author)

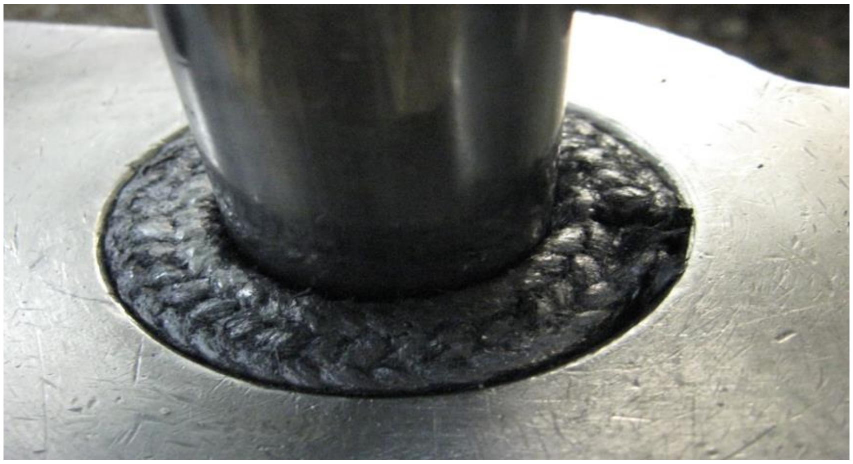

Figure 7. Braided Carbon/Graphite Ring in the Test Fixture Packing Box
(Source: Author)

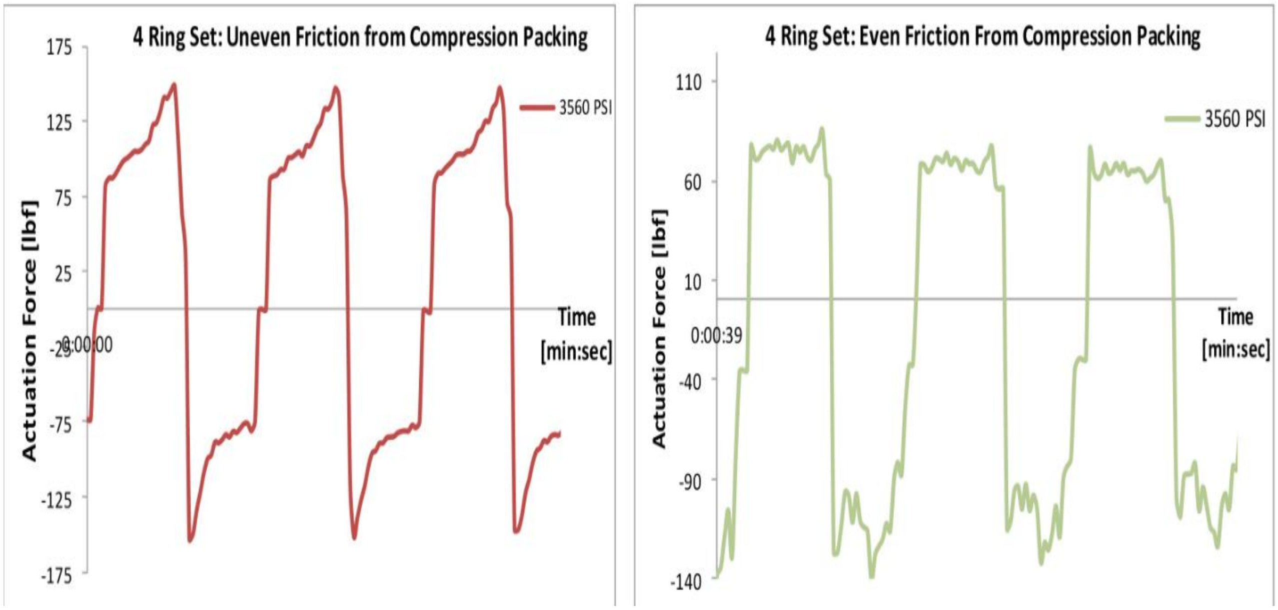

Figure 8. Packing Force Signature, Even versus Uneven
(Source: Author)

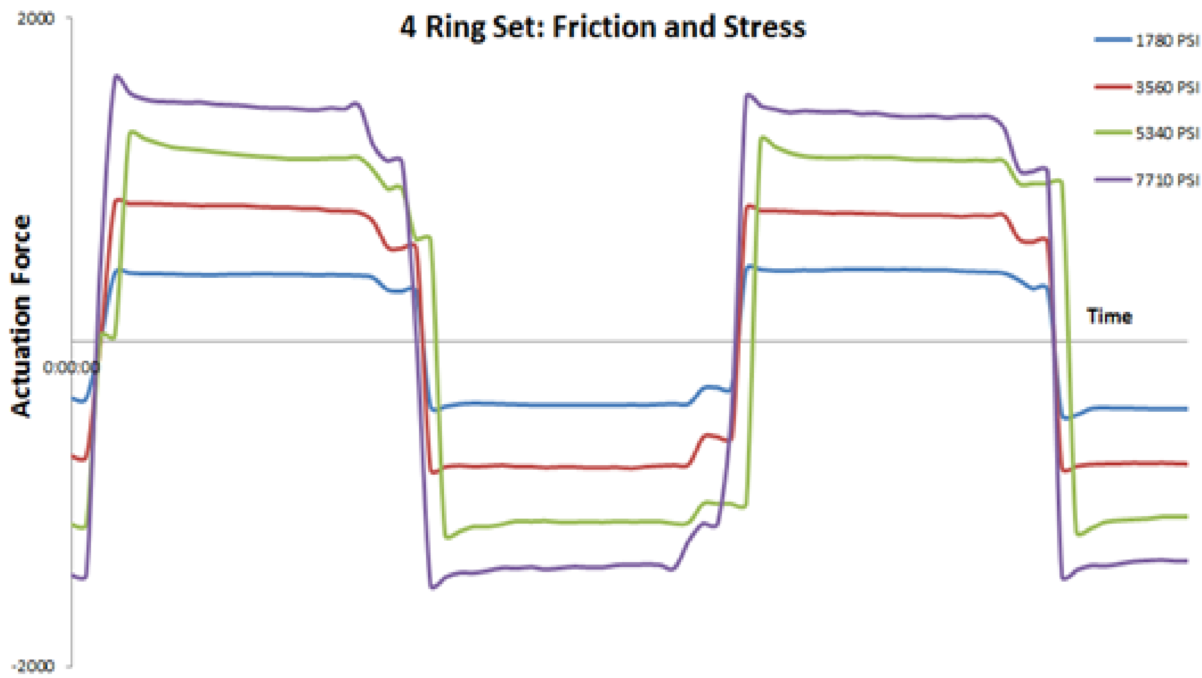

Figure 9. Actuation Force versus Compressive Stress
(Source: Author)

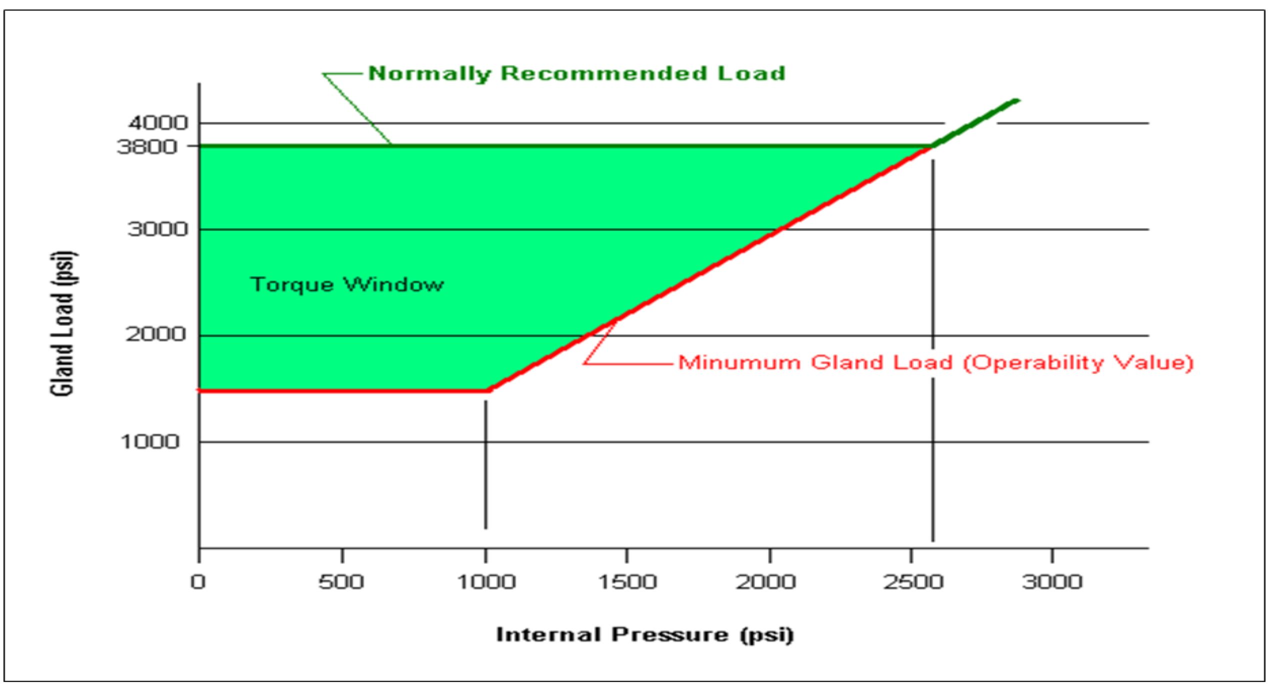

Figure 10. Typical Effective Packing Stresses
(Source: Author)

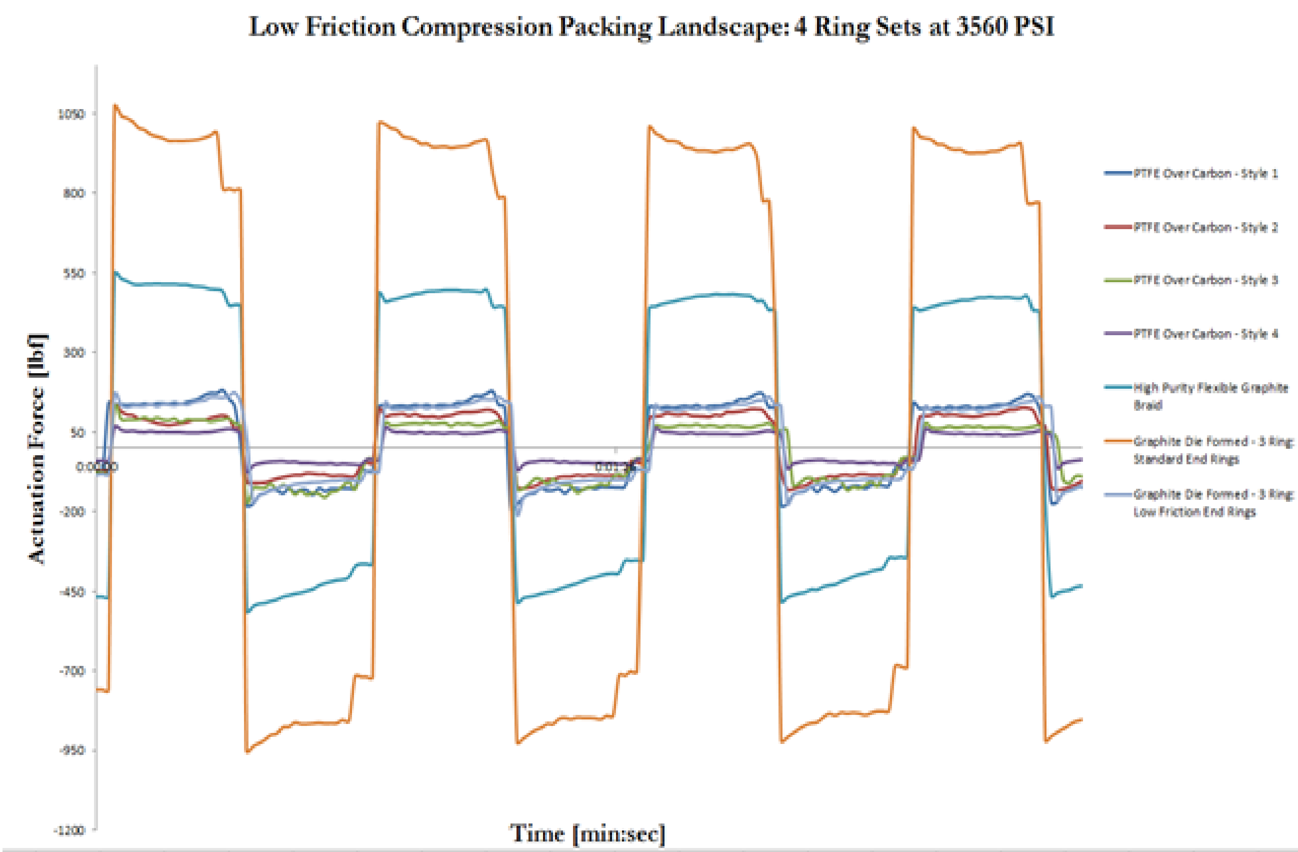

Figure 11. Actuation Force versus Various Packing Types at 3,560 psi Gland Stress
(Source: Author)

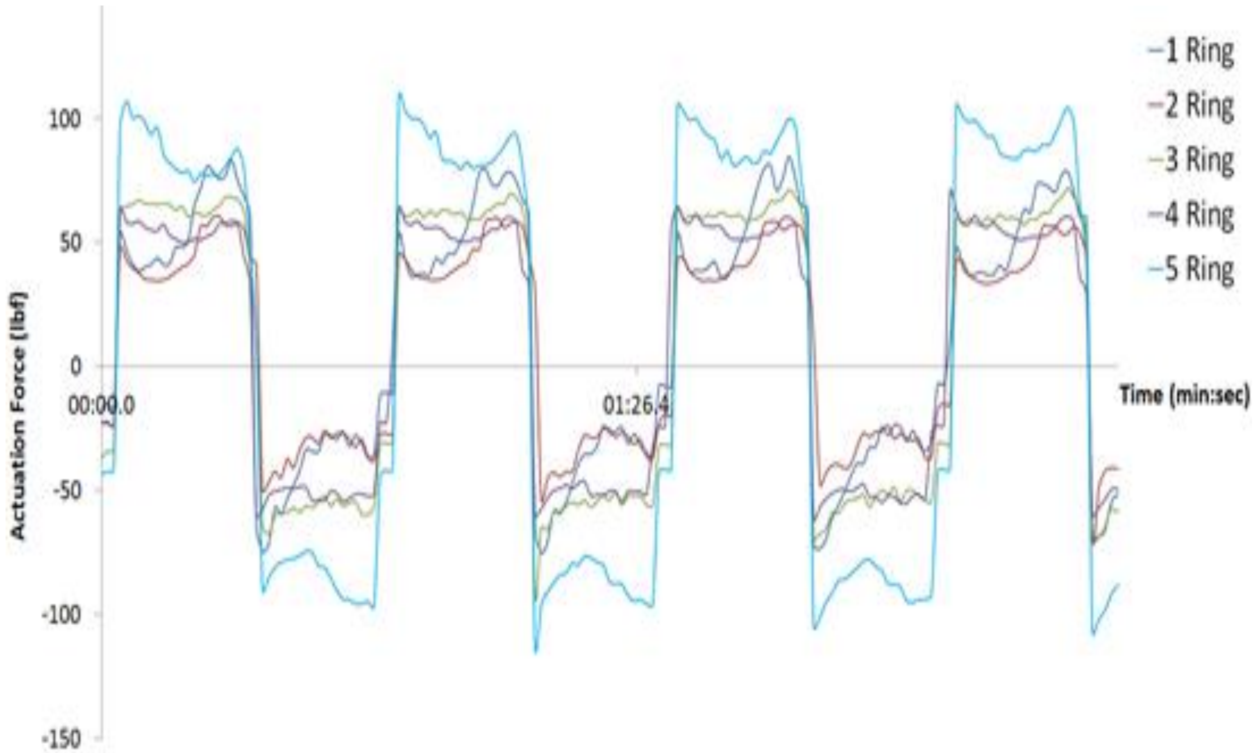

Figure 12. Actuation Force versus Number of Rings at 3,560 psi Gland Stress
(Source: Author)

Tables

Table 1. Testing Conditions
(Source: Author)

Shaft Finish:	16-32 μ-inch Ra
Speed:	0.5 inch/sec
Stroke Length:	2–4 inches

Table 2. Representative Gland Stresses
(Source: Author)

Stress 1	Stress 2	Stress 3	Stress 4
1,780 psi	3,500 psi	5,340 psi	7,710 psi
12.23 MPa	24.13 MPa	36.82 MPa	53.13 MPa

Table 3. Recommended Friction Factors versus Actual for Four-Ring Sets
(Source: Author)

Style	Recommended Friction Factor Value from Manufacturer	Empirically Calculated Friction Factors			
		1,780 psi	3,540 psi	5,460 psi	7,710 psi
PTFE over Carbon Core	.02	.0182	.009	.007	.009
PTFE Fiber	.042	.0384	.0353	.025	.018
Die-Formed Graphite	.063	.054	.047	.055	.057
Flexible Graphite Yarn	.080	.0718	.073	.071	.065
Wire Reinforced Flexible Graphite Yarn	.090	.09	.076	.069	.058

Curtiss-Wright Electro-Hydraulic Actuators for Main Steam and Main Feedwater Isolation Valves

Haykaz Mkrtchyan,[1] Ararat Torosyan,[2] and Hua Peng[3]
Curtiss-Wright Nuclear, Enertech, 2950 E. Birch St., Brea, CA 92821
haykazm@curtisswright.com[1]
atorosyan@curtisswright.com[2]
hpeng@curtisswright.com[3]

Abstract

This paper is about Curtiss-Wright's electro-hydraulic actuator environmental and seismic qualification for main steam isolation valve (MSIV) and main feedwater isolation valve applications. The qualification was performed in compliance with Institute of Electrical and Electronics Engineers (IEEE)-382 and Règles de Conception et de Construction des Systèmes et Matériels Electriques et de Contrôle Commande (RCC-E) international code requirements qualifying the actuator for U.S., Chinese, and European power plant designs. The qualification entailed several challenges and application of analytical and test methodologies. The weight of the actuator/yoke assembly made seismic qualification one of the most challenging steps in the program. The seismic qualification was performed jointly with the Areva U.S. Technical Center in Lynchburg, VA. The qualification program was designed to envelop the requirements of power plant designs in the United States, China, and Europe.

1. Introduction

MSIVs continue to challenge the reliable operation of nuclear power plants. A detailed review of various MSIV designs, maintenance practices, and industry failure databases reveals that there are types of MSIV failures that may have been prevented if the valve/actuator designs had been adequately validated and qualified in accordance with the latest industry qualification standards, such as American Society of Mechanical Engineers (ASME) Standard QME-1-2007 edition.

Both boiling-water reactors (BWRs) and pressurized-water reactors (PWRs) rely on MSIVs to isolate steam going into the main turbine. Various types of valves and actuator combinations are used in MSIV applications. For a typical MSIV, actuator closing force is generated by stored energy in the form of a compressed gas or springs. The closure signal is sent to solenoid valves that relieve the trapped fluid and allow the stored energy to close the MSIV. The MSIV has a critical function in ensuring public safety in case of an accident in the plant. The flow isolation time is typically required to be 2–5 seconds. MSIVs in both PWR and BWR designs have similar functions; however, some of their operational requirements are different.

In PWR designs, there is an MSIV in each of the main steamlines between the steam generators and main steam turbine. The MSIVs are located in a separate safety-related valve room outside the containment building. In BWR designs, typically two MSIVs are installed in each of the main steamlines (e.g., one is inside and one is outside the containment). The inboard valves are installed in the drywell, and the outboard valves are installed in the main steamline.

The primary functions of MSIVs in PWRs are to (1) protect against main steamline break (inside or outside containment), (2) isolate containment in case the containment pressure increases, (3) protect against spreading contamination in case there is steam generator tube failure, and (4) control the cooldown rate of the reactor.

In BWRs, the primary functions of MSIVs are to (1) rapidly stop the steam flow from the reactor to the turbine in case of a main steamline failure, (2) protect against radiation leaking out of the containment, (3) limit steam loss in case of a pipe break, (4) prevent the core from uncovering, and (5) prevent radiation release in excess of the regulatory requirements. Since MSIVs in BWRs perform a containment isolation function, they are required to be tested periodically for leakage (e.g., local leak rate testing) and partial stroke surveillance testing during normal operation.

The typical MSIV size range is DN450 - 900 (18 – 36-inch) and the most typical types of valves include Y-pattern globe valves, double-disk gate valves, and check valves. One of the most common types of actuators used in MSIVs is the electro-hydraulic/gas actuator.

Curtiss-Wright's electro-hydraulic actuator for MSIV applications is based on a gas spring configuration that uses hydraulic fluid to open the valve and gas pressure to close it. The actuator has a safety function to close the MSIV upon receiving a signal. The major components that have an active safety function are the solenoid valves, flow control valves, limit switches, pressure switches, and hydraulic dump valves. The actuator qualification incorporated the yoke to better simulate the interface between the valve and actuator. For added safety, the actuator design features dual redundant closing circuits that can be independently operated in case of emergency. Various industry-accepted qualification standards (e.g., IEEE 323, 344, and 382, RCC-E 2005, and International Electrotechnical Commission (IEC) 61000-4) were studied to develop a qualification program that will envelop all the requirements and qualify the actuator for use in plant designs that conform to these standards.

2. Qualification Program

The actuator qualification described here is based on the qualification tests performed on the actuator and supplemented by any required analysis and justification to support the component qualification. The qualification tests, in addition to engineering analysis, demonstrated the actuator's capability to perform its intended safety function during normal, abnormal, and postulated design-basis events (DBEs). The supplemental analysis was performed in accordance with the requirements of IEEE 382 and RCC-E standards. The qualification tests imposed accelerated and synergistically combined environmental conditions experienced by the actuator during its postulated service life, which includes normal, abnormal, and accident operating conditions. Acceptance criteria were defined for each qualification test based on the required performance characteristics of the actuator. The qualification program of this electro-hydraulic actuator envelops Curtiss-Wright actuators with similar design parameters with variation from the nominal value of the critical parameters of 50 percent smaller to 100 percent larger as defined by the extrapolation limits of IEEE 382. For design parameters outside of these limits, additional qualification tests or supplemental analysis may be required to adequately justify the equipment qualification. The purpose of the qualification test sequence was to expose the actuator to the most adverse expected aging mechanisms expected during its operating life before subjecting it to accident conditions.

The qualification program started with baseline functional tests to define actuator critical operating characteristics. Throughout the qualification program, these characteristics were verified between each qualification test to ensure that actuator performance remains within the defined acceptance limits. Following baseline testing, a thermal aging test was performed to bring the actuator to its end-of-life condition based on the thermal degradation elastomeric materials and components. Thermal aging parameters were defined using the Arrhenius equation for accelerated aging. Electromagnetic compatibility (EMC) testing was performed after thermal aging to confirm that the actuator and its electrical components conform to the requirements defined by applicable sections of MIL-STD-461E and IEC 61000-4. The EMC test is not considered to promote any known aging mechanisms, so its order in the qualification test sequence is not enforced. Following EMC testing, radiation tests subjected the actuator to a total integrated dosage (TID) consisting of the dosage from normal operating and accident conditions. Because radiation effect is cumulative, the qualification standards allow normal and accident radiation tests to be combined.

Seismic qualification tests were performed next in which the actuator was subject to seismic simulation tests to demonstrate its operability during and after the equivalent of five seismic events followed by one major seismic event where the actuator is supposed to close the valve to prevent a postulated major accident. The last qualification step was to expose the actuator to DBE accident environmental conditions (e.g., following a steam pipe break). These conditions are expected to take place only once during a 60-year plant life.

The rest of the paper provides more in-depth coverage for each qualification step. Each qualification step is discussed in more detail by highlighting key technical challenges and solutions during development and execution of a qualification program that envelops the qualification requirements for nuclear power plants built in the United States, Europe, and China using U.S. and European standards.

A summary of the qualification program is given in a table in Section 6 with all the major qualification steps and parameters listed.

2.1. Baseline Functional Test

The baseline functional test established reference performance parameters and acceptance criteria for the actuator. Some of the key parameters were the closing time, hydraulic/nitrogen pressure, and the resulting thrust. These parameters were measured, calculated, and later used for comparison at different stages of the qualification program. In addition to these parameters, the following performance aspects were recorded during baseline tests:

- proper pressure switch action
- opening/closing speeds under different loading conditions (e.g., minimum, nominal, and maximum motive power)
- observation and quantification of any leakage past the piston at 5,000 pounds per square inch gauge (psig) (34,500 kilopascals (kPa)) hydraulic pressure

2.2. Thermal Aging Test

The thermal aging test was performed at National Technical Systems (NTS) in Santa Clarita, CA. The purpose of the test was to age the actuator and its components to an equivalent of 55 degrees Celsius (C) for 13.2 years (12 years including an additional 10 percent margin). This is based on the elastomer qualified life requirement of 12 years. The metallic components are not subject to significant degradation from thermal aging; therefore, their qualified life is extended to 60 years. The test parameters were selected in accordance with the Arrhenius equation using activation energy of 1.0 electronvolt (eV)[1] as a basis for establishing test durations.

2.3 Radiation Exposure

The actuator components were qualified for radiation resilience using previously qualified units as a basis. It was shown that previously qualified similar electro-hydraulic actuators performed successfully when exposed to up to 182 Megarads (Mrads) of gamma radiation from a cobalt-60 radiation source. The radiation exposure from previous tests was significantly higher than the radiation levels for a main steam isolation service application; therefore, those tests fully envelop the maximum specified radiation dose. In addition, since beta radiation has far less penetrating power than gamma radiation, for additional conservatism, the qualification program considered the requirement of the total integrated dose to be the algebraic sum of the specified gamma (γ) and beta (β) radiation levels.

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[1] Based on the nonmetallic components in the actuator assembly, Viton was selected as the material with the lowest activation energy (1.0–1.11 eV) and was used to establish the thermal aging test duration. After completing the thermal aging test, the actuator performance was verified by repeating the test sequence established in the baseline operability tests.

2.4 Cycle Aging Test

The intention of the cycle aging test was to bring the actuator to its end-of-life condition (mechanical cycles) prior to DBE. IEEE 382 suggests a minimum of 2,000 cycles for an operator used in isolation service (on/off application). To qualify for cycle aging, the actuator was subjected to 3,305 cycles. The post-cycle aging performance verification test proved that the actuator still performs within the specified limits.

2.5 Normal External Pressurization Cycle

The qualification for normal pressurization cycle is intended to demonstrate the ability of the actuator to operate during and after exposure to a series of pressurization cycles expected during normal operation. During previous qualifications, Curtiss-Wright's actuator was exposed to 15 external pressure cycles, each cycle from 0 psig to 60 psig to 0 psig (0 kPa to 414 kPa and back to 0 kPa). Since the specified environmental pressure during normal and abnormal operating conditions is atmospheric, the qualified conditions envelop the required operating conditions.

2.6 Vibration Aging

Prior to DBE testing, the actuator was subjected to vibration aging. This aging process is designed to simulate the random vibrations the actuator will experience throughout its life. However, vibration aging by itself does not qualify the components for any specific plant operating condition.

The actuator assembly was tested in accordance with IEEE 382 and RCC-E for a minimum of 90 minutes in each orthogonal direction at 0.75g acceleration while sweeping from 5-200-5 hertz (Hz) at a rate of two octaves per minute. In the event of the test table limiting the range of the test frequencies, test duration can increase to account for the required equivalent number of cycles. During this test, the actuator was cycled every 15 minutes. These tests ensure that the critical components of the actuator were subjected to sufficient environment-induced vibration before the DBE.

2.7 Electromagnetic Compatibility Tests

The electronic components of the actuator were tested for electromagnetic and radiofrequency compatibility and susceptibility at TUV SUD America, Inc., San Diego, CA. The EMC test was performed in accordance with MIL-STD-461E and IEC 61000-4. The acceptance criteria were as specified in NRC Regulatory Guide 1.180, "Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems." Below are the applicable test specifications from MIL-STD-461E and IEC 61000-4.

MIL-STD-461E

Emission Testing	Susceptibility Testing
CE101: 25 Hz–10 kHz	CS101: 25 Hz–150 kHz
CE102: 10 kHz–2 MHz	CS114: 10 kHz–30 MHz
RE101: 25 Hz–100 kHz	RS101: 25 Hz–100 kHz
RE102: 2 MHz–10 GHz	RS103: 30 MHz–10 GHz
	CS115: 2A
	CS116: 5A，10 kHz–100 MHz

IEC 61000-4

4-2: E.S.D., Level 4: 8 kV contact discharge, 15 kV air discharge

4-4: E.F.T., Power: level 4 (4 kV), Signal: level 4 (2 kV)

4-5: Surge, Combination Wave, Power: level 4 (4kV), Signal: level 3 (2 kV)

4-12: Surge, 100 kHz Ring Wave, Power: level 4 (4 kV), Signal: level 3 (2 kV)

2.8 Seismic Simulation Test

The purpose of the seismic simulation test is to demonstrate the operability of the actuator during and after being subjected to the equivalent dynamic effects of five qualification operating-basis earthquakes (OBEs) followed by one qualification safe-shutdown earthquake (SSE).

2.8.1 Mounting and Configuration

The actuator was mounted on its yoke, and the yoke was welded to a steel plate. The steel plate was bolted to the shake table surface with sufficient attachment points to minimize resonance and ensure that the steel plate functioned as a rigid surface. The mounting configuration was representative of the installed condition and was adequate for line-mounted actuator applications. Electrical, hydraulic, and pneumatic connections simulate actual service and were made such that their impact on the seismic test results is minimized. Input motion was controlled in all three axes with accelerometers mounted directly to the shake table surface. In addition, triaxial accelerometers were mounted on the actuator at various points in order to monitor accelerations and deflections at significant locations. Throughout the seismic test, actuator performance was monitored with diagnostic equipment.

2.8.2 Test Conduct

Seismic testing was performed for line-mounted applications in accordance with IEEE 382-1996 and IEEE 344-2004. Testing was performed immediately following the vibration aging test. The following is an outline of the testing accomplished for each condition.

2.8.2.1 Resonance Search

The table was programmed for a resonance frequency search from 1 to 100 Hz in each orthogonal axis (X, Y, Z) at a constant acceleration of 0.2g with a sweep rate of one octave per minute. Transmissibility parameters were used to determine the resonance. The transmissibility parameters are software approximations and the data represent an amplification ratio. Natural frequencies are typically defined by amplifications greater than 4 on the transmissibility curves. The resonance search showed that the actuator's first fundamental frequency is 68 Hz.

2.8.2.2 Operating-Basis Earthquake

Two sine sweeps were performed in each of three orthogonal axes in a 2/3 required input motion (RIM) as shown in the figures at the end of this paper. The sweeps were from 2 Hz to 64 Hz to 2 Hz at a rate of one octave per minute. One sweep was performed with the actuator open; the second sweep with the actuator closed. OBE tests were performed at the full 4.4g (2/3 x 6.6g) input as required by the qualification plan.

2.8.2.3 Safe-Shutdown Earthquake

The actuator was subjected to a series of single frequency sine beats from 2 Hz to 32 Hz at 1/3 octave intervals, which continued from 32 Hz to 64 Hz at 1/6 octave intervals. There were 12 - 15 oscillations per beat at each frequency reaching the peak acceleration from the RIM chart. The actuator was cycled at each octave to demonstrate operability during a seismic event. The SSE test was repeated in each of three orthogonal axes.

2.8.2.4 Design-Basis Event Environment Test

The intent of the DBE test was to demonstrate that the actuator can successfully perform its safety function during exposure to extreme environment conditions that are representative of the actual conditions that the actuator can experience during an accident. The DBE accident is a single postulated event that can occur at any point during a 60-year installed life. During this event, the actuator can experience a temperature rise of up to 257 degrees C for a period of approximately 10 minutes. IEEE 323 requires the test temperature profile to envelop the required temperature profile by 8 degrees C at the peak in order to meet the required standard margins. The required accident temperature profile extended 14 days of exposure to 53 degrees C environment. In order to shorten the test time, the Arrhenius equation was used to establish an equivalent test duration by increasing the test temperature accordingly and limiting the test duration to 15 hours. During the test, the actuator was required to close once at the peak temperature and one more time after the actuator was subjected to the full temperature transient.

2.8.2.5 ASME QME-1 Flow Interruption Test

To verify the actuator's capability to demonstrate its operability during a simulated pipe break, a representative actuator was tested at Areva's Technical Center and Large Valve Test Facility GmbH at Karlstein. The test was performed with the actuator mounted on a representative size DN800 (32-inch) MSIV.

2.8.2.5.1 Test Setup

The test facility is designed for qualification of large steam isolation valves under pipe break transients. It is a full-size mockup of the secondary circuit of a PWR including an accumulator that has a size comparable to a steam generator size. There was a main stop valve installed on the top of the accumulator to isolate the accumulator from the test specimen if needed. Downstream of the test specimen, there were two quick opening valves that were used to initiate the test. After the steam passed through the test specimen, it was led to a condensing pool. The MSIV and the upstream/downstream pipes were thermally insulated with mineral wool mats. There were measurement transducers connected to the valve and the piping to measure pressures at different locations. Figure 5 shows the test schematic in more detail.

2.8.2.5.2 Flow Interruption Test Procedure and Summary

The flow interruption tests began with initial conditions at 11 MPa of saturated steam. The test started by quickly opening the downstream valves. The acceptance criteria for the flow interruption test was for the MSIV to close between 2–5 seconds against 8.4 MPa and 315 degrees C of saturated steam. The initial pressure was set high in order to ensure the minimum specified upstream pressure is available by the time the gate reaches its closed position.

After the valve closes, downstream pressure is atmospheric and the upstream pressure is the accumulator pressure. Following valve closure, the bypass line around the test specimen was opened to equalize the pressure across the MSIV. The test valve was then opened using the hydraulic pump within the required time.

3. Conclusion

The Curtiss-Wright electro-hydraulic actuator for main steam and main feedwater isolation services was successfully qualified through the program that was designed to envelop the requirements of U.S. and European qualification standards. The qualification validates the actuator for use in existing and new-built nuclear power plants that require compliance with these qualification standards. The qualification can be extended to address varying design and performance requirements in accordance with ASME QME-1, IEEE 382, IEEE 323, and RCC-E.

4. Acknowledgments

We are grateful to Curtiss-Wright's management team for providing the needed resources and funding to successfully develop and execute the qualification program. We also want to thank CNNC SUFA Technology Industry Co. team for its continuous support and cooperation in qualifying the actuator/valve interface, which also enabled us to qualify the actuator for flow isolation in Karlstein.

In addition, we are grateful for the support we received from Areva, NTS, and the TUV teams and for their excellent performance in conducting the difficult qualification tests in accordance with the program.

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6. Tables and Figures

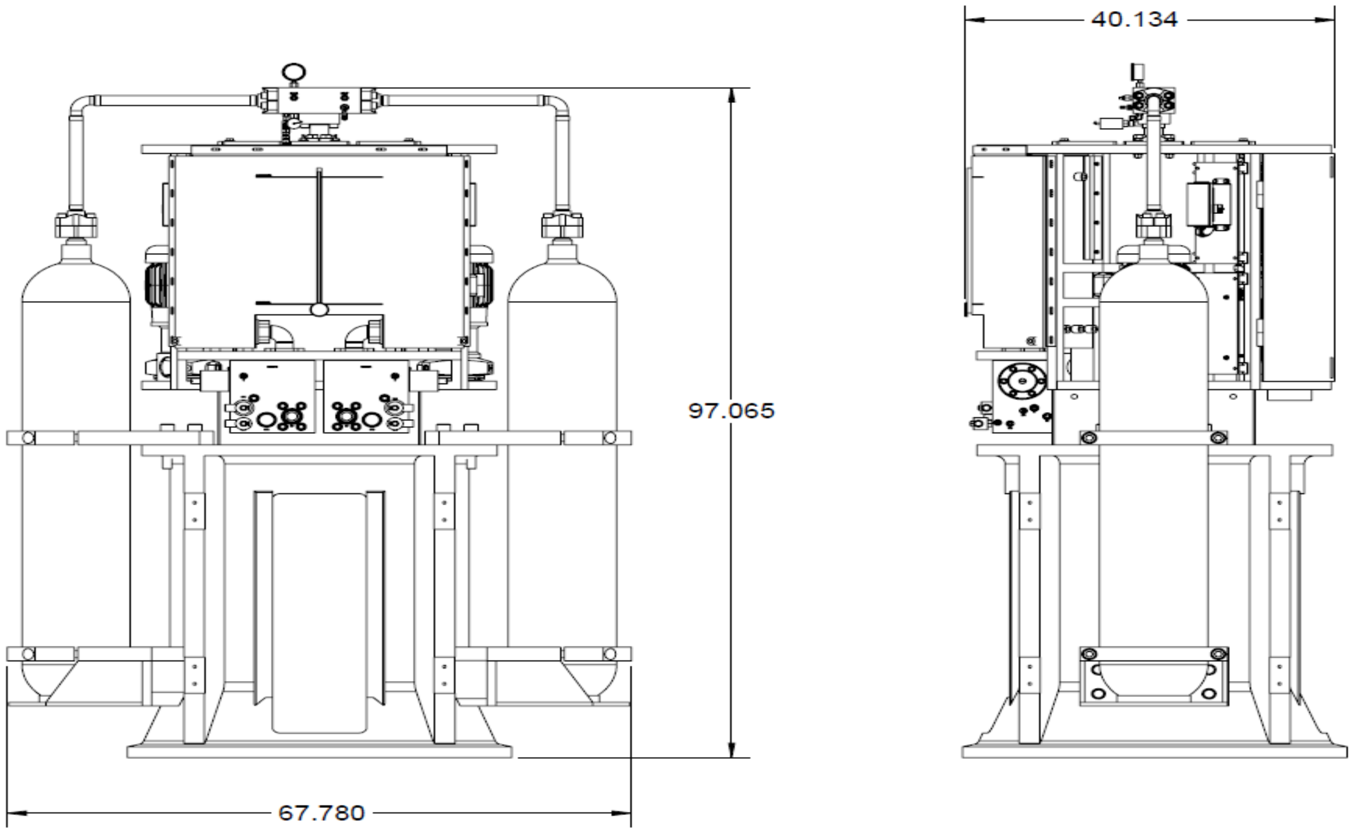


Figure 1: Qualification Actuator Assembly
(Source: Author)

Figure 2: Actuator Assembly with Valve Yoke
(Source: Author)

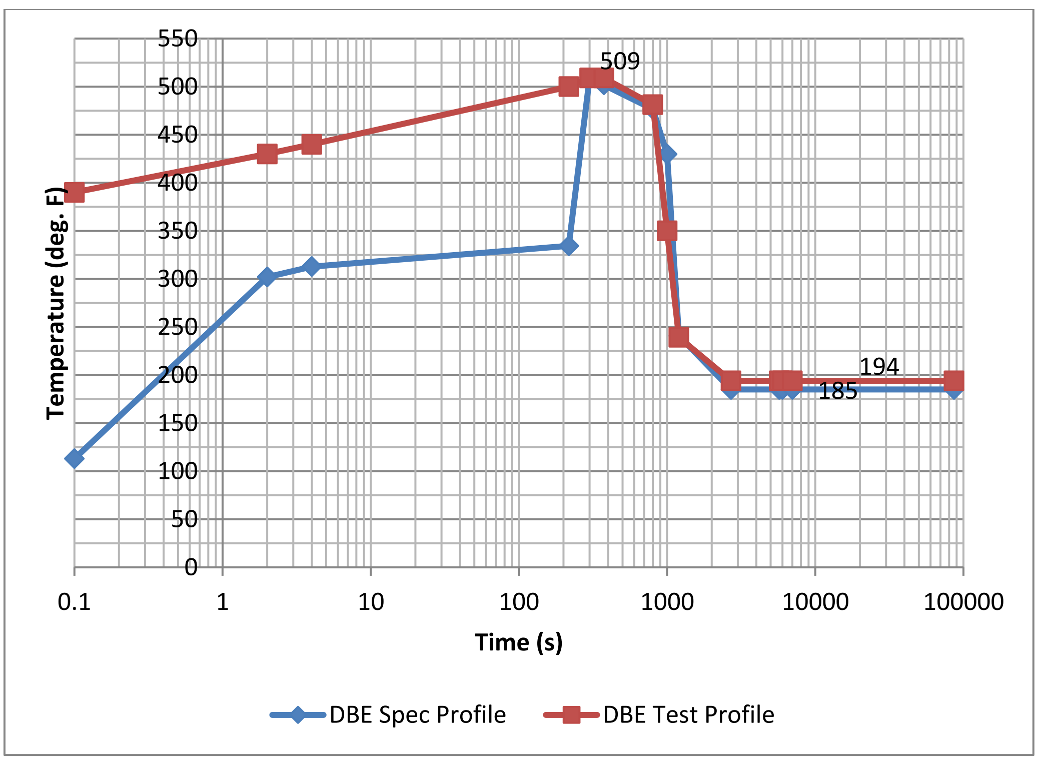


Figure 3: DBE Accident Temperature Profile
(Source: Author)

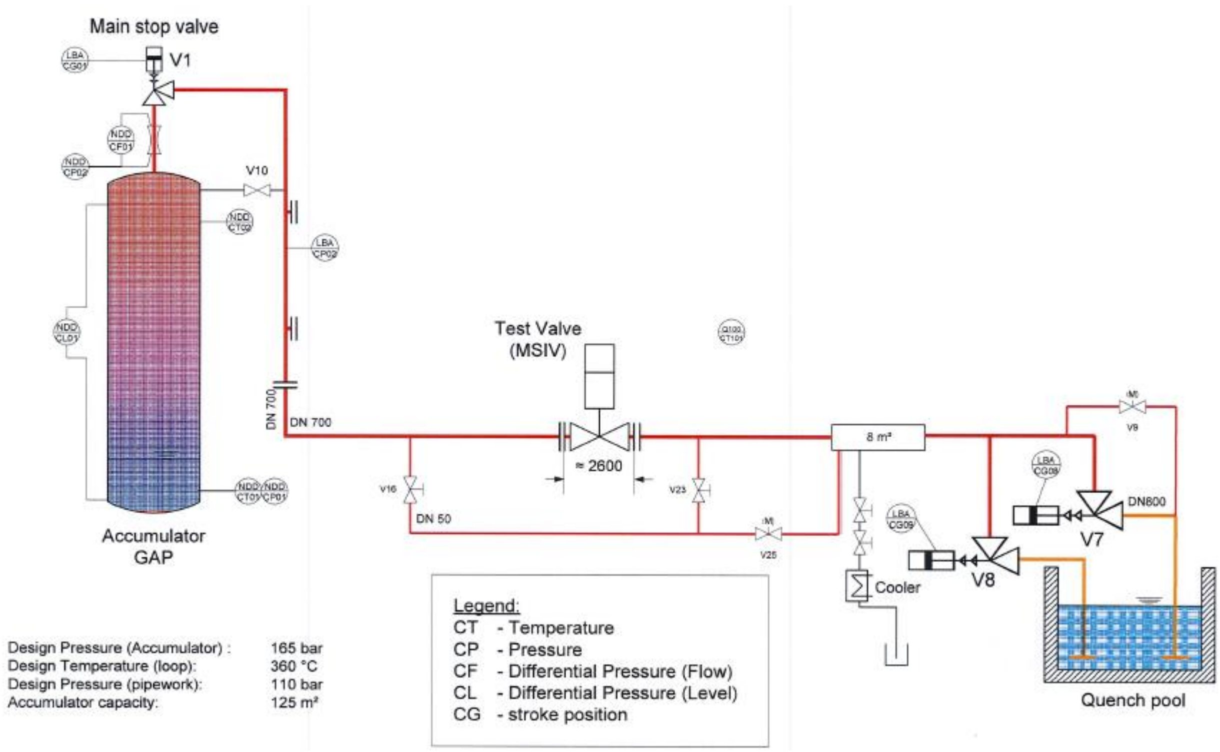


Figure 4: Flow Interruption Test Schematic
(Source: Author)

Figure 5: Curtiss-Wright Electro-Hydraulic Operator on MSIV at Karlstein
(Source: Author)

Qualification Test	Selected Parameters
Qualified Life	60 years
Baseline Functional	Selected performance parameters based on the specified operating conditions
Thermal Aging (nonmetallic components)	13.2 years at 131°F (55°C)
Radiation Aging	1.1×10^5 grays (Gy) (TID)
Electromagnetic Compatibility (EMC)	MIL-STD-461E, IEC 61000-4
Cycle Aging	3,300 cycles
Pressure Cycle	Atmospheric
Vibration Aging	0.75g (5-200-5 Hz)
DBE Radiation Exposure	γ-rad: 543 Gy β-rad: 2,783 Gy
Seismic Simulation	6.6g
DBE Environment Test	Temperature Profile

Qualification Program Summary
(Source: Author)

Effective Diaphragm Area Test Program for Air-Operated Valve Actuators

Zachary Leutwyler
Kalsi Engineering, Inc.
745 Park Two Drive
Sugar Land, TX 77478
zleutwyler@kalsi.com

Manmohan Kalsi
Kalsi Engineering, Inc.
745 Park Two Drive
Sugar Land, TX 77478
Kalsi@kalsi.com

Lisa Thidavanh
Kalsi Engineering, Inc.
745 Park Two Drive
Sugar Land, TX 77478
Lisa@Kalsi.com

Laurie Luckhardt
GE Oil & Gas Canada, Inc.
133 King Street West PO Box 65525
Dundas, Ontario, L9H 6Y6
Laurie.Luckhardt@ge.com

Thomas Cunningham
GE Oil & Gas, Inc.
85 Bodwell Street
Avon, MA 02322-1190
Thomas.Cunningham@ge.com

Abstract

General Electric (GE) contracted Kalsi Engineering, Inc. (KEI) to perform actuator testing to determine the effective diaphragm area for the Model 37/38 actuator line and to develop a bounding effective diaphragm area tolerance to account for measurement uncertainties and manufacturing tolerances.

The GE-sponsored test matrix includes Model 37/38 Sizes 9, 11, 13, 15, 18, and 24 actuators. The test matrix was primary defined to provide effective diaphragm area (EDA) data for actuators used in U.S. nuclear power plants. The test matrix was primarily designed to facilitate the evaluation of the effects of stroke position, pressure, diaphragm materials, and measurement uncertainty. The test matrix also included with and without spring test configurations, two spring options for the same actuator size and model, and two diaphragm materials: nitrile elastomer and silicone.

The test program provides reliable data for air-operated valve (AOV) design-basis evaluations as required by the U.S. Nuclear Regulatory Commission (NRC) Regulatory Issue Summary 2000-03, “Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves under Design Basis Conditions,” dated March 15, 2000. This paper presents the results for the Masoneilan Model 38 Size 11 diaphragm actuator, which show that EDA is strongly position dependent and weakly pressure dependent.

As part of the project, a method for determining the required EDA tolerance to account for manufacturing variations was developed, which allows EDA determined by testing to be used across the product line.

Introduction

EDA is a primary input for determining the output capability of AOV actuators. Potential nonconservatism in EDA for AOV actuators was identified as a key issue by the NRC in 1996, the Electric Power Research Institute (EPRI) AOV Evaluation Guide and the Duke Engineering Report sponsored by the Joint Owners’ Group AOV program. Because of the noted importance in EDA values, KEI performed a pilot test program. The GE-sponsored test program was built on an original pilot program initiated by KEI.

Nomenclature

B	:	Bias/systematic uncertainty
d_{eff}	:	Effective diaphragm diameter *(inches)*
d_c	:	Clamping diameter *(inches)*
d_p	:	Diaphragm plate diameter *(inches)*
EDA	:	Effective diaphragm area *(square inches)*
F_{fric}	:	Actuator friction force *(lbf)*
F_m	:	Measured thrust *(lbf)*
F_{spring}	:	Spring force *(lbf)*
H	:	Diaphragm height (or depth of dish-feature) *(inches)*
h_1	:	Offset between λ = -1 and y =0 *(inches)*
P_d	:	Diaphragm pressure *(psi)*
S	:	Random/Precision error
t	:	Student's t-value
u	:	Total uncertainty
y	:	Stem position y measured from fail position *(inches)*
Λ	:	Combined product of the weight factor and dimensional tolerance of key parameter in the calculation for EDA tolerance to account for manufacturing tolerances

Subscripts

EDA	=	Uncertainty in effective diaphragm area
F_M	=	Uncertainty in measured force
P_d	=	Uncertainty in diaphragm pressure

Background

Diaphragm actuators are typically single acting (i.e., the actuator is actuated in a single direction via air pressure, and the actuator relies on a spring to return the actuator stem to the fail position. Diaphragm actuators are further categorized by defining the actuator action. Actuator actions are direct-acting or reverse-acting. The actuator stem of a direct-acting actuator extends when the actuator is pressurized (Figure 1a). The actuator stem of a reverse-acting actuator retracts when the actuator is pressurized (Figure 1b).

