

Proceedings of the Fifteenth NRC/ASME OM Code Symposium

Held at the Bethesda North Marriott Hotel
Bethesda, MD
July 28-30, 2025

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American Society of Mechanical Engineers
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Abstract

The 2025 15th ASME/NRC OM Code Symposium, jointly sponsored by the American Society of Mechanical Engineers (ASME) and the U.S. Nuclear Regulatory Commission (NRC), provided a forum for exchanging information relative to the ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) on technical, programmatic, and regulatory issues associated with inservice testing programs at current nuclear power plants and planned for new and advanced reactors. The symposium provided an opportunity to discuss improvements in design, operation, and testing of valves, pumps, and dynamic restraints and components that perform similar functions at new and advanced reactors. The participation of industry representatives, regulatory personnel, and consultants ensured the presentation of a broad spectrum of ideas and perspectives on improving the inservice testing programs at current nuclear power plants and planned for new and advanced reactors. The slide presentations are publicly available at NRC Agencywide Documents Access and Management System Accession No. ML26023A052, ML26028A102, ML26033A253, ML26040A100, and ML26055A163.

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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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Mark Gowin

Tennessee Valley Authority

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Keynote Address

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Good morning and thank you for the opportunity to speak with such a distinguished group of engineers, innovators, and dedicated public servants. It is truly a privilege to be here today to discuss the exciting future of the U.S. nuclear energy industry and the essential role that inservice testing continues to play in meeting the energy needs of our great Nation.

In the past, keynote speeches at these symposia have rightly focused on the NRC's evolving regulatory responsibilities, the central importance of inservice testing to plant safety and public confidence, and the technical excellence that underpins our industry.

While all of that remains just as relevant today, I'd like to begin this symposium by zooming out to offer a broader perspective—one that reflects the energy challenges and opportunities now facing the United States.

It's clear that we are at a pivotal moment—one shaped by climate change, threats to grid reliability, a growing demand for energy independence, and a pace of innovation that continues to accelerate. These forces are converging in powerful ways, and they are prompting renewed interest, urgency, and investment in nuclear energy. Once again, nuclear is stepping forward as a cornerstone of America's energy strategy.

So, where do we stand today?

The United States remains the world's largest producer of nuclear power, with 94 reactors currently in operation. But we also recognize that the fleet is aging. And while nuclear power continues to deliver reliable, carbon-free electricity, new construction has—until recently—been relatively limited.

That is beginning to change.

Across the country, we're seeing renewed momentum for advanced nuclear technologies. The successful commercial operation of Vogtle Units 3 and 4—the first new reactors built in the U.S. in more than three decades—has marked a turning point, demonstrating what is possible when industry, government, and communities work together.

Plants that previously shut down due to poor economic conditions are returning to operation and just last week, the NRC authorized the restart of the Palisades Nuclear Plant in Michigan, the first ever regulatory approval to restart a commercial facility that had ceased operations.

In addition, there is growing interest and investment in small modular reactors and other next-generation designs that offer enhanced safety, flexibility, and the potential for widespread deployment.

These new developments signal a bright and dynamic future for nuclear generation in the United States—one that will rely on the continued excellence and vigilance of the inservice testing community to ensure that safety systems remain safe, resilient, and trusted.

What's driving this renewed momentum?

First and foremost, there's a recognition that nuclear must be part of our clean energy future. From the halls of Congress to the current Presidential Administration, there is strong bipartisan support for advanced nuclear deployment.

We've seen that reflected in landmark legislation such as the ADVANCE Act which passed last year with broad bipartisan support, further demonstrating Washington's commitment to modernizing our nuclear regulatory framework and accelerating the deployment of next-generation reactors.

This momentum has only accelerated in the last 6 months with President Trump issuing executive orders to unleash American energy and begin reforming our nuclear infrastructure—recognizing that energy independence and innovation go hand in hand.

There's a clear message from Washington: nuclear energy isn't just relevant—it's essential.

Key to making this vision a reality is the work underway at the NRC. We are undergoing a significant transformation, modernizing our licensing framework to accommodate the new generation of advanced reactors—many of which are smaller, safer, and more flexible than traditional light-water designs.

The NRC is also strengthening coordination with other federal agencies—including the Department of Energy, the Department of Defense, and the National Laboratories. This “whole-of-government” approach is critical as it ensures that technical review, policy development, national security considerations, and commercial deployment are all pulling in the same direction.

The NRC's work on risk-informed, performance-based regulation is particularly important. It recognizes that advanced reactor technologies require a different regulatory approach than their predecessors, one that balances safety with the need for innovation and speed to market.

The need for new, reliable, low-carbon power is only growing. Demand is being driven by electrification across every sector—transportation, industry, data centers, and more. As we transition to a cleaner grid, intermittent renewables will need strong baseload partners. Nuclear, with its round-the-clock reliability and zero emissions, is uniquely positioned to provide that stability.

Of course, we're not blind to the challenges. Capital costs, supply chain constraints, workforce gaps, and public perception remain hurdles. But every challenge presents an opportunity—for engineers like you to lead, to innovate, and to build....

Which brings us to the role of ASME's OM Code in the evolving nuclear landscape.

Inservice Testing has long been a pillar of safety assurance. But let me be clear: it's not just about compliance checkboxes. IST is an engineering-based activity rooted in performance and reliability. It remains a core element of the NRC's safety mission across the full lifecycle of nuclear facilities.

As we look toward the future, IST is not staying static. It's adapting — thoughtfully and rigorously — to meet the demands of next-generation reactors, digital modernization, and evolving risk-informed approaches.

Let me walk through a few important developments that reflect this forward momentum.

First, we must be ready to develop IST programs that are ready for advanced reactor designs. New concepts like small modular reactors and non-light water technologies are pushing the envelope, and this innovation is driving the need for tailored, yet consistent, regulatory frameworks.

ASME's development of new IST standards like OM-2 for advanced reactors is a major step forward. These efforts help ensure that even as designs evolve, we retain a common foundation of safety and operational readiness. We're developing the necessary guidance to support this shift, and we see it as a clear signal of where the industry is heading.

Second, we're seeing continued integration between component qualification and long-term reliability. Historically, we've had strong frameworks for equipment qualification. Now, the emphasis is on connecting that front-end assurance to the realities of long-term operation — especially in new reactor designs. ASME's work to align these areas through QME-1 is important, and the NRC is adapting our guidance to reflect that importance.

Third, digital technology is reshaping how we approach testing. Modern diagnostic tools — especially for valves and pumps — are giving operators more precise, more timely information. These aren't experimental anymore.

They're proven tools, already changing how IST is implemented, and how performance is monitored between test intervals. Digital diagnostics are no longer emerging — they're essential as they support smarter, more efficient testing strategies — helping reduce unnecessary wear and cost without compromising assurance.

Another shift is the move toward longer testing intervals, where appropriate. Modern IST programs are increasingly data-driven and performance-based. As a result, there's growing confidence — both among licensees and regulators — that we can safely extend test intervals for certain components. This evolution which is making its way into newer versions of the OM Code reflect the maturity of current programs and the quality of today's engineering analysis.

Looking even further ahead, we're preparing for the surveillance challenges that will come with new technologies. Advanced reactors will introduce passive safety features, high-temperature materials, and real-time performance monitoring — all of which will challenge our traditional frameworks for testing and inspection. We're engaging early with industry and standards bodies to ensure that IST remains effective in this new environment, and that expectations are aligned with what these technologies can and should deliver. Our oversight must evolve as the technology does — and it is.

One unique area where IST is also playing a role is in plant restarts. As I mentioned in my opening, we are now seeing renewed interest in restarting facilities that were previously slated for decommissioning. These efforts bring a unique set of challenges — not least of which is reestablishing operational programs like IST that may have lapsed or been scaled down. This is not routine work. It takes careful planning and close coordination, and the NRC is fully engaged in supporting these efforts. Restarting a plant is a major undertaking — and IST is a critical part of getting it right.

All of these efforts are supported by a broader shift toward risk-informed, performance-based regulation. The tools are there — from flexible code options to updated regulatory pathways — and more importantly, we're seeing licensees use them with maturity and discipline. Flexibility in IST must be paired with engineering judgment — and we're seeing that in practice.

And finally, none of this happens without collaboration. The NRC's work with ASME — on advanced reactor standards, on code modernization, and on equipment qualification — is a model for how regulatory bodies and technical organizations can work together to advance safety while enabling innovation.

The NRC values this partnership deeply — and we rely on it to fulfil our important mission to the public. As we look to the future of nuclear energy which is more advanced, more digital, more resilient — the role of IST and the OM Code will change and we're committed to working with you to ensure those tools continue to serve their purpose: assuring safety through engineering rigor.

Let me close by saying that as a Nation, we have never shied away from bold challenges. More than half a century ago, we set our sights on the moon—not because it was easy, but because it was hard. The Apollo mission showed the world what American ingenuity, determination, and unity could achieve when we dared to dream big and act boldly.