The results presented in this paper are for a Masoneilan Model 38 Size 11 diaphragm actuator, which is reverse-acting. The Masoneilan Model 38 actuator comprises the same type of primary components as a typical diaphragm actuator (Figure 2). The actuator components most relevant to this study are the diaphragm, diaphragm plate, diaphragm case, spring, and yoke packing.

The measured actuator output force (F_m) consists of the components defined in Equation (1), where EDA is dependent on both pressure and position and the spring force (F_{spring}) is dependent on position.

$$F_m = EDA * P_d - F_{spring} - F_{fric} \tag{1}$$

The diaphragm reacts against the diaphragm plate and case similar to a suspended cable carrying a distributed load. The diaphragm transmits part of the load to the diaphragm case and part to the diaphragm plate. The proportions of the load distribution depend on the shape of the diaphragm, which is largely determined by the position of the diaphragm plate relative to the diaphragm caps (see Figure 3).

The EDA is the area of the diaphragm that contributes to the actuator output by transferring load to the diaphragm plate. The EDA has a corresponding effective diameter (d_{eff}). The shape of the diaphragm is similar to a catenary curve, and the effective diameter corresponds to the location of zero slope in the curvature of the diaphragm (see Figure 3).

As illustrated by Figure 3, the EDA for a dish-style diaphragm at the fail position is typically the greatest. At the extreme stem position shown in Figure 3a, the diaphragm plate pulls the diaphragm taut and thereby pushes the effective diameter toward the diaphragm case. As the diaphragm plate is actuated away from the fail position, the relative distance between the diaphragm plate and the clamping diameter (i.e., the point on the diaphragm that is clamped by the case) decreases. The decrease in distance produces slack in the diaphragm. The slack in the diaphragm causes the effective diameter to move off the clamped diameter toward the halfway point between the clamped diameter and the diaphragm plate (Figure 3b). As the diaphragm plate is actuated to the extreme limit of travel (away from the fail position), the relative distance between the diaphragm plate and case again increases. At the extreme travel position illustrated in Figure 3c, the position of the diaphragm plate causes the effective diameter to rest on the edge of the plate minimizing the EDA.

In addition to the effect stem position has on EDA, the location of the effective diameter can also be affected by manufacturing tolerances in the diaphragm plate, diaphragm, and case. The effects of manufacturing tolerances are addressed in the GE-sponsored testing and discussed later in this paper.

Test Fixture and Test Procedures

Test Setup

The test fixture is shown as Figure 4. The test fixture is equipped with a double-acting hydraulic cylinder that provides a reaction force for the actuator. The reaction force (hydraulic pressure) is generated when the movement of the piston tries to discharge hydraulic fluid through a variable resistance. The test fixture is designed to allow multiple actuators to be mounted with minimal changes to the fixture.

The data were acquired using a National Instruments compact data acquisition system and sensors. The data acquisition system includes analog inputs, analog outputs, and digital outputs (i.e., relays) modules. The sensors include multiple pressure transducers, multiple force transducers, and a position potentiometer. The pressure transducers are used to measure supply pressure and diaphragm pressure. The force transducers are used to measure the actuator stem force, and the position potentiometer is used to measure stem travel.

The hydraulic system was automated to allow the test program to position the hydraulic valves, reducing manual setup for each dynamic test and resulting in more consistent dynamic tests.

Test Matrix

The test matrix included static, dynamic, and discrete position tests. Static tests were performed with the actuator decoupled from the hydraulic cylinder. The diaphragm pressure and position were recorded as the diaphragm pressure was increased from 0 pounds per square inch (psi) to the actuator casing pressure rating. Dynamic tests were performed with the actuator coupled to the hydraulic cylinder while maintaining a constant diaphragm pressure and using the hydraulic ram to control actuator position and provide the reaction for the actuator. The diaphragm pressure, position, and reaction force were recorded as the hydraulics allowed the actuator to slowly travel. Discrete position tests were performed with the actuator coupled to the hydraulic cylinder. The hydraulic ram was used to maintain a constant stem position. The diaphragm pressure, position, and reaction force were recorded as the diaphragm pressure was varied from the casing pressure to 0 psi. The discrete position test allows the EDA to be determined solely as a function of pressure, as position remains constant.

A single Masoneilan Model 38 Size 11 diaphragm actuator was tested with a new nitrile elastomer diaphragm.

Dynamic tests were performed for the Size 11 actuator at 20, 30, 40, 50, and 60 psi. Discrete position tests were performed at key stem positions for pressures ranging from the maximum casing pressure down to 0 psi.

Uncertainty Analysis

The uncertainty analysis is performed using the root sum of the squares method for combining uncertainties using the weight terms calculated by taking the partial differential of the result R with respect to the measurands x_1, x_2, …, x_n. The general expression of the partial derivative of the result R based on the independent measurands x_1, x_2… is given as Equation (2).

$$\delta R = \delta x_1 \frac{\partial R}{\partial x_1} + \delta x_2 \frac{\partial R}{\partial x_2} + \cdots + \delta x_n \frac{\partial R}{\partial x_n} \quad (2)$$

A simplified example of the measurement uncertainty analysis is provided. For a discrete position test, the position dependency of Equation (1) can be omitted because position is constant for each test set (see Equation (3)).

$$F_m(P_d) = EDA(P_d) * P_d - F_{spring} - F_{fric} \quad (3)$$

The EDA can then be expressed by Equation (4).

$$EDA(P_d) = \frac{F_m(P_d) - F_{spring} - F_{fric}}{P_d} \quad (4)$$

The spring force (if a spring is installed) and friction force correspond to the measured force with a diaphragm pressure of 0 psi, and Equation (4) can be rewritten as Equation (5).

$$EDA(P_d) = \frac{F_m(P_d) - F_m(0)}{P_d} \quad (5)$$

Applying Equation (2) to Equation (5), where the function R is the equation for EDA and measured pressure and thrust are the independent variables, the expression for the sensitivity of the EDA to pressure for a discrete position (constant position) test is given as Equation (6).

$$\partial EDA = \frac{1}{P_d} \partial F_m(P_d) + \frac{1}{P_d} \partial F_m(0) + \frac{F_m}{P_d^2} \partial P_d \quad (6)$$

The total uncertainty in the EDA (Equation (7)) comprises the systematic/bias uncertainty (B_{EDA}) and the random/precision uncertainty (S_{EDA}). The systematic/bias uncertainty is given as Equation (8) and accounts for uncertainty due to instrument accuracy, calibration accuracy, data acquisition accuracy, and data filtering, for example. The random/precision uncertainty is given as Equation (9) and accounts for sources of random error such as instrument repeatability, thermal stability of the apparatus and instrumentation, and repeatability of the experiment. The Student's t-value based on the EDA test setup and matrix is dependent on the desired confidence (95 percent) and the number of degrees of freedom: 4 degrees of freedom exist because five tests were conducted at each position.

$$u_{EDA} = \sqrt{B_{EDA}^2 + (tS_{EDA})^2} \tag{7}$$

$$B_{EDA} = \sqrt{2\left(\frac{1}{P_d} B_{F_m}\right)^2 + \left(\frac{F_m}{P_d^2} B_{P_d}\right)^2} \tag{8}$$

$$S_{EDA} = \sqrt{2\left(\frac{1}{P_d} S_{F_m}\right)^2 + \left(\frac{F_m}{P_d^2} S_{P_d}\right)^2} \tag{9}$$

Note that in Equation (6), the uncertainty due to the force measurement appears twice, as two force measurements are subtracted in Equation (5); the presence of the two force terms requires doubling the uncertainty due to the force measurement in the summation of the systematic/bias uncertainty in Equations (8) and (9).

Test Results

The nominal calculated EDA values based on dynamic stroke are provided as Figure 5. The dynamic stroke test and discrete position tests provide nearly identical results. Dynamic stroke tests provide efficient means of studying the effect of position, while the discrete position tests provide an efficient means of studying the effects of pressure. Agreement between the two test methods indicates that the ramp time used for varying position during the dynamic tests and pressure during the discrete position tests was sufficiently long to ensure that a quasi-steady state existed. Agreement between the two test methods also indicates that time/position history does not have a significant effect on the EDA. The dynamic stroke test results show the following:

- The EDA is largest at the fail position.
- The rate of change in the EDA (with respect to stem position) initially decreases as the actuator moves away from the fail position and is less sensitive to changes in position in the midstroke region.
- The rate of change in the EDA (with respect to stem position) increases as the actuator approaches the end of travel (fully retracted position), at which point the EDA reaches a minimum value.

The discrete position test results for 0.0 inch and 1.0 inches coupled stem position are shown as Figure 6 and Figure 7. The results of the measurement uncertainty analysis are also provided in these figures. The error bars about the EDA values indicate uncertainty in the calculated EDA due to measurement uncertainty.

Accounting for Manufacturing Tolerances

Variations in manufactured components exist due to their respective defined dimensional tolerances and the associated manufacturing processes. Variations in key actuator components affect the EDA with respect to position. A methodology was developed to calculate an EDA tolerance based on dimensional tolerances for each actuator size to ensure that the bounding EDA values remain conservative. The required EDA tolerance to account for manufacturing tolerances is calculated from Equation (10).

$$wEDA = \sqrt{(\Lambda_H)^2 + (\Lambda_{dc})^2 + \left(\Lambda_{dp}\right)^2 + \left(\Lambda_y\right)^2 + (\Lambda_{h1})^2} \tag{10}$$

Tolerance contributions due to the independent parameters (represented by the Λ terms) are determined using weight terms and corresponding dimensional tolerances for the key positions. The weight terms (built into the Λ terms) are derived using a sensitivity equation derived from a dimensionless analysis of the EDA. The Λ terms are linked to their corresponding independent parameter (H, d_c, d_p, y and h_1) based on the subscript. The contribution of these key parameters to the tolerance is provided as Figure 8.

The underlying principle of the methodology is that each key component essentially affects the EDA value with respect to stem position. As such, the methodology consists of a weight factor and the uncertainty in the parameter based on the dimensional tolerances. The weight factor accounts for the effect the parameter has on the EDA and its relationship with position.

Conclusions

Based on the results from dynamic and discrete position testing, the following conclusions are made.

For the actuator studied, the EDA is position and pressure dependent. The sensitivity to changes in position varies based on the distance between the diaphragm support point on the diaphragm plate and the diaphragm clamped point between the diaphragm case halves. Pressure affects the EDA via changing the effective diameter; therefore, over the region of travel in which the EDA is more position sensitive, the EDA will also be more sensitive to pressure.

An acceptable EDA value and tolerance must account for variations in manufacturing of the diaphragm case, diaphragm plate, and diaphragm.

In low margin applications, measuring the output force (instead of diaphragm pressure) under design-basis conditions may be required due to the relatively large tolerance required to bound the uncertainty due to manufacturing tolerances and repeatability.

Determining EDA values based on static stroke tests can result in nonconservative values. EDA values should be consistent with the pressure at which the actuator output capability evaluation is to be performed.

An uncertainty analysis is required to determine true changes in EDA and apparent changes due to measurement accuracy.

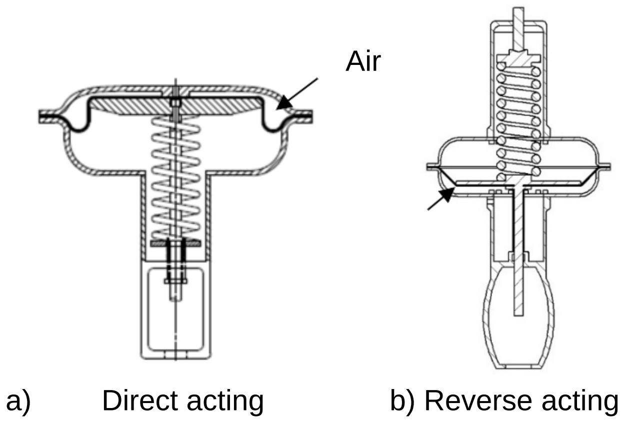


Figure 1. (a) Direct- and (b) Reverse-Acting Actuators
(Source: Author)

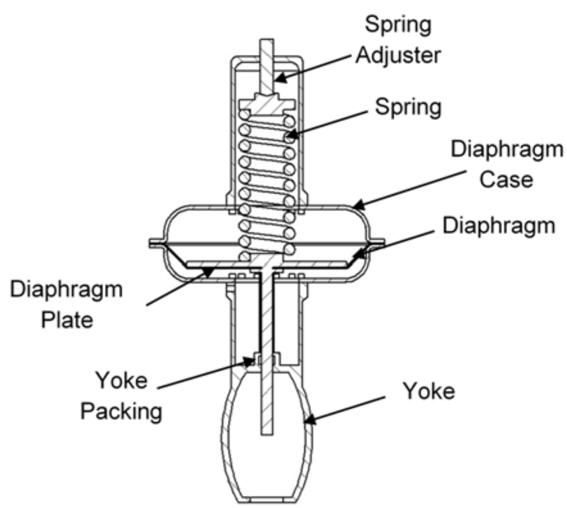
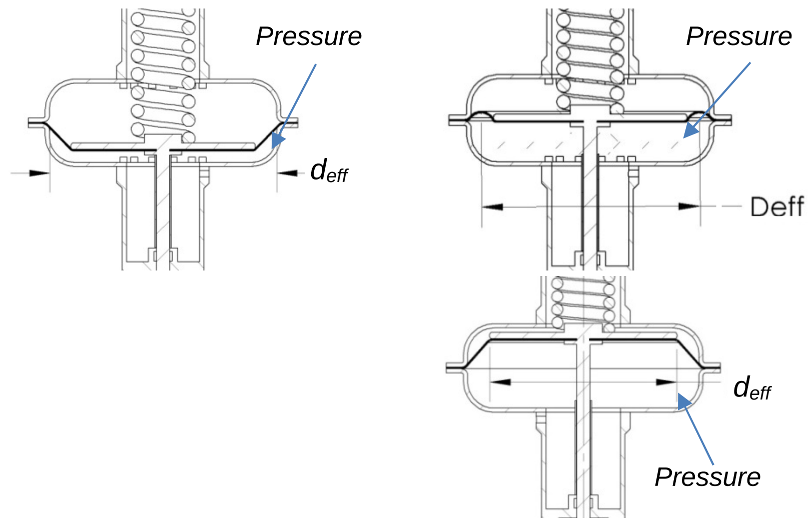


Figure 2. Masoneilan Model 38, Size 18, Air-To-Retract
(Source: Author)



a) Fully extended (fail position) b) Midstroke position c) Fully retracted

Figure 3. The EDA and corresponding effective diaphragm diameter (*deff*) change throughout the stroke due to the available slack generated by the relative distance between the diaphragm plate and the clamped diameter.
(Source: Author)

a) Front View b) Side View

Figure 4. Test Fixture with Actuator Yoke
(Source: Author)

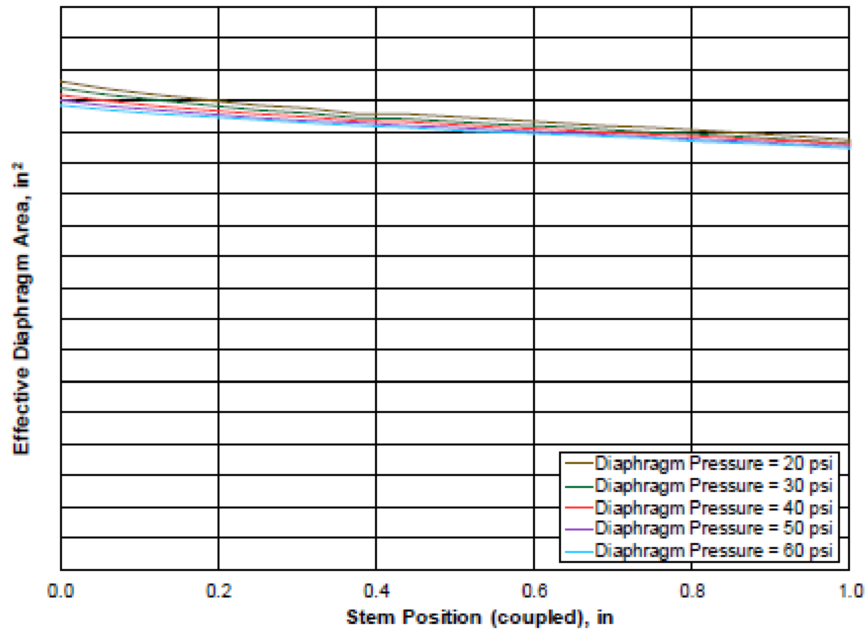


Figure 5. The Results of the Dynamic Tests at 20, 30, 40, 50, and 60 psi
(Source: Author)

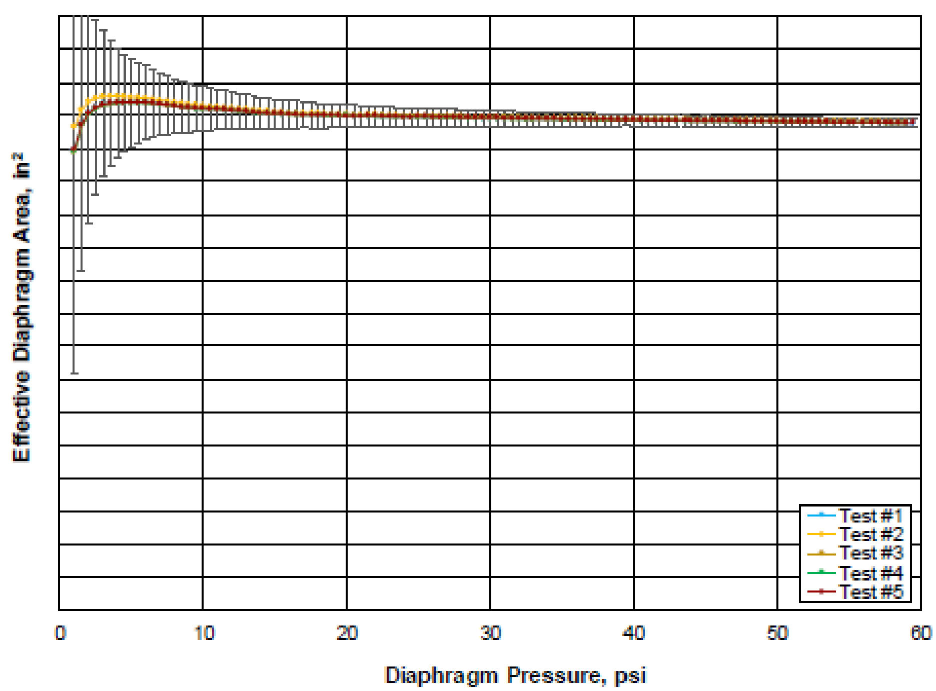


Figure 6. Discrete Test Results for a Coupled Stem Position of 0 Inches with Measurement Uncertainty Indicated by Error Bars
(Source: Author)

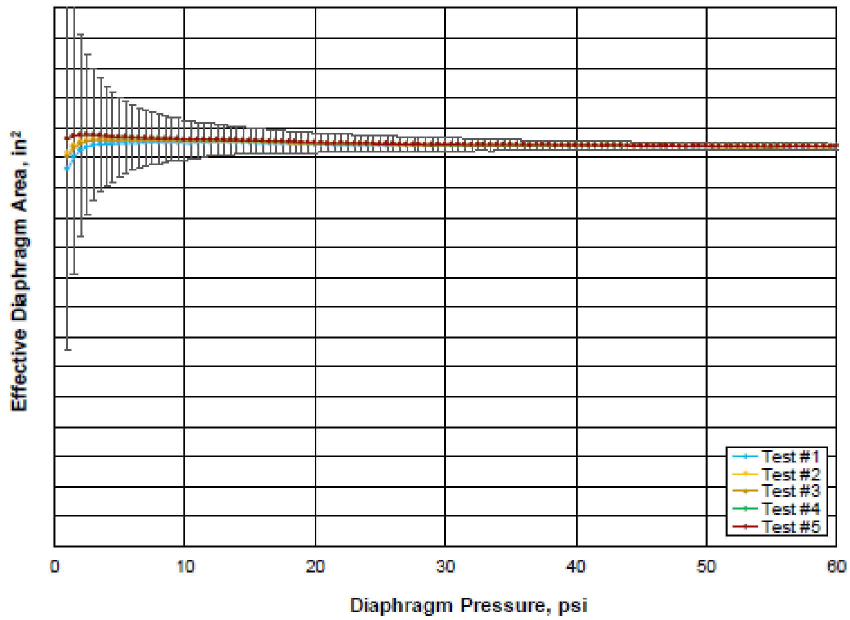


Figure 7. Discrete Test Results for a Coupled Stem Position of 1.0 Inch with Measurement Uncertainty Indicated by Error Bars
(Source: Author)

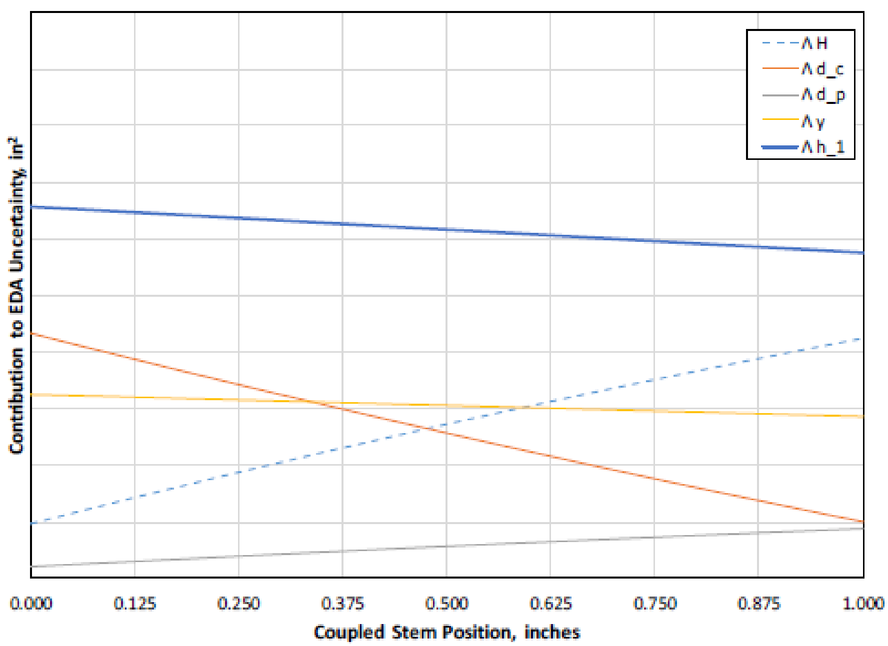


Figure 8. Contribution of Key Actuator Parameters to Account for Manufacturing Tolerances
(Source: Author)

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Track 5: Valves

Track Chair: Mark Gowin, Tennessee Valley Authority

Oil/Water Correlation for Pressure Relief Valves—Is the Measured Set Pressure the Same on Water Compared to Diesel Fuel, Lubricating Oil, etc.?

Robert J. O'Neill, P.E.,
Electric Power Research Institute

Abstract

In verifying pressure relief valve (PRV) setpoints, it is important to distinguish if there is any differential (±) between the measured set pressure (SP) of a PRV when tested on water versus testing on other fluids, such as diesel fuel or lubricating oil. It is also important to recognize that the standard test medium used by the PRV industry for liquid service testing is water. SP testing with other fluids involves issues such as possible serious health and safety effects as well as equipment cross-contamination.

Introduction

PRVs have been supplied for applications on emergency diesel generators (EDGs) to provide the following:

1. overpressure protection (OP) for the dedicated air receivers used in the starting cycle, as shown in Figure 1 of this paper

2. OP for the engine driven pump and in the fuel transfer system between the 1- and 7-day tanks; this PRV may also function as a pressure regulating valve. It is also common for this application to have a pressure regulating valve without an American Society of Mechanical Engineers (ASME) UV Stamp or National Board of Boiler and Pressure Vessel Inspectors (NB) Stamp. This situation may exist on *older plants* as opposed to *newer plants* within the ASME boundary applications

Item 1 above—The air receiver application is not discussed in this paper.

Item 2 above—A block diagram of the system application is shown in Figure 2 of this paper. Little historical data were available from the PRV original equipment manufacturers (OEMs) to either validate or repudiate the opinion held by the major OEM PRV subject matter experts (SMEs) that the SP performance would be the same, independent of the test medium. Further, there was a unanimity of opinion that if there were any lift pressure discrepancies, there would be negligible differences; it would be minor and well within the SP tolerance of the applicable ASME Codes.[12]

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[12] ASME Boiler and Pressure Vessel Code, Sections III and VIII PRV SP tolerances are identical: "Set pressure tolerances, plus or minus, of pressure relief valves shall not exceed 2 psi for pressures up to and including 70 psi and 3 percent for pressures above 70 psi."

Industry Response

The subject of an oil/water correlation had been a topic of discussion for several years in the nuclear industry. In 2009, a Constellation Ginna engineer and component engineer agreed to address the matter by sponsoring a test program with their PRV OEM. Coincidentally, this same subject had been under discussion at the ASME meetings for some time, including a white paper describing the differences between ASME Code PRV requirements in standards such as the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section III, “Rules for Construction of Nuclear Facility Components,” and Division 1, Section VIII, “Rules for Construction of Pressure Vessels,” and the ASME Power Test Code 25, “Pressure Relief Devices—Performance Test Codes.”

The details of the oil/water correlation test program were developed by the Constellation Ginna engineers and their PRV OEM, AG-Crosby. Testing was conducted at the Mansfield, MA, facility of AG-Crosby by the field service technician and reported in the AG-Crosby Test Report 5595, dated December 3, 2012. The following eight PRVs, encompassing three OEMs, selected by Constellation Ginna, were tested in this program for evaluation:

1. **AG-Crosby**—six PRVs consisting of four different models (all liquid trim) in SP ranges from 35 to 225 pounds per square inch gauge (psig)

2. **Fulflo™**—one PRV with an SP of 75 psig

3. **Keckley**—one PRV with an SP of 78 psig

The report results were subsequently presented to the ASME Operation and Maintenance (OM Code), Appendix I PRV subcommittee by the AG-Crosby field service manager, who, at that time, also was a voting member of the subgroup.

A summary of the relevant information extracted from the test report is as follows:

Scope—

ASME Section III requires that liquid relief valves be certified using water as the test medium and production tested using water as the test medium. The OM Code allows the use of water as the test medium for set pressure testing for valves that operate on other liquids provided a correlation exists between water and the operating fluid. This test program was conducted using a representative sample of liquid relief valves, tested on water and tested on two different oils to determine if a correlation could be determined.

Test Facility—

All testing was conducted on an AG-Crosby Model TB-3000 type test bench. The test gage was moved from its normal panel mounted position to a location nearer to the valve inlet connection. This unit is a limited volume test bench pressurized by a small volume Sprague™ pump used for opening pressure testing and is like those used for production testing. All gages were pre-calibrated and post-calibrated against a dead weight tester each test day.

Test Fluids—

The original and final opening pressure test was conducted on demineralized water. The **fuel oil** used during the test program was Low Sulfur Diesel Fuel ASTM D975-78. The **lube oil** used during the test program was Chevron URSA SP SAE 40."

Conclusion—

Based on the test results obtained there is no significant difference in the opening pressures between the three fluids used and the actual correlation is one-to-one.

The PRV testing was performed by an AG-Crosby service technician. The report was prepared by the AG-Crosby technical services manager and approved by the engineering manager. These individuals were employed during the test program by AG-Crosby. Some of these individuals were identified in the report. It should be noted that no operational tests (opening or closing characteristics) were conducted on either of the non-ASME/NB-rated PRVs evaluated in this test program.

Discussions in the ASME OM Code Appendix I PRV Subcommittee

There were discussions within the committee about the results reported in the AG-Crosby report. An initial topic of concern was the scope of manufacturers since only Crosby PRVs were tested. However, the input from the PRV industry SMEs concluded that there is no evidence to indicate the results are not valid for manufacturers of other devices that utilize the same basic design principles for their liquid service valves. Subsequently, other ASME members provided validation of the design similarities between Crosby's valves and the additional OEMs involved in providing PRVs for the EDG applications.

Dissemination of Information to the Industry and Obstacles

After reviewing the AG-Crosby report, the ASME OM Subcommittee on PRVs had two obstacles to contend with:

1. Obtain a release from the entities involved in the Test Program (i.e., Constellation Ginna and AG-Crosby's parent). At that time, AG-Crosby ownership was changing from TYCO to Pentair Controls. This ownership change caused a lengthy time delay in obtaining a legal release to use and publish the information.

2. What vehicle might we use to release the information to the industry?

Since this was not an ASME Code Case being considered or a possible addition or change to a future ASME Code, the committee had no way to distribute this information to the industry. This general subject had also been a topic of discussions at past annual PRV industry meetings: the Safety Relief Valve Users Group (SRVUG). An agreement was reached between the OM Subcommittee on PRVs and the SRVUG to make the report available on the Web site www.SafetyReliefValveUsersGroup.com.

PRV Applications of Interest

While attempting to gather relevant information for this project, contacts were made with several nuclear power plants to establish specifically what types of PRVs were provided or installed on the EDGs. As part of this process, the following summary of the EDG OEMs is provided, along with their market share as related to the U.S.-installed base.

Skid Mounted and Safety Related?

NRC Regulatory Guide (RG) 1.137, "Fuel-Oil Systems for Standby Diesel Generators." The Introduction states, "When a commercial NPP uses diesel fueled generators as part of their standby power source for the onsite electric power system, the diesel fueled generators and related components, including the fuel oil, are classified as safety-related equipment." That information immediately caused me some concern because, in 2016, I had reviewed a license event report (LER) involving an application on an EDG about a commercial bronze PRV that had experienced a failure in the valve inlet on the national pipe thread (NPT). This valve was classified by the PRV OEM as a noncode PRV for liquid service! How could that kind of PRV be used on something that was "safety-related"?

After questioning several industry people, I was advised that "skid-mounted equipment" was granted an exception from the safety-related requirement years ago. However, it was difficult to locate the source. Subsequently, I located the appropriate information in NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," Revision 2.

NUREG-1482, Paragraph 3.4, addresses "Skid Mounted Components and Component Subassemblies" and states the following in part or whole:

- The Code class piping system at a plant may include skid-mounted components or component assemblies such as valves in diesel air start assemblies, *diesel skid mounted fuel oil pumps* and valves... main steam isolation valves.

- If the licensee's safety analysis report (SAR) identifies these components as ASME Code Class 1, 2, or 3, they are subject to inservice testing (IST) required by 10 CFR 50.55a. By contrast, if the SAR does not identify these components as Code Class 1, 2, or 3 (or indicates that they are maintained as Code class, but are not required to be Code class), they are not subject to IST in accordance with 10 CFR 50.55a. Nonetheless, these components may be subject to periodic testing in accordance with Appendix A, “General Design Criteria for Nuclear Power Plants,” and Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” to 10 CFR Part 50.

ASME OM Code, Subsection ISTC, Paragraph 1200(c), “Exemptions,” states: skid mounted valves are excluded from this Subsection, provided they are tested as part of the major component and are justified by the Owner to be adequately tested. This test as part of the major component would be satisfied during the monthly EDG *start test and load run test* required by Regulatory Guide 1.9, Table 1.

NRC Summary of Basis and Recommendations—ASME OM Code Subsections ISTB-1200(c) and ISTC-1200(c) define the components that are subject to IST. The staff has determined that testing the major component is an acceptable means to verify the operational readiness of the skid-mounted components and component subassemblies if the licensee discusses this approach in the IST program document. Licensees should consider and document the specific measurements and attributes of major component testing that relate to the assessment of skid-mounted component condition. In addition, various continuous and periodic observations of the major components (e.g., system monitoring walkdowns or operator logs) may also support assurance of skid-mounted component readiness. This is acceptable for both Code class components and non-Code class components that are tested and tracked by the IST program.

Various pumps and valves that are procured as part of larger component subassemblies are often not designed to meet the requirements for components in ASME Code Classes 1, 2, and 3. In RG 1.26, “Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants,” the NRC gives guidance on classifying components for quality groups A, B, C, and D (Code Classes 1, 2, and 3, and ASME BPV Code, Section VIII, and American National Standards Institute Code B31.1, “Power Piping,” respectively). (For additional guidance, licensees should review NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition (SRP),” Section 3.9.6, “Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints.”) When many of the components were procured, the requirements for IST did not apply and, thus, the components may not have included features for IST. Licensees may, therefore, elect to use the IST program for testing these components and state in the IST program document that the surveillance tests of these components adequately test the skid-mounted components.

PRVs for the Skid-Mounted Equipment

In the gathering of information to determine the possible variations in the PRVs provided for this application, sampling from a minimal number of sites indicated several PRV OEMs with performance characteristics ranging from the following:

- a liquid trim with an ASME Code Stamp (UV) and an NB capacity certification
- a PRV specifically designed and manufactured for hydraulic bypass relief valve service with an Underwriters Laboratory (UL) listing
- a commercial “non-Code” valve void of ASME/NB Stamps, or other certifications/industry recognition, manufactured in large quantities to compete in a commercial, highly competitive market

PRV Comparison

Based on the above information that was gathered, and to elaborate further, it is obvious there are a significant number of differences in the PRVs provided with the skid-mounted equipment for the EDGs, some of which are listed below:

- A PRV provided by any one of the three major OEMs, all possessing liquid service ASME Code UV and NB Stamps, should not present any challenges.
- A PRV manufactured by Fulflo (see Figure 4 of this paper), with a UL listing, designed specifically for liquid (fuel oil) service. These valves are SP tested by the OEM, using oil with a viscosity 150 seconds Saybolt Universal (SSU) at 100 degrees Fahrenheit (F). Incidentally, when I had a telephone conversation with the general manager and engineer at Fulflo and asked if there would be any difference in the measured SP when tested on oil versus water, his response was “pressure is pressure - the opening would be the same” (another testimony from PRV SMEs!). No reason to challenge.
- A non-Code PRV may present challenges.

What type of performance can one expect from a non-Code valve after installation?

- Seat leakage and seat tightness duration - Are the seating materials provided suitable for extended service?
- Does the PRV have any features that reduce or eliminate chattering on liquid service?
- Cap gasket leakage (has occurred at three known sites) - Is this a testing/maintenance or generic issue?

As mentioned previously, periodic testing of these PRVs is very difficult. These valves may be part of a larger component and cannot be readily removed for periodic testing. Often, access is extremely difficult without disconnecting adjacent equipment. In some installations, the PRV is removed after 5 years (or much more) and replaced with a new PRV. The original PRV must be “as found” tested. These test results should be the basis of adjusting the frequency of preventative maintenance (if deemed necessary) or if a different PRV should be considered.

ASME Code PRV Liquid Capacity Recognition

Before 1972, liquid service PRVs had no ASME Code recognition. The only industry standard that recognized liquid service capacity for PRVs was American Petroleum Institute (API) Standard 520, Part 1, “Sizing and Selection (Flanged Steel Pressure Relief Valves).” The nonrated capacity was based on an accumulation (overpressure) of 25 percent at full lift, with a capacity correction factor of 0.6 to adjust (reduce) the capacity based on a lower lift with 10 percent accumulation (overpressure). It is important to be aware that this information was developed many years ago by API technical committees, before linear variable differential transformers and high-speed recorders existed. In 1972, ASME Code Case 1555 was issued, which recognized liquid capacity requirements and NB certification. The result of this change was that any sizing of a liquid service PRV to the original sizing criteria (API) was oversized by one alpha orifice size (reference API Standard 526, “Flanged Steel Pressure Relief Valves”). These requirements were incorporated into the 1979 editions of ASME BPV Code, Sections III and VIII. If a non-Code PRV is installed on liquid service without liquid trim or some other controlling feature, the chances of chattering/fluttering with associated damage occurring to seating surfaces are very high.

Final Conclusions

SMEs of three major PRV OEMs who have provided PRVs to the petrochemical and nuclear industries are unified in their opinion (based on their experience) that on noncompressible fluids, the measured SP on water will be the same on other liquids, such as on fuel oils and lubricating oils. This was reinforced by the oil/water correlation testing performed by AG-Crosby for the R.E. Ginna Nuclear Power Plant. Further, additional reinforcement was offered by another PRV OEM, Fulflo, which has provided specialized hydraulic bypass relief valves for liquid service, with nonchattering construction, for 100-plus years.

Nuclear Regulatory Guides, ASME Codes, and Industry Standards Referenced in This Paper:

American Petroleum Institute (API) Standard 520, Part 1, “Sizing and Selection (Flanged Steel Pressure Relief Valves),” API, Washington, DC.

API Standard 526, “Flanged Steel Pressure Relief Valves,” API, Washington, DC.

American National Standards Institute B31.1, “Power Piping,” American Nuclear Society, LaGrange Park, IL.

American Society of Mechanical Engineers (ASME), *Operation and Maintenance of Nuclear Power Plants*, 2009 Edition, ASME, New York, NY.

ASME, *Boiler and Pressure Vessel (BPV) Code*, Section III, “Rules for Construction of Nuclear Facility Components,” ASME, New York, NY.

ASME BPV Code, Section VIII, “Rules for Construction of Pressure Vessels,” Division 1, ASME, New York, NY.

ASME Power Test Code 25, “Pressure Relief Devices—Performance Test Codes,” ASME, New York, NY.

Electric Power Research Institute (EPRI) Guide 3002000742, “On-Line Monitoring of Emergency Diesel Generators,” EPRI, Palo Alto, CA.

U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.26, “Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants.”

NRC Regulatory Guide 1.137, “Fuel Oil Systems for Emergency Power Systems.”

NRC Regulatory Guide 1.9, “Application and Testing of Safety-Related Diesel Generators in Nuclear Power Plants.”

NUREG-1482, “Guidelines for Inservice Testing at Nuclear Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants. Final Report,” Revision 2, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Rockville, MD, October 2013.

AG-Crosby Test Report 5595, December 3, 2012 (See author for reference).

Monroe County Community College Web site.

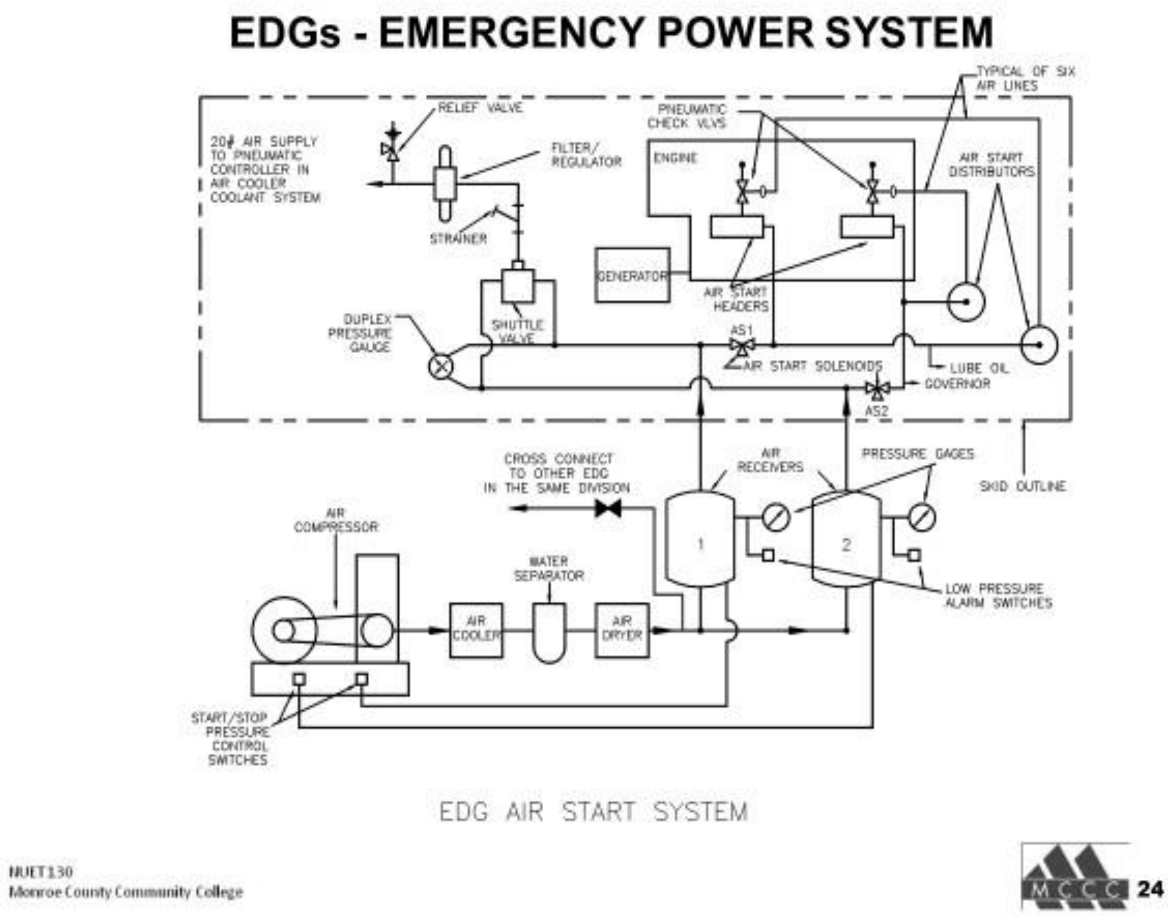

Figure 1. Typical EDG diagram—Dedicated air receivers would be protected by PRVs.
(Source: Monroe County Community College Web site)

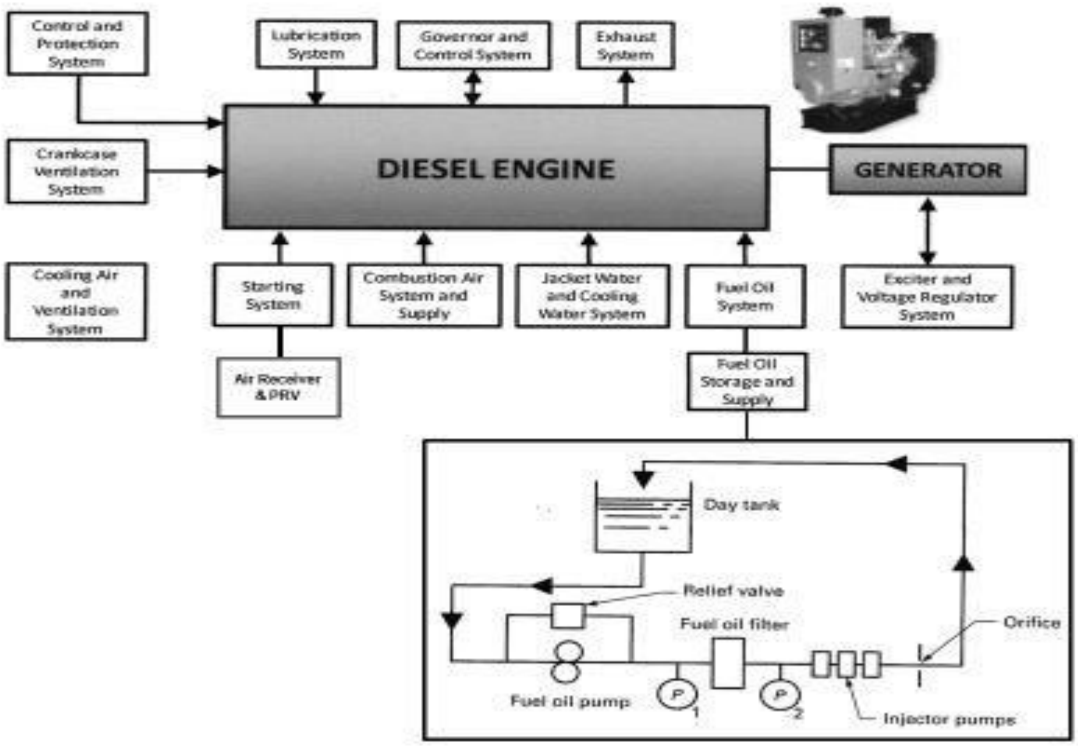

Figure 2. Regulatory Guide 1.9 Figure with Addition to Include Fuel Oil Transfer System
(Source: Extracted from ASME Code OM-2009, page 163, Figure C-5), and Author

EDG Summary by OEM

EDG OEM	Electro-Motive (EMD)	Fairbanks-Morse (opposed Piston)	Cooper Bessemer	Alco Power (FM is OEM REP)	FM COLT-Pielstick (V Block)	TD Enterprise (V Block)	Nordberg	Worthington McGraw Edison (Dresser)	SACM Compair - Luchard	TD Enterprise (in line block)
USA TOTAL	76	46	31	24	19	18	8	4	3	2
% of TOTAL	32.9	19.9	13.4	10.4	8.2	7.8	3.5	1.7	1.3	0.9

The totals above include NPPs that have been shut down such as Crystal River, Kewaunee, SONGS 2 & 3, & VY.

Figure 3. Number of EDGs Provided by OEMs
(Source: Author)

Fulflo SVB Series hydraulic bypass relief valves Page 1 of 1

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Primarily designed for use with fuel oils on oil burner service, the SVB valves may be used whereever Underwriter Listed valves are required. Each valve is pre-set to the specified pressure and is equiped with a limiting device to prevent over-adjustment. The valves can be mounted in any position. Our valves are for liquids only, no air gas or steam, but we can also offer specialized valves for your specific application. Contact our Engineering Dept. at 937-783-2411 for more details.

For complete SVB-Series valve information on sizes, materials, dimensions, application, installation, maintenance, disassembly, parts list, performance charts, and pressure ranges, click here to download the PDF.

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UNDERWRITER VALVE PRESSURE RANGE CHART

Pipe Size	"U.L." Symbol	SPRING PRESSURE RANGE AND PART NO. SUFFIX									
		RED-US		GREEN-WS		YELLOW-XS		WHITE-YS		BLUE-ZS	
		Low	High	Low	High	Low	High	Low	High	Low	High
3/8"	SVB-25	7	35	30	100	60	175	150	350	300	500
1/2"	SVB-35	7	35	30	100	60	175	150	350	300	500
3/4"	SVB-45	7	35	30	100	60	175	150	350	300	500
1"	SVB-55	7	35	30	100	60	175	150	350	300	500

Go to: [Engineering] [V-Series] [FV-Series] [OV-Series] [A-Series] [SVB-Series]

Fulflo Valves
Engineering Section
V-Series
FV-Series
OV- Series
A-Series
SVB-Series

Figure 4. Fulflo Hydraulic Fuel Oil PRVs

(Source: Fulflo Web site)

Figure 5. Fulflo PRV Installed at the Pilgrim Station
(Source: Author)

Application of Phased Array Sectorial Scanning to Determine Stem-to-Disc Separation in Globe Valves

Jesse R. Delgado
IHI Southwest Technologies, Inc.

Abstract

The reliability of globe flow control valves is paramount to the safe operation of the plant systems. Stem-to-disc failures in globe valves are difficult to identify given the failure causes. Globe valve failures are typically from the breaking of tack welds or worn threads causing the retainer nut to begin backing out, resulting in a disc separation condition. This paper provides a description of a method for applying advance phased array techniques to determine if a given valve has initiated a stem-to-disc separation condition. The Phased Array Sectorial Scanning (PASS) techniques take advantage of accessible areas of the stem to introduce and steer sound waves in the direction of the disc. The sound waves propagate through the stem and exit the bottom of the stem, entering a designed compliance gap between the stem and the disc, which is filled with water. The sound waves will reflect from the top of the disc and propagate through the water and back into the stem. The time of flight can be read and converted to a distance measurement to determine the existing gap. The measurement can be compared to the valve's design gap, and any measurement exceeding design value would indicate stem-to-disc separation has initiated. The data required to assess the valve can be acquired with the valve in the static mode or during dynamic stroking, providing a cost-effective method of assessing stem-to-disc condition in globe and gate valves.

I. Introduction

Stem-to-disc failures in globe valves are difficult to identify, given the failure causes and the limited access conditions associated with motorized operating valves. Globe valve failures are typically associated with the failure of tack welds or worn threads causing the disc nut to begin backing off until a disc separation condition is present. With recent changes in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, "Codes and standards," that now require the assessment of valves subject to stem-to-disc separation risk, a need to develop a method to determine the status of this condition became evident. In response to the aforementioned condition, IHI Southwest Technologies, Inc. (IHI) developed a nonintrusive method to evaluate the existence of the condition. In addition, IHI was able to migrate existing PASS techniques currently being applied to various valve configurations (i.e., swing, lift, tilting, and duo check valves) to address the stem-to-disc separation issue.