Today, we face a different kind of challenge. Building a framework to support a modern, resilient, and safe nuclear infrastructure, and it is not just a policy goal—it's a national imperative. It's about securing our energy future, combating climate change, and preserving our global leadership in innovation. As the NRC's Executive Director for Operations rightly described, this is our moon shot.

And like the Apollo mission, it will take vision, courage, and commitment from all of us—across industry, government, and communities. But if history has taught us anything, it's that when

America sets its mind to something, we do more than reach the stars—we redefine what's possible. Let's rise to this moment—together, I know we can do it.

Thank you.

New Reactors I

Track Chair:
Augi Cardillo
NuScale Power

QME-1 and OM-2, a Code and a Standard for Reactor Facilities

Thomas Ruggiero

Professional Engineer, ASME Fellow, OM Standards Committee Member

The new era of commercial nuclear power, with all the advanced reactor designs, will require that nuclear codes and standards better accommodate the needs of the new designs. As the details of many of the new design concepts develop, codes and standards committees need to move ahead realizing that future revisions may be required as new system design concepts are introduced. The transition from a design code to construction to operation and inservice testing (IST) needs to flow more efficiently. Both the ASME QME-1 Standard, “Qualification of Mechanical Equipment Used in Nuclear Facilities,” (QME-1) and the OM-2 Code deal with components rather than entire systems.

The QME-1 Standard was developed as a result of U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.48. In general, QME-1 had not been used for any of the current nuclear power plants with a few exceptions (Vogtle Unit 3 and 4, and newer nuclear power plants in China). While information from QME-1 can be referred to by the current OM, it wasn’t as specific as it needed to be. As currently formatted, QME-1 has requirements in several different places and uses several appendices. The ASME OM Code requires data for IST baseline that could be supplemented by QME Test data.

The OM Code is, for the most part, directed at Light Water Reactor (LWR) plants. The code was written after most of the operating plants were built and operating. Because of this, and the desire to avoid major modifications, several accommodations were made. A few examples of this are:

- Pressurized Water Reactors (PWRs) had pumping systems that did not have full flow test loops, while Boiling Water Reactors (BWRs) did. Some test lines lacked valves that are designed to be throttled (e.g., gate valves).
- BWRs have Testable Check valves; PWRs do not.

Additionally, valve exercise testing intervals based on when the system can be made available for testing. Considering that the code allows certain high safety significant intervals to be extended while low safety significant components still needed to be tested quarterly, the technical logic seems a bit flawed. Additionally, baseline data are difficult to obtain in situ.

In both documents, but more so in the OM Code, the scope might include components other than ASME Code Class 1, 2 and 3, scoped in components with emergency power. There are a significant number of new small modular reactor (SMR) designs where the same scoping rules would not be possible. Added to this is the fact that both the QME-1 Standard and OM Code are component documents. The decision made is that the determination of those components that

are important to safety need not rest with the code writers. Instead, it should be with the plant designer and their regulator.

These new documents need to consider the differences between the currently operating plants and the new designs being developed. There is a multitude of designs that are significantly different than LWRs. Many existing power plants were designed without consideration of inservice testing. Terms like Safe Shutdown, Cold Shutdown, Important to Safety, Design Basis Accident might not even apply to newer facilities. Finally, the new reactors will be used for more than powering the electrical grid (e.g., process steam, hydrogen generation, district heating, powering ships, remote locations, and backup power).

It needs to be understood that (1) there is a qualification standard and a testing code; (2) a component can never be qualified for parameters that were not included within its design, and (3) IST cannot correct an incorrectly designed system or component.

Risk Informed efforts can be used to select components to be qualified and that require IST. Pump, valve, and dynamic restraint functions are irrespective of system functions.

As a prerequisite, the component's specification, installation and qualification must include all parameters that it must withstand, and the system and component design must include the provisions necessary for IST. It is recognized that a component qualification is the baseline for subsequent IST in the QME-1 Standard (implementation of the OM Code can use data obtained during qualification).

Conceptually, both the QME-1 Standard and OM-2 Code need to be written so that they can be used at any nuclear facility. It follows then that the selection of components will not be within QME-1 nor OM-2 because components requiring qualification will be determined during design/licensing, manufacture process, and components required to be in the IST program will have been qualified via QME-1 as determined during the licensing process. Both documents will consider the function of the component rather than the function of the system in which it is installed. The documents also will provide a method to develop a Qualification Program and IST Program if a component is not called a Pump, Valve, or Dynamic Restraint.

In the case of QME-1, the committee needed to determine whether it was more efficient to write a new standard or build a new one. Since QME-1 has not been used in most of the existing plants and it currently has no discussion of environmental requirements for metallics in high temperature applications. Additionally, remote actuators are not currently in QME-1. Finally, the current layout is very cumbersome with a good deal of overlap. The decision was to revise the current QME-1.

In the case of the OM Code, we find that Scoping Issues continue to arise specifically because the scope may need to include components that are not ASME Code Class 1, 2 or 3, and the fact that some new plants might not need emergency power. The current code has many accommodations for plants that do not have provisions to test components. Finally, revising the current OM Code for new reactors would make the document very complicated to use and be very inefficient for the new generation plants.

It was decided that a new IST code would be more efficient and logical.

There are prerequisites to use these new documents. The scope is determined during facility design and licensing; not by ASME. Mechanical components must be designed and appropriate for their function, and the component needs to be correctly specified and designed.

Additional prerequisites for the QME-1 Standard require a detailed qualification specification that clearly lays out all parameters that the component must be able to withstand as well as its operational limits. The qualification must include those parameters for subsequent inservice testing.

In the case of the OM-2 Code, the facility is designed to include provisions to perform IST (test loops, isolation valves etc.). Further, the systems and components are designed to be tested when required irrespective of plant mode. There must also be a method to ensure that the QME-1 qualification is maintained by the IST Program.

Some QME-1 revisions are:

Mechanical equipment and functions that need to be qualified per QME-1 are to be determined by the system designers and the regulator as a prerequisite to implementing QME-1

QME-1 has been modified to be easier to use, such as the following:

- QME-1 sections have been reordered into a logical format
- Cross references are minimized
- Requirements for each type of equipment are included within the section for each type
- No Appendices are included in the revised QME-1
- “Active” is removed from the title of the standard as well as its definition because the standard will apply to all mechanical equipment
- In general, the current qualification requirements did not change
- Requirements have been included for metallics, high temperature, and equipment with remote actuators

The QME-1 Standard is arranged into Parts and Sections. There are no appendices. There is a separate part for each type of mechanical equipment. The Qualification Specification requirements appear in the first Section of each Part. All of the appendices have been eliminated, and applicable requirements are moved into the Part for each type of mechanical equipment. The documentation requirements have been simplified. The standard is written in clear language with the avoidance of redefining of words and terms. All definitions are in a Glossary and a separate Reference Section is provided. There are clear descriptions rather than shorthand terms (if necessary, more words are used) and adjectives that have multiple definitions are avoided.

In the case of the OM-2 Code, the scope of components requiring IST are selected outside of the Code. OM-2 is written in logical format minimizing or removing cross referencing to other sections using clear language with no redefining of words and terms. There are clear descriptions rather than shorthand terms (if necessary, more words are used), and adjectives

that have multiple definitions are avoided. Terms such as “practical/practicable” or other similar interpretive phrases are eliminated. Provisions specify manufacturer input to establish IST frequency as well as links to QME-1 for maintaining component qualification.

The format of OM-2 is arranged as follows:

- General Requirements are limited to Program Requirements
- Each Component Type has a separate section that:
 - Is stand alone
 - Incorporates applicable portions of the current OM Code appendices (Condition Monitoring, etc.)
- Valve Leakage Testing is a stand-alone section
- Accommodations for plant operating mode are eliminated (if not able to full stroke, part stroke, etc., is not discussed in OM-2)
- All definitions provided in single section
- All references provided in a single section
- No appendices

In general, IST requirements in the OM-2 Code are the same as OM except that:

- Test intervals can be based on prior performance or as determined by the manufacturer of the component
- When a component needs to be tested, it must be tested irrespective of plant operational mode
- Increased use of condition monitoring
- Use of pump and valve groups eliminated
- Several legacy issues with terminology were eliminated (e.g., operable, practical, practicable)

The OM-2 Code is currently published and available. The QME-1 Standard has been approved and is expected to be published in late 2025.

General Requirements

**Track Chair:
Shawn Comstock
GSE Solutions**

ASME OM Code Conversion to OM-1 Code

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This presentation addressed the conversion of the 2022 Edition of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) into a simplified and reformatted ASME OM Code, which is commonly referred to as the draft OM-1 Code. In 2024, ASME issued the OM-2-2024 Code, *Component Testing Requirements at Nuclear Facilities*, for Inservice Testing (IST) Programs in new and advanced reactors. Subsequently, the ASME OM Committee directed that the 2022 Edition of the OM Code be revised using concepts and formats comparable to those used to prepare the OM-2-2024 Code. The ASME OM Committee also directed that the revised OM Code be redesignated as the OM-1 Code. The main purpose of this presentation was to describe how the requirements in the 2022 Edition of the OM Code will be addressed during the conversion process. This presentation highlighted the significant changes between the 2022 Edition of the ASME OM Code and the draft OM-1 Code.