II. Definition of IHI Phased Array Sectorial Scanning

PASS utilizes phased array ultrasound as a method of generating and receiving ultrasound sound waves. These waves can be steered, focused, and optimized to interact with specific targets within a valve. Sweeping ultrasonic beams are generated by the use of multiple element probes and electronic timed delays. The pulsing time delays are programmed to generate beams at a given angle in relation to a target component. Figure 1 shows the method for beam steering using timed delays.

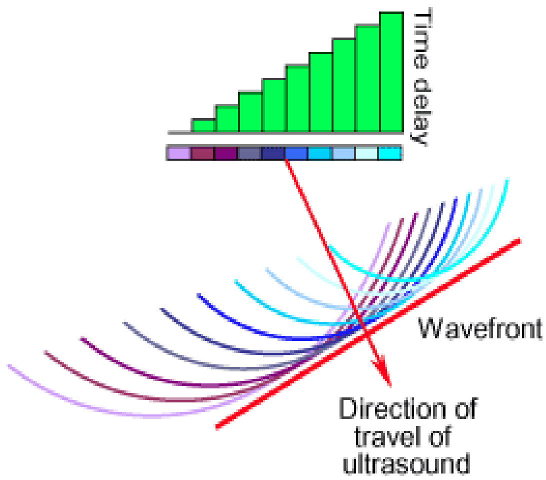

Figure 1. Phased Array Beam Steering
(Source: Author)

The PASS techniques use phased array probes to capture the interaction of the sound waves with the valve internal components, assemblies, or body structures. For a typical *swing check valve*, sound waves are propagated through the valve bonnet and body resulting in the sound waves entering the water medium and reflecting back from internal components, such as the disc, retaining nut, disc arm assembly, and body internal surfaces. The resulting sound beam interactions with internal components are time-encoded captured, allowing for data to be post-processed and analyzed. Analysis of the data yields information relating to disc position, fluttering rates, foreign material, gas intrusion, and internal assembly integrity. Figure 2 depicts a typical sound wave propagation for testing of swing check valves. Based on this method of sound propagation, a procedure was developed to assess globe valves for stem-to-disc separation condition. Section III of this paper describes the method in detail.

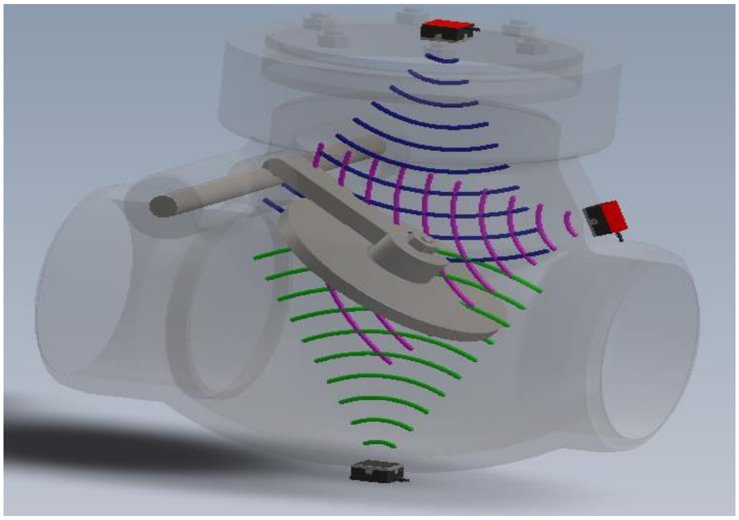

Figure 2. Typical Swing Check Valve NIT
(Source: Author)

III. Definition of IHI Phased Array Sectorial Scanning Test Method for Determining Stem-to-Disc Separation Condition

The PASS techniques take advantage of accessible areas of the stem to introduce and steer sound waves in the direction of the disc. An accessible stem area is defined as a bare metal area of the stem, accessible from the valve exterior in which a phased array probe can be coupled, allowing for the transmission of ultrasonic sound waves in the stem. A recent evaluation of motor-operated valves (MOVs) and air-operated valves (AOVs) at a nuclear power plant indicated that most valves have accessible stem areas from which to conduct testing. A variation in dimensions (such as stem diameter) and accessible areas along the length of the stem does require a variation in ultrasound probe sizes to accommodate the different valve designs. Figure 3 depicts the globe valve design specific to this discussion.

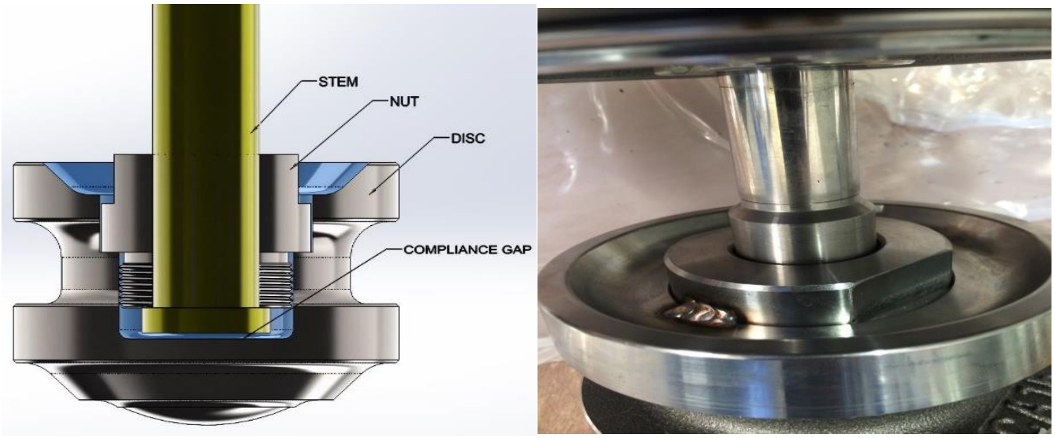

Figure 3. Globe Valve Design
(Source: Author)

The basis for evaluating the globe valve for stem-to-disc separation condition is to measure the compliance gap identified in Figure 3 and compare the measurement to the design value. When the nut is torqued and tack welded, the disc can be moved vertically within the compliance gap range. The compliance gap allows the disc to comply against the seat when the valve is moved to the fully closed position. The design compliance gap for the valve used in the development was physically measured to a value of 0.080 inches. This value is highlighted by the green area in Figure 4. When the valve has initiated the stem-to-disc separation condition, the compliance gap increases beyond the design value. Figure 5 depicts the compliance gap in green just before the release of the disc.

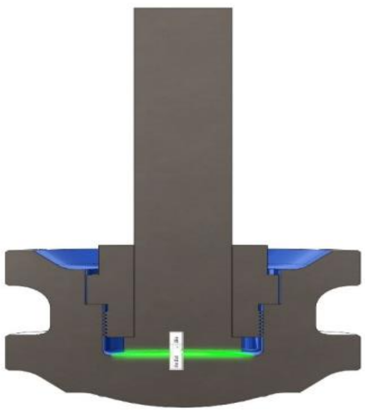

Figure 4. Compliance Gap 0.080″
(Source: Author)

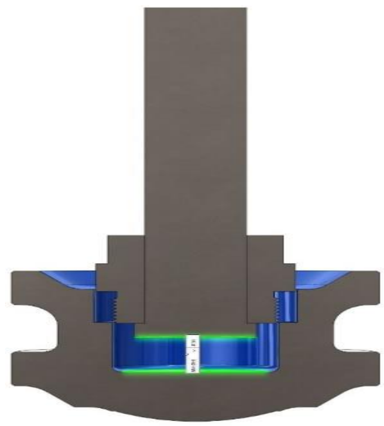

Figure 5. Gap 0.800″ Before Disc Release
(Source: Author)

IV. Methodology for Determining Stem-to-Disc Separation Condition

PASS measures the compliance gap by propagating sound waves through the stem first targeting the end of stem, as shown in Figure 5. When the sound waves arrive at the end of the stem, a large amount of energy is reflected back to the probe. The signal response clearly identifies the end of the stem, as seen in Figure 6.

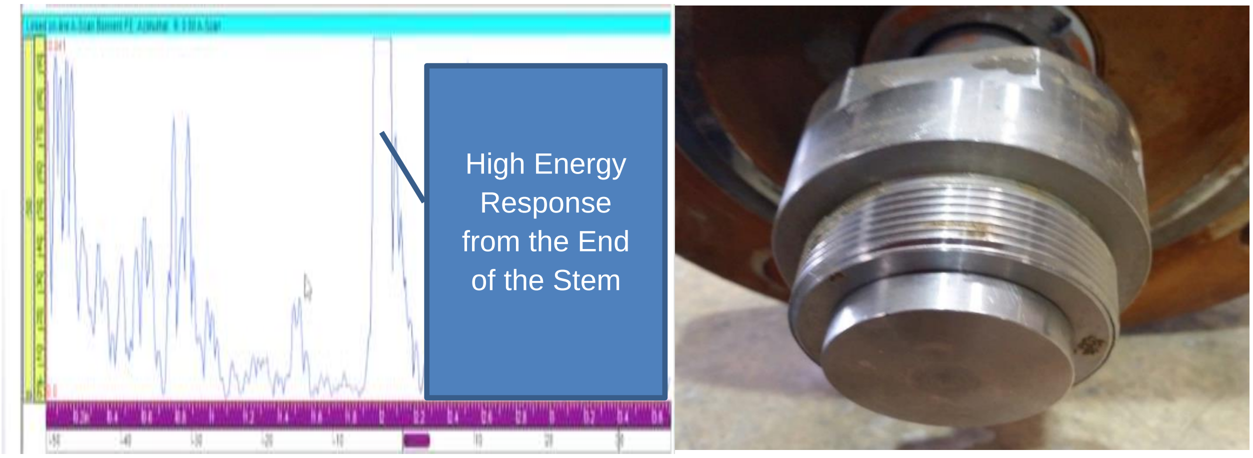

Figure 6. End of Stem Signal Trace
(Source: Author)

Although a large amount of ultrasound energy is reflected from the end of the stem, some energy exits at the bottom of the stem, entering the compliance gap between the stem and the disc through the water medium. When ultrasounds enter the water medium, the sound velocity slows down. The reduced sound velocity in the water medium is considered advantageous because a 0.080-inch gap will appear as approximately a 0.320-inch gap without data correction. This occurs as a result of the PASS system being calibrated to the sound velocity of steel. The sound velocity in steel is 0.2300 inches per microsecond, while the sound velocity in water is equal to 0.0584 inches per microsecond, resulting in a steel-versus-water ratio of approximately 4 to 1. The sound waves will reflect from the top of the disc (see Figure 7) and propagate through the water and back into the stem. The time of flight can be read and converted to a distance measurement to determine the existing gap. The measurement can be compared to the valve's design gap, and any measurement exceeding design value would indicate stem-to-disc separation has initiated. Figure 7 depicts signal responses from the end of stem signal and the top of the disc signal. The distance between the signal peaks is the time of flight in the water, which represents the measurement of the compliance gap.

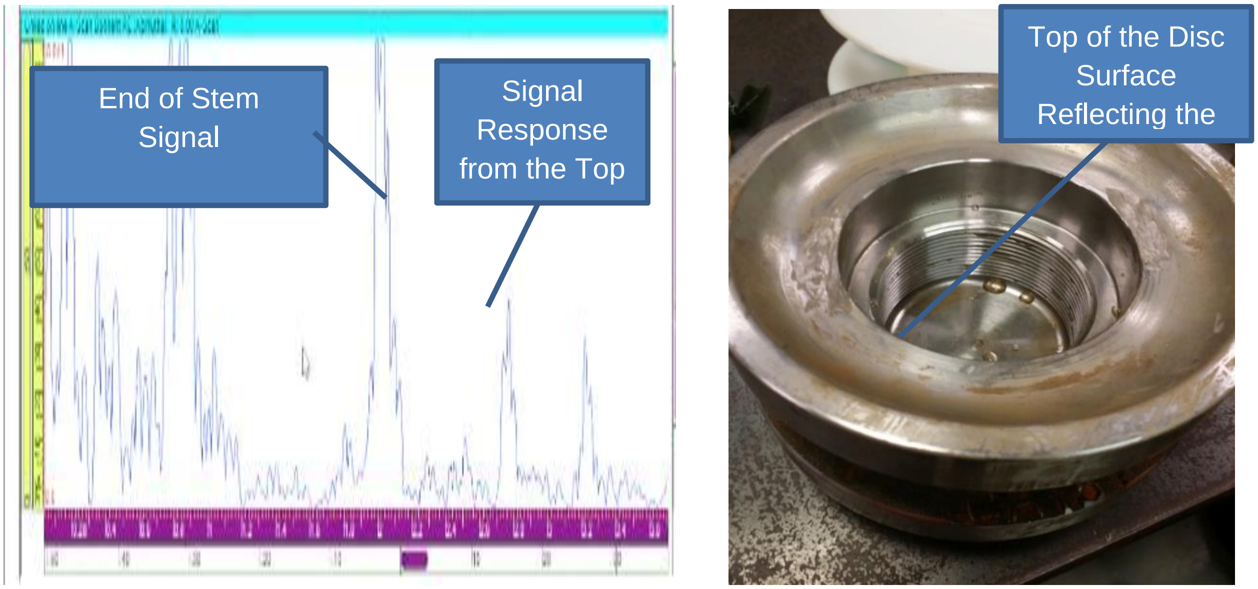

Figure 7. Signal Responses
(Source: Author)

The end of stem signal response was measured to 2.0 inches, and the signal response from the top of the disc was measured at 2.75 inches. When the 0.75-inch distance is corrected for the water velocity change, the resulting gap distance equals 0.187 inches. In this example, the compliance gap measurement exceeded the 0.080 maximum design value, indicating stem-to-disc separation condition has initiated.

V. Conclusions

As a nonintrusive test method, the application of PASS has proven to be an effective method for identifying the stem-to-disc separation condition; moreover, PASS leads to increasing safety and reliability margins while reducing cost. The PASS attributes are listed below:

- PASS ultrasonic data can be used to assess and determine globe and gate valve integrity (that is, disc and stem separation).
- PASS is an efficient application method, requiring only 5 to 10-second time encoded acquisitions.
- PASS is a scalable, nonintrusive test applicable to a broad population of MOVs and AOVs.
- PASS allows for periodic monitoring and trending of valve condition at any time during the valve operational life cycle.
- PASS provides the technical basis for reducing the risk of unnecessary valve disassemblies and allowing more of a "maintenance-on-demand" strategy.

Plant Performance History of an Innovative Gate Valve in Critical Service Applications

M.S. Kalsi
Kalsi Engineering, Inc.
Sugar Land, TX, USA

Daniel Alvarez
Kalsi Engineering, Inc.
Sugar Land, TX, USA

Thomas White
Entergy/Pilgrim Nuclear Station
Plymouth, MA, USA

Michael Green
Entergy/Pilgrim Nuclear Station
Plymouth, MA USA

Abstract

NUREG/CP-0152, "An Improved Gate Valve for Critical Applications in Nuclear Power Plants," Proceedings of ASME/NRC Pump and Valve Symposium, issued July 1996 [1], describes the key features of an innovative gate valve design that was developed to overcome seat leakage problems, high-maintenance costs, as well as issues with conventional gate valves, as identified in the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-10, "Safety Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989; GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated August 17, 1995; and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996 [2,3,4]. The earlier paper was published within a year after the new design valves were installed at the Pilgrim Station (Pilgrim); the plant that took the initiative to form a teaming arrangement as described in [1], which facilitated this innovative development. This paper documents the successful performance history of 22 years at the Pilgrim plant, as well as performance history at several other nuclear power plants where these valves have been installed for many years in containment isolation service that requires operation under pipe rupture conditions and requires tight shutoff in both pressurized-water reactors (PWRs) and boiling-water reactors (BWRs). The performance history of the new valve has been shown to provide significant performance advantage by eliminating the chronic leakage problems and high-maintenance costs in these critical service applications. This paper includes a summary of the design, analysis, and separate effects testing described in detail in the earlier paper. Flow-loop testing was performed on these valves under normal plant operation, various thermal binding and pressure locking scenarios, and accident/pipe rupture conditions. The valve was designed, analyzed, and tested to satisfy the requirements of American National Standards Institute (ANSI) Standard B16.41, "Functional Qualification Requirements for Power-Operated Active Valve Assemblies for Nuclear Power Plants" [9]; it also satisfies the requirements of American Society of Mechanical Engineers (ASME) Qualification of Mechanical Equipment (QME)-1-2012 [10]. The results of the long-term performance history, including any degradation observed and its root cause, are summarized in the paper.

Introduction

Background and Technical Approach

To address performance problems including damage under high-flow conditions, and pressure-locking and thermal-binding issues identified in NRC GLs 89-10, 95-07, and 96-05 with wedge gate valves [2,3,4], development of a new valve design was undertaken. One of the key development goals was to also address chronic seat leakage problems and high-maintenance burden/personnel radiation dosage in critical local leak rate testing (LLRT) and other tight shutoff applications reported by many U.S. nuclear power plants. The design was based on a "clean slate" approach (not limited by retrofit constraints within the existing valve bodies) to address these problems in a technically rigorous manner. The lessons learned from Electric Power Research Institute Motor Operated Valve Performance Prediction Methodology (EPRI MOV PPM) [5] were taken into account in the new valve design. A novel disc design was developed and patented [1] to eliminate potential for internal damage caused by disc tipping. The development also addressed disc pinching phenomenon induced by thermal binding and pressure changes [6,7,8] by incorporating enhanced flexibility in the disc design. These issues were outside the scope of the EPRI MOV PPM. The valve disc and guides were designed with controlled clearances to ensure reliable operation with the valve and stem in any orientation in the piping system. In addition to introducing innovative design features, extensive computational fluid dynamics and finite element analyses were performed to predict and ensure reliable operation under various thermal-binding scenarios [1].

The entire product line was developed based upon a rigorous design approach that was validated by separate effects testing performed on 4-inch and 8-inch Class 900 valves on a special valve design effects test fixture, as described in detail in [1]. The current paper describes the details of the qualification/validation testing performed on a 6-inch Class 900 valve including multiple high-flow/blowdown cycles in a flow loop. The paper also documents the performance history feedback provided by several nuclear plants where these valves have been installed for many years.

Key Design Features

Key features of the new valve design are described in detail in [1] and are briefly summarized below:

- A novel flexible wedge design [1] creates a nearly uniform seat contact stress between the wedge and seat ring faces all the way around the seat circumference for superior, leaktight performance.
- Enhanced disc flexibility (compared to conventional disc designs) makes it perform reliably under the worst-case thermal binding scenarios.
- Full-stroke, hard-faced body and disc guides, as well as radiused/chamfered leading edges eliminate midstroke disc tipping and related wear and damage.
- Closely controlled clearances and tolerance between all sliding surfaces ensure that valve performance is not affected by any mounting orientation in the piping.

Flow-Loop Testing

An extensive matrix of tests was performed on the 6-inch ANSI 900 Class Sentinel valve using water and steam as fluid media. The valve was subjected to various flow velocity (including blowdown) and differential pressure combinations. The test procedures followed the same preconditioning and flow rate-differential pressure (DP) combination approach that was used in the EPRI MOV PPM test program [5]. The valve was subjected to repetitive DP strokes as well as multiple blowdown closures. The test program went beyond the EPRI MOV PPM by including extensive thermal-binding and disc-pinching scenarios. The thermal-binding scenarios included repetitive tests under the closed-hot-open-cold (CHOC) and closed-cold-open-hot (CCOH) conditions. Tests were performed with two different disc designs: (1) conventional stiffness disc and (2) enhanced flexibility disc to quantify the benefits achieved by the enhanced flexibility disc under the worst-case thermal binding scenarios. The thermal binding test matrix included insulated and uninsulated valves.

Figure 1: An extensive matrix of flow-loop tests, including multiple blowdowns and thermal-binding scenarios, was performed to qualify the innovative gate valve design.

Flow-Loop Test Matrix

Disc Design without Enhanced Flexibility

1. Preconditioning - 1,800 pounds per square inch (psi) DP, cold water
   - baseline leakage test

2. Cold Water - 15 feet per second (ft/sec), DP of 600, 1,200, and 1,800 psi (total of 10 DP closures, 9 openings)
   - leakage test

3. Cold Water - 50 ft/sec, DP of 600, 1,200, and 1,800 psi (total of 10 DP closures, 9 openings)
   - leakage test

4. Steam Blowdown (3 closures) and Thermal-Binding Scenario (CHOC) - valve not insulated
    - closed hot at 1,150 psi DP
    - opened cold at 0 psi DP
    - leakage test

5. Steam Blowdown and Thermal-Binding Scenario (CCOH) - valve not insulated
    - closed cold at 0 psi
    - open hot at 1,150 psi DP (upstream)
    - leakage test

6. Disassembly and Inspection

All the valve body guides, disc guides, and seat faces were found to be in excellent condition after being subjected to multiple DP tests and thermal-binding scenarios (Figure 2). The conventional stiffness disc exhibited a significant increase in thrust after being subjected to either of the CHOC and CCOH scenarios; however, it was found the CCOH scenario resulted in the highest increase in opening thrust. This was consistent with the analytical predictions based on the coupled computational fluid dynamic and finite element analysis performed during the design phase of the project.

Enhanced Flexibility Disc

1. Preconditioning - 1,800 psi DP, cold water
    - Baseline leakage test

2. Steam Blowdown and Thermal-Binding Scenario (CCOH) - valve insulated
    - closed cold at 0 psi
    - open hot at 1,150 psi DP (upstream)

3. Steam Blowdown and Thermal-Binding Scenario (CCOH) - valve insulated (repeat of previous test)
    - closed cold at 0 psi
    - open hot at 1,150 psi DP (upstream)
    - leakage test

4. Steam Blowdown and Thermal-Binding Scenario (CCOH) - valve not insulated
    - closed cold at 0 psi
    - open hot at 1,150 psi DP (upstream)

5. Disassembly and Inspection

All the sliding surfaces for the enhanced flexibility disc were inspected and found to be in excellent condition after being subjected to multiple blowdown tests and thermal-binding scenarios.

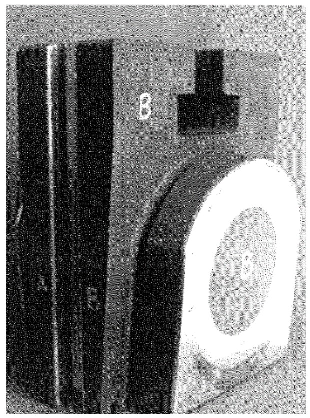

Figure 2. The valve disc and the seat faces were found to be smooth with no signs of any wear or galling after being subjected to the entire matrix of DP, blowdown, and thermal-binding tests.
(Source: Author)

Summary of Flow-Loop Testing

- A total of 86 DP and flow tests was performed on a 6-inch ANSI 900 Class Sentinel valve.
- Very tight shutoff characteristics were maintained throughout the testing for both conventional stiffness disc and for enhanced flexibility disc.
- Valve factors remained very consistent and within the predictable range for all test conditions and provided smooth performance for both opening and closing strokes.
- The enhanced flexibility disc performed successfully under all thermal binding scenarios and required a much lower unwedging thrust (than the disc without enhanced flexibility) under the worst-case scenario.

Plant Performance History

This section summarizes the performance of the new valves installed at several plants. These plants replaced the original valves because of chronic leakage and performance degradation problems. Since installation of the new valves, these plants have reported leaktight service and consistent operating performance for many years. Substantial cost savings have been achieved because of reduced maintenance. Additionally, significant reduction in dosage exposure was achieved.

Plant Performance - Pilgrim Station: The Plant That Championed the Innovation

Installed: 1995

The new design was installed in the four critical applications in the reactor water cleanup (RWCU) and high-pressure coolant injection (HPCI) systems as described in the table below. Previously, the plant had used conventional flexible wedge gate valves made by three different manufacturers. These valves had exhibited ongoing seat leakage and internal degradation problems resulting in high maintenance costs as well as radiation exposure.

System	Valve Description	Function
RWCU	6 x 4 x 6, Class 984, stainless steel	inboard containment isolation
RWCU	6 x 4 x 6, Class 984, stainless steel	outboard containment isolation
HPCI	10 x 8 x10, Class 900, carbon steel	outboard containment isolation
HPCI	10 x 8 x10, Class 900, carbon steel	turbine supply valve

The plant has reported 22 years of successful performance with the new valves in all four applications. The LLRT performed in the containment isolation valves always remained well below (a small fraction) the acceptance criteria for all those years with one exception, as described below.

In 2013, after 18 years of good LLRT history, the RWCU inboard containment isolation valve failed LLRT acceptance criteria significantly. Initial attempts to flush the seats during the first outage were unsuccessful in improving the LLRT results. Pilgrim was able to justify operating a cycle to allow for a potential replacement by crediting the margins available in other containment penetrations and valves. In parallel with planning a replacement, a team developed a procedure to allow a much more turbulent flush of the seats. In the next outage, the new flushing process was used and was successful at returning the valve to the original, good LLRT results. Based on this, the plant concluded that the leakage was caused by accumulation of debris in the body cavity and was not related to valve degradation. The valve has continued to maintain good LLRT history.

Plant Performance - Limerick Generating Station

Installed: May 1998

12-inch ANSI 900

Application: HPCI Steam Admission Valve

The new valve performed successfully for 12 years with no leakage. In 2010, a slightly elevated turbine casing temperature was noted, indicating a minor seat leakage from steam admission valve leak-by. Valve rework was performed in February 2012 on the valve disc and in-body seat faces to lap and remove minor indications. The valve was able to provide tight shutoff again. The valve continues to provide tight shutoff even after the torque switch trip setting was subsequently reduced (to prevent high seat load) by incorporating a procedural control that requires running the HPCI turbine to achieve thermal equilibrium before closing the valve.

Plant Performance - Waterford Generating Station, Unit 3

Installed: 2002

6-inch ANSI 900

Application: HPCI Turbine Steam Admission Valves

Installation: In a vertical pipe with valve stem horizontal

Two new design valves were installed in the HPCI turbine steam admission application in 2002. Both valves have continued to perform successfully for more than 15 years with no problems or degradations. The original valves were of a conventional flexible wedge gate design (supplied by a U.S. manufacturer), and the plant had continued to experience chronic seat leakage problems and degradation of the internals with the original valves, resulting in high, ongoing maintenance costs.

Plant Performance - James A. FitzPatrick Nuclear Power Plant

Installed: 2000

6-inch ANSI 900 (stainless steel)

Application: RWCU Containment Outboard Isolation Valve

Installed: February 2005

10-inch ANSI 900 (carbon steel)

Application: HPCI Turbine Steam Inlet Valve

RWCU Performance: Since its installation in 2000, the new RWCU valve has provided leak-free service and exhibited no signs of degradation for over 17 years.

HPCI Performance: The new HPCI valve performed leak free until June 2009; it was identified that the valve had seat leakage after 4.33 years of service. The valve was seat-leak repaired during a scheduled outage in January 2010. After repair, the valve performance was restored to the original leaktight history. The root cause analysis performed by the plant concluded that the leakage was from the impingement of debris on the downstream disc and seat faces by flashing of hot water condensate in the drain port at the bottom of the valve when the valve is opened. The HPCI valve function, its history, and the failure mechanism that scored the seat faces described by the plant engineer are given below.

Function

The HPCI turbine steam inlet valve, 23 MOV-14, is a normally closed valve with a design function to fully open within 10 seconds upon HPCI system initiation to provide steam to the turbine and to provide full HPCI design flow to the reactor pressure vessel. The valve provides a boundary between the reactor and HPCI turbine. The valve auto opens on an HPCI initiation signal (either high drywell pressure or low-low reactor pressure vessel water level) to admit steam to the HPCI turbine assembly.

History

In 2005, a design change replaced the HPCI turbine steam supply isolation valve to resolve recurring problems with seat leakage that caused pitting of the HPCI turbine shaft at the seals and HPCI lube oil contamination. The previous valve was a double-disc design gate valve. The recurring seat leakage problem with this valve impacted operations for frequent responses to alarms from the drain pot. These alarms are indicative of valve seat leakage. The leakage problems impacted outage planning and increased personnel radiation exposure in order to affect repairs. A body drain was provided to continuously remove condensate from between the seats of the new valve.

Failure Mechanism

The steam inlet side of the valve is connected to a dead leg that has a continuous saturated condensate volume. This area of the steam pipe is the collection point of all system surface oxide for the entire supply steam line. Over time, particulate buildup is concentrated in the condensate volume. Level control of the condensate is controlled by a spillway in the dead leg to a cycling water trap that cycles every 40 seconds. During initial valve opening, a pressure drop of over 1,000 psi occurs at the disc-to-seat interface area. This condition causes the condensate in the drain leg to flash or be driven to the valve, sending system particulate over the disc-to-seat area at the 5 o’clock position. Particulate buildup on the seat is sheared off by the disc sliding contact forces during a close action wearing the localized disc and seat areas. Over time, incipient leakage occurred and, with the valve in standby, leakage flows from the drainline to the valve leak area, bringing more system particulate thereby exacerbating the problem.

Plant Performance - Browns Ferry Nuclear Power Plant

Installed: 2012

10-inch ANSI 900

Application: HPCI Steam Admission Valve

The Sentinel valve design is installed as the HPCI steam admission valve (1/2/3-FCV-73-16) on all three units. The Sentinel valve replaced the previous double-disc design gate valves, which had chronic leakage problems.

These valves are not LLRT tested, so there is no leakage data. Surveillance testing is performed quarterly on these valves, and there have been no leakage problems (indicated by no abnormal temperatures in the turbine casing) since these valves were installed.

Plant Performance - Cooper Nuclear Station

Installed: October 2014

10-inch x 8-inch ANSI 900

Application: HPCI Turbine Steam Admission Valve

The Cooper Nuclear Station (CNS) installed the Sentinel valve for the HPCI turbine steam admission valve application. This is a 10 x 8 x 10 venturi design with an SB-1-60 Limitorque operator. The previous valve was a conventional flex-wedge gate valve.

Since the valve is normally closed and has full reactor steam pressure on the upstream disc, there had been issues with the previous flex-wedge gate valve not sealing tightly, causing elevated temperatures and condensation in the HPCI turbine chamber. The valve is stroked on a quarterly basis during the normal surveillance procedure for HPCI pump operability. Pump initiation begins with opening of the steam admission valve to allow steam flow to the turbine associated with the HPCI pump.

Since its installation in 2014, the CNS engineers have not observed any downstream elevated temperatures or any other signs of leak-by in the turbine chamber after the quarterly surveillance is performed. They are periodically diagnostically testing the valve every 6 years, with interim packing load verification occurring every 4 years.

The angled installation with the stem being about 15 degrees canted above the horizontal plane presented issues with repair of the previous valve, a 10-inch Anchor Darling Flex-Wedge design. The bolted-bonnet design of the Sentinel valve eliminates issues with bonnet and pressure seal installation that had occurred in the past with the previous valve design.

Conclusions

- Unique, proven design of the Sentinel valve provides significant performance advantages over conventional wedge gate valves and double-disk gate valves by providing long-term maintenance-free service in demanding applications.

- The valve is fully qualified by extensive flow-loop testing under all operating conditions including blowdown and worst-case thermal-binding scenarios.

- Because of long-term, maintenance-free service, the valve offers significant reduction in dosage exposure.

- The new valve design is based on consistent design rules and procedures, extensive analysis, and qualified by extensive testing that satisfies the requirements of ASME Qualification of Mechanical Equipment (QME)-1 [10]. The new valve is a good choice for critical service applications requiring tight shutoff in both existing and new BWR and PWR nuclear power plants.

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Predictive Monitoring of Main Steam Safety Valves

Jessica Patrone
Main Steam System Engineer
Exelon Generation—Braidwood Generating Station

Abstract

This report describes the tools employed by the Braidwood Generating Station (Braidwood) main steam system engineer to identify main steam safety valves (MSSVs) that may require refurbishment. These methods include inservice testing results, visual identification of steam leaks past the valve disc, external temperature readings on the body and tailpipe flange of the valve, thermography, and risk-rank charts. Utilizing these methods, Braidwood will begin the transition from preventative maintenance (PV) of the MSSVs to a more cost-effective predictive maintenance (PD), in which the valves are rebuilt or refurbished on an as-needed basis.

Introduction

In efforts to become more cost effective, a transition from typically PM to more PD has helped utilities remain competitive. The ability to monitor and trend equipment has helped in these transitions, and this includes MSSVs. Braidwood utilizes PM tasks to rebuild its MSSVs on a regular periodic basis to maintain the health of the valves but will be transitioning to an as-needed rebuilding frequency. With this transition, monitoring and trending must be adequate to identify the MSSVs that require maintenance. This discussion will cover several MSSV monitoring and trending methods utilized at Braidwood.

Background

While the focus will be on the MSSVs of Braidwood, the tools and monitoring methods discussed may be applicable to other sites and applications. For reference, Braidwood is a dual-unit Westinghouse pressurized-water reactor with four steam generators per unit, and the units began commercial service in 1988. The main steam header operates at pressures of approximately 1,020 pounds per square inch absolute (psia) and 902 psia for Unit 1 and Unit 2, respectively. The relief valves of the four steam generator lines on each unit are similar: one power-operated relief valve (PORV) and five MSSVs. The total 20 MSSVs on each unit are capable of relieving approximately 112 percent of the maximum main steam flow. The MSSVs are GE-Dresser-Consolidated model 3707R valves, and the setpoints of the five MSSVs on each of the four steam generator lines are staggered at 15-pounds per square inch gauge (psig) intervals, from 1,175 psig to 1,235 psig.

Currently, rebuilding of Braidwood's MSSVs are dictated by PM tasks set on a seven refuel outage (RFO) frequency (all 20 valves are rebuilt within a seven outage interval) or corrective maintenance work orders for valves that must be rebuilt outside the PM task frequency. The current PM task frequency is to allow timely installation of anti-vibration components in all MSSVs during scheduled 18-month refuel cycles. The duration of the seven RFO frequency is presently 10 1/2 years. After the installation of the modifications, the valves will be rebuilt based on required maintenance over a 10 RFO frequency, which is projected to be 15 years duration to rebuild all 20 MSSVs. To use a PD strategy, adequate tools for monitoring the health of the valves are necessary, which include inservice testing, visual observation of steam leaks, valve external temperatures monitoring, thermography, and risk-rank charts creation.

Inservice Testing

Inservice testing is performed to verify the setpoints of the MSSVs. The total population of valves (40 valves total between the two units) is tested every 5 years, and at a minimum, 20 percent of the total population of valves (four valves) is tested every 24 months. During each RFO, which occurs at 18-month intervals, approximately 7 to 10 valves are tested. Inservice testing is used to verify setpoints and is conducted the week before the beginning of the RFO. Valves are tested and are as-left adjusted to within +/-1 percent of the setpoint value for two consecutive lifts. Valves that are scheduled to be rebuilt during RFOs are also tested at this time. The inservice test is the most reliable indication of the health of the valve, and valves that fail an as-found lift within the acceptable +/-3 percent range or that require a significant number of adjustments and/or test lifts, may be required to be removed for refurbishment off site.

Steam Leaks

The Braidwood MSSVs are located near easily accessible permanent scaffolding to access the valves and the tailpipe bowls, which allows for simple identification of steam leaks past the valve disc. Larger steam leaks may be clearly visible as the steam exits the bowl drains. Small or invisible steam leaks may require the use of an inspection mirror on an extendable rod to check for condensate from the tailpipe. These checks are performed during periodic walkdowns of the system, and valves identified with steam leaks are scheduled to be removed and rebuilt during the next available outage.

Tailpipe and Body Temperatures

The MSSVs at Braidwood do not have permanently installed tailpipe temperature probes and, with the ease of access to check the tailpipe for steam leaks, the tailpipe temperature readings are not necessarily used to identify steam leaks. However, the temperature readings can be a beneficial method to trend the valve body and tailpipe temperatures. Using an infrared thermal gun or similar equipment, such as a contact pyrometer, two readings are taken at each valve: on the valve body and on the tailpipe flange. Figure 1 denotes the locations where the valve body (1) and tailpipe flange (2) temperature readings are collected on the Braidwood MSSVs. The readings are performed on easily identifiable locations, such as the nut on the valve body, for consistent data. Location 1 is about 2 inches above the main disc.

Figure 1. Temperature readings are collected on the valve body (1) and on the tailpipe flange (2).

A comparison of the valve temperatures can identify anomalies. Figure 2 shows the results of the most recent temperature readings for the Braidwood Unit 1 MSSVs in August 2016. Low body temperature of valve 1MS014C was noted, which may be an indication of a plugged drainline or condensate standing above the main disc in the valve. The valve is scheduled to be rebuilt during the next outage, at which point the drainlines will be inspected for blockages.

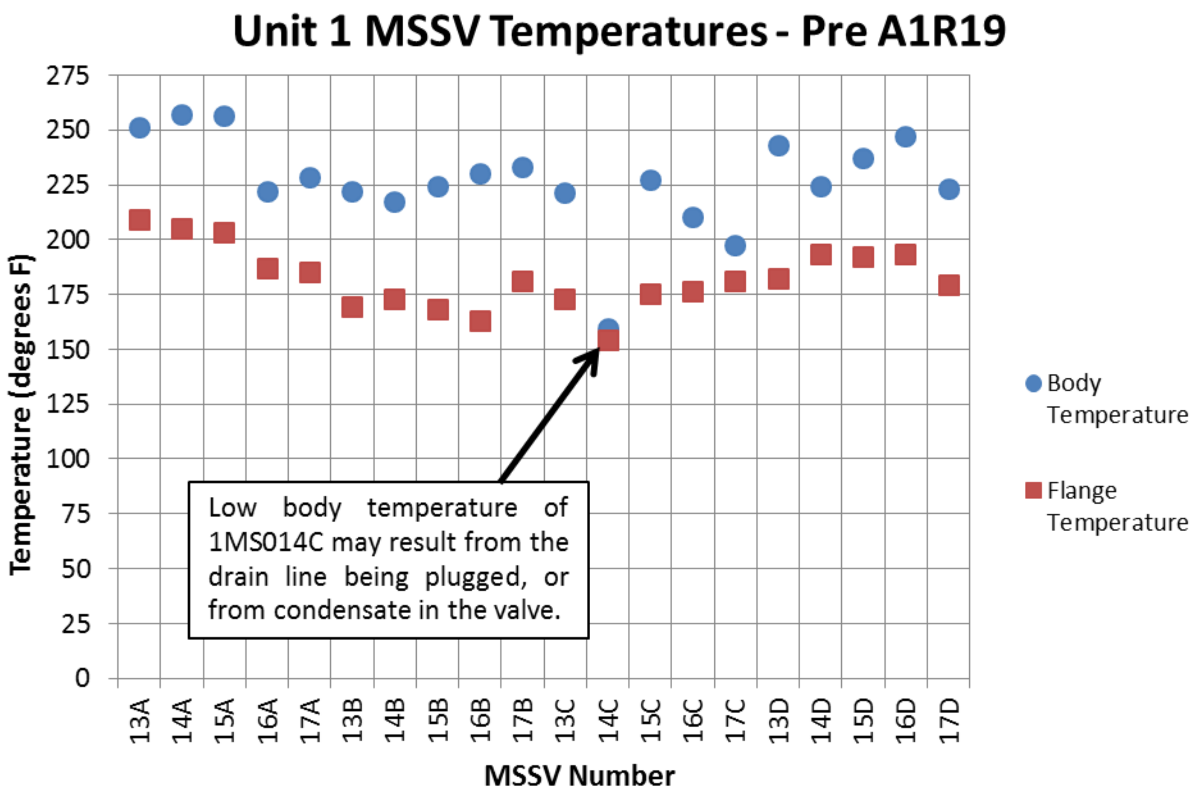

Figure 2. The body and tailpipe temperature plot. Valve 1MS014C was noted to have a low body temperature compared to other valves.

Thermography

With the ability to observe steam leaks, either visually or from tailpipe temperatures, thermography is not typically utilized for monitoring. However, thermography may provide additional steam-leak verification. Figure 3 shows two MSSVs, one with a verified steam leak and the other with no known leak.

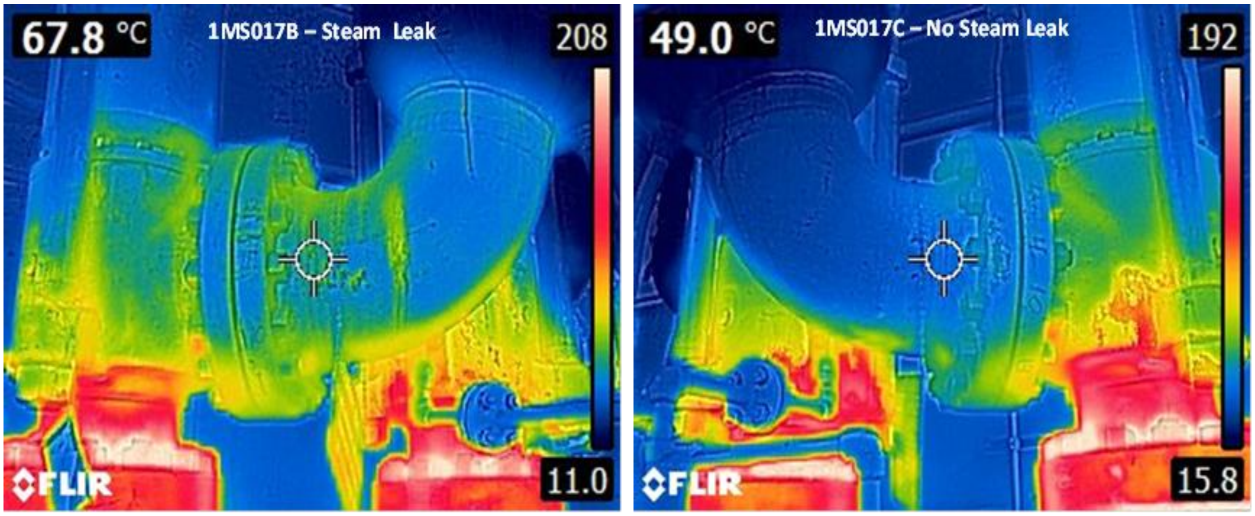

Figure 3. Valve 1MS017B (left), which has a visible steam leak in the discharge pipe elbow at 67.8 degrees Celsius (C) (154 degrees Fahrenheit (F)), compared to the 1MS017C valve (right), which does not exhibit indications of leak-by at 49.0 degrees C (120 degrees F).

The 1MS017B and 1MS017C valves in the figure are located in the same room and experience similar ambient conditions, but 1MS017B had visible steam exiting the bowl drain. Note the elevated temperature on the upper portion of the 1MS017B valve tailpipe discharge pipe elbow (left photo) at 67.8 degrees C (154 degrees F), compared to the 1MS017C valve discharge pipe elbow (right photo) at 49.0 degrees C (120 degrees F).

Additionally, thermography may be used to determine blocked drainlines. In the discussion regarding tailpipe temperature, the 1MS014C valve was noted to have a lower body temperature, which can be the result of condensate in the body or a plugged drainline. Thermography may be used to trace the drainline of the valve and determine if a blockage exists.

Risk Rank

The decision to rebuild valves can be represented by a risk-rank chart. The chart tabulates a list of criteria that can affect the valve, and a “criteria priority” provides a multiplier of 1 (low priority), 2 (medium priority), or 3 (high priority), based on the impact the criteria have on the health of the valve. Criteria that strongly affect the valve are given a higher criteria priority multiplier. In Figure 4, for example, the Braidwood MSSVs have 10 criteria that are utilized in the risk-rank chart. These criteria include results of the latest inservice testing, such as the amount and adjustment size of as-left setpoint adjustments and the number of lifts. Additional criteria include valve deficiencies, such as the presence of steam leaks and stem vibrations. Remaining criteria involve the type of vendor used during the rebuilding of the valve, how recently the spring was tested or replaced, as well as whether ultrasonic leak detection was used during as-left certification lifts.

The benefit of the risk-rank chart is to create a quantitative representation from a potentially subjective decision of which valves must be rebuilt; it also can be tailored to a specific site and valve type. An MSSV with a total risk-rank number between 100 and 200 is indicative of a higher risk MSSV that is presently not leaking but could develop a leak (100 to 124), is presently leaking (approximately 125 to 149), or could cause a unit SCRAM (approximately 150 to 200). Any MSSV with a risk-rank number above 100 is a candidate for out-of-cycle maintenance to lower the unit risk-rank level. This approach has enabled both of the Braidwood units to operate for more than 6 years without a SCRAM or power reduction from a leaking MSSV.

Braidwood Unit 1 experienced a SCRAM caused by a pressure transient, followed by an MSSV disc getting stuck in the open position and blowing down the unit on August 16, 2010. Afterwards, the risk-rank tool was developed by evaluating 10 characteristics of MSSV performance that could have contributed to unacceptable MSSV seat leakage, and this single MSSV had a significantly higher risk rank than the other 19 MSSVs in Braidwood Unit 1. If the risk-rank tool had been in use before the event, the problematic MSSV could possibly have been identified and corrected by scheduling an out-of-cycle maintenance activity. The risk-rank methodology was applied to units across the Exelon Nuclear Generation fleet and several other MSSVs with risk ranks greater than 100 because high-risk characteristics were given the higher priority for corrective PM to eliminate the potential for similar failures.

	Criteria										
Valve EPN	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Total Value**
1MS013A	1	1	1	1	1	3	3	1	1	3	38
1MS014A	1	1	1	1	1	3	3	1	1	3	38
1MS015A	1	1	1	1	1	3	3	1	6	3	53
1MS016A	1	1	1	1	1	3	3	1	1	1	32
1MS017A	1	3	1	1	1	3	3	1	1	3	40
1MS013B	1	1	1	1	1	3	3	1	1	3	38
1MS014B	1	1	1	1	1	3	3	3	1	3	42
1MS015B	1	3	1	3	1	3	3	1	1	3	46
1MS016B	3	1	1	1	3	3	3	1	1	3	50
1MS017B	3	3	1	1	3	3	3	6	6	3	77
1MS013C	1	1	1	1	1	3	3	1	1	3	38
1MS014C	3	3	1	3	3	3	3	1	1	3	58
1MS015C	3	6	3	1	3	3	3	1	1	3	59
1MS016C	3	3	1	3	3	3	3	1	1	3	58
1MS017C	3	3	1	1	3	3	3	1	1	3	52
1MS013D	1	3	1	1	1	3	3	1	1	3	40
1MS014D	1	3	3	6	3	3	3	1	1	1	59
1MS015D	1	9	9	9	1	3	3	1	1	3	86
1MS016D	1	9	9	3	1	3	3	1	1	3	68
1MS017D	1	3	1	1	3	3	3	1	1	1	40
Criteria Priority	3	1	2	3	3	2	2	2	3	3	

Figure 4. Example of a Risk Rank Chart of Braidwood Unit 1 MSSVs Prior to the 2016 RFO

Risk Rank: 20 to 49, is in the excellent range (low) and no maintenance problems are predicted.

Risk Rank: 50 to 74, is in the normal range (average) and no maintenance problems are predicted.

Risk Rank: 75 to 99, is in the normal range (medium) and no maintenance problems are predicted.

Risk Rank: 100 to 124, is in the slightly elevated range (medium-high) and with no active leakers.

Risk Rank: 125 to 149, is in the moderately elevated range (high) and could develop an active leaker.

Risk Rank: 150 to 200, is in the elevated range (very high) and could have an active leaker or SCRAM.

The risk-rank criteria should be used with appropriate judgment and are not values that should be strictly adhered to. As an example, in the Braidwood Unit 1 MSSV risk-rank chart, the 1MS015D and 1MS016D valves have high values for Criteria 2, 3, and 4, which correspond to larger adjustments and more lifts required during the last inservice test. However, the underlying cause for the additional lifts and large adjustments did not result from issues with the valve that required refurbishment. In this specific case, the adjustment lock nuts of several valves were found loose during testing several outages prior, which resulted in lower pressures at which the valves lifted. The next test for valves 1MS015D and 1MS016D is expected to produce results that will better reflect the health of the valve.

If a valve has not been rebuilt in a significant number of outages, the risk-rank value may be larger. If the valve continues to produce acceptable inservice as-found testing results, then the valve would not be a good candidate to be rebuilt outside of the planned maintenance schedule (example, Valve 1MS015D has a total value of 86, and because it is <100, routine maintenance will be performed as scheduled).

Conclusion

The previously discussed tools allowed the Braidwood main steam system engineer to accurately identify valves required to be rebuilt or refurbished. Using these methods, Braidwood will benefit from the cost savings associated with a transition from a PM to PD strategy of the MSSVs. Presently, Braidwood is refurbishing all of the 20 MSSVs in each unit over a seven-RFO frequency, which, with the 18-month cycles, is a 10 1/2-year interval. The present average is three MSSVs worked per RFO. Once all 20 MSSVs in each unit are converted with the original equipment manufacturer’s anti-vibration modification package, the PM strategy will extend the 20-MSSV maintenance cycle to a 10-RFO frequency, which is a 15-year interval. The future average will be two MSSVs worked per RFO. This change from PM to PD is expected to extend the maintenance cycle for the 20 MSSVs per unit from seven RFOs over 10 1/2 years to 10 RFOs over 15 years. This represents a 45-percent reduction in maintenance costs over 15 years.