Guide for Developing and Implementing an Inservice Testing Program

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Disclaimer: The views expressed in this guide do not necessarily reflect the views or policies of the Tennessee Valley Authority or Southern Nuclear Company. The views in this guide are based on the authors' personal experiences in performing IST Program interval updates.

Abstract

This paper describes how to develop and implement Inservice Testing (IST) Programs to comply with NRC regulations (10 CFR 50.55a), American Society of Mechanical Engineers (ASME) Operations and Maintenance (OM) Code requirements, and plant specific design criteria. It addresses the determination of IST Program scope, categorization of components, determining test frequencies, and optimization of the site-specific IST Program.

This includes development of requests for alternatives to or requests for relief from OM requirements to address situations when plant design or operating conditions are not conducive to compliance with OM requirements. In other cases, the implementor may identify alternative testing that provides an acceptable level of quality and safety, and request the NRC to authorize an alternative or to grant relief from OM requirements. The presentation will also address use of ASME OM Code Cases as a method to optimize IST Program implementation.

The paper provides some example cases that illustrate the complexity of determining IST program scope, categorization, and ensuring all test requirements are identified. In addition, it provides examples where use of OM Code Cases can reduce burden in the implementation of the IST Program.

The periodic interval update requirements are also addressed. This includes the OM interval update and the NRC Code of Record update.

1.0 Introduction

This guide provides recommended steps and actions to update an existing Inservice Testing (IST) Program and associated implementation documents to comply with a later edition of ASME Operation and Maintenance (OM) Code. It describes the regulatory requirements for updating the site-specific IST Program. The guide also includes recommendations for early preparation of the IST Program interval update, provides strategies to identify and manage differences between OM Code editions, and manage implementation of the OM Code changes into site specific implementation documents. For the purpose of this guide, the IST

Program interval update is complete when the revised IST Program is issued for use at the beginning of the next IST interval which includes the following attributes:

- Identification of applicable OM Code edition and site interval dates
- Specific plant information (name and address of Owner and plant, commercial service date, and name and number designation of the unit)
- List of components within scope of the IST Program
- Categorization of each component
- List of test requirements and frequency for each component
- Reference to deferred test justifications, requests for relief, requests for alternatives, and OM Code Cases to be used
- Cross-reference for each component test requirement to the implementing test procedure or document
- References to completed administrative procedures necessary for implementation of the IST Program (e.g., development of reference values and acceptance criteria) and associated sub-programs (e.g., snubbers, relief valves, check valve condition monitoring, motor-operated valves, and air-operated valves)
- Validation that each IST Program component test requirement has a procedure or document to ensure the required testing is performed at the required frequency.

The actions to develop an initial IST Program are essentially the same as provided in this guide, except this guide does not address development of the OM Code required Preservice Test (PST) Program or the transition between PST and IST Programs.

2.0 Requirement for Periodic Update of IST Programs

The United States (U.S.) Nuclear Regulatory Commission (NRC) promulgates regulatory requirements to develop, implement, and periodically update an IST Program in *Code of Federal Regulations* (CFR) Title 10, Chapter 50, Section 50.55a (10 CFR 50.55a). The 10 CFR 50.55a primary requirements for the IST Program are provided in 10 CFR 50.55a(f) with reference to other pertinent paragraphs as shown below. A graphical representation is also provided.

10 CFR 50.55a

(a) Documents approved for incorporation by reference

(1) American Society of Mechanical Engineers (ASME)

(iii)(H) ASME OM Code Case OMN-28

(iv) ASME Operation and Maintenance Code

(b) Use and conditions on the use of standards

(3) Conditions on ASME OM Code

(6) Conditions on ASME OM Code Cases

(f) Preservice and inservice testing requirements

- (1) Inservice testing requirements for older plants (pre-1971 CPs)
- (2) Design and accessibility requirements for performing inservice testing in plants with CPs issued between 1971 and 1974
- (3) Design and accessibility requirements for performing inservice testing in plants with CPs issued after 1974
- (4) Inservice testing standards requirement for operating plants
 - (i) Applicable IST Code: Initial code of record interval
 - (ii) Applicable IST Code: Successive code of record intervals
 - (iv) Applicable IST Code: Use of later Code editions and addenda
- (5) Requirements for updating IST program
 - (i) IST program update: Applicable IST Code editions and addenda
 - (ii) IST program update: Conflicting IST Code requirements with technical specifications
 - (iii) IST program update: Notification of impractical IST Code requirements
 - (iv) IST program update: Schedule for completing impracticality determinations
- (6) Requirements for updating IST program
 - (i) Impractical IST requirements: Granting of relief
 - (ii) Augmented IST requirements
- (7) Inservice testing reporting requirements

(y) Definitions

Code of record interval

Inservice examination and test (IST) code of record

Inservice examination and test (IST) interval

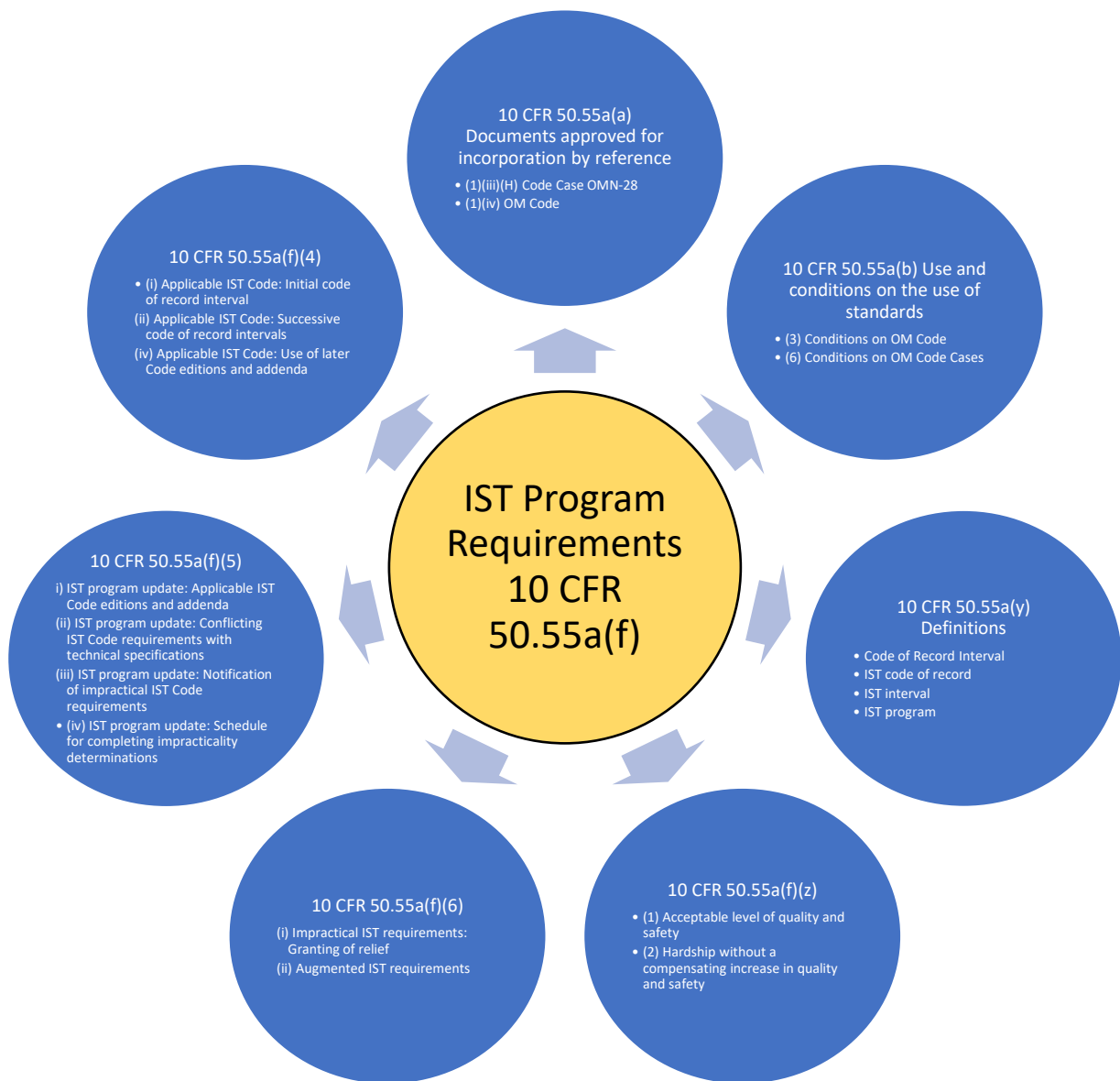
Inservice examination and test (IST) program

(z) Alternatives to codes and standards requirements

(1) Acceptable level of quality and safety

(2) Hardship without a compensating increase in quality and safety

Graphical Representation of 10 CFR 50.55a Requirements



[Editor's Note: 10 CFR 50.55a(f)(z) in the above circle should be 10 CFR 50.55a(z)]

3.0 Preparing for the IST Program Interval Update

The magnitude of work involved to complete an interval update is easily underestimated in both cost and person-hours. This guide provides information to better understand the scope of work involved and properly plan the interval update. Early preparation and planning are the key to a successful IST Program interval update.

Initial planning for an interval update should begin at least 3 years before the start of the next code of record interval (T-0) depending on how far in advance your company's budgeting process looks ahead and overall scope of work required. The major activities for an interval update are shown below and are discussed in more detail later in this guide.

T-3 years (or earlier)

- Determine scope of the IST Program interval update. See Section 3.2 for additional information.
- Develop an estimate for the total cost of interval update.
- Determine if the interval update effort will be managed as a project with a project manager (recommended) or will be managed by the site IST Program engineer.
- Determine whether the IST Program interval update will be performed by a specialty vendor with review and approval of the site IST Program engineer (recommended) or whether the work will be performed as level of effort by the site IST Program engineer.
- Determine team members and roles/responsibilities (e.g., site IST Program engineer, AOV Program engineer, MOV Program engineer, Snubber Engineer, Design Engineering, Operations and Operations procedure writers, Maintenance and Maintenance procedure writers, supplemental contractors, etc.).
- Develop a preliminary schedule of activities.
- Obtain funding allocation for the duration of the interval update effort.

T-2 years

- Develop IST Program which complies with expected OM Code edition to be incorporated by reference in 10 CFR 50.55a(a)(1)(iv) not more than 18 months before start of the code of record interval.
- Ensure credited safety-related design limits and associated adjustments (e.g., instrument accuracy, diesel generator frequency variation, etc.) for pumps and valves are available or created/clarified.
- Develop request for relief and request for alternatives as needed and submit to NRC for review/approval approximately 12 months before start of the code of record interval.

T-1 year

- Revise IST Program administrative documents (e.g., program plan/basis)
- Revise and create new IST Program test and examination implementation procedures to incorporate changes in the OM Code of record.
- Revise and create new Preventive Maintenance (PM) tasks to incorporate changes in the OM Code of record.

T-0 year

- Verify each component test listed in the next interval IST Program has a procedure, PM, or other document to implement the next interval OM Code requirements.
- Start code of record interval.

T-0 to T+92 days

- Submit IST Program to the NRC

3.1 Determine Expected OM Code Edition for Next Code of Record Interval

The NRC provides liaison reports at the ASME OM Code committee meetings. These liaison reports describe the NRC's rulemaking schedule and status. This is a good way to help predict when newly published OM Code editions will be incorporated by reference in 10 CFR 50.55a(a)(1)(iv). The liaison reports are publicly available in the NRC Agencywide Documents Access and Management System (ADAMS) and also available on the IST Owners Group (ISTOG) website if you are an ISTOG member. In addition, you can work through your Licensing department to get updated rulemaking status from your site's NRC project manager.

The code of record interval update must comply with the latest edition of OM Code incorporated by reference in 10 CFR 50.55a(a)(1)(iv) no more than 18 months before the start of the code of record interval. There are two variables which complicate the determination of which OM Code edition to be used.

1. The IST Program code of record interval dates have some flexibility allowed by OM Code, Subsection ISTA. Specifically, ISTA-3120(c) allows intervals to be extended or decreased by as much as 1 year total from the original pattern of intervals. ISTA-3120(d) allows the extension of an interval when a unit is out of service continuously for 6 months or more.
2. The actual date of final rulemaking which incorporates the latest OM Code edition can vary from the NRC estimated timeline in the liaison reports by several months (earlier or later) due to factors out of the control of the NRC staff. Therefore, it is necessary to keep a close eye on the final rulemaking if the schedule has potential to affect the edition of OM Code used for the next code of record interval.

The current IST Program document should list the dates of past and current intervals. It is recommended that these interval dates be reviewed to determine whether there is any remaining portion of the 1-year extension allowed by ISTA-3120(c). This will identify whether the next code of record start date has any flexibility for being extended. It is recommended that any available interval extension be reserved for contingency measures and the interval update project work to the interval date specified in the current IST Program.

NRC Regulatory Issue Summary (RIS) 2004-12, "Clarification on the Use of Later Editions and Addenda to ASME OM Code and Section XI," provides a method to use a later edition of OM Code in case it would be beneficial for a nuclear power plant (e.g., maintaining similar sites in a fleet on the same code of record).

3.2 Determine Scope of the Next Interval IST Program

This information below is provided to help understand the impact that the IST Program interval update might have on other existing site programs.

Dynamic Restraints

Dynamic restraints (snubbers) were initially addressed as part of the ASME *Boiler and Pressure Vessel Code*, Section IX, and the Inservice Inspection Program, and recently have transitioned to the ASME OM Code and the IST Program. The NRC condition at 10 CFR 50.55a(b)(3)(v) addresses this transition.

- Determine whether snubbers should be included in the next interval IST Program.
- If the site addresses snubbers in a separate Snubber Program with interval dates that are different than the IST Program, then it is recommended to consider whether it is advantageous to short cycle the Snubber Program interval to roll snubbers into the next interval IST Program.

Motor-Operated Valve (MOV) Program

If not already required, the next interval IST Program at operating nuclear power plants will require the site MOV Program to comply with OM Code, Mandatory Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants," rather than continuing to implement Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." If the site currently is implementing OM Code Case OMN-1, then this transition is fairly simple. If not, then additional work may be needed to reconcile discrepancies between the IST scope and active/passive categorization.

- OM Code, Appendix III, does not include the exclusions for plug, ball, and butterfly valves that was provided in GL 89-10. There may also be differences in scope due to the more broad intent of GL 89-10 (e.g., fire protection, not limited to safe shutdown mode, etc.)
- The active/passive categorization of MOVs may differ between the current IST Program and GL 89-10/GL 96-05 MOV Program. From an IST Program perspective, the only difference between categorizing an MOV as active versus passive was the addition of a stroke-time test so it was not that critical. For the GL 89-10/GL 96-05 MOV Program active MOVs require detailed calculations and diagnostic testing so the active/passive categorization was more carefully scrutinized.

- Appendix III allows use of a regulatory-approved probabilistic risk assessment (PRA) risk ranking of MOVs to better align the test frequency with the component contribution to overall plant risk. The use of MOV risk ranking provides a benefit to the site, but adds administrative burden for the management of the IST and MOV Programs to address the periodic PRA risk reviews and associated changes in MOV risk ranking.
- The site's licensing commitment/decommitment process may be used to decommit from GL 89-10 and 96-05 when the next IST Program interval starts because the MOV Program will have transitioned to a 10 CFR 50.55a controlled program.

Pneumatically Operated Valve (AOV) Program

If not already required, the next interval IST Program at operating nuclear power plants will require the site AOV Program to comply with OM Code, Mandatory Appendix IV, "Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants," rather than the current voluntary Joint Owners Group (JOG) AOV Program.

Most of the OM Code, Subsection ISTC, test requirements for AOVs (except leakage rate testing in ISTC-3600 and remote position indication testing in ISTC-3700) from 2017 Edition and earlier have been relocated to Appendix IV in the 2020 and 2022 Editions of OM Code. Therefore, there isn't much change with respect to current interval AOV test requirements. There is also no change in scope criteria for AOVs between the current interval and next interval like there could be for MOVs.

Appendix IV adds a new test Performance Assessment Test (PAT) requirement for AOVs. The PAT is essentially a diagnostic test that has typically been performed in the current JOG-based AOV Program with the exception that functional margin must be addressed in Appendix IV.

If the site currently has up to date AOV calculations for JOG Program Category 1 and 2 valves, then this transition should be fairly simple. If not, then additional work may be needed to address Appendix IV requirements. Appendix IV also allows use of a regulatory-approved PRA risk ranking for AOVs to reduce the PAT requirements to only high safety significant AOVs. Low safety significant AOVs do not require PAT (except following replacement, repair, modification or maintenance that affects the existing initial PAT bases). Low safety significant AOVs continue to use essentially the same testing as required for AOVs in the current IST Program interval. The use of AOV risk ranking provides benefit to the site, but adds administrative burden for management of the IST and AOV Programs to address the periodic PRA risk reviews and associated changes in AOV risk ranking.

Impact to the IST Program implementing procedures

The IST Program engineer should work with Owners of the implementing procedures (and project manager if applicable) to determine whether there is a desire or benefit to perform a

general upgrade of all implementing procedures to ensure consistency, improve usability, clarify acceptance criteria, corrective actions, post-performance IST Program engineer reviews, etc. This decision should consider quality and consistency of current interval procedures, possible timing of procedure upgrade (e.g., enough time available before the next interval start date), and whether the current procedures are adequate for use in the 20 - 25 year duration of the next interval. For example, if a future site project is planned to convert procedures to electronic format (e.g., use on tablets) in the future, then it may be prudent to delay a general procedure upgrade to coincide with that project versus the IST Program interval update.