# RFOs	1	2	3	4	5	6	7	8	9	10	TOTAL MSSVs
MSSV Now	3	3	3	3	3	3	2	3	3	3	29
MSSV Future	2	2	2	2	2	2	2	2	2	2	20

(29-20)/(20)×100 percent=(9)/(20)×100 percent=45-percent reduction in maintenance costs

Track 6: Snubbers

Track Chair: Glen Palmer, Palmer Group International, LLC

Snubber Program Transition from ISI Code to IST Code, ISTD

Glen R. Palmer
Palmer Group International, LLC

Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code), Subsection ISTD, “Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light Water Reactor Nuclear Power Plants,” is the required code for conducting preservice and inservice examination and testing of dynamic restraints (snubbers). The latest approved edition of the OM Code is now, or soon to be, the 2012 Edition. With the publication of the 2006 Addenda to Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” Division 1, of the ASME *Boiler and Pressure Vessel Code* (BPV Code), the snubber requirements, which were previously located in Article IWF-5000, were deleted. When the requirements of IWF-5000 were deleted, the requirements for examination and testing of snubbers, as given in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, “Codes and standards,” were required to be in accordance with the ASME OM Code, Subsection ISTD.

When Owners prepare their 10-year inservice inspection (ISI) program updates that incorporate the 2006 Addenda and later of the Section XI Inspection Code, the snubber requirements will be required to be in accordance with the ASME OM Code, Subsection ISTD, 2004 Edition with Addenda through 2006 or later approved editions. This edition of the ASME OM Code has been referenced in the NRC regulations as of June 21, 2011. Since that time, Owners have been required to meet the requirements of the latest approved edition of the ASME OM Code for snubber examination and testing when snubber programs are updated.

With the transition of the snubber program from the ISI program and ASME BPV Code, Section XI, requirements to the inservice testing (IST) program and the ASME OM Code, there is sometimes confusion and implementation gaps where regulatory program requirements could be missed.

This paper addresses the transition and identifies potential pitfalls and how to mitigate them.

Introduction

The NRC regulations for ISI and IST programs at operating nuclear power plants are specified in 10 CFR 50.55a, which incorporates by reference the ASME BPV Code, Section XI, Division 1 (Section XI) and the ASME OM Code. Located within the ASME OM Code is Subsection ISTD. The U.S. Nuclear Regulatory Commission (NRC) determines which edition of the ASME OM Code is applicable for all operating plants in the 10 CFR 50.55a regulations, which is updated from time to time as new code editions are published. The requirements listed in the regulations have the force of law for operating light-water reactors in the United States.

As stated in the regulations, every 10 years, nuclear plant owners are required to review the latest Code edition that is incorporated by reference in the regulations and make appropriate changes to their operating procedures to maintain compliance with the latest edition of the Code. For example, 10 CFR 50.55a(g)(4)(ii) states that inservice examination of components and system pressure tests conducted during successive 120-month inspection intervals must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in paragraph (b) of this section 12 months before the start of the 120-month inspection interval.

For operating plant programs with a Code of Record[1] before the 2006 Addenda of Section XI, snubber programs are required to be in accordance with the requirements of Section XI, Article IWF-5000, "Inservice Inspection Requirements for Snubbers." For those plants whose programs are subject to a Code of Record that includes or is after the 2006 Addenda, snubber programs must be in accordance with the ASME OM Code, Subsection ISTD. Snubber examination and testing requirements are no longer located in Section XI.

Pitfall one: not recognizing the proper Code of jurisdiction for the snubber program.

Snubbers

A snubber is identified as a member of the pipe support standard family for the purposes of design and fabrication.[2] The specific rules for pipe supports are contained in Section III of the ASME BPV Code, Subsection NF. Although snubbers are identified as "pipe supports" under normal operating conditions, they do not support any piping load but are free to travel during plant heatup and cooldown.[3] Snubbers become active during a sudden dynamic loading condition or event, where they will resist movement and stabilize the piping with respect to equipment or the building structure. Since snubbers are part of the pipe support family, they have also historically been part of the Section XI Inspection Code. However, since snubbers are devices with internal moving parts that cannot be verified as functional without some type of test, they are included within the scope of the ASME OM Code for examination and testing. Section XI has long pointed to ISTD for examination and testing of snubbers. However, licensees using ASME OM Code, 2004 Edition with Addenda though 2006 or later editions, are no longer required to satisfy IWA-2213 VT-3 method requirements of Section XI for visual examination of snubbers.

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[1] Code of Record is the Code edition to which the licensing basis of the plant refers for each 10-year operating interval.

[2] Reference Figure NF-1214-1.

[3] A common misconception is that snubbers are supporting a load during normal plant operation. This is not the case unless the snubber has been activated by a dynamic event or is not functional and has become rigid.

Program Plans

Both Section XI and the OM Code require program plans to be submitted for each 10-year operating interval of the plant. IWA-1400(d) states the following:

> The responsibilities of the Owner shall include ….submittal of plans, schedules, and preservice and inservice inspection summary reports to the enforcement and regulatory authorities having jurisdiction at the plant site.

Paragraph (a) in ISTA-3200, "Administrative Requirements," states, "IST Plans shall be filed with the regulatory authorities having jurisdiction at the plant site." Historically, snubber program plans have been very abbreviated and often a single paragraph included in the ISI plan with a pointer reference to Owner technical specifications (TS), an Owner-controlled technical requirements manual (TRM), or other engineering-controlled documents. Before approval of the 2006 Addenda of the ASME BPV Code, Section XI, in 10 CFR 50.55a, the OM Code, Subsection ISTD, 1995 Edition through the 2001 Edition with Addenda though 2003, was referenced as an acceptable alternative to the requirements of IWA-5000, Articles IWF-5200(a) and (b) and IWF-5300(a), provided visual examination of snubbers was performed using VT-3 methods referenced in IWA-2213. Once the 2006 Addenda of Section XI was approved in 10 CFR 50.55a, the requirements of the OM Code became applicable, along with the requirements of ISTA-3100 and ISTA-3200. Snubber program plan requirements are stated in ISTA-3110, "Test and Examination Plans," with additional guidance in OM Code, Nonmandatory Appendix A, "Preparation of Test Plans."

ISTA-3110 requirements include the following:

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

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

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

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

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

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

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

ISTD-9200, “Test Plans,” requires the following:

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

Pitfall two: not recognizing a Snubber Program Plan submittal is required.

10-Year Updates

Every 10 years, the inspection programs of operating plants must be updated (10 CFR 50.55a(g)) to consider any changes to the applicable Code of Record. For plants that have recently updated or are in the process of updating their snubber examination and testing programs, there needs to be a recognition that there has been a change in Code requirements for snubbers. Previously, snubber examination and testing requirements were found in the ASME BPV Code, Section XI, Article IWF-5000. This Article IWF-5000 has been deleted from the 2006 Addenda of Section XI. Snubber examination and testing requirements now only appear in the OM Code, Subsection ISTD. The Section XI Code is an “inspection” code, whereas the OM Code includes inspection and “testing.”

ISTA-3120, “Inservice Examination and Test Interval,” states the following:

> *(a)* Examination and test frequency shall be in accordance with the requirements of Section IST.
>
> *(b)* The examination and test interval shall be determined by calendar years following placement of the unit into commercial service.
>
> *(c)* The examination and test intervals shall comply with the following, except as modified by subparas. (d) and (e):
>
> *(1)* *Initial Examination and Test Interval:* 10 yr. following initial start of unit commercial service
>
> *(2)* *Successive Examination and Test Intervals:* 10 yr. following the previous test interval
>
> *(d)* Each of the inservice examination and test intervals may be extended or decreased by as much as 1 yr. Adjustments shall not cause successive intervals to be altered by more than 1 yr. from the original pattern of intervals.
>
> *(e)* In addition to subpara. (d), for units that are out of service continuously for 6 months or more, the examination and test interval during which the outage occurred may be extended for a period equivalent to the outage and the original pattern of intervals extended accordingly for successive intervals.

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

Pitfall three: not recognizing the Snubber Program Plan must be updated every 10 years.

When making this initial change from ASME BPV Code, Section XI, to ASME OM Code, Subsection ISTD, one must be mindful of the potential differences in interval dates from the ISI program interval to the IST program interval. For some plants, the ISI interval may end up being different than the IST inspection interval because of the allowable extensions of the ending dates of these separate intervals. Section XI, IWA-2430(c)(1), allows the ending date of the interval to be extended or decreased by up to 12 months. Likewise, OM Code, ISTA-3120(d), allows the IST program interval to be extended or decreased by up to 12 months. It is possible that when one interval ends, there may be a gap before the beginning of the other interval.

In the case when there is a gap between the interval dates, it is important that the updated program plan begins at the end of the earlier interval so there is no gap. In Figure 1 of this paper, the ISI interval may end earlier than the IST interval begins, or the ISI interval ending date may need to be extended to the beginning of the IST interval beginning date. This is important to avoid a gap in submitted program plans where there might be no program in place.

Pitfall four: not identifying the appropriate ending and beginning dates of the intervals.

Example

Plant A is a two-unit station, where Unit 1 came online on June 1, 1986, and Unit 2 came online on May 1, 1987. The first ISI interval for Unit 1 ended on May 31, 1996, with the Unit 2 ISI interval ending on April 30, 1997. The IST intervals were following along the same date pattern; however, it was decided to align the two IST intervals for the purpose of conformity to the same dates and same Code of Record during the third interval for IST. The new interval dates for the start of the fourth IST interval for both units became May 1, 2017. The third interval for the ISI program for Unit 1 ended on May 31, 2016, almost 1 year earlier than the start of the fourth IST interval (see Table 1 of this paper).

The snubber examination and testing program had been part of the ISI program interval through the first three operating intervals, but now with changes to 10 CFR 50.55a, the snubber program is no longer governed by the rules of Section XI, but now is governed by the rules of the OM Code. The ISI program plan submittal for the fourth interval did not address the snubber program since ISI is no longer responsible for the snubber program. The IST fourth interval program plan submittal was not required to be effective until May 1, 2017. Therefore, the snubber program for Unit 1 had expired before any IST snubber program submittal was made for the fourth interval.

Some program owners have opted to just continue with the ISI schedule of program updates and not acknowledge that the OM Code, not the Section XI Code, now governs snubbers. This may have been unintentional as they just kept the snubber program as a subset of the Section XI ISI program, or just considered the snubber program to stand alone without consideration of the IST interval program plan requirements set forth in the OM Code, Subsection ISTA. One of the challenges in the current nuclear climate is to maintain adequate experience in the area of snubber program owner in order to fully understand and implement the requirements of both 10 CFR 50.55a as well as the referenced ASME Codes.

Pitfall five: ignoring the change in Code jurisdiction for snubbers and maintaining the status quo.

Conclusion

The snubber program is often looked upon as a part-time job where some think it requires only 25 percent of the program owner's time. This is a gross misconception. The requirements of Subsection ISTD are comprehensive, including a visual examination program, sample plan testing program, as well as an integrated service life monitoring program for ALL snubbers installed in the plant. This could amount to more than 1,000 individual safety-related components for a two-unit site. Snubber program owners often have little experience with the details of ISTD and are unfamiliar with the 10 CFR 50.55a requirements and the 10-year program plan update submittals. They are also often burdened with several other component programs that contribute to their time management challenge. Fortunately, with recent industry operating experience, NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants - Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants," issued October 2013, as well as NRC information notices, regulatory issue summaries, and enforcement guidance memorandum notices, there is a significant amount of information readily available for the snubber program owner to use for guidance. In addition, the Snubber Users Group[4] provides an excellent forum for information and knowledge transfer. The governance over the snubber program has changed from ASME BPV Code, Section XI, to the ASME OM Code. Program owners and their supervisors should recognize this and ensure that they are taking appropriate steps to implement this change.

[4] The Snubber Users Group meets two times per year. The summer meeting is more widely attended by vendors who are providing services or products to the industry.

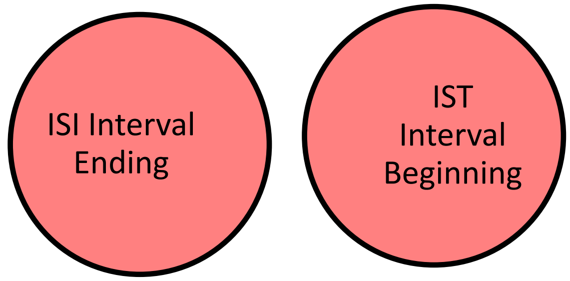

Figure 1. Illustration Showing Gap between the Interval Dates

Table 1. Interval Ending and Beginning Dates

Plant A	Ending		Beginning	Program
Unit 1 ISI	5/31/2016	GAP		ISI
Unit 1 IST		4/30/2017	5/1/2017	Snubbers OM
Unit 2 ISI		4/30/2017		ISI
Unit 2 IST		4/30/2017	5/1/2017	Snubbers OM

References

[1] American Society of Mechanical Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants*, 2004 Edition with 2005 and 2006 Addenda, American Society of Mechanical Engineers, New York, NY.

[2] ASME *Boiler and Pressure Vessel Code*, 2007—Addenda 2008, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” Division 1.

[3] *U.S. Code of Federal Regulations,* “Domestic Licensing of Production and Utilization Facilities,” Part 50, Chapter I, Title 10, “Energy,” Section 50.55a, “Codes and standards.”

[4] ASME *Boiler and Pressure Vessel Code*, 2007—Addenda 2008, Section III, “Rules for Construction of Nuclear Facility Components,” Division 1, “Metallic Components,” Subsection NF, “Supports.”

[5] NUREG-1482, “Guidelines for Inservice Testing at Nuclear Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants. Final Report,” Revision 2, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Rockville, MD, October 2013.

Delivering the Nuclear Promise through Effective ISE and IST Programs for Dynamic Restraints

Matt Palmer, P.E.
Anvil Engineered Pipe Supports

Abstract

Delivering cost reductions through the Nuclear Promise can appear to be at odds with the safe operation and maintenance of nuclear facilities. However, inservice examination (ISE) and inservice testing (IST) programs can deliver significant gains in efficiency and effectiveness with proper application of the American Society of Mechanical Engineers (ASME) Operation and Maintenance (OM) Code. Along with scheduled maintenance prescribed by the manufacturer, dynamic restraints (snubbers) require periodic visual inspection and testing to ensure that the installed population will perform its safety function during seismic events or dynamic operational transients. Methods prescribed in the ASME OM Code, Subsection ISTD, “Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light Water Reactor Nuclear Power Plants,” are effective in identifying bad actors and verifying the operational readiness of the population, but can come at a significant cost when not properly utilized, especially when the penalty for a failed test or inspection is applied to the ISE or IST campaign. The Nuclear Promise can be realized in a snubber ISE or IST program with a thorough understanding of the intent of the prescribed testing and the mechanics of the safety functions to be verified. With this understanding, legacy requirements that were grandfathered into a program can be examined as to their relevance, and procurement specifications and testing procedures can be written that are pertinent and current to industry best practices.

This paper, through the lens of a snubber manufacturer and ASME certificate holder, examines some common and uncommon examples of snubber issues found in industry that add significant cost, time, or dose to a snubber ISE/IST program and the basis for eliminating them. The methodology used to evaluate an ISE/IST program requirement and determine its effectiveness in verifying a snubber’s safety function while satisfying the OM Code could be used for other components under the jurisdiction of the OM Code. In this manner, the Nuclear Promise can be safely delivered in an ISE/IST program that does not compromise the intent or integrity of OM Code requirements.

Introduction

Safety is the paramount concern for any licensee operating a nuclear facility. To achieve a high degree of confidence that the safety systems of a facility will function as designed, constant maintenance and component/system surveillance are required. The cost in both dollars and dose of these maintenance programs is significant, especially when coupled with scheduling impacts created by unplanned activities during refueling outages. However, the fact that the licensee has legal and moral imperatives to conduct these surveillance and maintenance activities does not mean that facilities cannot have healthy bottom lines as well. Implementation of the ASME OM Code can be economically realized with a thorough understanding of the component in question and how the prescribed ASME OM Code ISE and IST activities for a component are designed to verify the safety function(s) of that component.

Dynamic restraints subject to ISE and IST activities under the ASME OM Code, Subsection ISTD, provide the perfect opportunity to examine these concepts in greater detail and deliver the Nuclear Promise through efficient and effective implementation of ASME OM Code activities. There are two types of dynamic restraints governed by Subsection ISTD: hydraulic snubbers and mechanical snubbers. The discussion will focus on snubbers designed and manufactured by the three primary providers of dynamic piping restraints to the domestic nuclear fleet: Anvil Engineered Pipe Supports (EPS) (Formerly Grinnell Corp.), Lisega, and Basic-PSA[1] (Figure 1).

Types of Dynamic Restraints and Their Methods of Operation

Dynamic restraints, commonly referred to as snubbers, are devices that limit either linear velocity or linear acceleration of piping and equipment. They are designed to move freely with minimal drag force along the axis of the snubber while a system is in normal operation, such as startup and cooldown. Should an operational transient or seismic event cause the snubber to move with a greater velocity or acceleration than the pre-set limit, the snubber will activate by applying a restraining force against further movement. The snubber will then displace (release) at a rate that is proportional to the applied load.

The ASME OM Code, Subsection ISTD-2000, defines these characteristics as follows:

- activation - the change of condition from passive to active, in which the snubber resists rapid displacement of the pipe or component
- release rate - the rate of axial snubber movement under a specified load after activation of the snubber takes place
- drag force - the force that will sustain low-velocity snubber movement without activation throughout the working range of the snubber stroke

Drag force is a characteristic common to all types of snubbers, but is more indicative of the health of a mechanical type snubber than a hydraulic type snubber.

Service life, while not a functional characteristic, is a design characteristic important to all snubbers and all snubber programs. ISTD-2000 defines service life as, “The period of time an item is expected to meet the operational readiness requirements without maintenance.” All manufacturers will recommend a service life in their design specification that is primarily a function of temperature and radiation exposure.

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[1] At the time of this writing, the majority of piping snubbers sold to commercial nuclear power plants in the United States come from one of these three manufacturers. Fronek/Anchor Darling and Bergen Patterson still provide small quantities to select plants.

Hydraulic Snubbers

Hydraulic snubbers manufactured by Anvil EPS and Lisega accomplish activation and release through similar means. A first-generation Grinnell style control valve is shown in Figure 2 of this paper. In this configuration, a check and metering (bleed) valve are placed in parallel on both sides of a hydraulic cylinder. Piston rod and thus piston movement displaces fluid through the spring-loaded check valve. Should a pressure head develop over the poppet that is greater than the spring force holding the valve open, the check valve will close and force fluid through the metering valve. The rate at which fluid passes through the metering valve is proportional to the pressure differential on both sides of the valve. The internal components of the valves may differ between model or manufacturer; for purposes of ISE and IST, the principles are the same.

Hydraulic snubber service life is governed by elastomer (seal) compression set. When a seal is installed in a gland, it is elastically deformed and an internal spring force fills the gaps and voids at the sealing surfaces, thus preventing the working fluid from moving beyond the seal. Over time, this elastic deformation becomes plastic, and the seal will fail under low pressure as the internal elastic energy is no longer sufficient to create a seal in the gland. The amount of time this takes is dependent primarily on temperature and is quantified by the manufacturer through use of accelerated aging testing based on the Arrhenius model [7]. This accelerated aging testing results in a published service life from the manufacturer that states the snubber is good for X amount of years at a continuous operating temperature not to exceed Y degrees.[2] These values are a baseline from which service life should be adjusted based on the environment at the installed location. For example, in a benign environment at less than 150 degrees Fahrenheit (F), the Arrhenius model predicts an Anvil hydraulic snubber should last 42 years. Conversely, in high-temperature or vibrating environments, snubber service life should be reduced.

Fluid level in a hydraulic snubber can also be indicative of the environment at the installed location. Hydraulic snubber seals are designed to be self-lubricating. Dynamic seal interfaces in the rod and cylinder have a specific surface roughness designed to carry a minute amount of fluid to ensure lubrication during movement. In a benign environment, a snubber should expect to see less than 10E3 movement cycles of the piston or piston rod. In a vibrating environment, this can be upwards of billions of cycles over an 18-month refueling interval, depending on the vibration frequency. Over a billion cycles, the minute amount of fluid present in the surface profile of the seal interface can add up to a measurable quantity that clearly indicates the presence of vibration. Vibration-induced frictional heat will prematurely age the snubber seals and alter the fluid viscosity so that a grease-like substance can be seen on the piston rod as the fluid is carried past the seal by the surface profile.

[2] At current writing, Anvil certifies its snubbers to 25 years at a maximum continuous operating temperature of 157 degrees F, and Lisega certifies its snubbers to 23 years at 176 degrees F [9][10].

Mechanical Snubbers

Basic-PSA-type mechanical snubbers utilize an inertial mass to maintain a constant linear acceleration. Figure 3 of this paper is a cutaway view of a Basic-PSA Size ¼—10 mechanical snubber. Piping movement actuates linear motion of the telescoping cylinder through the cylinder end lug. This linear motion is transformed to rotational motion through a ball screw, which in turn rotates the inertial mass. The inertial mass is free-spinning and accelerates from friction with the ball screw. Should the ball screw rotate faster than is permitted by friction alone, the inertial mass makes contact with a capstan spring, which squeezes the static torque transfer drum. The torque transfer drum then limits the rotational ball screw motion and, thus, linear acceleration of the telescoping cylinder and pipe.

For mechanical snubbers, it is critical that the friction between the ball nut, ball screw, and the inertial mass is carefully maintained. The primary failure mechanism, when an operable snubber does not meet its acceptance criteria, is grease that has had its viscosity changed from the heat. For the inertial masses to maintain the 0.02g maximum acceleration criteria with less than 2-percent drag, the grease must be evenly distributed and in a specific viscosity range. The manufacturer has done extensive testing on its grease and has time-temperature curves that can be used to predict service life and required maintenance intervals.[3]

A characteristic of mechanical snubber designs is that there are no visual cues analogous to fluid level on a hydraulic snubber that provide some assurance as to the operability of the unit. However, the health of a mechanical snubber can be qualitatively determined by pulling one of the attachment pins from the snubber and stroking the component in the field. The published drag force value in a mechanical snubber is 2 percent of the rated load. When applying force by hand, an experienced technician will not be able to discern a quantitative difference in load, but should be able to qualitatively know if snubber drag is closer to 5 percent or moves at all. This is an effective barometer for smaller units, where drag is in the tens of pounds-force (and move under their own self-weight), but not effective for larger units, where forces are in the thousands of pounds.

Regulatory History

Historically, hydraulic snubbers have been around since the 1960s, and ISE and IST of snubbers were addressed in plant technical specification (TS) surveillance requirements. NUREG/CR-5416, “Technical Evaluation of Generic Issue 113: Dynamic Qualification and Testing of Large Bore Hydraulic Snubbers,” issued September 1992 [1], identifies 13 manufacturers that had hydraulic snubbers installed in commercial nuclear power plants domestically. Early hydraulic snubber designs were not particularly reliable, with failure rates as high as 30 percent [2]. The most common failure mode was leakage of hydraulic oil caused by

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[3] Basic-PSAs time-temperature service life curves are dependent on size and grease type, with a 65.56 degree C (150 degrees F) temperature giving a predicted life of 8 years on the low end and over 500 years on the high end [11].

fluid/seal incompatibilities with the operating environment or poor seal design. This rendered the snubber inoperable, as it would be unable to transfer load from the component to the building structure. As a solution, mechanical designs were developed to remove the need to verify fluid level and rebuild each snubber every 5 to 7 years. However, operational experience with mechanical designs yielded failures caused by vibration or “baking off” of lubricant at higher ambient temperatures.

In response to the high rate of snubber failures, Section XI of the ASME *Boiler and Pressure Vessel Code* (BPV Code) added Article IWF-5000 around 1980. This addition mandated testing of 10 percent of the safety-related snubber population during each refueling outage. Under this test plan, for every failure, an additional 10-percent sample must be tested until 100 percent of the sample passed. Neither the initial 10 percent sample nor 10-percent scope expansion requirement had any basis in statistical methods or standard sampling practices, but rather were grandfathered in from the original TS. At that time, most plants had populations of several hundred snubbers to one thousand or more. A typical unit with 300 snubbers would be required to test 30 snubbers, with each failure requiring testing of an additional 30. It was not uncommon for plants to test their entire population during early refueling outages with significant costs in schedule, dollars, and dose.

The industry’s response to high snubber failure rates and the rising cost of ISE and IST programs provides an excellent historical example of stakeholders coming together to deliver the Nuclear Promise. The Snubber User Group (SNUG) was formed in 1983, with the mission of bringing licensees, manufacturers, and regulators together in a forum to improve snubber performance and test programs [3]. Many SNUG members had active roles in various industry initiatives, including snubber reduction programs, Electric Power Research Institute and NUREG published research, and ASME Code committee membership. Most of these initiatives were conducted in the 1980s and early 1990s,[4] beginning with the publication of the ASME/American National Standards Institute (ANSI) OM-4 Standard in 1982 and its subsequent adoption into the ASME OM Code as Subsection ISTD, “Inservice Testing of Dynamic Restraints.”

The body of knowledge that is Subsection ISTD prescribes a test plan rooted in Wald Sequential Sampling Theory designed to ensure that 90 to 100 percent of the population will be operable with 95-percent confidence level. IST scope expansions are not automatic with each failure, but are based on an allowed number of failures for the sample size that will maintain the 90-percent/95-percent operability and confidence threshold. There are also allowances for

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[4] NUREG-1482, Revision 2, “Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants,” issued October 2013 [4], Appendix A, “Guidelines for Inservice Examination and Testing Program for Dynamic Restraints (Snubbers) at Nuclear Power Plants,” Section 4, provides an excellent source of historical reference information for the interested reader.

known failure modes or severe environments. Coupled with improvements in snubber designs,[5] licensees with larger snubber populations have been able to realize significant gains in both snubber population health and IST program costs. Today, it is not uncommon for well-run snubber ISE and IST programs to satisfy both their moral imperative for safety and regulatory requirements with no scope expansions during an IST campaign.

Snubber Inservice Testing in Accordance with ISTD-5000

The intent of any ISE or IST program is to verify that the safety function of a component will perform as intended. To verify that a snubber is functional, the activation and release rate for all snubbers must be verified, as well as drag force for mechanical snubbers. The method of verifying these parameters is relatively straightforward: A snubber is installed in a test bench with standard hardware. A linear actuator strokes the snubber with increasing velocity or acceleration until the pre-set activation level is reached (see Figure 4 of this paper). Once this limit is reached, the snubber resists actuator movement, and the rated load is applied to the snubber to verify the release rate. For mechanical snubbers, drag force is measured at an actuator rate less than the activation level.

Test benches can be analog and manually controlled, as they were in the 1960s and 70s, or computer-controlled with XY plots printed out at the machine, and everything in between. As such, significantly different test results can be achieved with different benches, different settings on the same bench, or with different operators. There is at least one study on how different testing methods and equipment produce different results [13][14], but in all cases, it is up to the operator and engineer to determine how they perform the test and interpret the results.

Delivering the Nuclear Promise through ISTD

With the given background in the operation, testing, and failure modes of dynamic restraints, what follows are several scenarios that represent cost-saving opportunities through proper understanding of the components and OM Code.

1) Use of design test parameters versus acceptance test parameters

When performing IST, it is necessary to have criteria by which a test can be judged to be acceptable or unacceptable. Published values of activation and release rate for the three major snubber suppliers to the U.S. domestic fleet are in Table 1.

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[5] A parallel standard to OM-4 for snubber design and qualification testing was also developed and is now known as the ASME Standard QME-1, "Qualification of Active Mechanical Equipment Used in Nuclear Facilities," Section QDR, "Qualification of Dynamic Restraints."

Table 1. Published Values of Activation and Release Rate

Manufacturer	Activation Level	Release Rate	Units
Anvil	203.2±50.8 (8±2)	101.6±25.4 (4±1)	mm/min (in/min)
Lisega	120–381 (4.72–15)	12–120 (47–4.72)	mm/min (in/min)
Basic-PSA	0.02	0.02	Gs

These values are design characteristics, not acceptance criteria. This concept is similar to the idea of critical characteristics for design and critical characteristics for acceptance presented in EPRI Report NP-5652, "Plant Engineering: Guideline for the Acceptance of Commercial-Grade Items in Nuclear Safety-Related Applications: Revision 1 to EPRI NP-5652 and TR-102260" [5]. The values in Table 1 are used by the manufacturer to size appropriate springs and determine fluid or grease viscosity, and by the piping or component engineer to write a specification for procurement. The manufacturer will also use these criteria for factory acceptance testing.

ISTD-5210 is explicit, in that activation velocity, release rate, and drag force (for mechanical snubbers) must be verified during IST and intentionally nonspecific in acceptance criteria, as they can be different from plant to plant and manufacturer to manufacturer. As an example of developing acceptance criteria, consider a straight 30.48-meter (m) (100-foot (ft)) section of pipe at 21.1 degrees C (70 degrees F) that heats up to 315.5 degrees C (600 degrees F). In accordance with the ASME BPV Code [6], this section would expand linearly by 119.4 millimeters (mm) (4.7 inches (in)). If this expansion was to occur in 60 seconds at a constant rate, the velocity of the expansion would be 119.4 millimeters per minute (mm/min) (4.7 inches per minute (ipm)) and the acceleration would be 6.7E-6 G. In practice, startups and cooldowns take several hours, and piping velocities and accelerations would be well below the design activation limits for the majority of systems and events.

Typical values for hydraulic snubber acceptance criteria at the site are sometimes taken from the factory values or at different nominal values with tolerances ranging of ±50.8 mm/min to 127 mm/min (±2 to 5 ipm). Given that most piping and equipment move at rates that are orders of magnitude less than the design criteria, it can be shown that use of factory acceptance criteria is overly restrictive. Furthermore, studies have shown that for hydraulic snubbers, activation velocity can be varied between 6.35 mm/min and 1,016 mm/min (0.25 ipm and 40 ipm) with no significant effect on the dynamic performance of the unit [8]. Therefore, using nominal factory values with arbitrarily tight tolerances for acceptance criteria offers diminished returns to the moral imperative of plant safety.

Acceptance criteria are defined before a snubber test campaign. Any snubber that does not meet these criteria during a preservice or inservice test is defined in ISTD as a failure. In this context, the word failure does not mean inoperable, only that a criterion is not met. If one were to perform a failure modes and effects analysis as defined in [5], it could be argued that failure to satisfy an arbitrary value of a snubber IST acceptance criterion has no effect on the safety function of a snubber, so long as activation and release occur. However, changes in functional test values for individual components between test campaigns can reveal leading indicators of potential failure and are discussed in later sections of this paper. An example of overly restrictive acceptance criteria follows.

a. Preservice Test Criteria versus Operational Readiness Test Criteria

In this scenario, Plant A was installing new velocity-limiting hydraulic snubbers into existing locations as a like-for-like replacement. The manufacturer's test report was being used as a benchmark to measure against the preservice operational readiness test (ISTD-5100). The manufacturer used an analog test bench for design verification, and the owner hired a third party to perform its snubber testing with a computer-controlled bench. The owner's results were 25.4 mm/min to 101.6 mm/min (1 ipm to 4 ipm) higher than the manufacturer's and outside the owner's acceptance criteria.

The discrepancy in test parameters was caused by the difference in test procedures. In the analog bench, the snubber is activated before application of the rated load to verify release rate. There is typically a 3- to 5-second delay between when the snubber is activated and the load is manually brought up to the prescribed value. In the computer-controlled bench, the snubber is activated and rated load is applied instantaneously. The time it takes to apply the load is known as ramp rate, and when applied too quickly, the quasi-static deflection of the snubber fluid column and snubber assembly is included with snubber movement from fluid displacement through the control valve.

In resolution, to combat the effect of a steep ramp rate, testing was performed at 20-percent rated load. Reduced load testing is permitted per ISTD-3210 so long as the parameters are correlated to testing at rated load. All manufacturers have extensive data or charts similar to Figure 5 of this paper for this purpose. The acceptance criteria for reduced load testing were then written into the plant's standard operating procedure with the help of the manufacturer. This alleviated the amount of quasi-static deflection picked up by the test equipment and resolved the issue.

b. Operational Readiness Test Temperatures

In this scenario, Plant B was going to utilize the manufacturer's test report for the preservice operational readiness test as permitted by ISTD-5110. The manufacturer's testing procedure specifies testing to be performed between 18.3 degrees C and 23.9 degrees C (65 degrees F and 75 degrees F). The owner's specification required testing to be performed between 21.1 degrees C and 26.7 degrees C (70 degrees F and 80 degrees F). The temperature of the snubber assembly and testing room is maintained by the manufacturer at 20 degrees C (68 degrees F).

Because of delivery constraints and scheduling priorities, the manufacturer was unable to conduct its final testing at the required test temperature. In theory, snubber fluid or grease viscosity increases with temperature, thus increasing the activation velocity or acceleration. In practice, a 1.1-degree C (2-degree F) difference in fluid temperature will show a measurable difference in lockup, but on a negligible order of magnitude. In order for the site to accept the snubber, the manufacturer had to perform a calculation based on empirically derived formulas to prove to the site that the snubbers would lock up in the required range at the specified temperature. The site then had to review and accept the deviation through an engineering evaluation.

Test temperatures can have significant impact on snubber testing, including both activation levels and release rates. However, there is no impact on the ability of the snubber to perform its safety function. This is an example of a criterion that can cause manufacturers headaches when balancing the work through the shop. The manufacturer's internal test procedures state that the test temperature will be between 18.3 degrees C and 23.9 degrees C (65 degrees F and 75 degrees F). While not explicitly added to the price of the component, the cost of this requirement resulted in several hours of engineering time both to the utility and the manufacturer. Ultimately, this cost is passed on to the industry in the form of higher overhead to accommodate these types of criteria.

2) Obsolete Designs or Procedures

Snubbers have been around for as long as nuclear power plants have been generating megawatts. As such, there is a rich history of manufacturers and myriad designs. Most plants have snubber populations that wholly consist of designs from Anvil (Grinnell), Lisega, and Basic-PSA. However, there are still components within these populations whose manufacturers no longer exist or have been replaced by newer designs with longer service life. There are also a minority of plants that have entire populations of legacy snubbers (e.g., E-systems, Bergen-Patterson, Fronek/Anchor-Darling). For these plants, the large volume of legacy component parts reduces the unit cost of replacement or dedication, and it may make economic sense to continue with these programs. However, for plants with obsolete units scattered through the population, the unit cost of replacement or a potential failure can greatly exceed the cost of a new unit.

Supply chains for current manufacturers are also very different than they were during new construction in the 1970s and 1980s, and the number of ASME-certificate holders has dwindled significantly since that time. This has forced original equipment manufacturers (OEMs) to adapt by changing vendors, making parts themselves, procuring through commercial-grade dedication or unqualified source material, among others. Most utility procurement specifications are written with a high degree of specificity, sometimes including the actual vendor part drawing that can tie the utility to a specific material or subsupplier. If this vendor documentation is not kept up to date with current procurement practices, it becomes a special order with significant increases in cost.

a. Procurement of Obsolete Components

Plant C has a population of hydraulic and mechanical snubbers. Of the hydraulic population, the original supply was pre-1974 Grinnell cylinders. Since that time, Anvil has made the pre-1974 design obsolete, and the majority of the population has been upgraded to post-1974 Fig. 200N.

In 2016, Anvil received a request for quotation (RFQ) for a seal kit for a pre-1974 Fig. 200N. This snubber was previously classified as nonsafety related and therefore was not upgraded, but became safety related as a result of Fukushima Dai-ichi nuclear power plant assessment activities. The RFQ came from a new program owner not familiar with snubbers or the history of the upgrade campaign. Anvil provided a quote for a post-1974 consistent with the previous upgrades with no change to the form, fit, or function of the installed unit. The owner insisted on a like-for-like replacement, and Anvil initially no-bid the part. This was driven by poor response from the seal supplier, who did not want to make custom rubber molds for a quantity of one seal.

After some negotiating with the seal supplier, Anvil developed a proposal to the utility. Included in the proposal was the cost and time of the custom rubber molding for obsolete seals. The lead time was 20 weeks at a price 18 times the standard seal kit. This was driven by the cost of tooling at the seal supplier, and it is worth noting that the cost was comparable to that of a new unit. The owner issued a purchase order, and Anvil supplied the material. Even at 18 times the standard cost, it is likely that Anvil still lost money on this order once all the time and opportunity cost of the RFQ process is taken into account.

The utility rebuilt and reinstalled the snubber in the plant, with the pre-1974 service life of 7 years. The license for this plant runs into the 2030s, and this snubber will need to be refurbished two times before then, each time procuring expensive one-off seals. There is also a cost associated with maintaining a rebuild procedure and keeping technicians current on this procedure for a quantity of one snubber. With a better understanding of snubbers and the history of the component upgrades from pre-1974 designs to post-1974 designs, the owner could have used the existing equivalency evaluation to install a post-1974 design. This would have given a 25-year service life (effectively making the component life of plant) and further homogenized the snubber population. The cost of maintaining this snubber for the balance of the plant’s operating life will far exceed the cost of doing a design change for that location.

b. Procurement to Superseded Part Drawings

Plant D procured snubbers to a vintage 1976 Anvil design and currently buys parts to perform its own rebuilds and preventive maintenance (PM). Anvil still sells the component and replacement parts as a standard product. This design features a fluid reservoir with a borosilicate (Pyrex) sight glass that serves as a way to measure the reservoir fluid level. The reservoir is open to the air, and there is no internal pressure on the inside diameter (ID) of the sight glass. The form, fit, and function of the snubber and its internal parts have not changed since the product was first offered; however, the vendors for some of the components have changed.

In the early days of nuclear power, many plants demanded detailed technical manuals and maintenance procedures from their vendors that included subcomponent vendors, material specifications, and, in some cases, manufacturing drawings. Figure 6 of this paper shows an earlier revision that is used by the utility to verify part dimension during receipt inspection. During the original supply, these sight glasses were manufactured specifically for this vintage 1976 design. Sight glasses are exempt in accordance with ASME BPV Code, Section III, “Rules for Construction of Nuclear Facility Components,” paragraph 2121b [12], and as such, can be ordered from any laboratory supply or general-purpose suppliers, such as Grainger and McMaster Carr, as Pyrex tubing with a 9-mm outer diameter.

The critical characteristics for acceptance in the dedication process are that the material is glass and that the outside diameter of the tube is correct so that it seats properly in a fitting. The ID is not important to the function of the part, and in an effort to reduce costs, the snubber OEM loosened the tolerances on the tube ID. Plant D sent in an RFQ for a sight glass with the correct part number and referenced a 1980s vintage revision of the drawing in Figure 6, which, for all intents and purposes, is the same part as is supplied today. However, the snubber vendor currently permits a tube ID of 5.33 mm/6.1 mm (0.210 in/0.240 in) in lieu of the specified 5.33 mm/5.59 mm (0.210 in/0.220 in).

The utility received sight glasses to the current OEM print, which were not to its specifications, and promptly rejected the first shipment. The sight glasses were sent back to the snubber manufacturer, who confirmed that the part was correct. Over the next 18 months, several lots were sent to the utility and subsequently rejected and confirmed to be correct by the manufacturer. It is important to note that in this instance, the snubber OEM was four entities of procurement removed from the end user and at no time was able to contact the end user to amend its specifications.

The resolution was to write a utility-specific procedure, that every time a sight glass was ordered, it would be invoked on the purchase order. The manufacturer would then supply parts to the original print, rather than the latest revision used by the plant for standard orders. The impact of this requirement to the manufacturer is the cost of augmented surveillance and a high level of rejects of sight glasses for this utility. As a result, the manufacturer imposed a minimum order of $1,000 for this part to pay for the augmented procedural and documentation requirements. The manufacturer also increased the unit price of the part by 500 percent, and a part that can be bought from Grainger or McMaster Carr for tens of dollars now costs hundreds to this particular utility.

3) Poor Service Life Monitoring Criteria

The domestic nuclear power industry in the United States is a mature industry, in that many operating plants are several decades removed from the assumptions that defined the design criteria and design analysis. Industry turnover as well as a significant labor and skills shortage means that the knowledge transfer required to sustain this heritage becomes increasingly difficult. Most design criteria are well documented, but often the assumptions and reasoning behind these criteria are not and exist within a small group or with an individual. With some research and “forensic engineering,” this tribal knowledge can be recreated, usually with a substantial cost in time and dollars. That said, legacy design criteria can be worth challenging in order to realize a cost savings from implementing new technology or current best practices.

The previous discussion of acceptance criteria is a perfect example of this. If a plant uses the original Grinnell factory acceptance criteria for activation, differences in testing methodologies from the analog benches of the 1970s to modern computer-controlled benches will result in test failures. A testing scope expansion will far exceed the cost of an engineering evaluation to widen the operational readiness test acceptance criteria, especially when factoring additional dose.

Service life monitoring is also an excellent example of where significant cost savings can be realized by examining the assumptions and reasoning behind PM intervals. The intent of a service life monitoring (SLM) program as described in ISTD-6000 is to predict, based on available data, the point in time at which a snubber will become inoperable so that repair or replacement activities can take place before failure occurs. Elements of a successful SLM program include the following:

- consistent measurement and visual examination criteria between examination campaigns
- consistent test procedures and conditions between examination campaigns
- accurate recording of all available data points
- the ability to retrieve records of examination and test data between campaigns and over long timescales
- good relationships with vendors and industry groups on a technical level so that operating experience can be disseminated among all parties

With these elements, a snubber program owner can develop a profile of each snubber and begin to discretize their populations into more efficient service-life criteria and PM intervals based on the application and environment.

Originally as designed, the same service life was expected from each snubber regardless of the environment or application. Operating experience then found that different locations, manufacturers, and designs required different service lives. Challenges in analog recordkeeping and early data storage and retrieval methods made it impractical to gather and maintain the types of information required to run an efficient SLM program. Modern database systems make it easier to manage all this information, and the program owner can make more informed decisions on its PM intervals.

a. Service Life Extensions Beyond Published Manufacturer Values

Early Bergen-Patterson and Grinnell Corporation hydraulic snubber designs had a service life of 5 - 7 years. This was governed by poor fluid/seal compatibility (Bergen-Patterson) in a radiation environment and by use of external thread seals (Grinnell). The first generation of mechanical snubbers advertised a 40-year life but was found to be substantially less in service. With the arrival of second-generation hydraulic snubber designs and improved grease in mechanical units, all three current manufacturers publish a service life of at least 23 years at temperatures not to exceed the recommended sustained maximum. Hydraulic snubber service life is governed by seal compression set, and mechanical snubber service life is governed by grease viscosity. By understanding the qualification testing performed by the manufacturers and utilizing their empirical aging data, it is possible through an SLM program to extend the life of a snubber beyond the published values.

Using an Anvil hydraulic snubber as an example, the published service life is 25 years, with a continuous operating temperature not to exceed 69.4 degrees C (157 degrees F). Using the Arrhenius model, if the environment around the installed snubber is known to have an ambient temperature of 40.6 degrees C (105 degrees F), the predicted service life of the elastomers is 1,634 years.[6] If the snubber was functionally tested in year 20 of its initial 25-year service life with identical results to its preservice operational test, it could be argued that there is no credible degradation mechanism at that location for activation and release rate. Furthermore, should the fluid level in year 20 be equivalent to the fluid level measured during preservice inspection, it could also be argued that there is no credible mechanism for leakage. With these positive data points, the Arrhenius model can be used to quantify the predicted service life and extend it beyond the published 25-year value. With a large enough sample size, this could be extended to snubbers in similar environments or locations. The analysis can also be done for any snubber that utilizes elastomeric seals.

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6 It should be noted that this is the predicted service life in the laboratory setting for excessive compression set due to heat. At that timescale, other failure mechanisms would come into play well before failure due to excessive compression set.

b. Service Life Reductions More Exacting than Published Manufacturer Values

SLM is not meant to prove out a design, but rather to look for leading indicators of failure. As previously discussed, the acceptance criteria for functional testing themselves are not particularly important to the safety function of a snubber, but rather the delta between two campaigns of a particular component is. For example, locking velocities in hydraulic snubbers that decrease in time are indicative of fluid gelation from high temperature or radiation exposure, and increased drag in mechanical snubbers could be indicative of grease cookoff. There are myriad other indicators that can be used to predict reduced service life, and if this is known in advance, it could be planned for and mitigated.

Conversely, as in 3a, it can be advantageous to a utility to shorten service life for certain snubbers in certain applications. Consider an Anvil snubber in a 160 degree environment that would be predicted to have a service life of 20 years. If the snubber was to be found with no fluid in it at year 8, it would be counted toward a scope expansion. Upon inspection, discolored fluid and metallic wear would be indicative of vibration (a common failure mechanism of all snubbers). The Arrhenius model no longer applies, and the service life should be established as its last acceptable visual inspection.

A good example of this is the degraded criteria established by many plants for mechanical snubbers. Service life in a benign environment can be 40 years, but could be two refueling cycles in a location with elevated ambient temperatures. As acceptance criteria for mechanical snubbers, many plants have a “degraded” classification for drag force, where the snubber is replaced or rebuilt but is considered operable. This range is usually 2 percent and 5 percent of rated load before activation. Thus, a mechanical snubber can be replaced before it becomes inoperable and counts towards expanded testing scope. With enough testing, time-temperature profiles for areas of the plant can be established that predict when a snubber will become degraded from high drag force and replaced before it becomes inoperable.

c. Segregating Defined Test Plan Groups Intervals by Predicted Service Life

In order to have an effective SLM program that will predict failure, a large data sample must be obtained. Many plants utilize database programs or Excel spreadsheets for tracking and trending data. Manufacturers should also be utilized for their plethora of test data and service history. With this knowledge, a program owner can make intelligent decisions as to the scope of ISE and IST activities. The OM Code allows for a separation of the total plant snubber population into defined test plan groups (DTPGs) in ISTD-5250. These populations may be formed by size, application, design, or type.

Service life could also be considered as a basis for a separate DTPG. When sufficient data exist in an effective SLM program, justification can be made for separating bad actors with known or predicted failures into separate DTPGs for augmented testing and inspection activities. As an example, a plant may have 10 snubbers in a location with high vibration or ambient temperatures that result in a service life of 6 years, while the rest of the population is in a benign environment that uses a service life of 23 years. Irrespective of the sampling plan to be used (10 percent or 37 snubbers), this would limit the scope expansion because of any failures in the malignant locations to a maximum of 10. It may even be prudent to plan to test and refurbish all 10 locations at every outage to prevent emergent work from affecting outage budget and schedule.

Conclusion

In conclusion, with a thorough understanding of OM Code requirements, the operation and safety function of a component, and its common failure modes, opportunities exist to deliver the Nuclear Promise in an ISE and IST program. Collaboration with vendors is key to developing correct acceptance criteria, as well as maintaining current procedures and procurement specifications. SLM is an integral part of developing a cost-effective PM program and must include robust data collection and consistent testing to maximize impact. Challenges to these initiatives include ever-increasing turnover in program engineering and ever-shrinking budget resources. However, with the right investment, over the life of the plant, significant savings can be realized, and the amount of dollars expended on snubber ISE and IST can be significantly reduced.