Performing a general upgrade of implementing procedures will add time, burden, and cost to the IST Program interval update effort. However, it may be a worthwhile investment.

3.3 Determine Differences in Test Requirements Between Current and Next Interval

Perform a line-by-line comparison between the OM Code edition for the current interval and the expected OM Code edition for the next interval. The comparison should be as detailed as possible with clear disposition that identifies changes (e.g., additions and deletions) or no changes between each section or paragraph.

Perform a line-by-line comparison of the NRC conditions in 10 CFR 50.55a(b)(3) to determine those conditions that apply to the expected edition of the OM Code for the next interval. NRC conditions are often incorporated into later editions of OM Code. Therefore, it is important to understand which conditions are applicable for the next interval.

If the site uses a specialty vendor to develop the next interval IST Program, they will often provide these side-by-side comparisons as part of their scope of work.

Most sites preparing for an interval update at the time this guide was written, in the summer of 2025, will be transitioning from the 2004 Edition through 2006 Addenda of the OM Code to the 2020 or 2022 Edition of OM Code and associated 10 CFR 50.55a(b)(3) conditions. The major changes are listed below.

- Add new Pump Periodic Verification Testing (PPVT):
Site design requirements for pumps (e.g., flow, differential or discharge pressure, speed, instrument accuracy assumptions, and diesel generator frequency variation assumptions) credited in the safety analysis must be clearly understood. If the requirements are not clear, then additional funding and time may be needed to ensure that adequate site design information is available to identify the minimum requirements for PPVT Acceptance Criteria.
- Addition of Appendix III, Active MOV test requirements:
This change essentially transitions GL 89-10/GL 96-05 MOV Program testing requirements to OM Code, Appendix III, requirements with some fundamental differences.

- The GL 89-10 exclusion for ball, plug, and butterfly valves does not exist in Appendix III. Other scope differences between the GL 89-10 MOV Program and OM Code (e.g., active/passive classification) must be resolved.
- New requirement to monitor component functional margin for determination of future diagnostic test frequency.
- Replaces previous OM Code, Subsection ISTC, stroke-time test requirements, with Appendix III, full cycle exercise testing (no stroke-time unless required by a Technical Specification Surveillance Requirement per 10 CFR 50.55a (b)(3)(ii)(D)).
- If the site MOV Program does not already implement OM Code Case OMN-1, then additional MOV calculations and component modifications might be necessary to prepare for implementation of Appendix III.
- Previous OM Code Subsection ISTC, paragraph ISTC-3700, Remote Position Indication testing requirements have been relocated to Appendix III which may increase scope of IST implementing procedures that will require revision.
- Addition of Appendix IV, Active AOV test requirements:
This change formalizes AOV diagnostic testing requirements which are referred to as PAT in Appendix IV.
 - If the site has AOVs risk ranked by a regulatory approved PRA method, the PAT for inservice testing may be limited to only high risk AOVs.
 - If the site AOV Program is not robust (e.g., no calculations for Category 2 AOVs), then additional AOV calculations and component modifications may be necessary to prepare for implementation of Appendix IV.
 - The 2017 Edition and earlier OM Code, Subsection ISTC requirements for AOVs (except ISTC-3700 for remote position indication testing) were relocated to Appendix IV in the 2020 and 2022 Editions of OM Code. However, the previous requirements are essentially unchanged.
- New test requirements for supplemental valve position verification testing were added by NRC condition on OM Code, ISTC-3700, by 10 CFR 50.55a(b)(3)(xi).
 - This new testing requires verification of valve obturator position using means other than remote position indication such as observation of a change in flow, pressure, etc.
 - This testing is required at the same frequency as ISTC-3700, position verification testing (2-year interval).
 - This new testing is a significant burden in both time and cost to implement. The first step is to determine how to implement the new test requirements. In some cases, it will be possible to revise existing procedures to credit actions already being performed. In other cases, new procedures may be needed. It may also be necessary to seek a request for an alternative to the OM Code requirements as incorporated by reference in 10 CFR 50.55a for those components where it is not practicable to meet the new supplemental position verification requirements.
- The list above assumes that previous changes in 10 CFR 50.55a(f) requirements (e.g., change in IST Program scope to extend beyond ASME BPV Code Class 1, 2, and 3 components) and NRC conditions in 10 CFR 50.55a(b)(3) (e.g., staggering check valve condition monitoring activities, etc.) applicable to current interval OM Code edition have already been incorporated into the current IST Program.

In addition to the examples of major changes listed above, there are many minor changes that need to be understood and addressed.

4.0 Revise the IST Program to Comply With Edition of OM Code for Next Interval

Recommended Approach

Implement a process to maintain the current interval IST Program in compliance with the current interval OM Code edition and develop a separate draft of the next interval IST Program which complies with the expected next interval OM Code requirements. Then, at the start of the next interval, it is a simple matter of publishing the next interval IST Program document to replace the previous interval IST Program document. This strategy will ensure OM Code testing requirements that are removed from the next interval OM Code (e.g., MOV stroke-time testing) are not prematurely removed from the current IST Program. This strategy also works when adding new OM Code requirements as will be discussed in the next section of this guide.

The only downside to maintaining separate current interval IST Program and next interval IST Program documents is that changes in plant configuration (e.g., Engineering Change Packages) must be incorporated into both documents. This duplication of effort is usually minimal and worth the effort to ensure development of the next interval IST Program does not have an unintended adverse effect on the current IST Program.

Recommended Reviews to Validate IST Program Scope

Recent rulemaking added a new term “Code of Record Interval” in 10 CFR 50.55a which means future IST Programs that comply with the 2017 Edition of OM Code or later are required to update the IST Program to comply with the latest edition of OM Code incorporated by reference in 10 CFR 50.55a every successive IST 10-year interval (i.e., 20 years) which may be extended up to 25 years under certain circumstances. Considering this long-time frame between interval updates, it is recommended that a detailed fresh-look at the IST Program scope and categorization bases be performed to ensure industry Operating Experience (OE), lessons learned, and NRC recommendations provided in the latest revision of NUREG-1482 are incorporated into the next interval IST Program as applicable. Although not a regulatory requirement, it is recommended to completely reconstitute and update the IST Program Bases document for the next interval IST Program. Just like the IST Program documents, it is recommended to maintain two separate bases documents (current interval and next interval) during the interval update process. If the site does not currently have an IST Program Bases document, it is recommended that one be created as part of the interval update. An IST Program Bases document provides the critical thinking as to why a component is in scope or is exempt from the IST Program as well as documenting considerations for how the component is categorized (e.g., active or passive). Also, the bases document makes turnover in the IST Program engineer position less disruptive.

The fresh-look approach for the IST Program or IST Program Basis document should be performed on a system-by-system basis to help focus the reviews and reduce being overwhelmed with the overall volume of work involved.

Select the systems and components to be reviewed based on review of Updated Final Safety Analysis (UFSAR), Technical Requirements Manual (TRM), Technical Specifications (TS), system descriptions, failure mode analysis, safe shutdown analysis, and other design output documents that describe the site's credited safety-related functions.

Review each component, regardless of ASME BPV Code Class, in systems or portions of systems that may have safety-related functions which also meet scope of the OM Code. These are generally Nuclear Steam Supply Systems (NSSS) or NSSS support systems, but it is possible for some components in traditionally non-safety-related systems to have a safety-related function. For example, a vacuum breaker valve in the non-safety-related turbine side circulating cooling water system may have a safety-related function to prevent siphoning of warm non-safety-related circulating cooling water back into the safety-related service water cooling system that serves Emergency Core Cooling System (ECCS) equipment.

Ensure all components that have a potential safety-related function, regardless of ASME BPV Code Class, are evaluated to determine if they fit the scope criteria of the OM Code. The 2022 Edition of the OM Code added a clarification of the scope requirements. For example, ASME OM Code, Subsection ISTA, paragraph ISTA-1100 was revised to clarify that the scope is limited to components that are "credited" to perform a specific function in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, or in mitigating the consequences of an accident. This clarification helps distinguish those components which are capable of being used in abnormal or emergency operating procedures versus those components that are credited to perform a function in the site safety analysis. In addition, definitions for "accident(s)" and "safe shutdown" were added to paragraph ISTA-2000, "Definitions."

Final rulemaking for 10 CFR 50.55a which became effective on August 17, 2017, removed the previous 10 CFR 50.55a(f) language which limited scope of the IST Program to ASME BPV Code Class 1, 2, and 3 components. Now, 10 CFR 50.55a(f) requires all components which meet the scope of OM Code to be included in the IST Program with an exception that components not classified as Class 1, 2, or 3 may be satisfied as an Augmented IST (AIST) Program. However, the only difference between an IST and AIST Programs is that deviations from OM Code requirements for AIST components (e.g., Non-Code Class) do not require prior NRC approval before use. Deviations from OM Code for AIST components are still required to meet the same criteria as deviations for IST components (except prior NRC approval) and must be documented and available for NRC review.

The OM Code provides several exclusions to the scope criteria. These exclusions vary based on component type, but special consideration is needed for those components excluded as a skid-mounted component that is tested as part of the major component. Skid-

mounted exclusions require justification by the Owner that they are adequately tested by the major component testing. The OM Code does not mandate how or where this justification is documented; however, the IST Program Bases document would be a good choice.

Steps for Development of the Next Interval IST Program

After the scope is identified through a fresh-look scope review or use of the current interval IST Program scope, the next steps are to categorize the components and identify unique component characteristics which determine the applicable OM Code requirements. If a fresh-look scope review is performed, then the remaining steps for development of the next interval IST Program is recommended as part of a system-by-system review. This approach is especially helpful in performing the component categorization and active or passive determinations because the reasons for scoping a component into the IST Program are fresh and may impact the decisions.

In addition to understanding the OM Code requirements, other resources such as NRC conditions in 10 CFR 50.55a(b)(3), guidance in NUREG-1482, and ISTOG / industry peer forums or communications are very helpful in making decisions for development of the next interval IST Program.

Categorize components

Determining the correct category for each component is the most important step after determining IST Program scope. Component category is the main attribute which dictates test requirements for the component.

- Pumps are assigned to either Category A or Category B based on whether or not they are continuously or routinely operated, or not operated routinely except for testing.
- Valves are assigned to Category A, Category B, Category C, or Category D. It is possible for a valve to meet the criteria of two categories (e.g., A/C) in which case both apply except as specifically stated otherwise in the OM Code. It is also necessary to determine whether a valve is active or passive. It is important to note that OM Code definition of active and passive is different than other definitions in design requirements, etc. The active or passive designation is based on the valve and not the valve position. For example, if a valve has a safety function to change position from open to close (or vice-versa), then the valve is active. A valve cannot be active in one stroke direction and passive in another stroke direction. This difference is a common reason for discrepancies between the IST Program and GL 89-10 MOV Program that requires resolution.
- Snubbers do not require categorization in the same sense as pumps and valves, but they are required to be assigned to Defined Test Plan Groups (DTPGs) for application of OM Code requirements (e.g., sample size, corrective action, etc.).

Determine other component specific attributes which dictate OM Code test requirements

For Pumps:

- Determine if the pump has specific design-basis accident flow rates in the Owner's credited safety analysis for inclusion in a pump periodic verification test program.
- ASME BPV Code Class (e.g., Class 1, 2, 3, or non-code class)
- Pump type (e.g., centrifugal, vertical line-shaft, or positive displacement).
- Fixed or variable speed.
- Speed less than or greater than 600 rpm.

For Valves:

- ASME BPV Code Class (e.g., Class 1, 2, 3, or non-code class)
- Valve type (e.g., gate, globe, check valve, relief valve, thermal relief valve, etc.).
- Actuator type (e.g., AOV, MOV, solenoid operated, manually operated, explosively actuated, etc.).
- PRA component risk ranking (e.g., LSSC or HSSC, if applicable).
- Valve positions such as normal position, fail-safe position, and safety-related position(s).
- Identify whether the valve has remote position indication.
- Special valve functions such as pressure isolation valve, containment isolation valve subject to 10 CFR Part 50, Appendix J local leakage rate testing, etc.
- For check valves, identify whether they will be included in the Check Valve Condition Monitoring Program to designate whether exercise test requirements must comply with ISTC-5121 or ISTC-5122.

For Rupture Discs:

- ASME BPV Code Class (e.g., Class 1, 2, 3, or non-code class)
- Component type (e.g., rupture disk).

For Snubbers:

- ASME BPV Code Class (e.g., Class 1, 2, 3, or non-code class)
- Component type (e.g., mechanical, hydraulic)
- Manufacturer and Model
- Assigned DTPG
- Sample Plan assignment (e.g., 10% or 37 Plan)
- Accessibility (e.g., accessible for visual examination)

Assign OM Code Test Requirements for Each Component

For Pumps:

- OM Code, Subsection ISTB, provides specific pump test requirements.
- Table ISTB-3000-1, "Inservice Test Parameters," provides a summary of pump test requirements.
- Table ISTB-3400-1, "Inservice Test Frequency," provides a summary of the required test frequency for each pump test type based on pump group.

For Valves and Rupture Discs:

- OM Code, Subsection ISTC, provides specific valve test requirements.
- Table ISTC-3500-1, "Inservice Test Requirements," provides a summary of valve test requirements by valve type and category.
- Tables ISTC-3510, ISTC-3540, ISTC-3600, ISTC-3700, and ISTC-5260 specify the required test frequency for each valve test type.
- Additional test type and frequency requirements are provided in Appendix I (Pressure Relief Devices), Appendix II (CVCM), Appendix III (MOVs), and Appendix IV (AOVs).

For Snubbers:

- OM Code, Subsection ISTD, provides specific valve test requirements.
- ISTD-4200, "Inservice Examination," provides requirements and frequency for visual examination of snubbers.
- ISTD-5200, "Inservice Operational Readiness Testing," provides requirements and frequency for bench testing of snubbers.
- ISTD-6000, "Service Life Monitoring Requirements," provide requirements for additional testing beyond the visual examination and bench test requirements.

General:

- NRC conditions on use of the OM Code in 10 CFR 50.55a(b)(3) modify / clarify some OM Code test requirement and also added a new test requirement to verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications, such as flow meters or other suitable instrumentation to provide assurance of proper obturator position for valves with remote position indication. The NRC conditions are applicable to specific editions of OM Code so not all will apply to your site. However, later editions of OM Code often incorporate some NRC conditions.
- Review OM Code Cases to determine if any provide a benefit to the site IST Program. Keep in mind that OM Code Cases are often incorporated into later editions of OM Code. Therefore, OM Code Cases used in the current IST interval might not be applicable to the next IST interval. It is necessary to ensure an OM Code Case is applicable to the OM Code edition that the site will be required to

implement for the next interval IST Program. OM Code Cases are published as they are approved by ASME and are not part of the traditional OM Code edition publication cycle. OM Code Cases and associated applicability index are available for free on the ASME website. NRC Regulatory Guide (RG) 1.192 provides a list of OM Code Cases which NRC has reviewed and determined to be acceptable for use with or without conditions. RG 1.192 is revised periodically. If a published OM Code Case is not addressed in RG 1.192 and the site wants to use it, then the site must submit a request for alternative for NRC review and approval. [Since preparation of this guide, the NRC has issued RG 1.262 that also addresses ASME OM Code Cases as well as ASME BPV Code Cases.]

- Review current interval IST Program requests for alternatives and requests for relief to determine if they will be required for the next interval IST Program. Changes in the OM Code and the addition of new OM Code Cases may obviate the need for existing requests for alternatives or requests for relief.
- Review current interval IST Program deferred test justifications (e.g., cold shutdown justification, refueling outage justification) to determine if they will continue to be required for the next interval IST Program. New deferred test justifications may be necessary for implementation of the new NRC condition for supplemental valve obturator position verification.
- Recognize that new or revised requests for alternatives, requests for relief, and deferred test justifications may not be identified until the draft next interval IST Program is prepared and work begins on developing and revising the site IST Program implementation procedure and documents. The timing of this step is critical because requests for relief and alternatives must be submitted to NRC for review and approval approximately 12 months before start of the next interval. Requests for alternatives for the IST Program must be authorized by the NRC staff before use. The NRC regulations provide more flexibility for requests for relief.

Pull it all together to draft the next interval IST Program

- Draft the front matter of the next interval IST Program. Recommend use of the current interval IST Program front matter and updating it to reflect changes such as interval dates, OM Code Cases to be used, new or revised abbreviations for test requirements and frequencies to be used in the component test tables.
- Compile the component test tables. These tables provide a list of each pump, valve, and, if applicable, snubber critical attributes such as, component number, description, piping and instrumentation diagram or flow diagram, component categorization, component type, actuator type, etc. The component test table should also include the applicable OM Code required test frequency (or reference to a deferred test justification or request for relief/alternative). In addition, recommend the component test tables also include a reference to the implementing test procedure or document for each required component test. It may not be possible to include the cross-reference between component test and implementing procedure until later in the interval update process when new or relocated tests are landed in an implementing procedure or document.
- Compile a list of requests for relief or alternative with reference to associated components and test requirements (including frequency).
- Compile a list of deferred test justifications with reference to the associated component and test requirements (including frequency).

- Compile a list of site-specific IST Program implementation related positions or clarifications.
- Combine all of the above into the draft next interval IST Program document.

5.0 Revise IST Program Implementing Procedures, PMs, and Documents

Develop a process for updating IST Program implementing procedures

- Update of the IST Program implementing procedures is a more challenging task than development of the next interval IST Program document. This is because careful coordination is necessary to ensure implementing procedures continue to provide compliance with current interval IST Program component test requirements as they are being revised to incorporate next interval component test requirements.
- The IST Program engineer should work with owners of the implementing procedures (e.g., Operations and Maintenance) to identify an implementing procedure for each component test requirement. In cases where there are no changes in component test requirements from the current interval to next interval, then no change is necessary. New component test requirements added by the next interval IST Program must be assigned to an implementing procedure.
- Develop a method to track necessary changes to existing implementing procedures or creation of new implementation procedures.