Top Left —Anvil Fig. 200N and Fig. 3306N Hydraulic Snubbers [9]

Top Right—Lisega Type 30 Hydraulic Snubbers [10]

Bottom Right—Basic PSA Size 1 Mechanical Snubber [11]

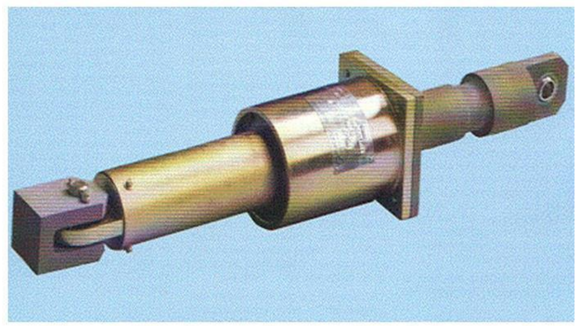

Figure 1. (Source: Author)

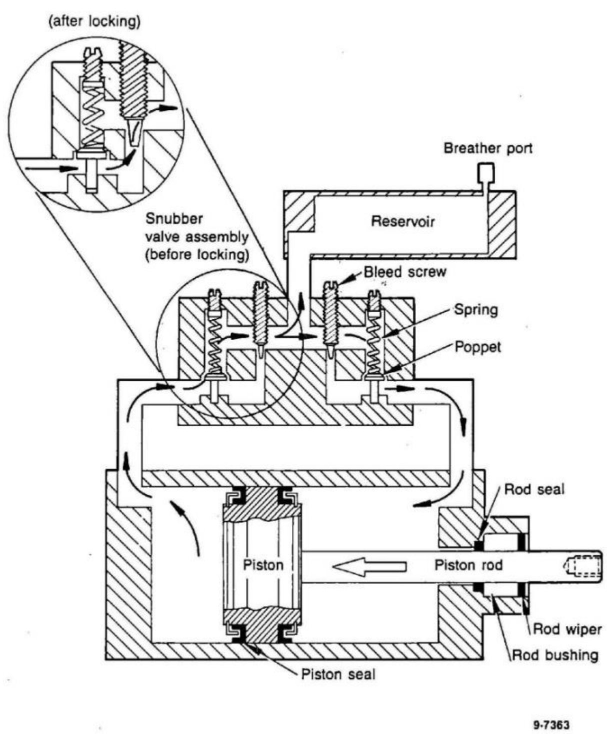

Figure 2. (Source: Author)

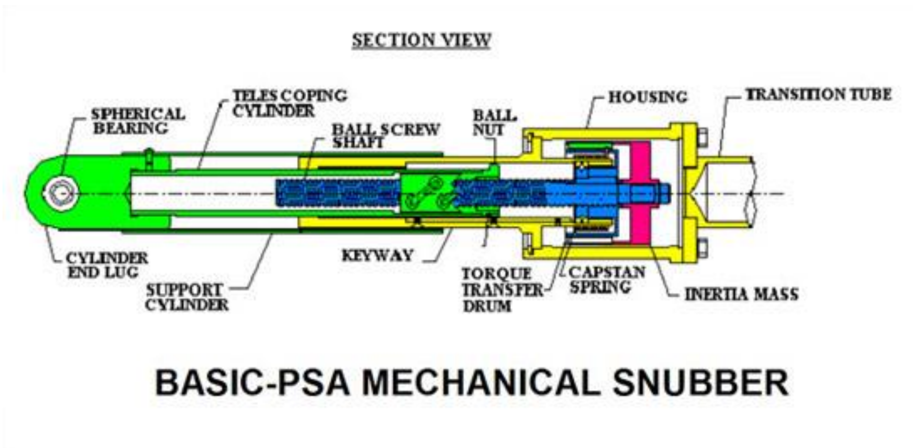

Figure 3. (Source: Author)

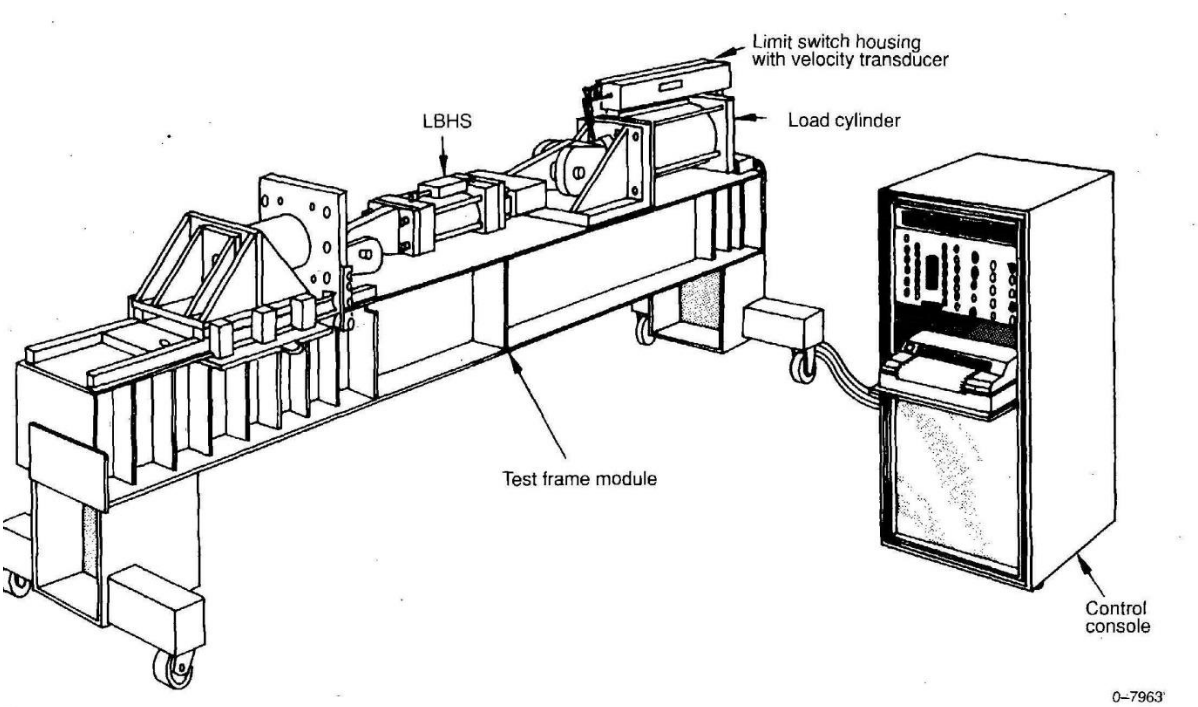

Figure 4. (Source: Author)

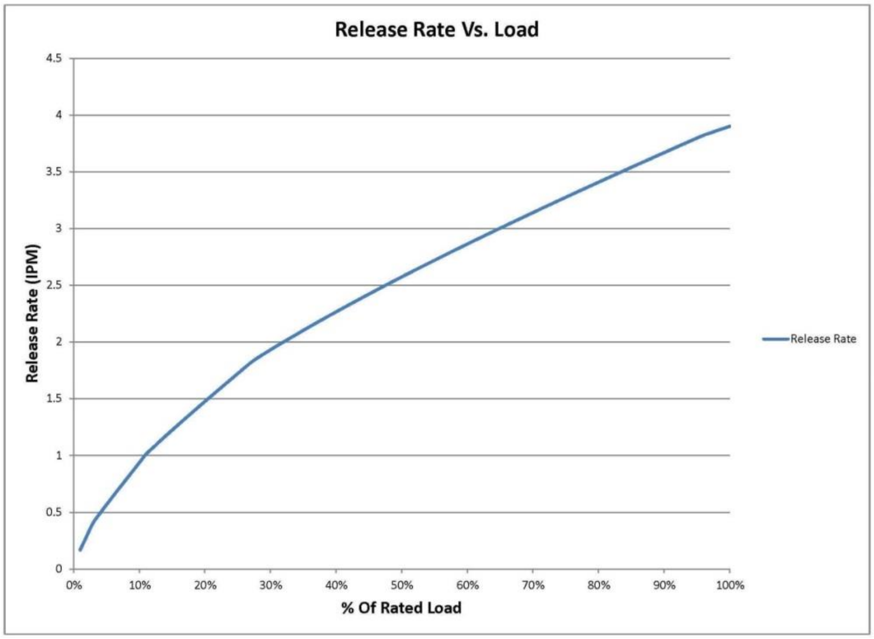

Figure 5. (Source: Author)

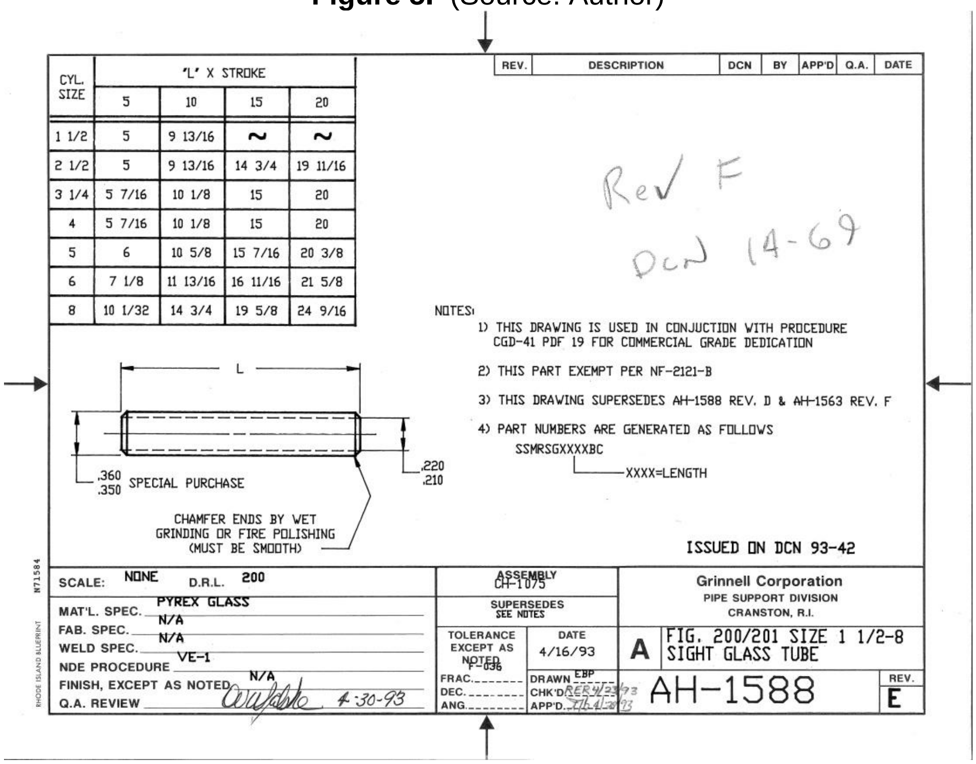

Figure 6. (Source: Author)

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Inservice Examination and Testing Issues for Dynamic Restraints (Snubbers) in Nuclear Power Plants

Gurjendra S. Bedi, P.E.[1]
Division of Engineering
Component Performance, Nondestructive Examination, and Testing Branch
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

Abstract

This paper discusses recent issues related to the inservice examination and testing of dynamic restraints (snubbers) at U.S. nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) staff identified these issues during its review of examination and testing snubber programs and relief requests, as well as operating experience. This discussion includes information that could apply generically to the implementation of effective snubber programs at U.S. nuclear power plants.

Introduction

The NRC staff has encountered a number of snubber inservice examination and testing issues since its paper presented at and published in the “Proceedings of the Twelfth NRC/ASME Symposium on Valves, Pumps, and Inservice Testing,” issued February 2015 (NUREG/CP-0152, Volume 9). This paper discusses the following:

- Regulatory and Programmatic Issues:
  - Temporary Instruction (TI) 2515/189, “Inspection to Determine Compliance of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a Regulatory Requirements for Inservice Examination and Testing of Snubbers,” dated September 25, 2013, and inspection results
  - snubber inservice examination and testing program (snubber program) and its submittal
  - scope of snubber program

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[1] This paper was prepared by staff of the NRC. It may present information that does not currently represent an agreed-upon NRC staff position. The NRC has neither approved nor disapproved the technical content.

- Snubber Operational Readiness Issues:

  - NRC Information Notice (IN) 2015-09, “Mechanical Dynamic Restraint (Snubber) Lubricant Degradation Not Identified Due to Insufficient Service Life Monitoring,” dated September 24, 2015

  - Event Notification 51788, “Part 21 - Hydraulic Snubber Seal Material Deviation Interim Report,” dated March 14, 2016

This discussion includes information that could have generic applicability in the implementation of effective inservice examination and testing snubber programs at U.S. nuclear power plants.

Temporary Instruction 2515/189 and Inspection Results

Background of Temporary Instruction 2515/189 Inspection of Snubbers

In 2009, the NRC staff discovered that some licensees were not following the requirements for inservice inspection (ISI) and testing of snubbers, as specified in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, “Codes and standards.” Therefore, the NRC issued Regulatory Issue Summary (RIS) 2010-06, “Inservice Inspection and Testing Requirements of Dynamic Restraints (Snubbers),” dated June 1, 2010, and Enforcement Guidance Memorandum (EGM) 2010-01, “Dispositioning Violations of Inservice Examination and Testing Requirements for Dynamic Restraints (Snubbers),” dated June 1, 2010. As noted in RIS 2010-06 and EGM 2010-01, the NRC believes that licensees who did not meet the 10 CFR 50.55a regulations should have completed all actions and have corrected any noncompliances with their snubber programs by June 1, 2012. In a followup, the NRC issued TI 2515/189 to review the compliance of licensees’ snubber programs with the 10 CFR 50.55a and American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (ASME OM Code) requirements. The NRC selected at least two plants from each region for inspection and review using TI 2515/189. By December 31, 2014, all the NRC regions had completed TI 2515/189 inspections of the selected plants. The TI 2515/189 inspections included the review of snubber program documents, snubber examination and testing, and service life monitoring (SLM)[2] of selected snubbers. Table 1 lists the results of the inspected plants.

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[2] SLM is the key element along with snubber examination and testing requirements, as specified by ASME OM Code, Subsection ISTD. SLM requires that the service life of each installed snubber shall be reevaluated once each fuel cycle. Reevaluation shall be based on examination, maintenance, performance, and operating service-life history data associated with representative snubbers that have been in plant service. For more details, see ISTD-6000 of the ASME OM Code.

Table 1. TI 2515/189 Inspection Results

NRC Region & Selected Plants	Selected Plants for TI Inspection	Applicable ASME *Boiler and Pressure Vessel Code* (BPV Code) or ASME OM Code, or Alternative Used for the Snubber Program	Remarks Based on TI Inspection Reports
Region I	Plant-A	Relief request in lieu of ASME BPV Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components”	
	Plant-B	ASME OM Code in lieu of ASME BPV Code, Section XI	
Region II	Plant-C	Relief request in lieu of ASME BPV Code, Section XI	
	Plant-D	No information in TI inspection report	
	Plant-E	Relief request in lieu of ASME BPV Code, Section XI	
	Plant-F	Technical specification (TS) in lieu of ASME BPV Code, Section XI, without updating to the latest ASME Code or without NRC approval	Plant initiated corrective action to correct the finding.
Region III	Plant-G and Plant-H	ASME OM Code	TI inspection report states that snubber program has not been converted from ASME BPV Code, Section XI, to ASME OM Code.
Region IV	Plant-I	Relief request and ASME OM Code	TI inspection report states that snubber program has not been converted from ASME BPV Code, Section XI, to ASME OM Code.
	Plant-J	ASME BPV Code, Section XI, and ASME OM Code	TI inspection report states that program was updated with applicable ASME BPV Code, Section XI, and ASME OM Code.

Temporary Instruction 2515/189 Inspection Results Summary:

All of the randomly selected 10 plants meet the respective plant's snubber program requirements, as specified in a licensee-controlled document and 10 CFR 50.55a requirements with the following comments:

- Confusion exists between ASME BPV Code, Section XI (ASME/American National Standards Institute (ANSI) OM, Part 4), and ASME OM Code requirements. For clarification, the ASME OM Code and ASME/ANSI OM Part 4 are two different ASME documents. The plants using ASME BPV Code, Section XI, Article IWF-5000 (i.e., ASME/ANSI OM Part 4) for their snubber examination and testing must use ASME/ANSI OM Part 4 for their snubber program. Whereas plants using the ASME OM Code, Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light Water Reactor Nuclear Power Plants," for their snubber examination and testing must use the ASME OM Code requirements. The ASME OM Code and ASME/ANSI OM Part 4 requirements are not interchangeable.

- Confusion exists between ASME BPV Code, Section XI, and ASME OM Code requirements for snubber examination and testing. Snubber inservice inspection and testing provisions are specified in the editions and addenda of the ASME BPV Code, Section XI, up through the 2005 Addenda. Snubber inservice inspection provisions were removed from Section XI in the 2006 Addendum. Snubber inservice inspection and testing provisions are also located in Subsection ISTD of the ASME OM Code, and 10 CFR 50.55a(b)(3)(v) allows licensees the option of using the inservice inspection provisions for snubbers in Section XI or the ASME OM Code. However, the ASME BPV Code, Section XI, option will no longer exist when using the 2006 Addendum and later editions and addenda of Section XI because these editions and addenda of Section XI do not provide inservice inspection provisions for snubbers. When using the 2006 Addendum or later editions of the ASME BPV Code, Section XI, snubber examination and testing must be in accordance with the ASME OM Code, Subsections ISTA and ISTD.

- Confusion exists while using TS and meeting 10 CFR 50.55a requirements. While using TS for snubber examination and testing, some of the licensees ignored the requirement to update the TS to the latest applicable ASME Code while updating their plants' 120-month inservice inspection and inservice testing intervals as required by 10 CFR 50.55a. For plants using their TS to govern inservice inspection and testing of snubbers, 10 CFR 50.55a(g)(5)(ii) requires that if a revised snubber program for a facility conflicts with the TS, the licensee shall apply to the NRC for an amendment of the TS to conform the TS to the revised program. Therefore, when performing their 120-month snubber program updates in accordance with 10 CFR 50.55a(g)(4), licensees must submit any required amendments to ensure their TS remains consistent with the new Code of record. The TS governing the snubber inservice inspection and test program

> does not eliminate the 10 CFR 50.55a requirement to update the program at 120-month intervals or to request and receive NRC authorization for alternatives to the Code requirements when appropriate.

Snubber Program and Its Submittal

Snubber Program and Its Submittal Requirement

The regulations in 10 CFR 50.55a(b) describe the codes and standards that the NRC has incorporated by reference in 10 CFR 50.50a, including the effective edition and addenda of the ASME BPV Code and the ASME OM Code.

The regulations in 10 CFR 50.55a(g) contain the ISI requirements that licensees must use when performing ISI of components (including supports). The regulation in 10 CFR 50.55a(g)(4) states, in part, the following:

> Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, components (including supports) that are classified as ASME Code Class 1, Class 2, and Class 3 must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of editions and addenda of the ASME BPV Code.

Snubbers are part of component “supports.” Supports are widely used to support various safety-related or nonsafety-related piping systems and components in nuclear power plants. Therefore, the regulations in 10 CFR 50.55a(g)(4) are applicable to snubbers.

The applicable ASME BPV Code, Section XI, Article IWA-1000, “General Requirements,” and ASME OM Code, Subsection ISTA-3000, “General Requirements,” provide the requirements for preparation of test plan documentation (snubber program) and submittal for inservice examination and testing of certain components in light-water reactors. Therefore, based on these requirements, licensees are required to submit their snubber examination and testing program plans and their updates every 120 months to the regulatory authorities. Similar requirements were highlighted in RIS 2010-06, and in NUREG-1482, Revision 2, “Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants—Final Report,” issued October 2013, Appendix A, “Guidelines for Inservice Examination and Testing Program for Dynamic Restraints (Snubbers) at Nuclear Power Plants.”

The NRC staff observed that some licensees have not submitted their snubber program plans[3] (and/or snubber program) to the NRC and that some of the submitted snubber programs do not meet all of the ASME OM Code requirements. The following are examples of problems identified in submitted programs:

- Some 10-year interval ISI or IST programs state that licensees have developed their snubber programs in accordance with the ASME OM Code as required by 10 CFR 50.55a(b)(3)(v), and the programs are included in their respective plants' procedures.

  The licensees should have included the snubber program plan[4] (and/or snubber program) in their submittal instead of just stating that snubber programs are included and available in their plants' procedures.

- Some plants submitted their TS pages containing snubber examination and testing requirements as the plants' snubber program. These submitted TS pages have been already deleted from the plants' TS.

  The licensees should have developed a new, updated snubber program plan (and/or snubber program) based on their current applicable ASME BPV Code, Section XI or ASME OM Code requirements instead of just submitting deleted TS pages containing the snubber requirements.

- Some 10-year interval ISI or IST programs state that the snubber program plan (and/or snubber program) is being developed under submitted snubber programs without giving additional information.

  The licensees should have submitted the developed snubber program plan (and/or snubber program) with the current 10-year ISI or IST interval instead of just saying that it is being developed.

- Some 10-year interval ISI or IST programs include snubber program sections that contain very limited information about snubber examination and testing. Some of these sections do not provide any information about SLM, which is an integral part of the snubber program.

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[3] ASME OM Code, Subsection ISTA-3100, provides snubber examination and test plan requirements, and Nonmandatory Appendix A, "Preparation of Test Plans," provides guidance for preparation of test plans. ASME OM Code, Subsection ISTD-3000, provides general requirements for snubber examination and testing.

[4] See footnote 3.

At a minimum, licensees should have developed a snubber program plan (and/or snubber program) and its bases containing all the requirements as specified under ASME OM Code, ISTA-3100, “Test and Examination Programs,” (for guidance, see Nonmandatory Appendix A of the ASME OM Code), and ISTD-3000, “General Requirements,” including (1) visual examination requirements, (2) functional testing requirements, and (3) SLM requirements. Individual aspects of each element in detail are outlined in Appendix A, Section 2.4 of NUREG-1482, Revision 2.

Furthermore, all the above-identified problems can be corrected by use of the guidelines provided in Appendix A to NUREG-1482, Revision 2. To ensure consistency throughout the industry, licensees are encouraged to use the guidelines listed in Appendix A to NUREG-1482 and to consult with the Snubber User Group for guidance when developing snubber programs and establishing their bases.

Scope of Snubber Program

The NRC staff has observed that some licensees have used ASME BPV Code, Section XI, IWF-1230, “Supports Exempt from Examination,” to eliminate certain snubbers from their ISI scope while exempting supports from ISI examination. The NRC staff has also observed that some vendor/contractor reports have referenced IWF-1230 when eliminating certain snubbers from the ISI scope.

The snubber program must include all snubbers used in a system that performs a specific function in shutting down a reactor to the safe-shutdown condition, maintaining the safe-shutdown condition, mitigating the consequences of an accident, or ensuring the integrity of the reactor coolant pressure boundary.

Licensees are required to demonstrate the continued operability of all snubbers within the scope of their snubber inservice examination and testing program. While using ASME BPV Code, Section XI, IWF-1230, to exempt specific supports from inservice examination, licensees should not use this code to exempt snubbers from ISI and testing.

Licensees should consider the following regulatory documents and guidelines in determining the full scope of their snubber programs:

- 10 CFR 50.55a

  The regulation in 10 CFR 50.55a(g)(4) requires that, throughout the service life of a boiling-water reactor and pressurized-water reactor nuclear power facility, ASME BPV Code Class 1, 2, 3, and metal containment components (including supports) meet the ISI and testing requirements of ASME BPV Code, Section XI, or the ASME OM Code, as incorporated by reference in 10 CFR 50.55a(a)(i).

- ASME BPV Code, Section XI

  - ASME BPV Code, Section XI, IWF-1230, states that supports that are exempt from the examination requirements in ASME BPV Code, Section XI, IWF-2000, "Examination and Inspection," are those connected to piping and other items that are exempt from volumetric, surface, or VT-1 or VT-3 visual examination by IWB-1220, IWC-1220, IWD-1220, and IWE-1220 titled "Components Exempt from Examination." In addition, the supports that are inaccessible because they are encased in concrete, buried underground, or encapsulated by guard pipe are also exempt from the examination requirements in IWF-2000.

  - IWF-2100, "Scope," states that "the requirements of this Article IWF-2000 apply to the examination and inspection of component supports, but not to the inservice test requirements of IWF-5000, Inservice Inspection Requirement for Snubbers."

  - ASME/ANSI OM Part 4, Section 1.3.2, "Operational Readiness," states that "OM Part 4 intends to demonstrate the operational readiness of ASME BPV Code Classes 1, 2, 3, and MC [metal containment] snubbers."

- ASME OM Code

  - ASME OM Code, Subsection ISTA-1100, "Scope," states that "dynamic restraints (snubbers) include those used in a system that perform a specific function in shutting down a reactor to the safe-shutdown condition, maintaining the safe-shutdown condition, mitigating the consequences of an accident, or ensuring the integrity of the reactor coolant pressure boundary."

- The plant's TS or technical requirement manual (TRM)

- 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities"

  - 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants"

    - General Design Criterion (GDC) 1, "Quality Standards and Records," requires that all structures, systems, and components that are necessary for safe operation be tested to demonstrate that they will perform satisfactorily in service. Among other requirements, GDC 1 states that components important to safety must be tested to quality standards that are commensurate with the importance of the safety function(s) to be performed.

- 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”

    - Appendix B describes the quality assurance program (which includes testing) for safety-related components.

- 10 CFR Part 100, “Reactor Site Criteria”

  The regulations in 10 CFR Part 100 specify structures, systems, and components that must be designed to remain functional during and following a “safe-shutdown earthquake” as those necessary to ensure (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 an accident that could result in potential offsite exposures that are comparable to the guideline exposures.

- NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition (SRP),” Chapter 3, “Design of Structures, Components, Equipment, and Systems,” Section 3.9.6, “Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints”

  - SRP Section 3.9.6 states that the review of the inservice testing program will include ASME BPV Code Classes 1, 2, and 3 system snubbers that are required for safety as well as snubbers that are not categorized as ASME BPV Code Classes 1, 2, and 3 but are safety related.

All of the above regulatory documents and guidelines show that the snubber program must include all snubbers used in a system that performs a specific function in shutting down a reactor to the safe-shutdown condition, maintaining the safe-shutdown condition, mitigating the consequences of an accident, or ensuring the integrity of the reactor coolant pressure boundary.

The use of ASME BPV Code, Section XI, IWF-1230, for the snubber program without consideration of other regulatory requirements might exempt some safety-related snubbers or nonsafety-related snubbers that are important to safety.

Licensees are cautioned that, while using ASME BPV Code, Section XI, IWF-1230, to exempt specific supports from inservice visual examination, they should not use IWF-1230 to exempt snubbers from inservice visual examination and testing.

The NRC staff may prepare an RIS in the future to clarify the scope of the snubber program.

Information Notice 2015-09

The NRC issued IN 2015-09 to alert addressees to potential degradation of the lubricant (grease) in mechanical dynamic restraints (snubbers) that were not identified because of insufficient SLM.[5] The NRC staff made this conclusion based on the information that it collected from the various plants' inspection reports and findings related to snubber failures, as specified in IN 2015-09. The various plants determined that grease degradation (i.e., oil separation from grease, dried or caked grease, excessive grease, sticky and tacky grease, and hardened or missing grease) caused most of the snubber failures.

During refueling outages, licensees typically select a small sample of snubbers for functional testing to demonstrate their operational readiness in accordance with the applicable ASME BPV Code or ASME OM Code, plant-specific TS/TRM, or NRC-authorized relief or alternatives. In accordance with the specific sampling method, licensees may select snubbers randomly or based on the size, design, configuration, operating environment, load capacities, and distribution of the snubber population using various sample techniques that consider test failure rates. With the small sample (10 percent of the total snubbers, or 37 snubbers) of snubbers selected for functional testing during each refueling outage, it might take decades before all nuclear power plants' snubbers are tested. Furthermore, some snubbers might never be tested during their service life. Therefore, SLM plays a very important role in maintaining the operational readiness of snubbers at a nuclear power plant along with visual examination and testing of snubbers. The SLM is a service life evaluation of all snubbers every refueling outage.

A well-planned SLM program for snubbers can minimize the number of snubber failures caused by grease degradation. An effective SLM program would include provisions for preventive maintenance (e.g., regreasing, partial disassembly for an internal inspection, or additional functional testing for SLM of mechanical snubbers) based on the results of performance monitoring and the evaluation of the service conditions for snubbers. In addition, the current condition of the grease and the shelf life of replacement grease are key factors in determining the service life of mechanical snubbers during SLM. The operational readiness of snubbers is maintained by a combination of inservice examination, testing, and SLM, as required by 10 CFR 50.55a and the applicable ASME BPV Code or ASME OM Code.

EVENT NOTIFICATION 51788

During routine refueling outage activities in October 2015 at the Peach Bottom Atomic Power Station (PBAPS), the licensee discovered that 9 out of 14 newly installed hydraulic snubbers had no fluid in their reservoirs. PBAPS installed these new hydraulic snubbers during recent extended power uprates on the modified main steam system piping.

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5 The ASME OM Code defines the term "service life" as "the period of time an item is expected to meet the operational readiness requirements without maintenance." The ASME OM Code is incorporated by reference in 10 CFR 50.55a with conditions.

The licensee determined that the cause of the hydraulic fluid leak was premature aging of the reservoir piston seal resulting from vibration-induced friction heat. The laboratory testing of the seal material by the licensee revealed that a material substitution of a different grade of ethylene propylene was used instead of the previous vendor-approved ethylene propylene.

The snubber vendor confirmed that the seal vendor substituted the seal material. The snubber vendor performed additional qualification testing of the substitute seal material and found it acceptable. In followup qualification testing, the snubber vendor determined that a specific defect was not caused by the seal vendor's substitute seal material.

Event Notification 51788 concludes that, during extended power uprates, licensees should use the guidelines in NRC Regulatory Guide 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," to avoid snubber failures caused by vibration. Event Notification 51788 provides more details on the "Part 21—Hydraulic Snubber Seal Material Deviation Interim Report."

Conclusion

The purpose of this paper is to make licensees aware of the snubber inservice examination and testing issues that the NRC staff has encountered since the Twelfth NRC/ASME Symposium on Valves, Pumps, and Inservice Testing in 2014. Licensees who believe that some of the items discussed apply to their facilities may wish to review their current inservice examination and testing programs for snubbers and modify or update their programs, as appropriate.

References

ASME *Boiler and Pressure Vessel Code*, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," New York, NY.

ASME/American National Standards Institute (ANSI), "Operation and Maintenance of Nuclear Power Plants (OM)," Part 4 (OM-4), 1987 Edition with OMa-1988 Addenda, New York, NY.

ASME *Code for Operation and Maintenance of Nuclear Power Plants*, 2004 Edition with 2005 and 2006 Addenda, New York, NY.

U.S. Nuclear Regulatory Commission (NRC), EGM 2010-01, "Disposition Violation of Inservice Examination and Testing Requirements for Dynamic Restraints (Snubbers)," dated June 1, 2010, (Agencywide Documents Access and Management System (ADAMS) Accession No. ML101390020).

NRC, Event Notification 51788, "Part 21—Hydraulic Snubber Seal Material Deviation Interim Report," dated March 14, 2016.

NRC, Information Notice 2015-09, "Mechanical Dynamic Restraint (Snubber) Lubricant Degradation Not Due to Insufficient Service Life Monitoring," September 24, 2015 (ADAMS Accession No. ML15126A531).

NRC, NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition,” Chapter 3, “Design of Structures, Components, Equipment, and Systems,” Section 3.9.6, “Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints,” Revision 3.

NRC, NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants—Final Report,” Revision 2, October 2013.

NRC, NUREG/CP-0152, Volume 9, “Proceedings of the Twelfth NRC/ASME Symposium on Valves, Pumps, and Inservice Testing,” Rockville, MD, June 23–25, 2014, February 2015 ADAMS Accession No. ML15049A522).

NRC, Regulatory Guide 1.20, “Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing,” Revision 4.

NRC, Regulatory Issue Summary 2010-06, “Inservice Inspection and Testing Requirements of Dynamic Restraints (Snubbers),” June 1, 2010.

NRC, “Scope of the Snubber Program,” presentation at the Inservice Testing Owner Group December 2016 Meeting, Clearwater, FL, December 12–13, 2016 (ADAMS Accession No. ML16335A386).

NRC, Temporary Instruction 2515/189, “Inspection to Determine Compliance of Dynamic Restraint (Snubbers) Program with 10 CFR 50.55a Regulatory Requirements for Inservice Examination and Testing of Snubbers,” September 25, 2013 (ADAMS Accession No. ML12156A241).

U.S. Code of Federal Regulations (CFR), “Domestic Licensing of Production and Utilization Facilities,” Part 50, Chapter I, Title 10, “Energy.”

CFR, “Reactor Site Criteria,” Part 100, Chapter I, Title 10, “Energy.”

Track 7: Risk-Insight Activities

Track Chair: Craig Sellers, Enercon Services, Inc.

Risk-Informed Inservice Testing Programs

Bradley J. Scott
True North Consulting, LLC

Abstract

This paper reviews three options for applying risk insights to the inservice testing (IST) program for pumps and valves. The current regulatory framework allows for risk-informing pump and valve testing through the implementation of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.69, "Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors," or by submittal to the U.S. Nuclear Regulatory Commission (NRC) in accordance with 10 CFR 50.55a, "Codes and standards," for risk-informed testing in accordance with the American Society of Mechanical Engineers (ASME) Operation and Maintenance of Nuclear Power Plants (OM Code), either using OM Code Case OMN-3 and the risk-related OM Code Cases or Subsection ISTE. This paper offers a third option, which involves the combination of the first two options. Each of these IST risk-informed program options is explored by presenting a general discussion of each option's risk-ranking process and anticipated risk-ranking results. The risk-ranking review is followed by a discussion of the implementation processes and finally a look at plant impacts and potential benefits for each option.

IST program scope and testing requirements are identified for each of these risk-informed program options. References for the implementation processes are provided and used for the basis of this discussion. The intent of this paper is not to provide a "how to" for each of these options, but rather to provide information to the reader to allow further detailed review of each option. It is expected that through further investigation of these options and discussions with plant management, each site may find the option or process that best suits the respective regulatory and plant safety culture.

Introduction

Risk-informed applications have received much attention in the nuclear industry, including the NRC and ASME. The evaluation of the safety significance of structures, systems, and components (SSCs) allows a means to identify which SSCs are most critical to safety at nuclear power plants. IST program resources can be efficiently utilized and provide the most impact on nuclear plant safety by categorizing the program components into high safety-significant components (HSSCs) and low safety-significant components (LSSCs). Plant resources can then be more focused on the HSSCs to realize a net benefit to health and safety of the public and plant operational safety.

The NRC issued 10 CFR 50.69 to provide the regulatory framework for licensees to categorize SSCs and implement treatment strategies commensurate with the safety significance of the component. The NRC has also endorsed Nuclear Energy Institute (NEI) 00-04, "10 CFR 50.69 SSC Categorization Guideline," as an acceptable categorization method of SSCs, as required by paragraph (c) in 10 CFR 50.69. The NEI 00-04 categorization process is a very robust methodology for categorizing SSCs in a complete system and is used for implementation of the 50.69 rule, which allows the removal of many special treatments normally required for safety-related SSCs.

Separately, a categorization process for pumps and valves was developed by pilot plants and resulted in regulatory guidance for a risk-informed IST program (Regulatory Guide (RG) 1.175, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing”). This same general process has been codified by the ASME in OM Code Case OMN-3 and Subsection ISTE in the OM Code. This risk-informed process is intended to be used for categorizing pumps and valves that are in the scope of the IST program, and the results are used specifically to address the IST program testing only. This categorization process will allow the adjustment of IST component treatments in accordance with the risk-informed OM Code Cases or Subsection ISTE. In this process, IST components are not removed from the program if they are determined to be LSSC. Instead, the test intervals of LSSCs are extended or alternative testing methods used if approved by the licensing agent with jurisdiction at the plant. The aggregate effect on testing interval changes for all IST components is evaluated and determined to be acceptable, consistent with RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” which is summarized in Nonmandatory Appendix L in the OM Code.

It should be noted also that there are other categorization processes that are often applied to components that are in the IST program scope. For example, the NRC has approved a method for categorizing motor-operated valves (MOVs) that are subject to Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” dated January 24, 1996, and Generic Letter 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” dated September 18, 1996. This categorization method affects the testing required by the generic letters, which is very similar to the testing requirements of OM Code Case OMN-1, which has now become Mandatory Appendix III in the OM Code. Additionally, many plants have air-operated valve (AOV) programs that use a graded approach to AOV reliability requirements that are derived from a ranking process. This process has not been presented to the NRC for endorsement; however, the ranking process includes safety significance in the evaluation method. Most AOVs that are in the IST program are also being categorized in site-specific AOV reliability programs. Similar to Mandatory Appendix III for MOVs, Mandatory Appendix IV has been developed and may soon be endorsed for AOVs, which includes risk-informed testing of AOVs.

10 CFR 50.69 Option for the Inservice Training Program

Regulations in 10 CFR 50.69 allow licensees to reduce certain special treatments required for safety-related SSCs. Reducing certain special treatment is allowed for SSCs that have been determined to be LSSCs. Some of these special treatment processes include IST, seismic qualifications, leak-rate testing in accordance with 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities,” Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” maintenance rule, and others. A categorization process (NEI 00-04) may be used by licensees for determining the safety significance for SSCs. The risk-ranking process is very involved and cannot be completely described in this paper; however, the following description focuses on areas that are important and have specific bearing on the differences related to IST components intended to be demonstrated in this paper.

10 CFR 50.69 Risk Categorization Process

The categorization (i.e., risk-ranking) process described in NEI 00-04 is a robust method that considers functional importance so that the final risk categorization for any SSC can be used for special treatment applications. Categorization of components requires quantitative probabilistic risk assessment input whenever the component functions are modeled in the level 1 probabilistic risk assessment (PRA) model. The basic event Fussel-Vesely (FV) and risk achievement worth (RAW) values are determined for each modeled component. Using guidelines established in RG 1.174, the risk significance of the component is determined to be high safety significant (HSS) or low safety significant (LSS). The normal thresholds for HSS is 0.001 for FV and 2.0 for RAW. Any component with an FV greater than 0.001 is evaluated as high risk significant. If the FV is less than 0.001, but the RAW is greater than 2.0, then the component evaluation results in an HSS outcome. However, in some cases, the component may be designated as low risk significant if the RAW is less than 10 and component reliability history is acceptable. For example, a quantitative risk assessment of the low head safety injection pump 1A discharge MOV results in an FV value of 2.92E-06 and a RAW value of 1.01. The functions modeled in the PRA for this valve include “fail to close” and “fail to remain open.” The initial quantitative risk assessment categorization for this valve is LSS.

In addition to the quantitative assessment of the safety significance of a component, a qualitative assessment of the component is also performed to include functions that may not be specifically modeled in the plant PRA. The process requires that the categorization be performed on complete systems. This requirement is necessary since all functions of the specified system must be identified. The system functions are then categorized as high or low safety significant. An example of a system function is to supply low-pressure water to the RCS. This system function is considered HSS and is required to prevent core damage during the design-basis accident. A table of system function examples is provided as Table 1 to this paper.

Once all system functions for the system under consideration have been identified and categorized, then the SSCs can be mapped to these system functions and their importance determined. The SSC (pump or valve if the SSC is an IST component) is evaluated by identifying which of the system functions are supported by the component. The highest categorization for a system function that is supported by the pump or valve becomes the safety significant categorization for that component. The purpose of any specific application is not considered nor is the fact that there may be several trains within that system that support the same system function (i.e., component-level redundancy is not considered). Using the low-head safety injection pump discharge MOV as a component example, Table 2 of this paper lists the system functions supported by this valve.

Based on the system functions supported by the MOV, the initial qualitative safety assessment for the valve is HSS. An expert panel will deliberate and approve the final categorization of the valve.

The purpose of the categorization of SSCs (including IST pumps and valves) is to determine which SSCs impact plant safety to a greater degree. The categorization of all SSCs for a given system results in each SSC being placed in one of four risk-informed safety class (RISC) boxes (i.e., RISC-1, 2, 3, or 4) as typically shown in the table below. The applicability of only safety-related components in 10 CFR 50.55a has been recently changed to include all components that meet the OM Code scope criteria in ISTA-1100. This will impact the discussion of the IST program scope as it relates to the risk-informed safety classes shown below.

RISC-1 Safety-Related High Safety Significant	RISC-2 Nonsafety-Related High Safety Significant
RISC-3 Safety-Related Low Safety Significant	RISC-4 Nonsafety-Related Low Safety Significant

Implementation Aspects for an Inservice Training Program under 10 CFR 50.69

It is expected that using a risk-informed process, such as in 10 CFR 50.69, more resources can be applied to HSSCs to improve reliability and plant safety. LSSCs must also perform their safety functions, but since their importance to safety is less, fewer resources can be expended compared to the HSSCs. RG 1.174 identifies benefits that can be realized using the risk-informed applications. Some of the identified benefits are simplifying plant operation, focusing resources on the most important safety issues, applying resources to unquantified risks for nonsafety-related SSCs, small increases in risk when there is sufficient defense in depth and performance margins, and reduced radiation exposure.

Regulations in 10 CFR 50.69 can be described as a scoping rule based on risk. HSSCs will continue to be included in the regulatory programmatic requirements, while the LSSCs are removed from the scope of regulatory special treatments, such as 10 CFR 50.55a. So then, what does this mean for the IST program? RISC-1 HSSCs remain in the IST scope, which involves the typical OM Code testing used in current IST programs including use of the OM Code Cases and relief requests as appropriate. RISC-2 HSSCs require additional treatment, which may include testing to ensure their functional capability, but these SSCs are <u>not required to be included in the IST program</u>. Other treatments may be applied to RISC-2 SSCs so that their reliability and functionality are assured. Licensees may elect to include these RISC-2 HSSCs as augmented, but this is **not** a requirement.

Under 10 CFR 50.69, RISC-3 LSSC pumps and valves can be removed from the IST program scope. However, 10 CFR 50.69(d)(2) requires that—

> the licensee or applicant shall ensure, with reasonable confidence, that RISC-3 SSCs remain capable of performing their safety-related functions under design basis conditions, including seismic conditions and environmental conditions and effects throughout their service life. The treatment of RISC-3 SSCs must be consistent with the categorization process. Inspection and testing, and corrective action shall be provided for RISC-3 SSCs.

The testing and treatment of RISC-3 SSCs should be less than HSSCs, but provide reasonable confidence that the components will perform their intended safety functions. OM Standard OM-29 has been written to provide a process for developing the basis for reasonable confidence for the LSSCs removed from the IST program scope. A discussion of the intent of the standard was provided in a previous pump and valve symposium and is in NUREG/CP-0152, “Proceedings of the NRC/ASME Symposium on Valves, Pumps and Inservice Testing,” Volume 6, issued August 2007 (ADAMS Accession No. ML072700042). Since the RISC-3 LSSCs are no longer in the scope of the IST program, the licensee is not obligated to any OM Code requirements, including the use of the OM Code Cases or the IST rule requirements for relief from OM Code IST requirements.

All components in a system must be categorized in accordance with 10 CFR 50.69(c)(1)(v), so the risk-ranking process involves many more SSCs than are in the IST program scope. Insights into the categorization results can be found in a 2004 pump and valve symposium paper in NUREG/CP-0152, Volume 5, issued July 2004 (ADAMS Accession No. ML041900037). As a general summary from that paper, it is noted that **all** safety and nonsafety-related SSCs are categorized. Twenty-five percent of safety-related components are HSSCs, and 75 percent are LSSCs. Less than 1 percent of the SSCs have been categorized RISC-2, nonsafety-related, safety significant.

Table 3 of this paper represents an approximation of IST program scope component risk rankings using 10 CFR 50.69 categorization.

Benefits of 10 CFR 50.69

Benefits of 10 CFR 50.69 are that testing, examination, and programmatic resources are focused on the HSSCs. There is a reduction of costs associated with the reduced scope of IST component testing and trending. Benefits resulting from other programs are not addressed in this paper but can also be significant. It must be emphasized that 10 CFR 50.69 is a scoping rule that allows the removal of applicable LSSCs from specifically identified special treatment requirements. <u>The benefit of applying 10 CFR 50.69 is the broad application of the risk categorization to numerous regulatory special treatment programs resulting in the reduced program scope and associated costs</u>.

OM Code (ISTE) Option for the IST Program

Development of a risk-informed IST program under the current regulatory framework using the OM Code requires the use of OMN-3 Code Case for component categorizations and other risk-informed OM Code Cases for testing requirements. All conditions placed on these Code cases by the NRC are identified in RG 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code." Subsection ISTE has been published in the 2009 edition of the OM Code; however, the NRC has not yet endorsed it for use. The NRC has stated that it will allow users to submit an alternative request using ISTE and associated conditions found in 10 CFR 50.55a as the basis for a risk-informed IST program. ISTE has been revised to incorporate NRC conditions. When the latest version of ISTE is published in the OM Code and receives NRC endorsement, then users will be able to implement a risk-informed IST program without an alternative request. Risk rankings and treatments using the OM Code are focused specifically and are used **only** for the IST program. The OM Code risk-ranking process <u>cannot</u> be used to adjust scope or treatments of other regulatory treatment programs. The following description of the OM Code risk categorization process focuses on areas that are important and have specific bearing on the differences related to IST components intended to be demonstrated in this paper.

OM Code Risk Categorization Process

Categorization of IST components can also be performed using the methodology provided in Code Case OMN-3, which has been codified in Subsection ISTE of the OM Code. This process was developed based on the insights provided during the risk-informed pilot projects at the Comanche Peak and Palo Verde Nuclear Generating Stations and from experiences gained during the San Onofre Nuclear Generating Station risk-informed IST program development and submittal review. The categorization process is intended for IST components and may also apply to nonsafety pumps and valves that, based on HSS, could be evaluated by the licensee for inclusion in the IST program.

The Code Case OMN-3 categorization process includes the use of the quantitative input from the PRA as described above and qualitative input from an expert panel. The difference in this process is that not all functions are necessarily included in the evaluation process. Some component functions, such as pressure boundary or passive functions, are not tested in the IST program requirements. These functions, though some may be safety significant, are tested in other programs or addressed by other technical specification surveillance requirements. An example of this is the case where a valve is maintained in the open position to ensure that the correct flowpath is available during accident conditions. In some cases, the power to the valve operator is removed, or the technical specifications require monthly verification that the valves in the required flowpath are aligned correctly.

In the evaluation of IST components in comparison to the global categorization, the difference in the use of the term "passive" was noteworthy. Valves may be identified in the active valve list of the safety analysis, but considered passive by the PRA. The PRA considers the valve as passive since the valve remains in the required position to perform the safety function to prevent core damage. In IST terminology, the function is considered passive if the valve is not repositioned routinely. The contribution of the valve to the aggregate risk is by the failure to remain in the required position. The frequency of valves transferring to another position without outside action is small, and therefore, the basic elemental risk is small and the FV number is low.

The residual heat removal (RHR) heat exchanger control valve, for example, is used to control cooling during cold shutdown during refueling outages or following accident conditions and fails to the open safety position on loss of electrical power or loss of air. The valve is maintained open with the electrical power removed during normal operation to ensure safety injection and recirculation flowpath availability for long-term cooling. The open function, as evaluated, has HSS; however, the valve does not change positions to perform this function. The PRA models this valve to stay open, which is a passive function in the PRA; therefore, the transfer close function is low risk in the PRA. The heat removal function can be performed by each independent safety train.

The low head safety injection pump discharge outside containment isolation valves (one valve in each of three safety trains) remain open to inject borated water during the short-term core cooling and cold leg injection phase of safety injection. The valve is also open to recirculate water from the containment sump to cold leg and hot legs during long-term core cooling. During cooldown using RHR, the valve is closed and leaktight to provide containment integrity. The close function is also identified as a prevention for intersystem loss-of-cooling accident. These MOVs are normally open and, therefore, do not have to change positions to perform safety-significant function for safety injection and recirculation. The PRA does not model passive open functions. The values of FV (2.92E-06) and RAW (1.01) are for the active closing function. There are three upstream check valves that perform a redundant closing function. Open function for safety injection is performed by each independent safety train.

Safety injection accumulator tank discharge MOV remains in the open position in the power lockout position during normal operation. The valve is closed and the power removed during cold shutdowns to prevent inadvertent actuation. The HSS open function is required for the flowpath to supply borated water during the design-basis accident. The valve also is closed to allow cold shutdown using RHR. The accumulators are not credited by the PRA for core damage prevention.

In each of these examples, the component supports an HSS function, resulting in a categorization of HSS using the NEI 00-04 method. However, the actual use of the component and other actions taken during normal operations result in situations where the failure of the valve does not prevent the component from performing its HSS function. Categorization of the component for the active IST functions results in a different, but reasonable, outcome.

Comparison of OM Code Inservice Training Categorization Results

Safety-significance categorizations have been performed at several plants. The results of these categorizations provide insight into the extent of the difference in ranking methods. Tables 4 and 5 of this paper provide the results of these categorization processes.

Tables 4 and 5 show that generally 25 percent of the IST components are categorized in the HSS category using the OM Code Case OMN 3 method. By contrast, 50 percent of the IST components categorized as HSSC using the NEI 00-04 method, as shown in Table 3. Table 6 of this paper depicts how IST program components would be distributed if both processes were used. It shows that 50 percent of the IST components would be LSS using either categorization process. Some components would be HSSC using NEI 00-04 but LSS using the OMN-3 process. Finally, approximately 25 percent would be in the HSS category using either process. Each column represents a risk-informed IST program using one of the above methods. A third option employs both methods, and the results of the risk categorization is shown in the middle column. The next section of this paper discusses how one can implement a combined risk-informed ISTE program.

Implementation of a Combined Risk-Informed Inservice Training Program

As stated previously, 10 CFR 50.69 is a rule that determines whether components remain in the scope of regulatory special treatment requirements, such as an IST program. Based on the results shown above, the typical IST program scope is reduced by half. Components remaining in the program are tested in accordance with OM Code rules. The OM Code Case OMN-3 (ISTE) process allows changes to the testing requirements, but does not reduce the scope of the IST program. In this case, the categorization results in all IST components remaining in the IST program with testing strategies, as allowed by the risk-informed OM Code cases or the new ISTE subsection of the Code when published and adopted for use.