Determine priority and schedule for implementing procedure revisions

- Determine the latest date that new next interval component test requirements must be performed. For example, the NRC condition which adds supplemental valve position testing is tied to the current interval ISTC-3700 remote position indication testing. Therefore, if a current interval ISTC-3700 test schedule is such that the carried-over next interval ISTC-3700 test is due on day one of the next interval, then the NRC condition supplemental valve obturator position test is also due on day one of the next interval. This is different than new OM Code test requirements which are only required to be completed within the OM Code frequency beginning at the start of the next interval which imposed the new test (e.g., new pump periodic verification testing must be performed within 2 years from the start of the next interval).
- Determine which new next interval component test requirements must be performed during a refueling outage and prioritize the associated implementing procedures accordingly based on duration from the time new test requirements are identified and number of refueling outages remaining before the next interval test requirement is due to be completed.
- Next interval IST Program component tests which are new may be added to existing or new procedure at the site's earliest convenience. An IST Program implementing procedure can always include testing that is above and beyond the current interval IST Program regulatory required testing. Therefore, it is recommended that new next interval IST Program required component tests be integrated into existing or new implementing procedures before the start of the next interval. While this approach adds testing scope that is not technically required by regulations in the current interval IST Program, it is useful to validate the new test requirements work as

intended (e.g., acceptance criteria is valid and can be met). Experience has shown that some new tests and methods will not work as intended and adjustments to the implementation method will be required. It is best to validate the test method works before the next interval due date for the component test requirements.

- Current interval IST Program component tests which are not required by the next interval IST Program (e.g., stroke-time testing of MOVs not in Technical Specification Surveillance Requirement) cannot be removed from implementing procedures until after start of the next interval date.
- Technically, not all required procedure revisions necessary to implement the next interval IST Program component tests have to be completed by the interval start date. For example, it may be necessary due to resource availability or other schedule issue to revise quarterly frequency or refueling outage frequency procedures after the next interval has started. This is referred to as just-in-time procedure revision and is not a desirable situation. However, it can be used as a contingency plan provided the procedures are revised to incorporate the new component test requirements and performed before the next interval component test due date.

Develop a method to track the changes in OM Code test requirements assigned to each implementing procedure

- Each next interval IST Program component test must be assigned to an implementing procedure (PM or other document). In some cases, assignment of component test requirement to a procedure may need to be changed to improve efficiency or a change in test frequency (e.g., need to move a test to a cold shutdown or refueling outage condition). Therefore, the method to track component test assignments to implementing procedures should accommodate these dynamic changes.
- Recommend the tracking method include a side-by-side comparison of current interval component tests and next interval component tests assigned to each procedure. This will provide a way for a procedure writer to easily determine which component tests must be added to the procedure and which component tests may be removed from the procedure.

IST Program engineer support required for implementing procedure changes

- The IST Program engineer will be required to provide guidance to procedure writers which identify the necessary changes for each component test type. Recommend the IST Program engineer develop a generic template or boilerplate for each new or deleted component test type which shows the change in each procedure section. For example, the scope or purpose section should provide an example of how the new component tests are to be listed, the acceptance criteria should provide an example of the intended acceptance criteria, and the performance section should provide an example of the steps/actions necessary to perform the required component tests. These template/boilerplates combined with the previous component test assignment to implementing procedures will allow the procedure writers to revise procedures with minimal interruptions to both procedure writer and IST Program engineer.

- IST Program engineers should perform an independent reviewer or affected organization reviewer to ensure the test requirements are correctly incorporated to meet the next interval OM Code requirements.

Revise or create IST Program implementing procedure

- Track completion of implementing procedure revisions. Verify the planned component tests are incorporated into the intended procedure.
- When every next interval component test is verified to be incorporated into an implementing procedure, the next interval update may be considered complete.
- It may be necessary to revise some implementation procedures again after the next interval starts to remove deleted component tests or incorporate new acceptance criteria based on new reference values established as part of the initial next interval test performance.

6.0 Submit IST Program Document to NRC

The completed next interval IST Program document is required to be submitted to NRC within 90 days of start of the interval. Specifically, 10 CFR 50.55a(f)(7) states:

Inservice Testing Program Test and Examination Plans (IST Plans) for pumps, valves, and dynamic restraints (snubbers) prepared to meet the requirements of the ASME OM Code must be submitted to the NRC as specified in § 50.4. IST Plans must be submitted within 90 days of their implementation for the applicable inservice examination and test interval. Electronic submission is preferred.

This regulatory requirement is easy to overlook. Therefore, recommend adding a placeholder for this action in the overall IST Program interval update schedule.

Conclusion

The IST Interval update process is comprehensive and the 10CFR 50.55a requirements must first be understood. Start the planning process at least 3 years ahead of the start of the new IST Interval. Key players need to be involved early in the process due to the complex nature of the interval update and the many moving pieces with several different departments. Look for improvement opportunities and any Code Cases that can be implemented to improve efficiencies or gain margin for acceptance criteria. Procedures, including the IST Program plan, should be updated (or ready to be issued) prior to the start of the new interval, if possible, to alleviate the number of updates at the beginning of the new interval. Lastly, ensure the IST Program Plan is submitted to the NRC within 90 days of the start of the new interval. Following this guide will help ensure a successful IST interval update.

ASME OM Code Case to ASME OM Code Requirement

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Introduction

The American Society of Mechanical Engineers (ASME) writes and maintains a series of technical publications called Codes and Standards for commercial nuclear power plants. ASME Codes and Standards Committees for this industrial sector are staffed by volunteers who are acknowledged as highly skilled in their respective areas of engineering expertise. As volunteer stakeholders from the nuclear industry, their interests are expressed regarding technical requirements to reach an agreement through a consensus process. These consensus agreements concern the treatment of essential systems, structures, or components at nuclear power plants that are relied upon to protect the health and safety of the public. Creating a written technical agreement using the ASME Codes and Standards consensus process ensures that every stakeholder's interests are included in the finished publication.

ASME Codes and Standards incorporated by reference in government regulation 10 CFR 50.55a include the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section III and Section XI, and the ASME *Operation and Maintenance of Nuclear Power Plants* (OM Code). This paper will present an existing OM Code Case recently incorporated into the ASME OM Code. ASME utilizes a unique publication that allows innovation to be quickly and retroactively applied to past editions or addenda of ASME Code documents. The documents that serve as the vehicle to swiftly convey innovations to past and present Code requirements are called Code Cases.

Like other ASME Committees, the ASME OM Committee volunteers use Code Cases for several reasons. Code Cases may be initiated by using the ASME OM Code Inquiry process. The Inquiry process may be used when requirements are unclear or to challenge the intent of ambiguous statements. It may also be used to initiate a Code Case to convey an alternative means to an existing requirement that provides an equivalent outcome. One of these ASME Code Cases recently incorporated as new ASME OM Code requirements is ASME Code Case OMN-24, "Alternative Requirements for Testing ASME Class 2 and 3 Pressure Relief Valves (For Relief Valves in a Group of One)."

Code Case OMN-24 Background

ASME OM Code Case OMN-24 is an alternative to the existing group test requirements specified in ASME OM Code, Appendix I, for ASME BPV Code Class 2 or 3 valves. The maximum test interval for an ASME BPV Code Class 2 or 3 relief valve in the 2022 Edition of the ASME OM Code is up to 10 years. Paragraph I-1350(a) additionally conveys a minimum test-to-test interval of 48 months for valve groups. Beginning with the 2015 Edition, a clarification was added to specify that a valve in a group of one had to be tested every 48 months. Code Case OMN-24 was created to convey an alternative means to the group sample

plan. This Code Case utilizes a performance-based approach that allows relief valves not in a group with others to reach a 10-year test-to-test interval.

Present Requirement

Under the group sample plan, valves may be removed from a component location and replaced with a different valve to satisfy the test interval. An as-found test of the removed valve is then required to determine if sample expansion is needed. No sample expansion may occur when a valve is not in a group with other valves. The alternative to this approach addresses valves individually instead of treating a group of valves that may be installed in a location as a single component.

Code Case Benefit

When this Code Case is invoked following a successful as-found test, a 24-month extension may be implemented for a 72-month test interval. This enables an individual valve not in a group with other valves to be tested less often than the minimum ASME OM Code, Appendix I, paragraph I-1350(2) requirement to test a group containing only one valve at least once every 48 months.

Code Case Logistics

The Code Case mandates that valves be tracked using the manufacturer's serial number or a unique identification number assigned by the Owner, such as a warehouse tracking number used for safety-related material quality control. This Code Case is presently approved in NRC Regulatory Guide 1.192 without conditions for use. It may be invoked as an alternative to the ASME OM Code, Appendix I, paragraph I-1350(a) 48-month requirement following a successful as-found test to increase the test interval by up to 24 months.