If a nuclear station has already categorized components according to OM Code Case OMN-3, then all components remain in the IST program; however, most of the components would have the testing intervals relaxed in accordance with the risk-informed OM Code cases. When this same plant opted to voluntarily use 10 CFR 50.69, then the IST program scope would be reduced based on the categorization performed in accordance with NEI 00-04 and applicable regulatory guidance. This would result in a reduction of the number of components being tested with the alternative testing strategies for low-risk components.

In a similar manner, if a nuclear station has already categorized components according to 10 CFR 50.69, then the IST program scope would be reduced and OM Code testing would be performed on only those components that were categorized as HSSC. This same plant may choose to further define and enhance the testing strategies of components by categorizing the components remaining in the IST program scope using the OM Code Case OMN-3 (ISTE) process. This would allow relaxation of testing for those components that may have an important, but passive, function that is being addressed by some other program scope or by other technical specification surveillance requirements.

It is possible to implement both processes at the same time since the resources used for each process may be independent of the other. However, it is recommended that the processes be implemented one at a time to gain insight and experience in risk applications along the way. The order in which one elects to implement a combined program would appear to be inconsequential based on the end results. However, there are many factors that would be considered by a plant on how to proceed with both processes.

First, one may consider the benefit to be gained by implementation. Since 10 CFR 50.69 is a broad-based application of risk, the benefits come from the reduced scope of several programs and results in greater savings than the specific OM Code IST-only application.

Second, as one would expect, the resources required for the broad-based 10 CFR 50.69 risk application are more involved and take a longer time to develop and implement. The component function-specific categorizations and specifically identified reduced treatments of the OM Code IST-only program are more easily managed and completed.

Third, if the 10 CFR 50.69 IST program is developed first, then there are fewer IST-scoped components to risk-rank when the OM Code portion of the combined IST program is developed. The 10 CFR 50.69 program will also identify any non-safety pumps or valves that may be considered for the OM Code portion of the IST program.

If the 10 CFR 50.69 process is completed first, then the experience and risk insights can be used for the implementation of the affected programs. Other risk-informed applications, such as the OM Code IST application, can be developed further independently.

Conclusion

IST program scope and testing requirements were identified for each of these risk-informed program options. References for the implementation processes are available to allow further detailed review of each option. Through further investigation of these options and discussions with plant management, each site may find the option and process that best suits their regulatory and plant safety culture.

References

1. *U.S. Code of Federal Regulations*, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,” Section 69, Part 50, Chapter I, Title 10, “Energy.”

2. Nuclear Energy Institute, NEI 00-04, “10 CFR 50.69 SSC Categorization Guideline,” July 2005 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML052910035).

3. U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.175, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing” (ADAMS Accession No. ML003740149).

4. American Society of Mechanical Engineers, Operation and Maintenance Code Case OMN-3, “Requirements for Safety Significance Categorization of Components Using Risk Insights for In-service Testing of LWR Power Plants,” New York, NY.

5. NRC, RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis” (ADAMS Accession No. ML1009100006).

6. NRC NUREG/CP-0152, Volume 6, “Proceedings of the Ninth NRC/ASME Symposium on Valve and Pump Testing, July 17–19, 2006” (ADAMS Accession No. ML072700042).

7. NRC NUREG/CP-0152, Volume 5, “Proceedings of the Eighth NRC/ASME Symposium on Valve and Pump Testing, July 12–14, 2004” (ADAMS Accession No. ML041900037).

8. American Society of Mechanical Engineers *Operation and Maintenance of Nuclear Power Plants* (OM Code).

9. NRC Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” January 24, 1996.

10. NRC Generic Letter 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” September 18, 1996.

11. 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities,” Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.”

12. ASME OM Code Part 29, “Alternative Treatment Requirements for RISC-3 Pumps and Valves.”

13. NRC RG 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code.”

Tables Referenced in Paper

Table 1. Examples of System Functions

Function Risk	Function Description
High	Injection Mode—Deliver borated water from refueling water storage tank (RWST) and accumulators to RCS cold legs to make up for loss of coolant resulting from a LOCA, rod ejection accident, or a steam generator tube rupture (SGTR)
High	Provide a backup source of borated water from the RSWT to the CVCS charging pumps
Low	Provide a makeup water source from the RWST to the spent fuel pool
Low	Provide SI system pressure boundary
High	Maintain the integrity of the RCS pressure boundary
High	Provide manual start and alignment capability for the safety injection system
Low	Provide instrument signals for alarm functions
Low	Provide local indication
Low	Add or vent nitrogen to maintain accumulator within its proper operating range

Table 2. SI System Functions Supported by the LHSI Pump Discharge MOV

Function Risk	Function Description
High	Injection Mode—Deliver borated water from refueling water storage tank (RWST) and accumulators to RCS cold legs to make up for loss of coolant resulting from a LOCA, rod ejection accident, or a steam generator tube rupture (SGTR)
Low	Provide for system testing, maintenance, venting, and draining
Low	Provide containment isolation
Low	Provide SI system pressure boundary
High	Cold leg recirculation mode—Recirculate borated water from the containment sump, through the RHR heat exchangers, and back to the RCS cold legs
High	Hot leg recirculation mode—Recirculate borated water from the containment sump simultaneously to the RCS hot legs by one train and to a cold leg by another train

Table 3. Initial Risk Ranking of IST Components for South Texas Project Using NEI 00-04 Type Categorization

Categorization	Pumps	Valves	Total	Percent of IST SSCs
High—In IST Scope	26	263	289	47%
Low—Exempt from IST	8	316	324	53%

Table 4. Risk Ranking of IST Components Using OMN-3 Type Categorization

Comanche Peak (data from RI-IST submittal dated 11/27/1995)				
Categorization	Pumps	Valves	Total	Percent
High	42	377	419	26.0%
Low	22	1,169	1,191	74.0%
Totals	64	1,546	1,610	

Table 5. Risk Ranking of IST Components Using OMN-3 Type Categorization

San Onofre (data from RI-IST submittal dated 12/28/1998				
Categorization	Pumps	Valves	Total	Percent
High			144	15.8%
Low			767	84.2%
			911	

Table 6. IST Program Categorizations, Scope, and Treatments

<table>
<tr><td>50.69</td><td>Combined</td><td>ISTE</td></tr>
<tr><td rowspan="2">High
In IST scope
OM Code testing requirements</td><td>High
In IST scope
High IST treatment</td><td>High
High IST treatment
In IST scope</td></tr>
<tr><td>In IST scope

Low IST treatment</td><td rowspan="2">Low
Low IST treatment
In IST scope</td></tr>
<tr><td>Low
Not in IST scope
Alternative treatments</td><td>Not in the IST scope
Alternative treatments</td></tr>
</table>

Estimating Safety Valve Stochastic Failure-to-Close Probabilities for the Purpose of Nuclear Reactor Severe Accident Analysis

S. Tina Ghosh, Alfred Hathaway, III, and Hossein Esmaili,
U.S. Nuclear Regulatory Commission

Kyle W. Ross and Douglas M. Osborn, Sandia National Laboratories

Kenneth C. Wagner, Dycoda LLC

Abstract

Recent consequences analyses of potential station blackout (SBO) accidents at nuclear power plants have shown that an important uncertainty in accident progression and radionuclide release is the probability that a safety valve (SV) will fail to close after it has opened to relieve pressure [1]. The U.S. Nuclear Regulatory Commission's (NRC's) State-of-the-Art Reactor Consequence Analyses (SOARCA) and associated uncertainty analyses for SBOs at a pressurized-water reactor (PWR) indicated that SV behavior is an important determinant of whether an induced steam generator (SG) tube rupture (an undesirable bypass event) may develop [2], and an important determinant of whether a PWR with an ice condenser containment may experience an early containment failure [3]. Given the importance of SV failure-to-close probabilities in these accidents, available information was reviewed to help develop better estimates of the probability for an SV's failure to close on demand. The SVs of interest in the SOARCA PWR analyses are the PWR code SVs, designated SVVs (Code Safety Valves) in a study of SVs issued March 2007 (NUREG/CR-7037, "Industry Performance of Relief Valves at U.S. Commercial Nuclear Power Plants through 2007") [4]. There are two sets of failure probabilities reported in NUREG/CR-7037: failure probabilities based on behavior after reactor scrams (i.e., after actual operating events), and failure probabilities based on tests. Information is included for both the secondary-side, main steam system (MSS) valves, as well as reactor coolant system (RCS) valves.

The NUREG/CR-7037 failure probabilities based on actual operating events differ markedly from the failure probabilities based on tests. Further inquiries on valve testing and review of testing requirements show that the focus of testing is to demonstrate that the valves will open to relieve pressure during design-basis accidents to prevent overpressure events. The reseating or closing capability is not tested under severe accident conditions, that is, the valve's repeated full-stroking and passing steam. As such, the testing data were not considered applicable for severe accident modeling purposes. Furthermore, the assumption was made that MSS data were representative of RCS valve failures during severe accident scenarios, as it is judged that they are similar enough in weighing the difference between the valves against the lack of operational data on the RCS SVs (only four data points, and one of two failures having a now-defunct cause of failure). Lastly, recovered valve function (e.g., a previously stuck-open valve closing when pressure reduces) was not considered as a successful valve operation based on a review of licensee event reports.

1. Introduction

Recent consequences analyses of potential SBO accidents at nuclear power plants have shown that an important uncertainty in accident progression and environmental radionuclide release is the probability that an SV will fail to close after it has opened to relieve pressure. The NRC's SOARCA and associated uncertainty analyses for SBOs at a PWR indicated that SV behavior is an important determinant of whether an induced SG tube rupture (an undesirable bypass event) may develop, and an important determinant of whether a PWR with an ice condenser containment may experience an early containment failure. Accidents resulting in containment bypass or early failure of containment are of particular interest because of their potential offsite consequences to members of the public.

Given the importance of SV failure-to-close probabilities in these accidents, available information was reviewed to help develop better estimates of the probability for an SV's failure to close on demand. The SVs of interest in the SOARCA PWR analyses are the PWR code SVs, designated SVVs in a study of SVs (NUREG/CR-7037) [4] published by the NRC based on nuclear power plant safety relief valve data from 1987–2007. There are two sets of failure probabilities for SVVs reported in NUREG/CR-7037: failure probabilities based on behavior after reactor scrams (i.e., after actual operating events), and failure probabilities based on tests. The NUREG/CR-7037 failure probabilities based on actual operating events (Table 20) differ markedly from the failure probabilities based on tests (Table 22); the failure probabilities are about one to two orders of magnitude lower if based on tests (which, in NUREG/CR-7037 Table 22, do not count failures in the "setpoint drift" category) compared to failure probabilities based on operating events. Furthermore, the distribution assumed the SVV failure to close has a significant impact on projected SBO consequences. Hence, the underlying information was further investigated to decide how best to use the available information to model SVV failure to close in PWR SBOs analyzed in the SOARCA uncertainty analyses [2] [3].

2. Operating Experience on SVV Failure to Close on Demand

2.1 Reactor Coolant System SVV Operating Experience

In NUREG/CR-7037, the RCS SVV failure to close on demand is reported in Table 20. As noted, the number of demands, and the number of failures, is based on actual behavior after scram events at nuclear power plants. Table 20 reports two failures to close, zero failures to open, and four demands. These were all initial (first) demands - there were no subsequent demands reported. The licensee event reports (LERs) for these events were consulted to gather details.

The two failures to close occurred in 1992 [5] and 1994 [6].

In the 1992 event -

> While the plant was operating at 100% power, the Reactor Protection System automatically tripped the reactor due to high pressurizer pressure. The event

> was initiated as a result of maintenance on a non-safety related inverter…A subsequent failure of a pressurizer code safety valve resulted in high pressure in the pressurizer quench tank that blew the tank's rupture disk and resulted in the loss of approximately 21,500 gallons of contaminated water to the containment building sump. [5]

The root cause analysis concluded, "The malfunction of Pressurizer Safety Valve RC-142 was determined to be the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out" [6]. The LER also noted that the affected safety valve had a loop seal, which caused chatter in the valve and was a contributing factor to its failure. The corrective actions identified in the LER included (1) adding a mechanical locking device to the SVV adjusting bolt, and (2) evaluation of options to relocate the pressurizer SVVs to eliminate the loop seal. Following an Electric Power Research Institute valve evaluation and recommendation in the mid1990s, PWRs in the United States subsequently removed these loop seals to alleviate this failure mechanism.

In the 1994 event -

> The unit tripped from 100 percent power due to a Reactor Protection System (RPS) actuation. The RPS actuation was the result of low steam generator water levels due to level shrink after all four main turbine stop valves unexpectedly closed. During the resulting transient both the [RCS] power-operated relief valves [PORVs] opened and one code safety relief valve (RV) [SVV] opened, closed, and then began leaking by its seat at approximately 25 gpm. [6]

The LER also notes that two PORVs' setpoints are 2,385 plus or minus 15 pounds per square inch absolute (psia), and the lower setpoint code SVV's setpoint was 2,500 plus or minus 1-percent psia. The setpoint of the higher setpoint code SVV that did not reseat properly was 2,565 plus or minus 1-percent psia. The post-trip maximum recorded pressure of the RCS was 2,410 psia. The hardware root cause analysis concluded that the improper assembly or maintenance was the cause; specifically -

> The cause of the premature lift was determined to be an improperly staked disc holder [that]… was improperly staked to the bellows assembly, allowing the disc to rotate and drift downward toward the lower adjusting ring. This valve specific deficiency effectively lowered its setpoint when subjected to other contributing factors such as valve leakage, elevated RCS pressure, and flow-related vibration created by opening of [the PORV]. The cause of the subsequent [SVV] leakage was that the valve failed to properly reseat after the lift transient due to damage and misalignment of the valve's internal components resulting from the valve lift and/or flutter occurring during the transient. [6]

The corrective actions noted in the LER included (1) replacing the SVV that failed to close, and (2) the valve manufacturer initiating improvements to the disc holder/bellows assembly staking process.

In considering the actual RCS SVV demand events that were captured in NUREG/CR-7037, it was noted that these occurred during full and sudden loss-of-load events. In these events, the initial RCS pressure spike was enough to open not only lower setpoint PORVs, but also high setpoint SVVs simultaneously. Furthermore, discussions with the authors of NUREG/CR-7037 confirmed that there is no way to know how many additional RCS SVV demands that were successful (i.e., SVV reseated after opening) occurred. If the LER did not report the demand, there is no way to know. Reactor operators may not have sufficient indication to know whether one or more SVVs opened and then reseated successfully. Hence, the team concluded that additional unreported demands may have occurred.

2.2 Main Steam System SVV Operating Experience

In NUREG/CR-7037, the MSS SVV failure to close on demand following actual scram events is also reported in Table 20. Table 20 reports 15 failures to close, zero failures to open, and 769 demands. These included 15 failures to close in 573 initial (first) demands, and zero failures in 196 subsequent demands. The LERs for the failure events were consulted to gather details. Notable features of these events include the following:

- Multiple MSS SVVs failed to reseat simultaneously in some events (for example, see reference [7]).
- In at least one event, the MSS SVV failed to reseat due to aging [8].
- In most "recovered" cases, operators lowered the system pressure until the stuck-open valve reseated, but the valve was not demanded to open again afterwards (for example, see reference [9]).
- The cause of several cases pointed to inadequate assembly or installation (for example, see reference [10]).

2.3 Distributions for Reactor Coolant System and Main Steam System SVV Failure to Close on Demand in the State-of-the-Art Reactor Consequence Analyses

The assumption was made that MSS data were representative of RCS valve failures during severe accident scenarios, as it is judged that they are similar enough in weighing the difference between the valves against the lack of operational data on the RCS SVVs (only four demands recorded, all of which likely occurred at pressures lower than designated SVV setpoints; and one of two failures with a now-defunct contributing cause to failure). Lastly, recovered valve function (e.g., a previously stuck-open valve closing when pressure reduces) was not considered a successful valve operation based on a review of LERs. Since "recovered" valves were not demanded to cycle further in the events reported, there is no information on whether the valves would continue to cycle successfully if demanded after recovery.

The data collection for NUREG/CR-7037 ended in 2007. For the Sequoyah SOARCA project, NRC staff and contractors performed an additional operating experience search (using the same methodology as that used for NUREG/CR-7037) to capture additional events through

March 2016. The numbers in Table 1 of this paper reflect updated data, which are separated between initial demands and subsequent demands, compared to Table 20 in NUREG/CR 7037 [4]. A beta-binomial distribution was used to model cycles until a failure-to-close event.

The beta-binomial distributions for initial and subsequent demands were derived to reflect the high level of uncertainty surrounding valve failure. To do this, the beta distributions were calculated by incorporating the data from NUREG/CR-7037 to refine a Jeffreys uninformed beta distribution.[6] The Jeffreys uninformed beta distribution, defined as $Beta(0.5\ 0.5)$, is commonly used as a "prior" distribution in Bayesian analysis with limited data. The mean of the Jeffreys "prior" can be interpreted as roughly half a failure per trial, representing the lack of knowledge about the probability of failure. This methodology is preferable when the data are sparse because it allows sparse data to be used in informing a distribution without placing undue confidence on the data. Based on this data, Figure 1 of this paper shows the cumulative probability function defined for a pressurizer and SG SV to experience a failure to close for the first demand. Figure 2 shows the cumulative probability function defined for the pressurizer and SG SV to experience a failure to close on subsequent demands.

3. SV Testing Requirements and Practices

Further inquiries to personnel responsible for conducting or overseeing nuclear valve testing, and discussion of testing requirements, show that the focus of testing is to demonstrate that the valves will open to relieve pressure during design-basis accidents to prevent overpressure events. The testing does not necessarily fully stroke an RCS SV at pressure like an actual demand would in the severe accidents modeled, but rather unseats the RCS SV at design pressure. In fact, no testing facility in the United States has the flow capacity to fully stroke a PWR RCS SV at design pressure. Hence, the reseating or closing capability is not tested under conditions likely during an SBO accident progression, that is, the valve repeatedly full-stroking and passing steam. Considering these details and the marked difference in failure-to-close rates during operational events versus testing, the testing data were not considered applicable for severe accident modeling purposes. In addition, the same knowledgeable personnel explained that passing water is not necessarily threatening to an SV, but passing cold fluid is (cold being relative to the valve's design conditions).

4. SVV Open Area Fraction Upon Failure to Close

The majority of failed SVV events describe a "weeping" or "leaking" SVV upon failure to close. Separately, the description in one LER reported a 20-percent flow area upon failure. It was judged that the open area fraction upon failure to close was most likely to be small. The team assigned a probability of 0.5 that the flow area would be in the 1 - 10-percent flow area, and a probability of 0.1 that the flow area would be 10 - 30 percent. In the events where an SVV

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[6] http://www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr6823/

energetically opens fully and suffers mechanical deformation of internal parts that prevents reclosure, it is judged that the flow area can be closer to 100 percent. The team assigned a probability of 0.3 to the flow area in the interval 90 - 100 percent. Lastly, since there is little operational data, the chance that failure to close might be something in between the more-likely “weeping” or fully open conditions cannot be discounted completely. Hence, the team assigned a residual probability of 0.1 to the flow area in the 30 - 90-percent interval. Figure 3 of this paper shows the open area fraction probability density function, and Figure 4 shows the cumulative probability function defined for the pressurizer and SG SVs.

5. Conclusion

From discussions with nuclear valve testing personnel and scrutiny of Licensee Event Reports documenting actual operating experience at nuclear power plants, the SOARCA team assumed the following for the purposes of the SOARCA accident progression modeling:

- If an SV was going to fail to close, it would most likely do so on initial demand.
- If an SV functioned per design on initial demand, it would most likely function on all subsequent demands.
- An SV is very unlikely to experience a failure to open.
- Passing water is not necessarily threatening to an SV, but passing cold fluid is (cold being relative to valve’s design conditions).
- Meaningful differences exist between the construct of pressurizer and steam generator SVs, but these differences may be discounted when weighing whether to use MSS SV data for RCS SVs against the lack of operational data for RCS SVs.
- If an SV fails open, it is more likely to fail with a very small open flow area fraction (weeping) or a very large open flow area fraction, and less likely to be something in between.

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[5] Fort Calhoun Licensee Event Report LER 2851992023R00, http://lersearch.inl.gov/

[6] Calvert Cliffs Licensee Event Report LER 3171994007R01, http://lersearch.inl.gov/

[7] Davis-Besse Licensee Event Report LER 3462013001R00, http://lersearch.inl.gov/

[8] Braidwood Licensee Event Report LER 4562010001, http://lersearch.inl.gov/

[9] Davis Besse Licensee Event Report LER 4562004002, http://lersearch.inl.gov/

[10] Arkansas Nuclear One Licensee Event Report LER 3131996005R00, http://lersearch.inl.gov/

[11] Sandia National Laboratories, NUREG/CR-7110, Volume 2, “State-of-the-Art Reactor Consequence Analyses Project Volume 2: Surry Integrated Analysis,” U.S. Nuclear Regulatory Commission, Washington, DC, August 2013.

[12] NRC NUREG/CR-6823, “Handbook of Parameter Estimation for Probabilistic Risk Assessment,” September 2003.

Table 1. SV Failure Data (from scram events) and Associated Epistemic (state-of-knowledge) Uncertainty Distributions for Probability of Occurrence on Demand for FTC

Demand	# Failures	# Demands	Distribution
Initial	16	621	Beta(α = 16.5, β = 605.5)
Subsequent	0	223	Beta(α = 0.5, β = 223.5)

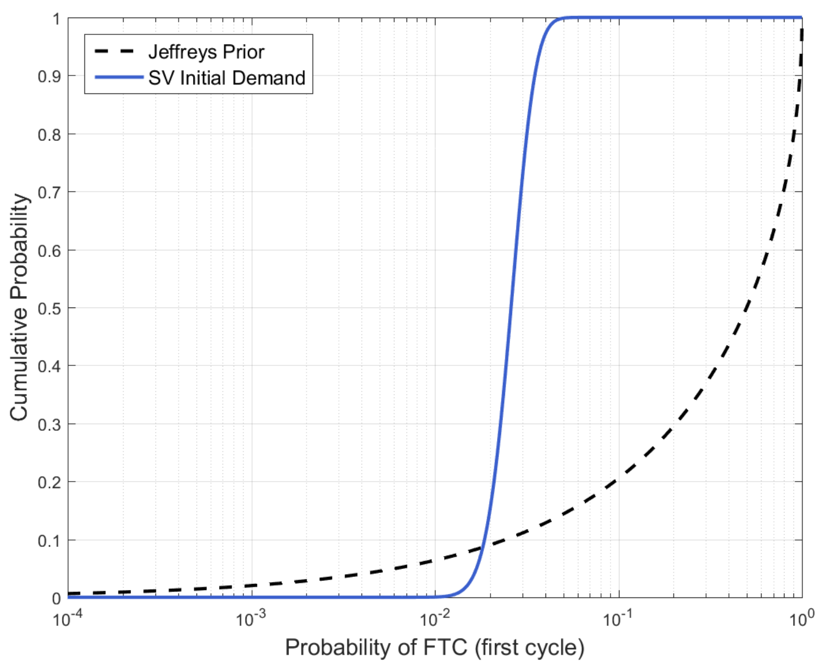

Figure 1. Cumulative probabilities (per valve) of a failure-to-close event on initial demand for the pressurizer SVs; this distribution was also used for the SG SVs.

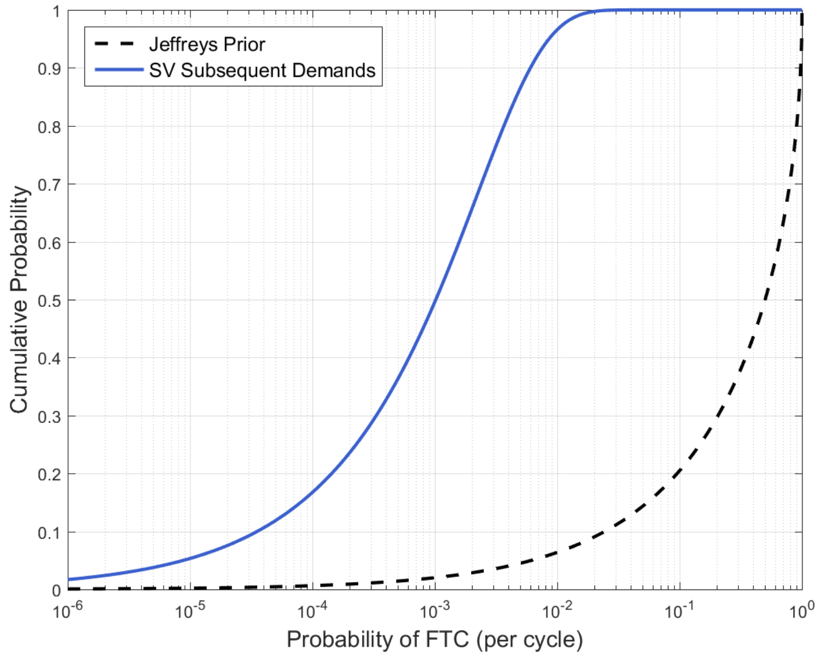

Figure 2. Cumulative probabilities (per valve) of a failure-to-close event on subsequent demands for the pressurizer SVs; this distribution was also used for the SG SVs.

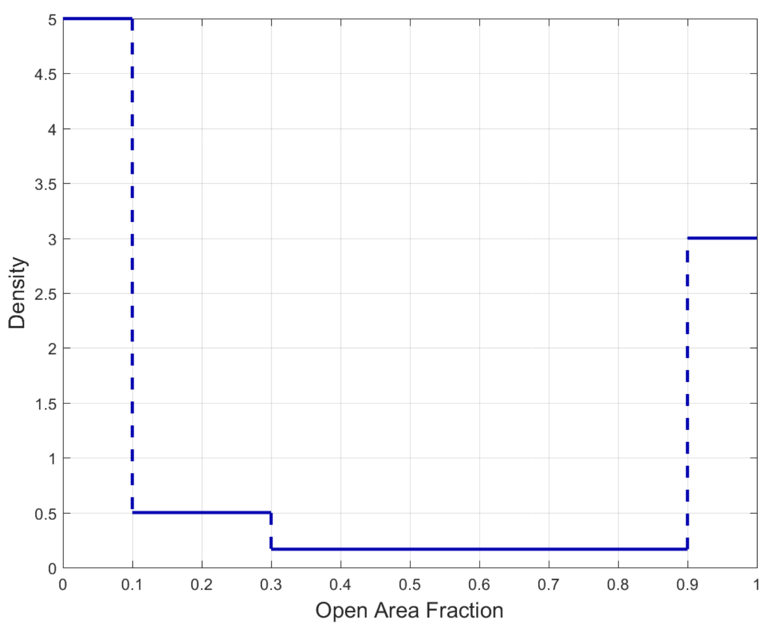

Figure 3. The density function for open area fraction for each pressurizer SV failure to close; this density function was also used for the SG SVs.

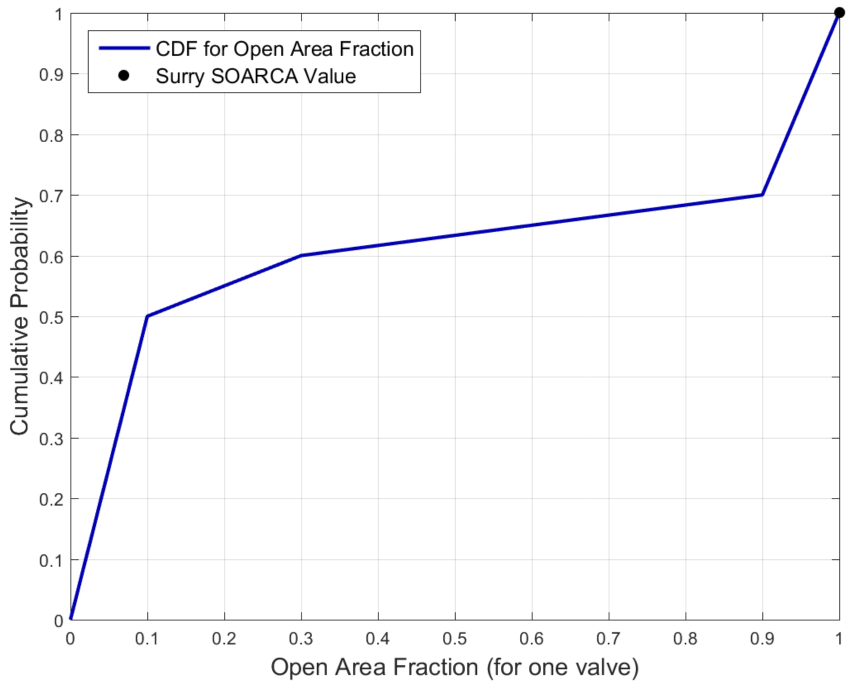

Figure 4. Core damage frequency[7] for the pressurizer SV failure to close open area fraction; this distribution was also used for the SG SVs.

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[7] The black dot shown at 1:1 in Figure 4 is provided for information only and shows the original Surry SOARCA study value [11].

ASME OM Code Subsection ISTE—A Discussion of the Upcoming Subsection

Craig D. Sellers, Enercon Services, Inc.

Abstract

The American Society of Mechanical Engineers (ASME) Operation and Maintenance of Nuclear Power Plants, Division 1, "OM Code: Section IST," Subsection ISTE, "Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants," provides mandatory requirements for owners who voluntarily elect to implement a risk-informed inservice testing (RI-IST) program. The subsection was originally prepared by combining the component categorization requirements and methodology from Code Case OMN-3, "Requirements for Safety Significance Categorization of Components Using Risk Insights for In-service Testing of LWR Power Plants," with component-specific testing requirements developed, or under development, by the component-specific subgroups. Many of these requirements were based on the existing risk-informed code cases.

The original publication of ISTE was not endorsed by the U.S. Nuclear Regulatory Commission (NRC). The Operation and Maintenance Subcommittee on Risk-Informed Activities has revised the subsection over the last 4 years, and it is now expected to satisfy NRC concerns. This paper presents the upcoming proposed requirements for categorizing plant pumps and valves as either high safety-significant components (HSSCs) or low safety-significant components (LSSCs) in accordance with Subsection ISTE and presents examples.

1.0 Introduction

Subsection ISTE provides mandatory requirements for owners who voluntarily elect to implement a risk-informed IST program for pumps and valves. The subsection was originally prepared by combining the component categorization requirements and methodology from Code Case OMN-3 with the test requirements of the risk-informed component code cases, Appendix II for check valves, Appendix III for electric motor-operated valves (MOVs), and the proposed but unpublished Appendix IV for pneumatically operated valves (AOVs).

Subsection ISTE does not address hydraulically operated valves (HOVs) or dynamic restraints (snubbers). Code Case OMN-10, "Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for Inservice Testing of LWR Power Plants," provides different requirements for the safety significance categorization of snubbers than ISTE. The incorporation of HOVs and snubbers may be addressed by the incorporation of alternate risk ranking provisions and component IST treatment requirements in future revisions of ISTE.

2.0 Technical Requirements

2.1 General Requirements

2.1.1 Implementation

Subsection ISTE contains a number of general requirements, the first of which is a requirement on implementation. The requirement on implementation requires the owner to implement ISTE on the entire population of the same type of component in the plant. Component types are defined as follows:

- centrifugal pumps, including vertical line shaft pumps
- positive displacement pumps
- MOVs
- AOVs
- check valves (CVs)

While this requirement requires owners to implement ISTE on the entire population of the same type of component in the plant, it also allows owners to implement ISTE on individual component types at a time and even only a single component type.

It must be emphasized that ISTE requires the subsection to be implemented on the entire population of the same type of component in the plant, not just the components in the existing IST program. Owners must evaluate every component of the selected type in the plant for safety significance categorization. This may include components outside the IST program as well as components not modeled in the probabilistic risk assessment (PRA). Components outside the IST program and components not modeled in the PRA that are classified as HSSCs must be included in the risk-informed IST program. However, components outside the IST program and components not modeled in the PRA that are classified as LSSCs are not required to be included in the risk-informed IST program.

2.1.2 Probabilistic Risk Assessment

Subsection ISTE requires the owner to demonstrate the technical adequacy of the plant-specific PRA to perform component risk ranking and for estimating the aggregate risk impact. PRA technical adequacy shall be assessed using the ASME/American Nuclear Society RA-S-2008, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," with the RASb-2013 Addenda or acceptance criteria that are acceptable to the regulatory agency having jurisdiction over the plant site.

ISTE contains requirements for PRA configuration control. The PRA must reflect plant modifications in a timely manner and at least once every two refueling outages or 5 years, whichever is shorter.

2.1.3 Integrated Decisionmaking

Subsection ISTE requires that an IST-specific plant expert panel be established and that this expert panel make component-specific, as well as integrated risk-informed, decisions. The plant expert panel is required to combine risk-informed component information with deterministic engineering and performance information for each component in order to categorize each component as HSSC or LSSC.

The plant expert panel is also required to consider the integrated effects of multiple risk-informed applications, including risk-informed applications outside the ASME scope. The integrated effect of all risk-informed applications at the plant must be considered, including the risk-informed IST program.

2.1.4 Evaluation of Aggregate Risk

The plant expert panel is also required to evaluate the aggregate risk impact of implementation of the risk-informed IST program using both quantitative evaluations and qualitative assessments. Additional information on aggregate risk evaluation is presented under specific requirements.

2.1.5 Feedback and Corrective Action

Subsection ISTE requires that feedback and corrective action processes be established for the risk-informed IST program. Additional information on feedback and corrective actions is presented under specific requirements.

3.0 Specific Component Categorization Requirements

The specific component categorization requirements of Subsection ISTE apply to all components evaluated. These requirements are the same for all component types addressed by ISTE.

The categorization process is a two-phase process. The first phase is risk categorization using the PRA. The second phase is safety categorization, where deterministic criteria are blended with the risk criteria to establish the final categorization of the components as HSSCs or LSSC.

3.1 Component Risk Categorization

Component risk categorization is performed with information taken from the plant-specific PRA.

3.1.1 Appropriate Failure Modes

Components are usually modeled in the PRA as "basic events," which represent different failure modes or other reasons the component may not be available to perform its function. Typical failure modes for PRA components are as follows:

Valves

- fail to open
- fail to close
- transfer (spurious) open
- transfer (spurious) closed
- plugged (disk stuck)
- maintenance unavailability
- common-cause failure

Pumps

- fail to start
- fail to run
- fail to provide sufficient flow
- maintenance unavailability
- common-cause failure

The failure modes appropriate for risk-informed IST are those failure modes that can be identified by IST activities. These include, for valve, fail to open, fail to close, and plugged. For pumps, the appropriate failure modes could be fail to start and fail to provide sufficient flow.

Maintenance unavailability failure modes are not applicable to IST for valves or pumps because these are usually planned activities, and IST results will not identify this unavailability. Transfer open and transfer closed failure modes for valves typically represent spurious operation of the valve. These failure modes are also not applicable to IST.

There are often multiple common-cause failure basic events for components. These will represent groups of redundant or diverse components serving a common or similar function. Common-cause failure-basis events are important, but it must be verified that the failure mode being modeled is applicable to IST.

3.1.2 Importance Measures

Many importance measures can be derived from a PRA. Subsection ISTE does not disallow the use of any importance measures. However, ISTE does require the use of the Fussell-Vesely (FV) and risk achievement worth (RAW) importance measures.

The FV importance measure represents the fractional contribution to the total of the selected figure of merit (e.g., core damage frequency (CDF) and large early release frequency (LERF)) for all accident sequences containing that basic event. The RAW importance measure represents the increase in a selected figure of merit when a system, structure, and component (SSC) is assumed to be unable to perform its function because of testing, maintenance, or failure. It is the ratio or interval of the figure of merit, evaluated with the SSC's basic event probability set to one, to the base case figure of merit.

3.1.3 Screening Criteria

Subsection ISTE does establish screening criteria for the initial risk categorization. For those components modeled in the PRA, a threshold value of FV >0.005 or a RAW >2 based on either CDF or LERF should be initially considered as HSSC. If the FV and RAW for a component in the PRA are less that these screening criteria, the components should initially be considered as LSSC.

3.1.4 Sensitivity Studies

Subsection ISTE requires sensitivity studies to be performed. The objective of these sensitivity studies is to investigate whether any components classified as LSSC through the screening process should be considered HSSCs.

The following sensitivity studies are required:

- Data and uncertainties - Failure probabilities of selected components within the PRA shall be assessed to determine if the results are sensitive to changes in the failure data.

- Human recovery actions - The PRA shall be requantified, and the FV and RAW importance measures recalculated, after human actions modeled in the PRA, to recover from specific component failures, are adjusted in the models. This sensitivity shall ensure that the categorization has not been unduly affected by the modeling of recovery actions.

- Test and maintenance unavailabilities - The PRA shall be requantified with test and maintenance unavailabilities appropriately adjusted and the importance measures recalculated.

- LSSC failure rates - Failure rates shall be simultaneously increased by a factor representing the upper bound (95 percent) of the failure rate and the PRA models requantified.

- Truncation limits - If the PRA has not been quantified with a truncation limit 10^{-4} below the baseline PRA CDF, the PRA model shall be requantified with the truncation limit lowered to this value. The importance measures shall then be recalculated.

- Common cause - Sensitivity analyses shall be used to determine the impact of increased or decreased common-cause failure rates.

The results of these sensitivity studies and any others that are performed are required to be documented, including the magnitude of the changes to the CDF or LERF. The results and insights of these sensitivity studies are provided to the plant expert panel for consideration in the final categorization of the components.

<u>3.1.5 Qualitative Assessments</u>

Subsection ISTE requires qualitative assessment to be performed. Similar to the sensitivity studies, the objective of these qualitative assessments is to investigate whether any components classified as LSSC through the screening process should be considered as HSSCs.

Qualitative assessments are required to be performed for plant-specific design-basis conditions and events not modeled in a PRA.

The following qualitative assessments are required to be considered:

- impact of initiating events - the impact of LSSC failure or degradation as it might result in an initiator or component contribution to initiating events represented by point estimates

- shutdown conditions - the potential consequences of shutdown (outage) conditions on LSSC importance

- external initiating events - LSSC response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding)

- large early release frequency - LSSC impact on LERF if not quantified in the screening assessment

- LSSC impact on the plant to do the following:
  - prevent or mitigate accident conditions
  - reach and/or maintain safe shutdown conditions
  - preserve the reactor primary coolant pressure boundary integrity
  - maintain containment integrity

- LSSC considerations of the following:
  - safety function being satisfied by the component's operation
  - level of redundancy existing at the plant to fulfill the component's function
  - ability to recover from a failure of the component
  - performance history of the component
  - plant technical specification requirements applicable to the component
  - emergency operating procedure instructions that use the component(s)

  - design and current licensing basis information relevant to RIST component function
- the cumulative impacts of combinations of LSSC unavailability, which could impact an entire system (e.g., multi-train impacts) or critical safety function (e.g., multi-system impacts).

The results of these qualitative assessments are required to be documented and made available to the plant expert panel for consideration in the final categorization of the components.

3.1.6 Components Not Modeled in the PRA

If IST components not modeled in the PRA are subsequently determined by the plant expert panel to have an impact upon the ability of the facility to respond to analyzed events, consideration should be given to updating the PRA model to incorporate the effects of the component(s) and then using the updated model to provide a quantified basis for categorization (either HSSC or LSSC).

3.2 Component Safety Categorization

The component safety categorization process is one in which the plant expert panel categorizes components relative to their safety significance as HSSCs or LCCS using both deterministic and probabilistic insights. The probabilistic insights come from the component risk categorization above.

3.2.1 Plant Expert Panel Utilization

Subsection ISTE specifies requirements and guidance for the plant expert panel to blend deterministic and probabilistic information to classify IST components into HSSC or LSSC categories.

3.2.2 Plant Expert Panel Requirements

Subsection ISTE establishes basic requirements for the plant expert panel for developing and implementing a risk-informed IST program.

3.2.2.1 Procedure

An approved plant procedure shall describe the process and include the following:

- designated members and alternates
- designated chairperson and alternate
- quorum
- attendance records
- agendas
- motions for approval

- process for decisionmaking
- documentation and resolution of differing opinions
- minutes
- implementation of feedback and corrective actions
- feedback to the PRA
- required training

3.2.2.2 Training

The plant expert panel shall be trained and indoctrinated in the specific requirements to be used for Subsection ISTE. Training and indoctrination are required to include the application of risk analysis methods and techniques. At a minimum, the risk methods and techniques should include the following:

- PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty)
- use of risk-importance measures
- assessment of failure modes
- reliability versus availability
- risk thresholds
- expert judgment elicitation

3.2.2.3 Expertise

Subsection ISTE requires that the expertise level for plant expert panel members be documented and maintained.

3.2.2.4 Plant Expert Panel Membership

Subsection ISTE requires at least five experts to be designated as members of the plant expert panel. Members may be experts in more than one field; however, excessive reliance on any one member’s judgment shall be avoided.

The chairperson is required to be familiar with Subsection ISTE and is responsible to facilitate plant expert panel activities to ensure that the requirements of ISTE are satisfied.

Subsection ISTE requires expertise in the following functions be represented on the plant expert panel:

- operation
- safety analysis engineering
- PRA
- ASME inservice testing

Additional members of the plant expert panel may be selected who have the following plant expertise:

- systems performance
- maintenance
- licensing
- component performance
- quality assurance
- design engineering

<u>3.2.3 Plant Expert Panel Decisions</u>

Plant expert panel decision criteria for categorizing components as HSSC and LSSC are required to be documented. Subsection ISTE requires that decisions of the plant expert panel be arrived at by consensus. Differing opinions are required to be documented and resolved, if possible. If a resolution cannot be achieved concerning the safety significance classification of a component, then the component is required to be classified HSSC.

3.3 Test Strategy Formulation

Test strategies must be developed to allow for the evaluation of aggregate risk. Test strategies differ from specific test treatments. Test strategies include consideration of test frequency, testing effectiveness, and out-of-service duration. Many test strategy considerations have competing effects on the PRA.

For example, testing effectiveness can be increased by the acquisition of additional diagnostic performance information from the component. Acquiring this diagnostic information often increases the out-of-service duration for each component-specific test. However, acquiring this diagnostic information may be performed at an extended test frequency, which may compensate for this increased test-specific out of service duration.

3.4 Evaluation of Aggregate Risk

The evaluation of aggregate risk includes a combination of quantitative and qualitative evaluations. It is required that appropriate decision criteria for aggregate risk effects be established and documented for both quantitative and qualitative assessments. The evaluation of aggregate risk must be performed before implementation of the risk-informed IST program.

3.4.1 Quantitative Assessment of Aggregate Risk

Subsection ISTE requires that proposed IST program changes be assessed to determine compliance with approved decision criteria and to quantitatively determine if any adjustments or compensatory measures are warranted. Types of quantitative attributes that should be considered in the quantitative evaluation include changes in the following:

- testing frequency
- out-of-service duration
- failure rates
- failure modes
- common-cause failure susceptibility
- compensatory measures
- testing scheme (staggered or simultaneous testing)

Compensatory measures include both those specifically incorporated into plant programs and those developed for specific situations. Example compensatory measures are (1) restricting testing to one system/train, and (2) increasing test frequency or effectiveness on specific components. Management-directed compensatory measures should also be included in the quantitative assessment, as appropriate. Documented failure rates shall be used in the quantification process for the IST component.

Once all appropriate inputs have been incorporated, the PRA is to be rerun to assess the overall risk impact.

3.4.2 Qualitative Evaluation of Aggregate Risk

Subsection ISTE requires that aggregate risk effects be qualitatively evaluated (i.e., risk decreases as well as risk increases) for IST program changes (e.g., testing effectiveness). Pertinent performance indicators, industry programs, or other scrutable methods for establishing aggregate risk effects are required to be identified and monitored. Feedback processes and corrective action programs are to be considered in the evaluation of aggregate risk.

3.5 Defense in Depth and Safety Margin

As with other risk-informed application and programs, defense in depth and safety margin must be maintained. Subsection ISTE contains requirements and guidelines for maintaining defense in depth and safety margin.

3.6 Inservice Testing Program

Subsection ISTE has specific requirements related to the IST program that apply to all components in the IST program.

3.6.1 Maximum Test Interval

The maximum test interval for a component, or group of components, cannot exceed any of the following:

- the maximum interval allowed by the results of the aggregate risk evaluation
- the maximum interval supported by the performance history of the component(s)
- the maximum interval specified in Section 4.0 of this paper.

3.6.2 Transition Plan

A transition plan is required to be developed for each component type to ensure that adequate information is collected to support justification of stepwise test interval extension up to and including the maximum allowable interval. Staggered test intervals are allowed to be used for implementing a stepwise test interval extension.

4.0 Specific Component Testing Requirements

4.1 Pumps

4.1.1 High Safety-Significant Component Pumps

Pumps categorized as HSSCs are required to meet all requirements of Subsections ISTA, ISTB, or ISTF.

4.1.2 Low Safety-Significant Component Pumps

In general, LSSC pumps are required to be tested less frequently and farther from the design flow conditions than HSSC pumps.

4.1.2.1 Pre-2000 Plants

LSSC pumps are required to meet all the requirements of Subsections ISTA and ISTB, except that the testing intervals are essentially doubled. LSSC pumps are also required to receive an initial Group A test conducted within ±20 percent of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST program. Thereafter, LSSC pumps are required to be Group A-tested within ±20 percent of pump design flow rate at least once every 5 years, or three refueling outages, whichever is longer.

4.1.3 Post-2000 Plants

Pumps categorized as LSSCs are required to meet all requirements of Subsections ISTA and ISTF, except that the testing requirements of ISTF-3400 may be substituted by the following testing requirements:

- LSSC pumps are required to receive an initial test conducted within ±20 percent of the pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST program.

- Thereafter, the LSSC pumps are required to be tested every 2 years in accordance with Subsection ISTF.

4.2 Check Valves

4.2.1 High Safety-Significant Component Check Valves

Subsection ISTE requires that HSSC check valves be placed in a condition monitoring program and tested in accordance with Mandatory Appendix II of the OM Code.

4.2.2 Low Safety-Significant Component Check Valves

LSSC check valves are required to be tested in accordance with ISTC or placed in a condition monitoring program and tested in accordance with Mandatory Appendix II of the OM Code.

4.3 Motor-Operated Valves

Electric MOVs are required to be tested in accordance with Mandatory Appendix III of the OM Code. This appendix specifies different test requirements for HSSC and LSSC MOVs.

4.4 Pneumatically Operated Valves

AOVs will be required to be tested in accordance with Mandatory Appendix IV of the OM Code, which is yet to be published. This appendix is expected to specify different test requirements for HSSC and LSSC AOVs when published.

5.0 Monitoring, Analysis, and Evaluation

5.1 Performance Monitoring

Subsection ISTE specifies different performance monitoring requirements for HSSC and LSSCs.

5.1.1 High Safety-Significant Component Attribute Trending

For HSSCs, a set of performance attributes to be tested is required to be established and compared to acceptance criteria and a trending program be implemented for those attributes. This is individual component-specific trending but can be applied to groups of similar components.

5.1.2 Low Safety-Significant Component Performance Trending

For LSSCs, the IST is required to be supplemented by performance monitoring. The performance of the LSSCs shall be trended to ensure that the LSSC component failure rates do not increase to unacceptable levels. This performance trending need not be component specific and may be performed on the entire population of LSSC components of the same type.

5.2 Feedback and Corrective Action

Subsection ISTE requires a feedback process be developed incorporating elements of both conditional and periodic feedback such that component performance information is directed to both the IST and PRA programs. Conditional feedback is required in a timely fashion following component failure. Periodic feedback is considered for maintenance of the PRA. The periodic feedback frequency should not exceed two refueling cycles.

In addition to the requirements in the IST code of record with respect to corrective actions, Subsection ISTE requires a corrective action program to be established that identifies and tracks to resolution all failures of similar types of components within the IST program, incorporating risk insights, including evaluation of generic implications.

Track 8: New Reactors

Track Chair: Christopher Pendleton, Southern Nuclear Co.

Inservice Testing for Small Modular Nuclear Reactor Plants

Gary P. McGee, P.E.
Principal Design Engineer
NuScale Power, LLC
Corvallis, OR, USA
gmcgee@nuscalepower.com

Steven M. Unikewicz
Member, ASME Subcommittee, New Reactors
NuScale Power, LLC
Ashburn, VA, USA
sunikewicz@nuscalepower.com

Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, "OM Code: Section IST" (OM Code) defines a post-2000 plant as a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

The NuScale advanced small modular reactor (SMR) plant is a passive, pressurized-water reactor (PWR), designed such that from 1 to 12 nuclear power plant modules (NPMs) can operate within a single reactor building. Each NuScale NPM consists of a reactor core, two steam generator tube bundles, and a pressurizer contained within a single reactor vessel, along with the containment vessel (CNV) that immediately surrounds the reactor vessel and is rated at 160 megawatts-thermal.

The ASME OM Code was written considering single-unit reactor plants, not multi-modular SMRs. The ASME Subcommittee for New Reactors is developing a new Subsection ISTG to address inservice testing (IST) of valves for all new and advanced reactor types.

This paper reviews the unique aspects and programmatic solutions for preservice testing (PST) and IST specific to the NuScale SMR. The functional design and qualification provisions and IST program are described. The PST and preservice test period will be discussed, as some PST may be completed in the factory before shipping the reactor module to the site. Additionally, methods that eliminate overlap, redundancy, and excessive testing between the PST and IST program plans will be explored.

The intent of these solutions is to provide reasonable assurance that the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section III, Classes 1, 2, and 3, nonsafety-related and non-ASME valves that have an important function will operate when needed. The IST program considers both deterministic and risk insights in its evaluation of PST and IST and meets the requirements of the ASME OM Code as endorsed by Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, "Codes and standards."

I. Introduction

The NuScale Power Plant SMR is designed to operate from 1 to 12 NPMs with the associated primary and secondary systems and components necessary to produce power and maintain the facility. This includes main steam systems, turbine generator sets, condensate and feedwater systems, and shared external cooling water systems, plus module assembly equipment, fuel handling equipment, turbine maintenance equipment, and radioactive waste processing equipment. The net total output for a NuScale Power Plant with 12 operating NPMs is approximately 570 megawatts-electric.

The NPM is designed to operate up to full-power conditions using natural circulation as the means of providing reactor coolant flow, eliminating the need for reactor coolant pumps.

The NPMs are partially immersed in a reactor pool and protected by passive safety systems. Each NPM has a dedicated emergency core cooling system (ECCS) and decay heat removal system (DHRS).

Important features of the NPM include the following:

- a small, modular design
- an integral PWR nuclear steam supply system (NSSS) that combines the reactor core, steam generators (SGs), and pressurizer within the reactor pressure vessel (RPV), eliminating the need for external piping to connect the SGs and pressurizer to the RPV
- natural circulation provides the driving force for reactor coolant flow, eliminating the need for reactor coolant pumps and associated support systems
- an RPV housed in a steel containment partially immersed in water, providing an effective passive heat sink for long-term decay heat removal
- a steel containment operated at a vacuum, eliminating the need for insulation on the RPV, the CNV, or any piping within the CNV
- passive safety systems that are not reliant on electrical power (i.e., no safety-related pumps, valves, or related equipment)

A benefit to this design is that once started (with more than one NPM installed), the plant is always running. A refueling outage only removes a fraction of the plant's output capacity. The challenge is that with 12 NPMs operating on a staggered, 2-year fuel cycle, it is expected that there will be six refueling outages a year. The simplified, passive NuScale design facilitates less-challenging outage schedules. Additionally, the NuScale design also results in a simplified IST program.

II. NuScale Design

a. NuScale Power Module

An NPM, shown in Figures 1 and 2 of this paper, is a collection of systems, subsystems, and components that, together, constitute a modularized, movable, NSSS. The NSSS consists of a reactor core, two helical-coil SGs, and a pressurizer integrated within the RPV. The RPV is enclosed in an approximately cylindrical CNV that sits in the reactor pool. The reactor core is located below the helical-coil SGs inside the RPV. Using natural circulation, the primary reactor coolant flowpath is upward through the central hot leg riser and then downward around the outside of the SG tubes with return flow to the bottom of the core via an annular downcomer. As the reactor coolant flows across the SG tubes, heat is transferred to the secondary side fluid inside the SG tubes. Concurrently, as the secondary side fluid progresses up through the inside of the SG tubes, it is heated, boiled, and superheated to produce high-pressure steam for the turbine generator unit.

The NuScale design features the following:

- no alternating current (ac) or direct current (dc) power required for safe shutdown and cooling
- compact helical-coil SGs with reactor pressure on the outside of the tubes
- high-strength steel containment immersed in a pool of water
- subatmospheric containment pressure during normal operation
- small core with a correspondingly small source term
- comprehensive digital instrumentation monitoring and control
- scalable plant design, which allows for incremental plant capacity growth

b. Reactor Building

The reactor building is located above and below grade and houses the NPMs and the following facilities:

- ultimate heat sink (reactor pool, refuel pool, and spent fuel pool)
- fuel-handling areas
- remote shutdown station
- primary systems

The reactor building is a seismic Category I, reinforced concrete structure with design considerations for the effects of aircraft impact, environmental conditions, postulated design-basis accidents (internal and external), and design-basis threats. The reactor building also provides radiation protection to plant operations and maintenance personnel. Each NPM is located in the common reactor pool in its own three-walled bay, with the open wall toward the center of the pool. The bays are arranged into two rows with six bays per row along the north and south walls of the reactor pool at the east end of the pool. A central channel is provided between the bays to allow for movement of the NPMs between the bays and the refueling pool. The normal reactor pool water depth is approximately 21 meters (m) (69 feet (ft)), which is just below the CNV head weld. Each bay has a concrete bioshield to reduce radiation levels in the reactor building and to prevent deposition of foreign materials onto an NPM. Bioshields are installed to provide local shielding and to limit access to the NPM and are designed to be removed during refueling outages.

c. Containment

The NuScale CNV is a supported, cylindrical vessel-type containment that is designed to withstand limiting high-pressure transients. The CNV is an ASME BPV Code Class MC (steel) containment that is designed, analyzed, fabricated, inspected, tested, and stamped as an ASME BPV Code Class 1 (NB) pressure vessel. The CNV internal pressure is maintained at a vacuum during normal operation; as such, insulation materials are not required between the reactor vessel and the CNV. The containment vessels are mounted to the reactor building module compartment walls and at the bottom within the reactor pool.

The CNV houses the RPV, control rod drive mechanisms, and associated NSSS piping and components. The CNV has an overall height of approximately 23 m (76 ft), an outside diameter of approximately 4.6 m (15 ft), and consists of an upper CNV section with a welded torispherical top head and a lower CNV section with a welded head. The upper and lower CNV sections are flanged together using bolts. The flange connection permits the CNV to be separated to provide access to the RPV for refueling and maintenance.

The safety functions of the CNV are to contain the release of radioactive material following postulated accidents and to provide heat rejection to the reactor pool following ECCS actuation. The CNV also provides support for the RPV.

The CNV is partially immersed in the reactor pool, which provides a passive heat sink for containment heat removal. The CNV is designed to withstand the external environment of the reactor pool as well as the internal pressure and temperature of a design-basis accident.

The CNV is maintained at a vacuum under normal operating conditions. The benefits of maintaining a vacuum in the CNV include the following:

- minimizes moisture content that could impact the reliability and contribute to corrosion of components within the CNV

- facilitates detection of leakage from the reactor coolant pressure boundary, which reduces potential debris generated in the CNV

- limits the initial amount of oxygen in containment (severe accident combustible gas consideration)

Following an actuation of the ECCS, steam is vented from the RPV through the reactor vent valves. This results in an initial spike in containment pressure and temperature. Steam in contact with the inside surface of the CNV is passively cooled and condensed by conduction and convection to the reactor pool water. This passive process rapidly reduces containment pressure and temperature and maintains containment pressure and temperature at less than design conditions indefinitely.

d. Reactor

The NuScale NSSS is a passive NuScale-designed small modular PWR. This design comprises an integral power module consisting of a reactor core, two SG tube bundles, and a pressurizer contained within a single reactor vessel, along with the containment vessel that immediately surrounds the reactor vessel. This design eliminates the need for external piping to connect the SGs and pressurizer to the RPV. Natural circulation provides reactor coolant system flow, thereby eliminating the need for reactor coolant pumps.

The RPV consists of an approximately cylindrical steel vessel with an inside diameter of approximately 2.7 m (9 ft) and an overall height of approximately 18 m (58 ft) designed for an operating pressure of approximately 12.76 Megapascals (MPa) (1,850 pounds per square inch absolute (psia)). The upper and lower heads are torispherical, and the lower portion of the vessel has a flange to provide access for refueling.

e. Emergency Core Cooling System

The ECCS provides a passive means of decay heat removal in the event of a loss-of-coolant accident (LOCA). The ECCS consists of three independent reactor vent valves and two independent reactor recirculation valves (Figure 3). All five valves are closed during normal operation.

During ECCS operation, the reactor vent valves vent steam from the RPV into the CNV where the steam condenses and collects in the bottom of the containment. The reactor recirculation valves allow water to reenter the RPV and be circulated through the core. When reactor coolant temperature is reduced to below the boiling point, core cooling continues through conduction directly into the reactor pool. The cooling function of the ECCS is entirely passive, with heat being conducted through the CNV wall to the reactor pool.

There are no piping, pumps, or dynamic restraints associated with the ECCS.

f. Decay Heat Removal System

The decay heat removal system (DHRS) provides secondary side reactor cooling for non-LOCA events when normal feedwater is not available. The system, as shown in Figure 3 of this paper, is a closed-loop, two-phase natural circulation cooling system. Two trains of decay heat removal equipment are provided, one attached to each SG loop. Each train is capable of removing 100 percent of the decay heat load and cooling the reactor coolant system (RCS). Each train has a passive condenser immersed in the reactor pool. In the event of SG tube rupture, the affected SG is isolated and the DHRS provides cooling through the intact SG.

On receipt of an actuation signal, feedwater isolation valves (FWIV) and main steam isolation valves (MSIV) are closed and the DHRS valves open. Reactor coolant continues to circulate through the RPV collecting decay heat from the core. As water from the DHRS condenser travels through the SG tubes, it is converted to steam, absorbing decay heat from the reactor coolant. The steam then flows back to the DHRS condenser, where it gives up excess heat to the reactor pool water and is condensed, and the cycle is repeated. This transfer of heat promotes natural circulation in both the RCS and the DHRS.

There are no pumps or dynamic restraints associated with the DHRS.

g. Chemical and Volume Control System

The chemical and volume control system (CVCS) is simple in design, and operation is not credited during or after an accident. During normal operation, the CVCS recirculates a portion of the reactor coolant through demineralizers and filters to maintain reactor coolant cleanliness and chemistry. A portion of the recirculated coolant is used to supply pressurizer spray for controlling reactor pressure. Reactor coolant inventory is controlled by injection of additional water when reactor coolant levels are low or letdown of reactor coolant to the liquid radioactive waste system when coolant inventory is high.

Additionally, during the NPM startup process, the CVCS is used, in conjunction with the module heatup system, to add heat to the reactor coolant to establish natural circulation flow in the RCS.

Boron concentration in the RCS is controlled by a feed-and-bleed process. Injection pumps provide borated water or clean demineralized water that is delivered into the RCS with excess reactor coolant being let down to the radioactive waste system. Safety-related protection is provided for an anticipated operational occurrence involving unintended dilution of the RCS from CVCS equipment failure or operating error.

h. Ultimate Heat Sink

The ultimate heat sink is a large, stainless steel-lined, reinforced concrete pool located in the reactor building below plant grade level. The ultimate heat sink consists of the reactor pool area, the refueling pool area, and the spent fuel pool area. During normal plant operations, heat is removed from the pool through the reactor pool cooling system and rejected into the atmosphere through a cooling tower or other external heat sink. The spent fuel pool has an independent spent fuel pool cooling system.

In a design-basis accident involving a sustained loss of all ac power, decay heat is removed from the NPMs through passive heat transfer to the pool resulting in pool heatup and boiling. Water inventory in the reactor pool is adequate to cool the NPMs for at least 72 hours without adding water.

i. Plant Cooling Water Systems

The plant cooling water systems include several systems that are important to supporting plant operation but are all nonsafety related. These systems include the following:

- reactor component cooling water system
- reactor pool cooling system
- site cooling water system
- circulating water system

The ultimate heat sink is the only safety-related cooling in the NuScale plant, and it is a passive pool design.

III. NuScale IST Program

For the purpose of the IST program, a plant or unit is what is defined by a "single" license issued by the governing regulatory authority. A plant or unit may consist of multiple "reactors" as long as the reactors are defined in a single license. The NuScale Power Plant consists of up to 12 NPMs licensed under a single operating license. Therefore, a single IST program is used and is adjusted as each new NPM train is constructed and exposed to nuclear heat. This approach may be submitted as an alternative to the OM Code upon development of the IST program.

IV. Functional Design

The NuScale power plant standard design does not have any safety-related pumps, dynamic restraints, or motor-operated valves.

The NuScale IST program is a valve-only test program.

A unique design aspect is that all containment isolation valves are located outside of the CNV. Approximately 60 percent of valves in the NuScale IST program are located on top of the CNV head, under the bioshield, and are tested every refueling outage. This includes primary and secondary systems containment isolation valves and DHRS actuation valves. All pressure-relief devices in the NuScale IST program are located inside the CNV.

The functional design and qualification of safety-related valves are performed in accordance with the ASME Qualification of Mechanical Equipment (QME-1) 2007 standard, as endorsed in NRC Regulatory Guide 1.100, Revision 3, "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," issued September 2009.

In accordance with 10 CFR 50.55a(f)(3), all Class 1, 2 and 3 valves are designed and provided with access to enable the performance of IST to assess operational readiness in accordance with the ASME OM Code and as defined in the IST program. All valves in the augmented program are designed and provided with access to enable the performance of IST to assess operational readiness. Working platforms are provided in areas requiring inspection and servicing of valves.

A combined operating license applicant that references the NuScale power plant design certification will incorporate all IST access requirements into the design and construction, as specified by 10 CFR 50.55a(f)(3). The quality assurance requirements for the design, fabrication, construction, and testing of safety-related pumps, valves, and dynamic restraints is controlled by the plant Quality Assurance Program and in accordance with 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

V. IST Program for Valves

The NuScale IST program applies to valves classified as ASME BPV Code Class 1, 2, or 3 valves and non-ASME valves that meet the criteria of ISTA-1100. The NuScale IST program is summarized in NuScale's design certification application submittal, Section 3.9.6. This includes tables that delineate the scope of the valve program, valve functions, valve categories, and test frequencies.

Valves are exercised at a frequency in accordance with ASME OM Code, Subsection ISTC, to affirm their continued availability for service. Periodic verification of the ability of power-operated valves to perform their design-basis function will be in accordance with the ASME OM Code and the requirements of 10 CFR 50.55a.

VI. Valve Grouping for a 12 NPM Plant

Each NPM and the auxiliary systems are identical in design. An IST engineer at a NuScale plant will have 12 small reactors with identical valves in the IST plan. Grouping is done by valve type, model, and size. The population of each group is made up of valves from all 12 NPMs. There are 47 valves per NPM. The NuScale IST plan consists of 564 total valves divided into 15 valve groups. Table 1 describes the valve population in the NuScale IST program.

VII. Factory Testing

A large portion of the NPM will be assembled at the factory and transported to the site. This presents a unique opportunity to perform some PST. Any PST that can be performed in the factory would provide a cost benefit and construction time savings.

IST-3100(a) requires that any pretested valve that has undergone maintenance that could affect the PST shall be retested. Shipping the valve with the NPM and installing it in the plant is not "maintenance." However, it is recognized that further qualification of this concept will need to be performed, such as onsite retesting and evaluation to justify factory PST.

VIII. Risk-Informed Opportunities

Risk-informed IST is not available to initial NuScale combined operating license applicants. There is insufficient performance history for this new design. However, with 12 NPMs per plant, and the factory production of identical units, the risk-informed implications for IST and other NuScale programs is a possibility and will be explored as operational experience is gained. Component design operational history will be accumulated at a much faster rate than in the past, as with the current operating designs, because of the number of NPMs operating. The application of risk-informed principles for IST, ISI, and technical specifications may ease the outage burden and make a more cost-effective operation and maintenance plan for the owner.

- **Unique Aspects of the Inservice Test Program**

I. Emergency Core Cooling System

The ECCS consists of five valves connected to the RPV. The system has no tanks, pumps, pipes, or external water sources (see Figure 3). These five valves open to establish a natural circulation flowpath between the PRV and CNV using the existing reactor coolant system inventory and the reactor pool as the ultimate heat sink. The ECCS valves are power-operated relief valves with remote pilot valves (a trip valve and a reset valve).

Design-basis verification testing will be part of the ISTs for these valves. This will include periodic testing of the valve flow coefficient (Cv) and a functional test of the inadvertent actuation block. ECCS is actuated during a LOCA at lower RCS pressures. The inadvertent actuation block is a design feature that does not allow inadvertent opening of an ECCS valve at power by blocking the pilot signal at high RCS pressure.

The remote pilot valves are tested as part of the main valve as a unit for IST. Only the trip valve has a safety function; however, both valves are located outside the CNV and have a double o-ring seal that requires 10 CFR Part 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” Type B testing.

IST of the ECCS valves will likely occur during Technical Specification Mode 4, “Transition.” To enter Mode 4, the ECCS valves are normally opened and critical operating parameters may be recorded and trended to assure operational readiness.

Testing will be in accordance with ASME OM Code, Section ISTC-5110.

II. Primary System Containment Isolation Valves

All primary and secondary system containment isolation valves are located outside the CNV. During an ECCS actuation, containment peak pressure can reach over 900 psia. This design allows all containment isolation valves to be outside of the potentially harsh containment environment. The primary systems containment isolation valves are welded directly to the CNV through the nozzle safe-ends. A single valve body contains both containment isolation valves in series (there is no pipe between the two valves). The inboard valves are more accessible for testing and maintenance.

Because of the high test pressure, the 10 CFR Part 50, Appendix J, Type C leak criteria on these valves may be challenging. However, there are only eight primary nozzle penetrations in a CNV, each penetration protected by a pair of 2-inch valves; thus, testing should be able to meet Appendix J and ASME OM Code criteria.

Testing will be in accordance with ASME OM Code, Section ISTC-5140.

III. Secondary System Containment Isolation Valves

MSIVs, bypass valves, and FWIVs are normally exempt from Appendix J leak testing for PWRs. However, in the NuScale design, MSIVs and FWIVs close to form the DHRS boundary. This creates an ASME BPV Code Class 2 closed-loop, outside containment that is connected to an ASME BPV Code Class 1 and 2 closed-loop, inside containment.

The MSIVs, bypass valves, FWIVs, and their backup valves all have specific leakage criteria to maintain DHRS operability.

Testing will be in accordance with ASME OM Code, Section ISTC-5140.

IV. Main Steam Safety Valves

The NuScale NPM does not utilize main steam safety valves. Instead, the piping from the RPV to the MSIVs and FWIVs is ASME BPV Code Class 2 and is rated at RCS design pressure and temperature. The DHRS piping, which branches from inside the MSIVs and FWIVs, is ASME BPV Code Class 2 and is rated at RCS design pressure and temperature. This further simplifies the NuScale IST program requirements and refueling outage planning.

V. NuScale Unique IST Program Aspects

The NuScale design includes the following:

- small (2-inch) primary containment isolation valves of identical design (16 per NPM)

- secondary containment isolation valves of similar design and similar to the primary containment isolation valves (4 per NPM).

- limited number of check valves (4 per NPM); all are the same-sized nozzle check design

The NuScale design **does not** include:

- pumps
- dynamic restraints
- motor-operated valves

- main steam safety valves
- pressure isolation valves
- manual valves
- explosively activated valves

Conclusion

The NuScale 12 NPM plant plans for six refueling outages per year. A typical IST program for a 12-unit plant may challenge both test personnel and an outage schedule.

The safe, simple design of the NuScale plant resulted in an NPM that can safely shut down and self-cool with no operator action, no ac or dc power, and with no additional water for all design-basis events. The plant has far fewer components than a traditional light-water reactor, no pumps, and no dynamic restraints. The majority of valves are of identical or similar design, and all valves are accessible.

If it can be shown to meet the OM Code requirements and be cost effective, some PST may be performed at the factory. Risk-informed IST can be applied very effectively to the NuScale design. When sufficient performance history is obtained by the NuScale fleet, a new risk-informed IST plan should be submitted.

The IST burden for NuScale will be substantially less than the current nuclear fleet, and further savings can be gained by applying risk-informed concepts in the future after sufficient plant performance data have been obtained. This type of IST program is essential for NuScale to successfully meet the requirements to provide a safer, simpler, and more cost-effective nuclear option.

References

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V. *U.S. Code of Federal Regulations*, “Domestic Licensing of Production and Utilization Facilities,” Part 50, Chapter I, Title 10, “Energy.”
VI. ASME *Boiler and Pressure Vessel Code*, Section III, “Rules for Construction of Nuclear Power Plant Components, Division 1,” New York, NY.

Table 1. Valves in the NuScale IST Program

Type	Groups	OM Code Section	Valves / (number of valves)
Power-operated relief valves	2	ISTC-5110	ECCS reactor vent valves (3) ECCS reactor recirculation valves (2)
Active pneumatic-operated valves	4	ISTC-5130 Mandatory App III	CVCS boron dilution isolation valves (2) Feedwater regulating valves (2) Backup MSIVs (2) Backup MSIV bypass (2)
Active hydraulically operated valves	5	ISTC-5140	Primary systems containment isolation valves (16) FWIVs (2) MSIVs (2) MSIV bypass (2) Decay heat removal system actuation valves (4)
Check valves	2	ISTC-5220 Mandatory App II	Feedwater isolation check valves (2) Feedwater isolation backup check valves (2)
Safety and relief valves	2	ISTC-5240 Mandatory App I	Reactor safety valves (2) SG thermal relief valves (2)
Totals	15		47 total valves per NPM

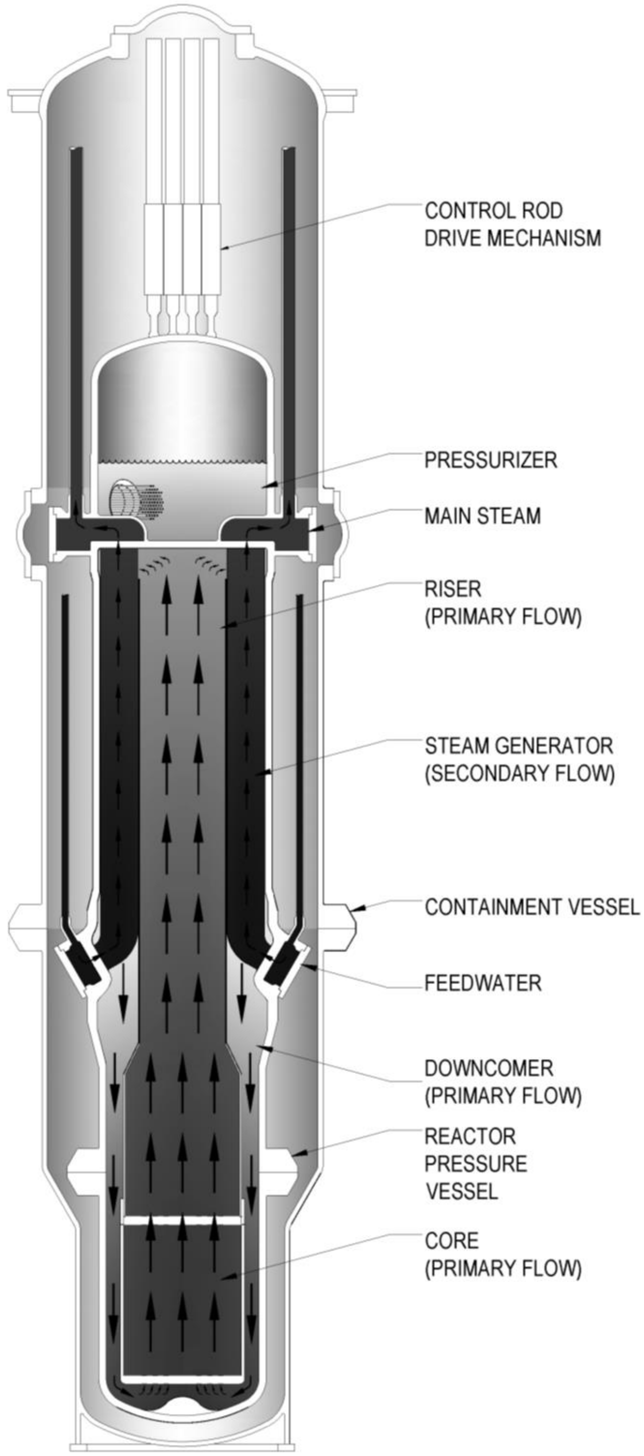

Figure 1. Cutaway View of NuScale Power Module

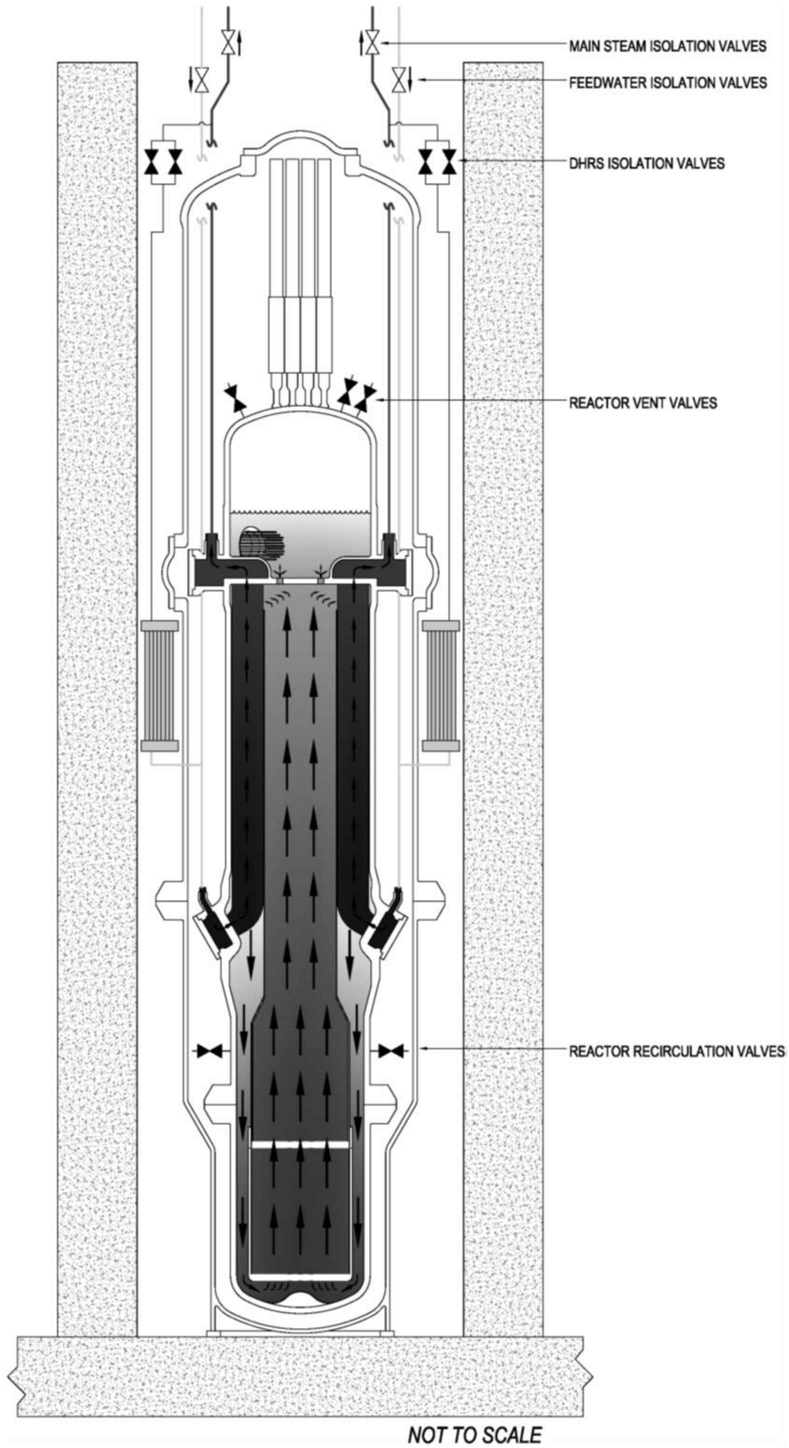

Figure 2. Steam Generator and Reactor Flow

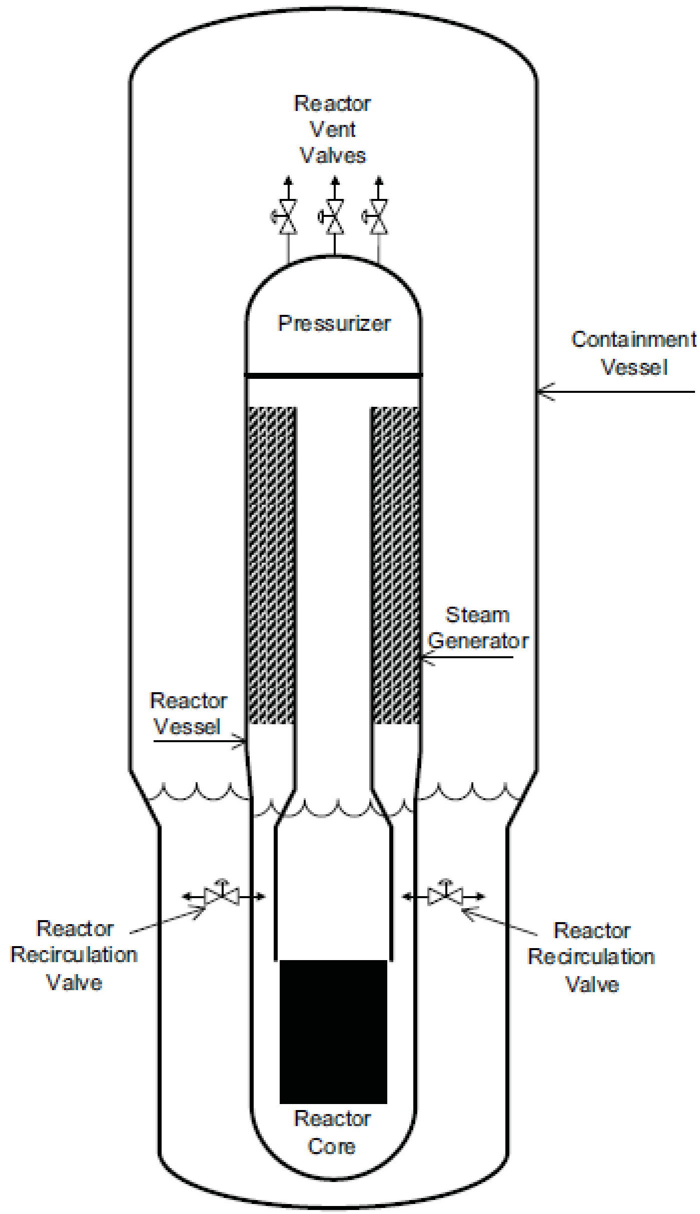

Figure 3. Emergency Core Cooling System Operation

Curtiss-Wright Advanced NozzleCheck Valves for Generation III+ Nuclear Power Plants

Haykaz Mkrtchyan,[1] Ararat Torosyan,[2] and Tsolag Apelian[3]
[1,2,3] Curtiss-Wright Nuclear, Enertech, 2950 E. Birch St., Brea, CA 92821
haykazm@curtisswright.com[1]
atorosyan@curtisswright.com[2]
tapelian@curtisswright.com[3]

Abstract

Curtiss-Wright introduced the first Normally Open NozzleCheck valves to the nuclear power industry nearly 20 years ago. This passive valve design was developed to address reoccurring maintenance and reliability issues often experienced by various check valve types because of low-flow conditions. Specifically, premature wear on the hinge pins, bushings, and severe seat impact damage had been discovered in several applications while the systems were in steady-state operating conditions.

Over the last two decades, Curtiss-Wright has continued to improve the design of the valve, with the latest generation coming most recently in support of the Westinghouse AP1000 design and similar Generation III+ passive reactor requirements. This entirely new valve is designed with minimal stroke, ensuring quick closure under specified reverse-flow conditions that no other check valve design could support. Additionally, features such as first-in-kind test ports, visual inspection points, and the ability to stroke the valve manually or with system fluid in line have resolved many of the shortcomings of previous inline welded flow check valves.

Most importantly, advanced test-based methodologies and models developed by Curtiss-Wright allow for accurate prediction of NozzleCheck valve performance. This paper presents the development of Curtiss-Wright's advanced Normally Open NozzleCheck Valve for Generation III and Generation III+ nuclear reactor designs. The valve performance was initially determined by using verified and validated computational fluid dynamic (CFD) methods. The results obtained from the CFD model were then compared to the data gathered from a prototype valve that was built and tested to confirm the performance predictions. Curtiss-Wright has fully tested and qualified the Normally Open NozzleCheck valve, which is specifically designed for applications that require a high capacity in the forward flow direction and a closure at low flow rates with short stroke to minimize the hydraulic impact on the system.

1. Introduction

Generation III+ nuclear power plant designs utilize a diverse group of safety systems to achieve a passive cooling and safe shutdown unique to the nuclear industry. The Passive Core Cooling System (PXS) is one of the key safety-related systems that provides a safe shutdown function. The PXS relies on a system of redundant methods to ensure that the critical components are maintained within safe limits during plant shutdown operations, and that the methods rely on the ability of valves to align the appropriate systems at the required times. To ensure that these valves are operational when required, an inservice testing program, defined by the American Society of Mechanical Engineers (ASME) Operation and Maintenance Code (OM Code), is used to continually monitor and verify the integrity and operability of these safety-related valves.

One of the safety-related functions performed by the PXS involves the use of nozzle check valves to provide coolant to the core from core makeup tanks (CMTs). The nozzle check valves are specified to be open during normal operation such that no flow is required to open the valves. The valves are required to close to prevent reverse flow from the safety injection tank, which would bypass the reactor vessel in the event of a loss-of-coolant accident (LOCA). The ASME OM Code requires that these check valves be tested with flow such that the valve disc normally maintains the full open position; upon reversed flow, the valve disc travels to the seat (closes).

The nozzle check valve discussed in this paper is 8 inches (DN200). One of the design requirements for this check valve was to verify operability with flow using only the maintenance water source available in the installation location. The available pressure and flow limited the use of other check valve designs in this application.

This paper provides a qualification summary for Curtiss-Wright's nozzle check valves that were qualified in compliance with the ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants."

2. System Description

The AP1000 pressurized-water reactor design uses passive safety systems to enhance the safety of the plant. See Figure 1. The system requires no operator action to mitigate design-basis accidents. The AP1000 system safety injection system utilizes three sources to make up the reactor coolant system (RCS) water. One of the sources is the CMT, which provides water at the same pressure as the RCS. The CMTs can be used to mitigate small LOCA events. The CMT provides coolant makeup and allows time for the RCS to depressurize to in-containment refueling water storage tank (IRWST) pressure level.

Another source of accident mitigation is provided by the safety injection accumulators, which are tanks containing borated water with a nitrogen blanket pressurized at 4.9 megapascals (MPa).

These are used to supply coolant flow to the reactor at a high flow rate for approximately 6 minutes in order to prevent mitigate LOCA events.

The third water supply source is the IRWST, which is a large stainless-steel tank located below the operating deck. The tank contains approximately 2,233 cubic meters of borated water to be used as a low-pressure makeup supply and heat sink.

The normally open NozzleCheck valves are installed between the high-pressure safety injection accumulator and the IRWST to prevent high-pressure water from flowing into the unpressurized IRWST when the safety injection accumulator is supplying water into the reactor.

3. Curtiss-Wright—Normally Open NozzleCheck Valve Design Concept

NozzleCheck valves are self-actuated valves that rely on the flow forces to overcome an inline spring and either close or open the valve depending on the check valve configuration. The four main components of the NozzleCheck valve are the body, the diffuser, the disc, and the spring. The valve body, the spring, and the diffuser are stationary components, while the disc is the moving component that seats against the body (to close the valve).

Curtiss-Wright's Normally Open NozzleCheck valve has the spring configured such that at its default state (failed position), the spring force maintains the valve in the fully open position. During an accident, the reverse flow in the pipe acting on the back side of the disc through the diffuser penetrations closes the valve. Figures 2 and 3 of this paper show the valve at its open and closed state, respectively.

When the valve is closed (Figure 3), the fluid backpressure maintains the disc closed. Upon relieving the backpressure, the spring force returns the disc back against the diffuser and opens the valve (Figure 2).

The design requirements also specified this particular valve to close at approximately 20 percent of the minimum required reverse flow rate because of limitations of onsite maintenance water supply. In order to accommodate this requirement, the valve diffuser was redesigned to include jet flowpaths to accelerate the water supply from the test port shown in Figure 4 of this paper, and create sufficient jet impingement force behind the disc to overcome the spring and close the valve. Figure 4 shows CFD study results used for preliminary sizing of the jet ports. The fluid travels farther down the port and enters diffuser channels, where it is equally divided into three flowpaths. At this stage, the accelerated fluid imparts on the back side of the disc and forces the disc to close.

NozzleCheck valve design has a significant advantage over other types of check valves used in the nuclear industry. Primarily, whenever there is a pipe break in the system, the instantaneous pressure drop forces rapid reversal in a fluid flow direction. Check valves are designed to close in such events and prevent further depressurization of the system. However, upon closure, traditional check valve designs, such as swing check valves, generate a significant pressure rise (water hammer) in the system because of the long-duration closing action (disc rotating about the pivot point). Pressure rise is proportional to the square of velocity in the pipe. The NozzleCheck valve design features a much shorter stroke and is capable of closing, at minimal, fluid velocity. Curtiss-Wright's NozzleCheck valve's short stroke, fast response time, and small disc mass allow rapid valve closure and prevent flow velocity increase in the line, and greatly reduce the hydrodynamic impact on the system.

4. Qualification Program

In order to demonstrate that the valve can perform its safety-related function during and after the specified plant accident conditions, Curtiss-Wright developed a qualification program in accordance with ASME QME-1-2007. Due to the criticality of the valve, the entire qualification program was thoroughly reviewed and witnessed by the customer and the U.S. Nuclear Regulatory Commission (NRC).

Curtiss-Wright developed a qualification plan to define the ranges of test pressures, temperatures, and flow requirements for the valve along with the acceptance criteria for each step of the qualification. Parameter ranges established the validation domain for the valve, which consisted of critical dimensions, sealing capability limits, and detailed sensitivity analysis for each of the critical parameters.

The qualification program consisted of the following steps:

- initial critical dimensional inspection
- baseline test
- sealing capability
- intermediate inspection
- end loading qualification
- seismic qualification
- functional qualification
- opening (forward flow)
- closing (reverse flow)
- intermediate inspection
- LOCA test for design-basis event (DBE) accident condition
- final critical dimensional inspection

4.1. Development and Validation of Test-Based Analytical Methodologies

As a part of the qualification program, Curtiss-Wright developed and validated several analytical test-based methodologies that can be used to qualify similar nozzle check valves within the validation domain. A set of broader qualification efforts involved testing nozzle check valves between nominal pipe size (NPS) 25.4 and 203.2 millimeter (mm) (1 and 8 inch). Flow performance characteristics obtained from CFD models were successfully verified and validated against the test results.

The rest of this paper summarizes each step of the qualification program in more detail. For the functional qualification portion, the CFD model prediction will be compared and correlated to test results.

4.2. Critical Dimensional Inspection

After receiving parts from the vendors, each part was inspected with calibrated and controlled equipment for acceptance, as outlined in the qualification procedure. In addition to the initial inspection, parts went through intermediate inspections after functional and seat leakage tests to confirm that the critical dimensions did not change significantly to impair the valve's performance. All functional critical dimensions were found to be within the design allowable limits.

4.3. Baseline Test

In order to be able to determine potential degradation in the valve performance characteristics, baseline tests were performed to collect diagnostic data (e.g., spring force, seat leakage, friction, surface conditions) to use for comparison during later stages of the qualification. Data collected from the parent valve baseline tests also established acceptance basis for conducting diagnostic tests on the production valve assemblies.

4.4. Sealing Capability

The sealing capability of the qualified parent valve assembly was verified by manually closing the valve and subjecting the disc to the specified differential pressure in accordance with the American National Standards Institute B16.34, "Valves - Flanged and Buttwelding End," standard. The sealing test was performed twice, once before the design basis flow tests and once after. This was done to confirm that the disc impact loads against the body seating surface did not adversely impact sealing capability of the valve.

4.5. End Loading Qualification

ASME QME-1-2007 requires that the valves are qualified for end loading induced by the connected piping. The normally open check valve qualified by Curtiss-Wright is classified as a Category A valve, as defined by the QME-1 standard. The standard defines Category A valves to be those that are required "to isolate flow under conditions associated with pipe rupture within the pipeline in which they are located." It further allows qualification of the end loadings to be performed analytically to determine the maximum loads (forces and moments) that can be imposed on the valve body without adversely affecting its performance.

Curtiss-Wright performed several finite element analysis studies to assess the valve performance based on stresses and deflections of the valve body resulting from pipe loads. The results indicated that in an event of excessive loads generated by the piping, the attached pipes will fail before degrading the performance of the valve.

4.6. Seismic Qualification

For valves without extended top works, such as self-actuated check valves, the QME-1 standard does not require seismic evaluation by testing. Curtiss-Wright's NozzleCheck valve's body has a simple cylindrical shape without any extended top works; therefore, seismic qualification was performed through analysis by calculating stresses and deflections of the valve body under the specified seismic accelerations under each plant operating condition.

4.7. Valve Qualification for Forward Flow

The valve was specified to have a minimum flow capacity in the forward flow direction. It was also required to open and remain open without any flow in the normal direction (i.e., normally open nozzle check valve). In order to verify the valve's ability to meet its performance requirements, the valve was first tested in the Utah Water Research Laboratory (UWRL). Several flow rates were tested and averaged. The measured pressure drops and flow rates at different points were used to determine the valve flow coefficient.

Since the acceptance criteria were given in equivalent pipe length to pipe diameter ratio (L/D), the valve flow coefficient, C_v, value was converted to an equivalent L/D value and then compared to the maximum specified L/D in the subject valve data sheet. Using Crane 410 to calculate valve resistance in terms of equivalent pipe lengths—

$$\frac{L}{D} = \frac{890.3d^4}{Cv^2 f} \tag{1}$$

Where:

f = 0.015 pipe friction factor based on the internal diameter of the 203.2-mm (8-inch) Schedule 160 pipe

d = 173.0 mm (6.81 inch), 8-inch Schedule 160 pipe internal diameter

The calculated L/D was 20 percent below the maximum specified L/D; therefore, the results were considered acceptable with adequate margin.

4.7.1. Computational Fluid Dynamics Model and Validation

Before building and testing the prototype valve, several CFD studies were performed and the results suggested that the key performance parameters (e.g., C_v, disc position, minimum flow required to close) of the valve are satisfactory. After the flow tests, the CFD models were verified and validated for normally open and normally closed nozzle check valves from 2-inch (DN50) NPS to 8-inch (DN200) NPS. Such validation domain was defined based on several other QME-1 tests on nozzle check valves between sizes 2-inch (DN50) and 8-inch (DN200) NPS. The difference between expected test values and predicted CFD values is presented in Figure 5 of this paper. As shown in the results, the CFD models used for predicting flow capacities of the valve have less than 2-percent error. In addition, Figure 5 shows how the increase in reverse flow rate overcomes the spring force to close the valve.

4.8. Valve Qualification for Reverse Flow

In order to verify the valve's capability to close under the specified maximum reverse flow rate, after completing the forward flow tests, the valve orientation was reversed and it was installed in the same test loop in the reverse direction with approximately 20 pipe diameters of straight pipe upstream of the valve to ensure uniform inlet flow conditions. Reverse flow rate was increased gradually until the valve closed. This test sequence was repeated three times and the results were averaged. The average reverse flow rate at which the valve closed was approximately 20 percent below the maximum specified value; therefore, the test results were considered acceptable with adequate margin.

4.8.1. Qualification for Closing During Loss-of-Coolant Accident

This portion of the QME-1 qualification test was intended to prove that the valve will perform under the expected differential pressures across the disc during a simulated plant operating conditions from a rapid flow reversal (pipe break). The valve was required to maintain its operability and have no significant structural damage during this DBE.

Following the inspections performed after the tests at UWRL, the valve was installed in a test loop designed to simulate an accident condition in the power plant, where the valve experiences an instantaneous pressure drop from a double-ended, guillotine-type pipe break. The normally open NozzleCheck valve was installed horizontally in the test fixture. In order to simulate an instantaneous pressure drop across the valve, rupture discs were installed immediately downstream of the valve. Schedule 160 pipe was connected to the valve inlet and the entire system was slowly pressurized until the set pressures were reached and the rupture discs burst. System pressurization was achieved through a pressurized nitrogen blanket on top of the water column in the pipe (as shown in Figure 6 below).

In order to compensate for the nitrogen pressure loss from expansion during closure, the rupture discs were selected to have set pressures above minimum required values. A pressure-relief valve was installed upstream of the valve to protect the system against over pressurization. Pressure transducers were installed upstream of the valve and connected to a data acquisition system to collect pressure versus time plots during and after valve closure. Following the valve closure, the system was depressurized until the spring force on the disc was able to overcome the backpressure and open the valve. Following the testing, the valve was disassembled and inspected for damage.

The following plots show the pressure transient upstream of the valve after the valve is closed.

It was successfully demonstrated that in an event of a LOCA, the valve is able to close and isolate the system to prevent further loss of coolant. Subsequent critical dimensional inspections revealed no signs of valve internal surface degradations. This test concluded the QME-1 qualification of the Curtiss-Wright NozzleCheck valve for an application in PXS of Generation III+ commercial nuclear power plants.

5. Conclusions

Inspection of Critical Dimension

Critical dimensions were inspected using calibrated equipment. All the measured and recorded dimensions were within the Curtiss-Wright allowable design tolerances for the critical dimensions. No significant changes were noted in the critical dimensions after functional and seat leakage tests.

Sealing Capability

The sealing capability of the valve was verified successfully to meet the specified requirements. In addition, since the critical dimensions did not change after the high-pressure, reverse-flow test, the high-energy impact on the disc on the body did not render the valve vulnerable to failure to perform its safety function under the DBE conditions.

Qualification for Forward Flow

This particular nozzle check valve design featured a normally open configuration; the QME-1 requirement of demonstrating check valve position versus flow rate was not applicable. The valve flow coefficient (C_v) was determined by plotting flow rate versus square root of the measured pressure drop. The slope of the line is considered the value for the C_v. Since the customer-specified acceptance criteria define the valve resistance in terms of equivalent pipe length (L/D), the C_v value was converted into L/D using Crane 410 equations. It was assumed that the pipe friction factor, *f*, was equal to 0.015 (corresponding to the friction factor of the 8-inch Schedule 160 pipe).

There was no disc chatter observed during the test throughout the entire range of flow rates. This is critical because chattering can degrade the guide surfaces and, therefore, adversely affect the valve’s dynamic characteristics over time and can progressively and appreciably render the valve vulnerable to failure to perform its safety function.

Qualification for Closure under Reverse Flow

The performance of the valve under reverse flow was tested at UWRL to determine its capability to close and isolate against the maximum specified reverse flow and differential pressure.

The second part of the test was conducted at Curtiss-Wright in Brea, CA, where the valve was subjected to a high-pressure, reverse-flow test under the most adverse postulated DBE, where the valve is subject to an anticipated pressure drop resulting from a double guillotine pipe break during a LOCA event. Before pressurizing the test loop, the test loop was filled with water to the desired level. During the test, the actual maximum pressure drop established across the valve before closure was conservatively set to approximately 20 percent higher than the maximum specified upstream pressure. The valve was required to close and remain closed after the event. In addition, after the safety injection tank completely discharged into the reactor vessel, the valve was expected to reopen upon relieving the back pressure from the disc without any flow through the pipe. The transients shown in Figures 7 and 8 are from the pressure wave reflecting inside the test loop.

After verifying that the valve was closed, nitrogen pressure was relieved. The volume of water that passed through the valve during closure was determined by comparing the water column heights before and after close.

In order to allow the valve to reopen, the disc back pressure was lowered by draining the water from the upstream side. As a result, the disc reopened when the differential pressure dropped below 0.034 bar (0.5 psig). This was consistent with the opening differential pressure measurements obtained from the factory acceptance tests and the reverse flow test conducted at UWRL.

Acknowledgments

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Figures and Tables

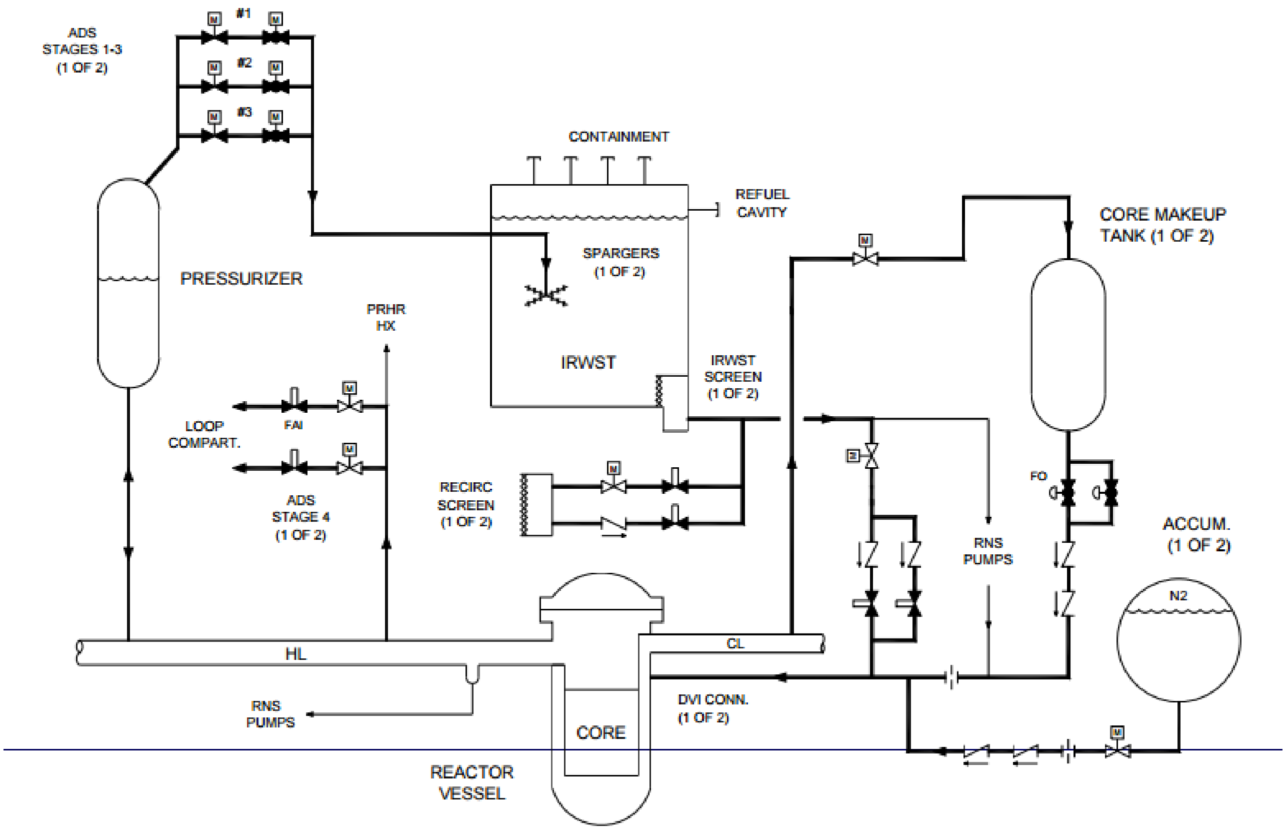

Figure 1. AP1000 Passive Core Cooling System (Source: AP1000 2011)
(Source: Author)

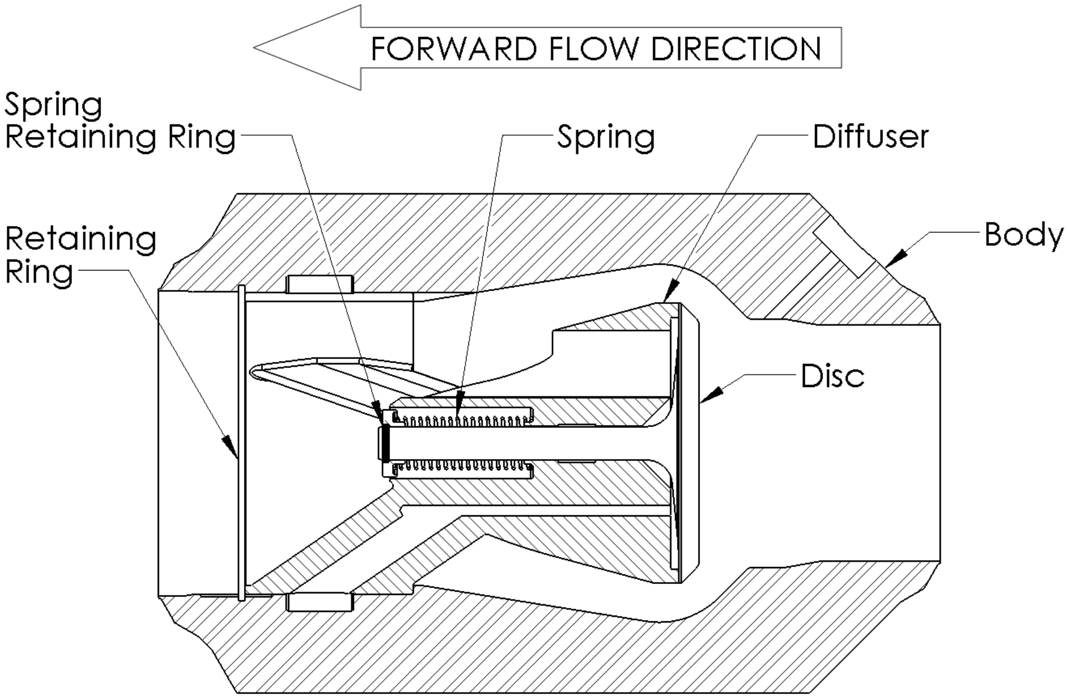

Figure 2. Normally Open NozzleCheck Valve—Open
(Source: Author)

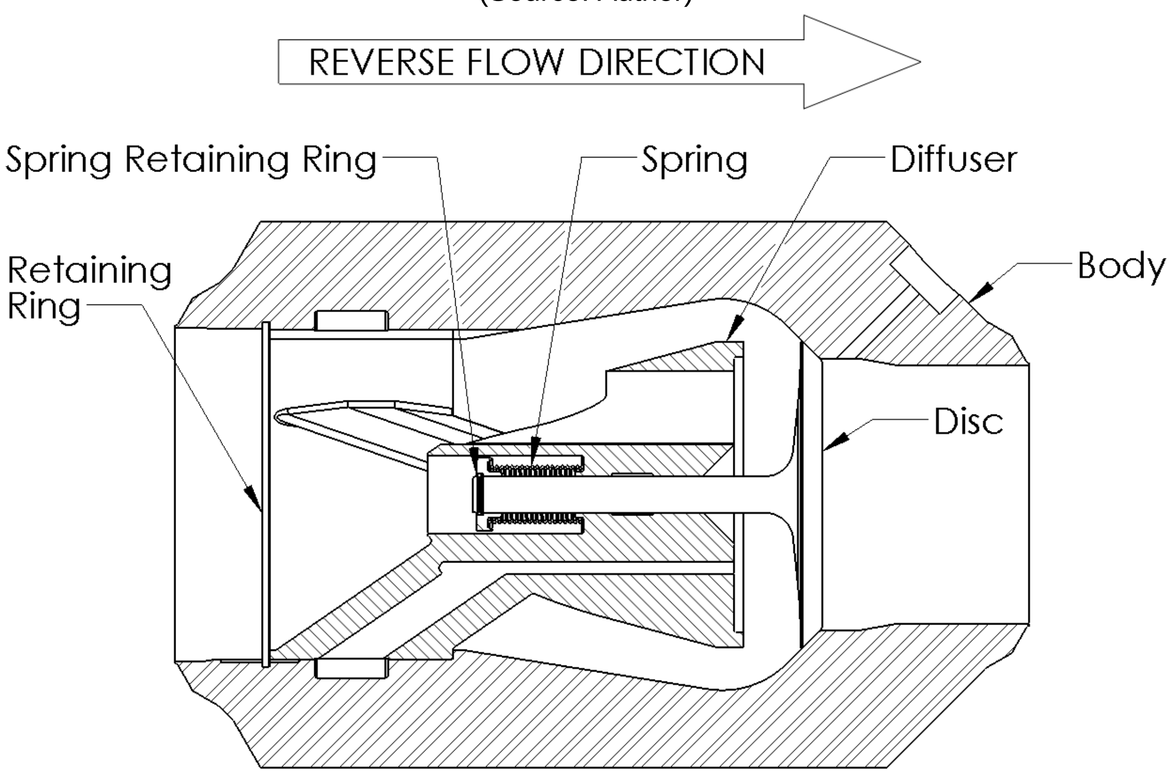

Figure 3. Normally Open NozzleCheck Valve—Closed
(Source: Author)

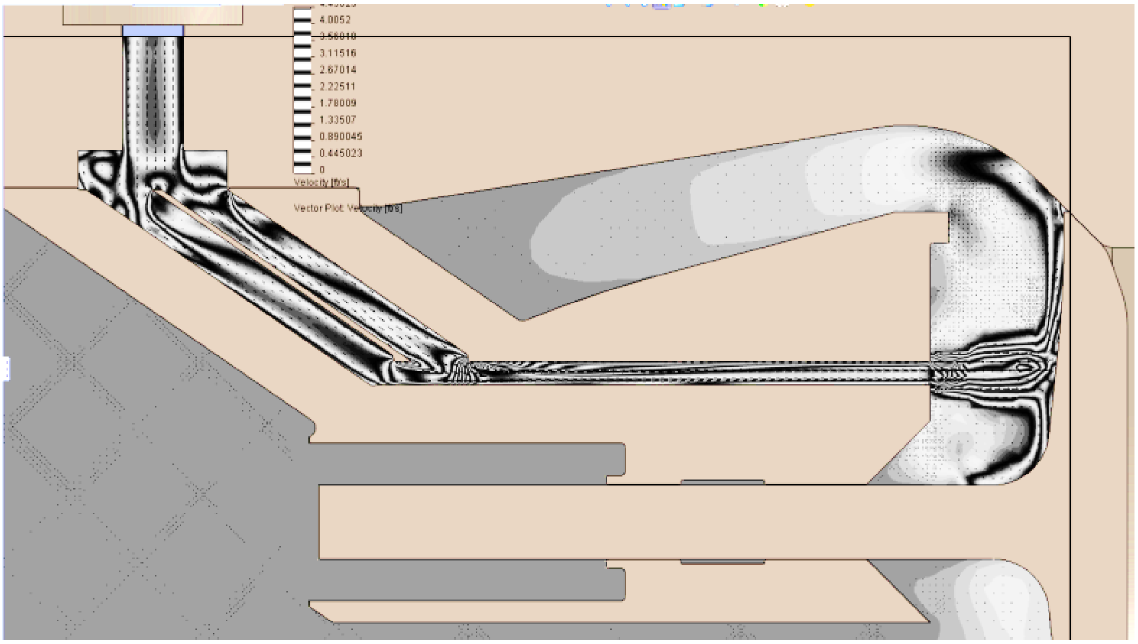

Figure 4. CFD Results from Diffuser Jet Impingement on the Disc
(Source: Author)

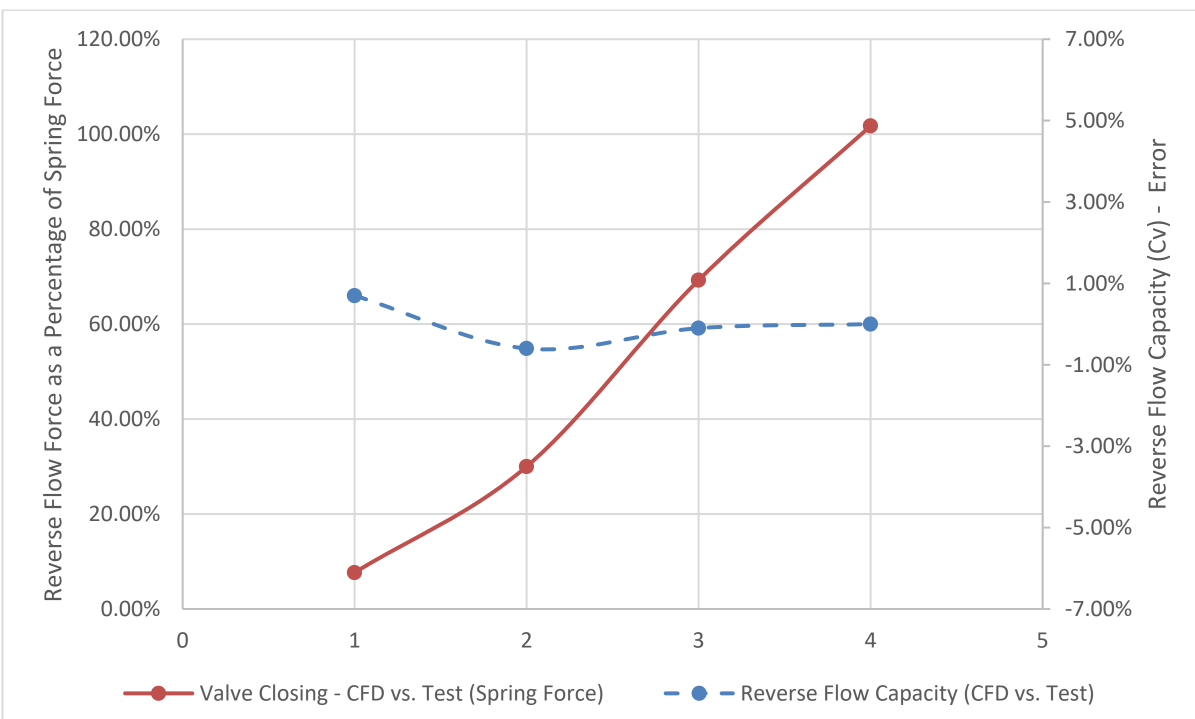

Figure 5. CFD Model Validation Summary
(Source: Author)

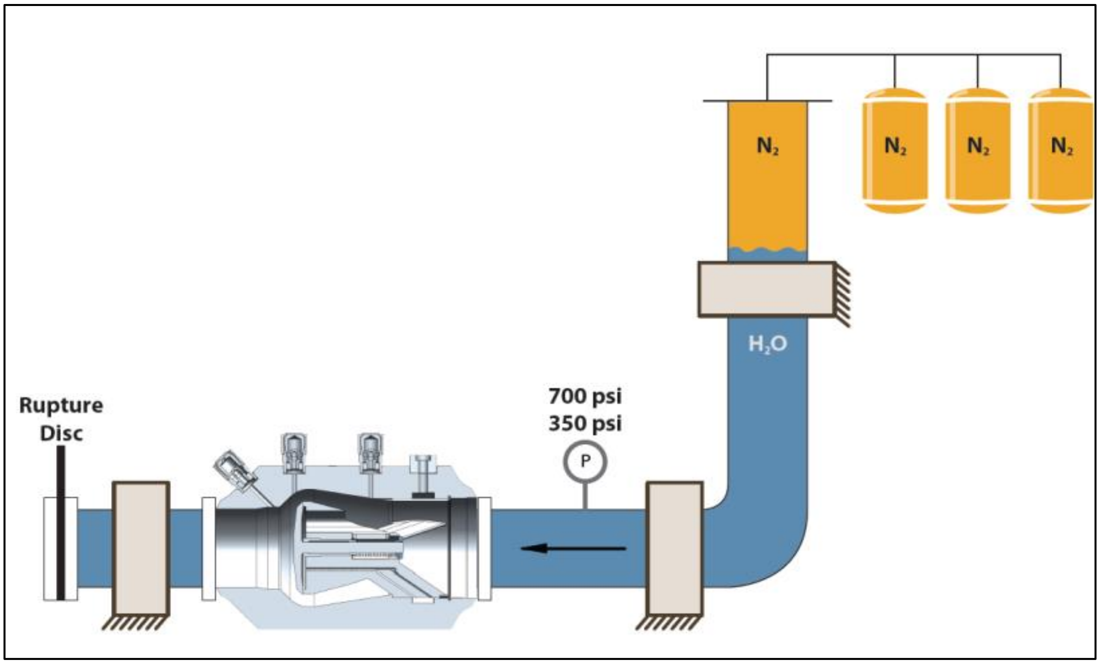

Figure 6. LOCA Test Setup
(Source: Author)

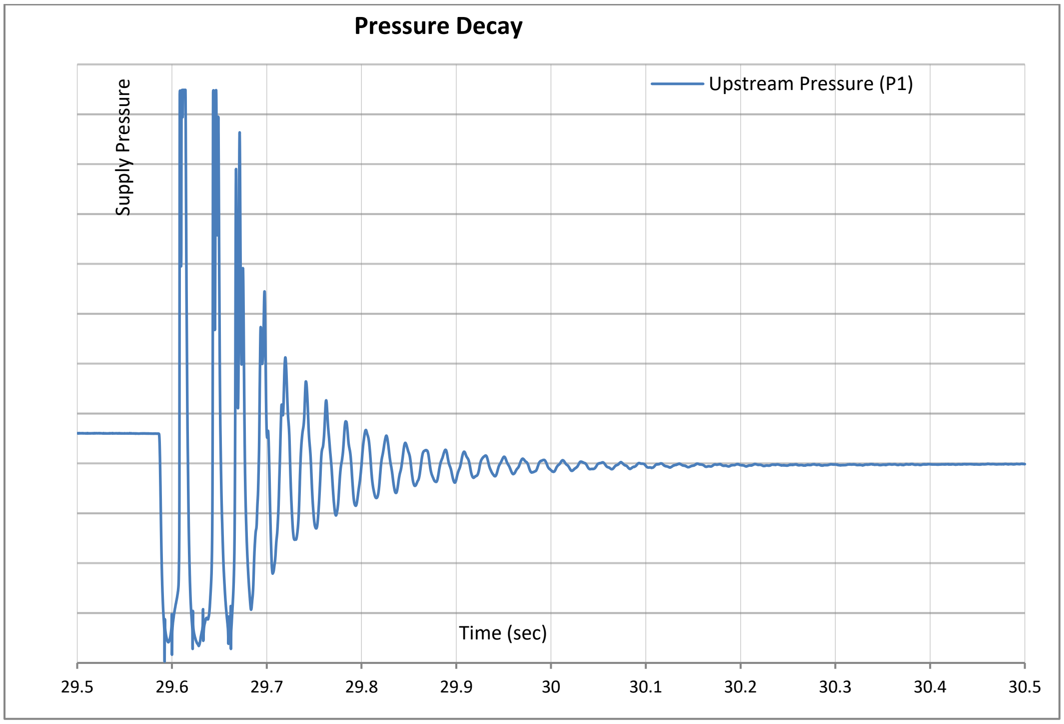

Figure 7. Low-Differential Pressure Transient
(Source: Author)

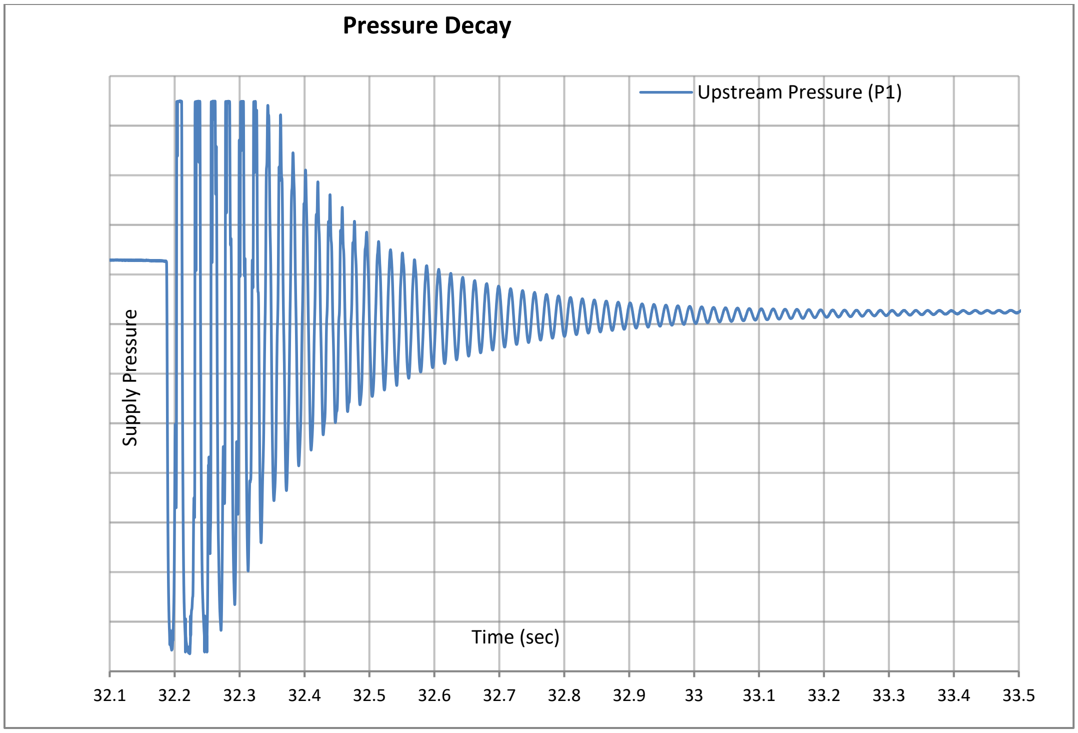

Figure 8. High-Differential Pressure Transient
(Source: Author)

ASME OM Code Implementation Lessons Learned for the *AP1000*® Plant

Augustine A. Cardillo
Westinghouse Electric Company, LLC
Cranberry Twp., PA, USA

Natalie M. Rodgers
Westinghouse Electric Company, LLC
Cranberry Twp., PA, USA

Abstract

The Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants," process and unique aspects of a passive plant design have presented new challenges for the development and implementation of the American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code) requirements. This paper discusses lessons learned from the development and implementation of preservice testing (PST) and inservice testing (IST) program plans for the *AP1000*®[30] plant, for both international and domestic. Topics addressed include the following:

- level of detail in design certification
- treatment of unique passive plant features
- design certification commitments beyond OM Code requirements
- future regulatory requirements for high-risk, nonsafety-component PST and IST
- implementation challenges for international plants

Introduction

The development and implementation of PST and IST requirements for new reactors such as the Westinghouse *AP1000* plant have posed unique challenges because of the 10 CFR Part 52 licensing process, passive plant design features, and the evolution of regulatory requirements between the time of design certification and plant operation. These challenges include complications from excessive detail in the design certification, questions regarding the treatment of unique passive plant features, implementation issues from licensing commitments that are not in alignment with the ASME OM Code[31], and uncertainty involving future PST and IST requirements for certain nonsafety components (i.e., regulatory treatment of nonsafety systems

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30 *AP1000* is a trademark or registered trademark in the United States of Westinghouse Electric Company LLC, its subsidiaries, and/or its affiliates. This mark may also be used and/or registered in other countries throughout the world. All rights reserved. Unauthorized use is strictly prohibited. Other names may be trademarks of their respective owners.

31 Note that although the *AP1000* design control document (DCD) references the 1995 Edition and 1996 Addenda of the ASME OM Code, this paper references the 2001 Edition through 2003 Addenda, which is the Code version being used for a current PST/IST requirement update effort.

(RTNSS)). Additional challenges with implementation have been encountered for international plants because of differing regulatory frameworks and limited owner experience.

Acronyms and Abbreviations

ADS	automatic depressurization system
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
CFR	*Code of Federal Regulations*
CMT	core makeup tank
COL	combined license (per 10 CFR Part 52)
CVS	chemical and volume control system
DCD	design control document
DVI	direct vessel injection
HVAC	heating, ventilation, and air conditioning
IRWST	in-containment refueling water storage tank
IST	inservice testing
LOCA	loss-of-coolant accident
LWR	light-water reactor
MOV	motor-operated valve
OM Code	*Code for Operation and Maintenance of Nuclear Power Plants*
POV	power-operated valve
PRHR	passive residual heat removal
PST	preservice testing
PWR	pressurized-water reactor
RCS	reactor coolant system
RTNSS	regulatory treatment of nonsafety systems
SSCs	systems, structures, and components

AP1000 Plant Overview

The *AP1000* plant differs from legacy (Generation II) pressurized-water reactors (PWRs) in its use of passive safety features. The plant does not require alternating current power or pumps to provide motive force in order to shut down the reactor, establish and maintain safe shutdown, or mitigate the consequences of an accident, for a design-basis time period of 72 hours.

Instead, processes such as gravity injection and natural circulation are utilized, along with one-time realignment of fail-safe or direct current-powered valves.

Key passive safety features for the *AP1000* plant include passive residual heat removal (PRHR), passive high-pressure safety injection using core makeup tanks (CMTs) and accumulators, passive containment cooling, passive low-pressure safety injection from a large in-containment refueling water storage tank (IRWST), passive containment recirculation, automatic depressurization system (ADS) valves (to passively transition from high-pressure to low-pressure injection sources), passive spent fuel pool cooling (accomplished by boiling), and passive main control room habitability.

Although safe shutdown and accident mitigation can be accomplished using the passive safety systems alone, the plant also includes active systems typical of legacy PWRs; these active systems are nonsafety related and provide defense-in-depth functions that can prevent actuation of the passive safety features. Key defense-in-depth systems include startup feedwater, which provides the first line of defense for PRHR; chemical and volume control system (CVS) makeup, which provides defense in depth for CMT injection; and spent fuel pool cooling pumps and heat exchangers, which provide the first line of defense for passive spent fuel pool cooling via boiling.

A conceptual figure of the *AP1000* plant reactor coolant system (RCS) and its PRHR and safety injection features is shown in Figure 1 of this paper. The RCS is a two-loop, four-pump system with two seal-less canned-motor pumps attached directly to the cold leg channel heads in each of the two steam generators. The PRHR heat exchanger is submerged in the IRWST and cools water drawn from the hot leg and returns it to the steam generator cold leg plenum through natural circulation. The two CMTs have inlet lines that branch off the cold legs and inject into the reactor vessel through direct vessel injection (DVI) lines, also through natural circulation. Two accumulators also inject into the DVI lines, driven by pressurized nitrogen.

During extended PRHR operation, the water in the IRWST heats up and eventually boils, with steam exiting the enclosed tank through covered vents that open at specified differential pressures. The steam condenses on the inside of the containment vessel shell (which is cooled externally by passive gravity water flow and evaporation), and the majority of the condensate is returned to the IRWST through a network of downspouts and collection boxes.

In the event of a loss-of-coolant accident (LOCA), the CMT liquid level drops because of inventory loss, and it becomes necessary to depressurize the RCS through the ADS. The ADS consists of four stages of valves: three stages (each with two trains) connected to the pressurizer steam space for controlled depressurization and one stage connected to the hot leg (with two trains on each hot leg). After the fourth ADS stage actuates, gravity injection from the IRWST through the DVI lines begins. Once the IRWST inventory starts to deplete, the final means of injection is by containment recirculation from the containment sump. The water source transition automatically actuates based on the previous source’s depletion.

Level of Detail in Design Certification

As explained in U.S. Nuclear Regulatory Commission (NRC) Regulatory Issue Summary (RIS) 2012-08, Revision 1, "Developing Inservice Testing and Inservice Inspection Programs Under 10 CFR Part 52," dated July 17, 2013, a design control document (DCD) submitted for design certification applications as part of the 10 CFR Part 52 licensing process is expected to include "general descriptions" of inservice inspection and IST programs to provide a "foundation for the plant-specific operational programs" and to ensure "accessibility for performance of IST activities."

With the intent of capturing the testing provisions envisioned by plant designers for future use, the *AP1000* plant DCD specified extensive PST and IST requirement details, including not only specific tests, but also testing frequencies and justifications for deferral of testing to cold shutdown or refueling outages. This information was not intended to constitute a PST or IST program plan, which is the responsibility of the combined license (COL) licensee. While beneficial in promoting the understanding of the plant designers' intent, the excessive detail on PST and IST in the DCD obfuscates the scope division between the design center and the COL licensee for these site-specific operational programs. As indicated by RIS 2012-08, the true design center responsibility is to provide a foundation for the plant-specific program and ensure that components are accessible for testing. However, inclusion of excessive test requirement details in the DCD has led to the presumption of design center ownership for those details. As a result, the burden of resolving PST and IST requirement issues (such as those discussed in the remainder of this paper) has largely fallen to the design center.

Another negative impact of including excessive detail regarding PST and IST in the DCD is the limitation of flexibility for the licensee to use optional methodologies. Examples include DCD commitments to perform quarterly check-valve exercising and to perform motor-operated valve (MOV) stroke-time testing in conjunction with exercise testing. These commitments preclude the options of check-valve condition monitoring, in accordance with Appendix II of the OM Code and the allowance to not perform stroke-time testing for MOVs, in accordance with Code Case OMN-1 [2] or Appendix III in later OM Code editions.

Furthermore, the extensive detail in the *AP1000* plant DCD regarding PST and IST requirements has resulted in impacts to the DCD from the effort of developing and refining the PST and IST program plans. This causes the process of PST and IST program development to be more onerous.

The lesson learned from these challenges is that less detail regarding specific PST and IST methods and frequencies in new plant DCDs would likely be beneficial for both the design center and licensees. In alignment with RIS 2012-08, the focus of the DCD should be providing a foundation for the unit-specific program and ensuring accessibility and designed-in capabilities for testing.

Treatment of Unique Passive Plant Features

As explained in the initial overview, among the key passive *AP1000* plant components are the PRHR heat exchanger and the IRWST, together which provide (non-LOCA) core cooling for design-basis events. The PRHR heat exchanger consists of vertical C-shaped tubes submerged in the IRWST and cools incoming water from the RCS hot leg, returning this cooled water to the steam generator cold leg plenum through natural circulation. The IRWST itself is a large, stainless-steel-lined enclosure formed by concrete and structural steel wall modules within containment.

As discussed previously, extended PRHR operation causes the water in the IRWST to heat up and eventually boil, with steam exiting this enclosed tank through covered vents that open at specified differential pressures. The steam condenses on the inside of the containment vessel shell, and most of the condensate is returned to the IRWST.

The IRWST steam vent covers, along with overflow covers and vacuum relief vent covers that protect IRWST structural integrity, pose unique questions and challenges for PST and IST. Although they perform safety-related functions, these components are hinged metal plates attached to structural walls and do not fall within the scope of ASME *Boiler and Pressure Vessel Code* (BPV Code), Section III, requirements. The *AP1000* plant DCD did not list these devices as requiring PST or IST because of their structural nature, although the need to test them periodically to confirm their ability to perform their design functions was included in applicable design documentation.

However, upon further review and consideration of the scope criteria in the OM Code, Section ISTA-1100, it became apparent that the IRWST steam vent, overflow, and vacuum relief vent covers meet the criterion of “pressure relief devices that protect systems or portions of systems” that perform functions to shut down the reactor to safe shutdown, maintain safe shutdown, or mitigate the consequences of an accident. Since these devices function to prevent excessive internal or external differential pressure that could challenge the integrity of the IRWST, they are providing a pressure-relief function for a portion of a system credited for safe shutdown and accident mitigation. Although the IRWST vent and overflow covers are not ASME BPV Code, Section III, Class 1, 2, or 3 because of their structural nature, they are designated as Quality Group C; therefore, regulatory and industry precedent indicate that they must be considered for inclusion in the PST or IST program based on the OM Code criteria.

The assessment of the IRWST vent and overflow covers for inclusion in the PST and IST program led to questioning whether other structural devices credited for safe shutdown and accident mitigation functions should also have PST and IST requirements. The *AP1000* design credits blowout panels that open to prevent room pressure and temperature conditions from damaging structures or exceeding equipment qualification limits from pipe breaks or spent fuel pool boiling. Also credited are flood louvers and panels that open to prevent flooding of areas with safety-related equipment. Like the IRWST vent and overflow covers, these structural components do not fall within the scope of ASME BPV Code, Section III, requirements but are designated as Quality Group C. An example of a louvered structural device used for such types of applications is shown in Figure 2 of this paper.

Historically, blowout panels that prevent room pressurization have not been included in PST or IST programs, but flood devices do not have a readily apparent precedent for inclusion in or exclusion from PST and IST. Although their functions are similar to those of the blowout panels, the flood devices more directly protect system components, since without their actuation, safety-related components (e.g., active power-operated valves (POVs)) would be submerged and likely fail. However, the flood louvers and panels would fit the criteria of ISTA-1100 only if they are considered to be pressure-relief devices, which is not strictly the case, since they protect components from flooding as opposed to overpressure.

Complicating matters further is the issue that the OM Code testing requirements are not written with the intent of addressing structural-relief devices, such as those used in the *AP1000* design. Identifying which sections of the OM Code apply is challenging enough since, although the scope criteria in ISTA-1100 and applicability statement in ISTC-1100 appear to refer to “pressure relief devices” in general, the only non-valve devices specifically addressed within Subsection ISTC and Appendix I to the OM Code are non-reclosing pressure-relief devices (i.e., rupture disks). Following the pressure relief and vacuum relief valve requirements in Appendix I to the OM Code initially seems logical; however, method requirements in Appendix I dictate that testing must be performed with fluid flow (e.g., I-8110, I-8120, and I-8130).

Alternatively, a structural-relief device could be treated as an OM Code Category C check valve. Applying the philosophy of Note 4 of Table ISTC-3500-1 would suggest that the structural-relief devices should be tested as check valves since they are not capacity certified. In fact, the check-valve periodic exercising requirements in ISTC-3522 and ISTC-5220 are feasible to apply to the structural devices (employing the allowance for using a mechanical exerciser in accordance with ISTC-5221(b)), although the quarterly testing frequency requirement imposes more burden than the Appendix I frequencies for relief device testing.

Based on these challenges, it is apparent that clarification of OM Code requirements as they apply to structural pressure and flood-relief devices would be prudent. There is a clear need to perform appropriate testing and inspection for passive plant structural devices, such as the *AP1000* IRWST vent and overflow covers and flood-relief devices to ensure their ability to perform their safety-related functions is maintained. However, force-fitting such components to meet testing requirements to which they were not intended to apply is not only a challenge for initial program development but is likely to cause further questioning and confusion in the future.

Design Certification Commitments beyond Operation and Maintenance of Nuclear Power Plants Code Requirements

Another challenge faced in the development of the *AP1000* plant PST and IST requirements is the implementation of commitments in the DCD that are beyond the requirements of the OM Code. Some of these commitments were included because of regulator concerns related to unique *AP1000* plant features, while others were based on industry operating experience as it was understood at the time.

One feature that was of concern to the NRC in the evaluation of the AP600 plant—the predecessor to the *AP1000* plant—was the reliance on check valves to open at very low differential pressures for low-pressure injection and containment recirculation. This is the case for swing check valves located in gravity injection lines from the IRWST (described in the preceding section) to the reactor vessel, and in containment recirculation lines that connect to the IRWST gravity injection lines. These flowpaths—first IRWST injection and then containment recirculation—provide long-term, low-pressure safety injection after high-pressure safety injection sources have been exhausted and the RCS is depressurized.

The initial concern from the NRC was in large part because of the significant reverse differential pressure to which the check valves would be subjected during normal operation—RCS pressure at the valve outlet and only gravity head from the IRWST at the valve inlet. This, along with other factors, was thought to increase the risk of the valves sticking closed and failing to open at the low-forward differential pressure. As a result, the requirement to test the check valve differential pressure required to initiate flow was introduced. Subsequent design changes added explosively actuated (squib) isolation valves between these check valves and the RCS, thus resulting in no normal operating reverse differential pressure across the check valves, but the cracking pressure test requirement was not removed.

The licensing commitment to test the cracking pressure of the IRWST injection and containment recirculation swing check valves has led to challenges because of the lack of applicable OM Code requirements or standard testing methods and concerns regarding repeatability. In particular, for the containment recirculation check valves, it is not feasible to perform the testing with fluid flow and, therefore, a mechanical exerciser must be inserted into the pipe to push the valve open. Ensuring accurate acceptance criteria in terms of force based on the required cracking differential pressure is challenging because of the influence of the location on the valve disk at which the force is applied. This also causes repeatability concerns in addition to the potential repeatability issues that exist in measuring valve-opening pressures of fractions of a pound per square inch.

Another unique *AP1000* plant feature that drove special PST and IST licensing commitments is the high-pressure, nonsafety-related CVS purification loop. The CVS purification loop is designed for RCS pressure; therefore, the valves that isolate it from the RCS are not considered to be RCS pressure-isolation valves in the plant technical specifications. However, beyond the third isolation valve from the RCS, the CVS purification loop piping and components—located entirely within the containment—are nonsafety-related since they are not relied upon to perform any safety-related functions. The valves that isolate the CVS from the RCS are active, safety-related MOVs and check valves, and because of their unique function of isolating nonsafety-related piping from the RCS pressure boundary, they are also specified with PST and IST leakage testing requirements.

Challenges with this licensing commitment stem from confusion regarding whether this leakage testing falls within the scope of the OM Code. At the time the DCD requirement was established, the testing was believed to be outside of OM Code scope, and leak-testing multiple valves as a group was thought to be acceptable. Further investigation has determined that since the valves have an established leakage limit related to their safety function, the valves meet the criteria for Category A in Subsection ISTC and must meet the applicable leak-testing requirements in accordance with Table ISTC-3500-1. Unfortunately, the requirement to leak-test each valve individually cannot be met without the addition of new test connections, thus driving the need for a physical design modification.

An additional licensing commitment unrelated to unique *AP1000* plant features has also resulted in challenges. The *AP1000* plant DCD commits to "operability testing" for all POVs. Although "operability test" is not a term defined or used in the OM Code, the DCD describes it as "diagnostic testing to verify the capability of the valves to perform their design basis safety functions" and refers to 10 CFR 50.55a(b)(3)(ii) for MOVs and the Joint Owners Group MOV Periodic Verification Program.

Although there is a clear framework for performing diagnostic testing for MOVs in Code Case OMN-1 (or Appendix III in later versions of the OM Code) and for air- and hydraulically operated valves in Code Case OMN-12, the DCD also imposes this requirement for solenoid-operated valves. The lack of diagnostic testing requirements or standard testing methods makes this licensing commitment for solenoid-operated valves infeasible to fulfill.

The primary lesson learned from these challenges is that the feasibility of implementing testing requirements should be more thoroughly understood by the design center before making licensing commitments. These challenges also reinforce the lesson discussed previously that less detail in DCDs related to PST and IST would likely be beneficial.

Future Preservice Testing and Inservice Testing Requirements for Regulatory Treatment of Nonsafety System Components

The awareness of the NRC's proposed rule change to require PST and IST for components that fall within the scope of RTNSS, without the details of the expected implementation of this requirement being fully understood, has also posed challenges for the development of the *AP1000* plant PST and IST requirements.

Because of concerns related to the significant departure from legacy (Generation II) light-water-reactor (LWR) design philosophy presented by advanced passive LWR designs, the NRC developed papers providing criteria for nonsafety systems, structures, and components (SSCs) that would require additional regulatory oversight because of their risk significance.

These RTNSS SSCs include those important to the probabilistic risk assessment, those used for onsite support for safety functions beyond 72 hours after an event, those relied on for anticipated transient without scram (ATWS) mitigation or station blackout, those needed for severe accident containment performance, and those relied on to prevent adverse system interactions. For the *AP1000* plant, certain nonsafety, defense-in-depth SSCs fall within the scope of RTNSS, but most do not as they do not meet the criteria. The *AP1000* plant RTNSS components are addressed in Section 16.3 of the DCD, which defines short-term availability controls, similar in format to technical specifications, for these SSCs. Like technical specifications, the short-term availability controls define plant modes when each component should be operable, actions to be taken if a component is not operable, and surveillance requirements that prescribe periodic testing.

In a proposed rule change documented in the *Federal Register*, the NRC proposed to add Section 50.55a(b)(3)(iii)(D) to require licensees for new (post-2000) reactors to “establish a program to assess the operational readiness of pumps, valves, and dynamic restraints” that fall within the scope of RTNSS, with the proposed rule itself using the term “high risk non-safety systems.”

As this proposed rule change is expected to come to fruition in the near future, its implementation is being considered in the development of the *AP1000* unit-specific PST programs. However, uncertainty in the intended scope of the rule change has made it difficult to determine the population of components to which it will apply. The expected scope is strictly those components that meet RTNSS criteria; however, it is currently unclear whether other defense-in-depth components may need to be included, which would significantly expand the scope. As the reliability of non-RTNSS defense-in-depth components is much less significant to plant core damage frequency than those identified as RTNSS, there does not appear to be a solid basis for such a scope expansion.

Another uncertainty in accounting for the expected rule change is the rigor of the testing that is expected for high-risk nonsafety components. An ASME OM Code task team from the Subcommittee on New Reactors is currently developing a standard for this testing, but the requirements to be included in this standard have not yet been finalized. Implementing test methodology in accordance with the OM Code would be conservative; however, it is undesirable to impose unnecessarily burdensome requirements on nonsafety components.

More clarity is needed in the near future regarding the scope and rigor of PST and IST for RTNSS components to support the development of new plant PST programs. It is expected and recommended that the scope be restricted to components that meet the RTNSS criteria previously defined by the NRC, and that the testing requirements be less rigorous than those for safety-related components, consistent with the philosophy of treating SSCs commensurate with their importance to safety.

International Implementation Challenges

Implementation of the ASME OM Code internationally also presents unique challenges. For the *AP1000* plant, the development and implementation of PST and IST programs in China have presented difficulties because of the different regulatory framework along with the lack of plant owner experience with the OM Code.

In China, there are not regulatory requirements similar to 10 CFR 50.55a, “Codes and standards,” in the United States. The Chinese regulations do not clearly define permissible OM Code years and addenda for use or provide limitations or means for seeking relief from or alternatives to OM Code requirements. The process for regulatory review of PST and IST programs is also not clearly defined. This has led to confusion regarding what is permitted and what is not.

Further challenges arise from the plant owner’s inexperience and lack of understanding of the use and implementation of the OM Code. For the China *AP1000* plants, the plant owner has primary ownership of the PST and IST programs; however, the owner has expected the design center to answer questions and provide guidance on OM Code implementation, which is outside design center scope.

The owner’s lack of experience has brought about gaps in understanding regarding how to apply certain testing methodologies, such as Appendix I for pressure-relief devices and Appendix II for check-valve condition monitoring. In addition, the owner has limited capabilities for implementing these OM Code methodologies.

As discussed in the preceding paragraphs, the use of the OM Code internationally has brought on several challenges. China has formed an ASME international working group (CIWG) for ASME BPV Code, Section III, and Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” and, just recently, the OM Code. However, because of its limited experience base, the CIWG relies on the ASME to provide guidance on the application of OM Code requirements.

Conclusions

Implementation of the ASME OM Code for the *AP1000* plants has provided lessons learned for design centers as well as insights regarding the need for clarity in OM Code and regulatory requirements.

Lessons learned for design centers include the benefit of including less detail regarding specific PST and IST methods and frequencies in new plant DCDs, in alignment with RIS 2012-08. Also, the feasibility of implementing IST-related licensing commitments in DCDs should be fully understood before making such commitments.

It is recommended that clarifications be made to the OM Code regarding the applicability of OM Code requirements to structural-, pressure-, and flood-relief devices that perform safety-related functions. There is a clear need to perform appropriate testing of such devices, but the current OM Code requirements are not written with the intent of addressing them.

Additional clarity is also needed in the near future regarding the scope and rigor of PST and IST for RTNSS components to support the development of new plant PST programs. Defining the scope in alignment with the RTNSS criteria previously defined by the NRC and the rigor of testing consistent with the philosophy of treating SSCs commensurate with their importance to safety are recommended.

Internationally, developing the experience base of ASME international working groups as well as international personnel on the application of the OM Code should be beneficial to all parties involved.

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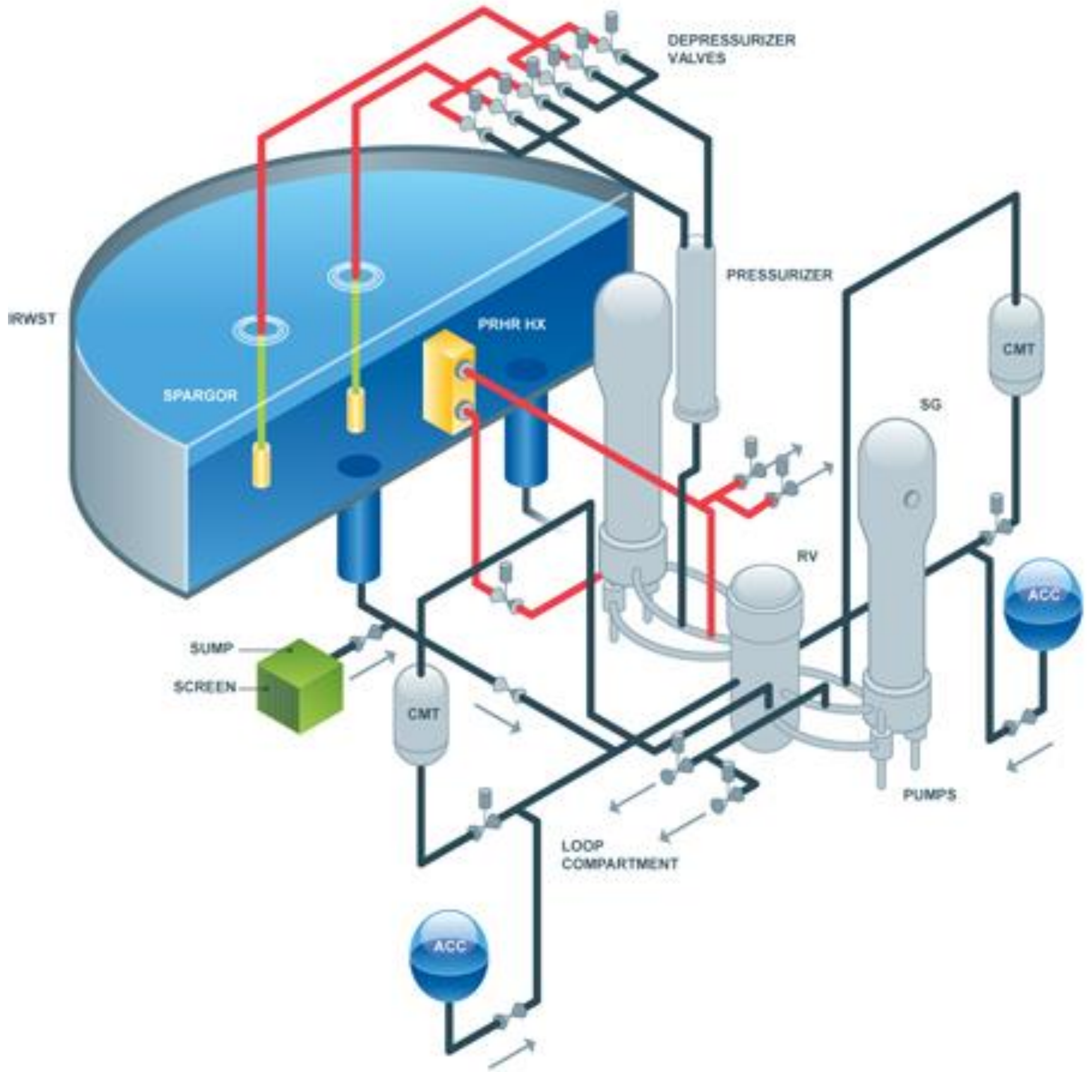

Figure 1. ***AP1000*** **Plant Conceptual Diagram**
(Source: Author)

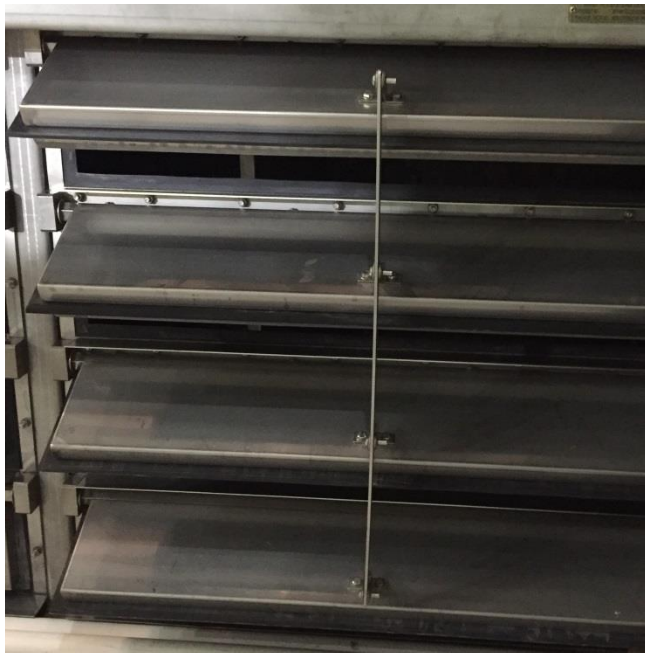

Figure 2. Louvered Structural Device Example
(Source: Author)

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The 2017 Symposium on Valves, Pumps, and Inservice Testing for operating and new reactors, jointly sponsored by the American Society of Mechanical Engineers and the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic, and regulatory issues associated with inservice testing programs at nuclear power plants, including the design, operation and testing of valves, pumps, and dynamic restraints. The symposium provides an opportunity to discuss improvements in design, operation, and testing of valves, pumps, and dynamic restraints that help to ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives on the improvement of testing programs and methods for valves and pumps at nuclear power plants.

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