Code Case to Code Incorporation

ASME OM Code Case OMN-24 and the 2022 Edition of the ASME OM Code were used to develop the initial proposal to incorporate the alternative means as new Code requirements. ASME uses a web-based platform known as CStools (cstools.asme.org). CStools controls the administrative review and approval process for ASME Codes and Standards. The CStools platform ensures that Code and Standard revision proposals follow an independently accredited process that serves the interests of all stakeholders. The following outlines how Code Case OMN-24 was implemented as a new change to the ASME OM Code.

ASME Accredited Standards Process

CStools requires the assignment of an individual designated as the Project Manager for changes. The cognizant ASME Secretary for each committee controls the CStools proposal input to satisfy American National Standards Institute (ANSI) accreditation requirements. The initial proposal to implement ASME Code Case OMN-24 was provided to the ASME OM

Committee Secretary with an explanation of what was intended and a background document that conveyed additional technical details for review.

Initial Proposal

This proposal was initially reviewed by all voting members of the ASME OM Committee under Ballot 24-2027 beginning June 28, 2024, and concluding on July 29, 2024. Reviewers made a total of 17 comments during this stage of the process. The project manager addressed these comments in the ASME CStools platform, leading to several changes.

Revised Proposal

After these changes were addressed and the actions were documented in the CStools system, Ballot 24-2334 was initiated. This ballot received three disapproval comments. This indicated that consensus on the updated proposal was achievable. The comments were similar and were addressed by an editorial change. After reaching out to confirm that a draft editorial change would satisfy the three committee members who provided the negative comments, Ballot 24-2334RC1 was issued. The ballot obtained unanimous approval.

Approved Proposal for Code Incorporation

The version in the 2022 Edition of ASME OM Code, Appendix I, paragraph I-1350(a)(2) looks like this:

I-1350(a)

(2) For valve groups containing only one valve, the valve shall be tested at least every 48 months.

The Code Edition published after the 2022 Edition of ASME OM Code, Appendix I, paragraph I-1350(a)(2) will reflect the new change. The new requirements are expected to look like this:

I-1350(a)

(2) The Owner shall choose which approach to utilize from the following two options for individual valves.

(-a) For valve groups containing only one valve, the valve shall be tested at least every 48 months, unless performance data indicate the need for more frequent testing.

(-b) A performance-based test plan shall be used for valves not in a group.

(-1) The relief valve shall be tracked by its unique identification number as provided by its manufacturer (e.g. serial number) or as applied by the Owner.

(-2) The initial test interval shall not exceed 48 months since the last set-pressure test.

(-3) A relief valve that satisfies the as-found set-pressure test criterion may have its test interval extended by up to 24 months. The test interval shall begin from the date of the as-left set-pressure test for the installed valve.

(-4) A relief valve that fails the as-found set-pressure test shall have its test interval reduced by 24 months. The minimum required test frequency for this circumstance is a 24-month interval.

(-5) The test interval for any individual relief valve shall not exceed 120 months except that a 6-month grace period is allowed by ISTA-3170.

New Inservice Update and Interval Extension Regulations

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Introduction

A revision to 10 CFR 50.55a in 2024 significantly changed the update requirements associated with the Inservice Inspection and Inservice Testing Programs. The first change was the acceptance of Code Cases that extend the 10-year interval to 12 years. For Inservice Testing, this Code Case is OMN-31. The NRC limited the use of ASME Code Case OMN-31, which requires it to be used at the beginning of an Inservice Testing update to the 2017 or newer Edition of the ASME OM Code. The second change to the regulations doubled the time the ASME Code may be used for an Inservice Inspection (ISI) or Inservice Testing (IST) program. Under the new rules, the same ASME Code may be used for 20 years without the 12-year ASME Code Case. Using ASME Code Case OMN-31, the same ASME OM Code may be used for up to 24 years. A point of confusion with the new regulation is that an update is still required after the first 10- or 12-year Inservice interval ends. The new interval requirements are summarized in this presentation as follows:

“Inspection/Testing Interval” – Defined by Section XI and OM Codes (10 yrs per Codes, 12 yrs per Code Cases)

“Code of Record Interval” – Defined by 50.55a as ‘equal to 2 consecutive Inspection Intervals’ (so either 20 yrs or 24 yrs)

Inservice Testing Regulations

The requirements for Inservice Testing are outlined in Title 10, Chapter I, of the *Code of Federal Regulations* (CFR). This chapter contains two volumes establishing regulations for using nuclear materials and operating nuclear facilities. Within these volumes, various Parts detail the requirements for different areas of nuclear power regulation. Specifically, Title 10, Part 50 CFR addresses the domestic licensing of production and utilization facilities, which include nuclear power plants that generate electricity. Under Title 10, Part 50 CFR is Section 55a for Codes and Standards, which is commonly referenced in its abbreviated form as 10 CFR 50.55a.

The ASME OM Code Referenced by 10 CFR 50.55a

Without expert input, the United States federal government cannot produce and maintain the many technical requirements for use in its regulations. The National Technology Transfer and Advancement Act of 1995 was partly written to resolve this practical problem. Federal agencies are to use standards developed by private, consensus organizations recognized under the National Institute of Standards and Technology Act to the extent possible. This input is obtained from volunteers who support various Codes and Standards bodies as stakeholders. Codes and Standards referenced by federal regulations are “incorporated by reference” and, from a legal standpoint, become part of the regulation. The Codes and Standards organization that authors

and maintains Code requirements for Inservice Inspection and Testing is the American Society of Mechanical Engineers (ASME). The ASME *Operation and Maintenance of Nuclear Power Plants* (OM Code) is referenced by regulation 10 CFR 50.55a for Inservice Testing.

Design Basis Verification

In September 1991, NRC representative J. Richardson wrote a letter to the ASME OM Code Chairman F. Rhodes requesting that the ASME OM Committee improve its Code requirements. Mr. Rhodes agreed with the Commission and began leading the ASME OM Code Committees to convey these requirements. This effort continued for decades, and many requirements were improved so they could be used to verify design basis capabilities.

With the publication of the 2017 Edition of the ASME OM Code, the NRC determined that the ASME OM Code Committee's design-basis verification objective was met to the extent practical. Because of this, the update regulations were changed because, from the NRC's point of view, the 2017 Edition and newer ASME OM Codes verify pump, valve, and snubber design-basis capabilities in a way that sufficiently addresses the NRC's need to demonstrate each power plant's ability to protect of the health and safety of the public.

IST Updates Are Still Required

While an Inservice Testing update is still required every 10 years, or 12 years if implementing Code Case OMN-31, an update to the latest edition approved by the regulations is only needed for every other update. Since the IST Update is still required by 10 CFR 50.55a every 10 or 12 years, the cost of completing this process did not go away. While the intention was to provide financial relief to the power plant Owners who can avoid changes to the latest ASME OM Code, no changes after the 2017 Edition publication are considered burdensome. Instead of additional burdens, advantages are gained using the latest ASME OM Codes. This value-added approach by the ASME OM Committee is intended to provide real incentives to continue updating to the latest edition and addenda of the ASME OM Code approved by the NRC.

Air-Operated Valves

**Track Chair:
Michael Barlok
Tennessee Valley Authority**

Implementation of Appendix IV at Palo Verde

Chuck Linden

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Background

Air-Operated Valve (AOV) Programs in the industry were previously implemented by the nuclear industry under the Institute of Nuclear Power Operation (INPO) Document NX-1018, Revision 1, "Joint Owners Group (JOG) Air Operated Valve Program." This document predates the 2017 Edition of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix IV, "Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants."

The Electric Power Research Institute (EPRI) Technical Report 30030112918 (2019), "ASME Operation and Mandatory Code: Mandatory Appendix IV Implementation Guide," states that nuclear power plants, which voluntarily implemented the INPO Document NX-1018, have already completed much of the effort required to meet the requirements of the ASME OM Code, Appendix IV. AOV Programs previously established under INPO Document NX-1018 should only require some administrative changes to procedures and enhancements for analysis and evaluation processes to meet the ASME OM Code requirements, which are in progress at the Palo Verde Generating Station.

ASME OM Code, Mandatory Appendix IV, is incorporated by reference in Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.55a, "Codes and standards." Implementation of Mandatory Appendix IV will be required during the next ASME OM Code update for the Palo Verde Generating Station in 2028.

Mandatory Appendix IV, Paragraph IV-3820, Risk-Informed Methodology

AOVs shall be evaluated and categorized using a documented Risk-Ranking Methodology.

ASME OM Code, Subsection ISTE, "Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants," provides an acceptable methodology for Risk Ranking of AOVs.

Utilities should have developed Risk Ranking for their AOV Programs as defined by the INPO Document NX-1018.

Note: Risk Ranking is the **Foundation** for meeting the requirements in Mandatory Appendix IV to have a successful AOV Program.

Mandatory Appendix IV, Paragraph IV-3821, High Safety Significant Components (HSSCs)

AOVs classified as HSSCs require Performance Assessment Testing (PAT) to assess their functional margin.

The AOV JOG Document defines HSSCs as Category 1 AOVs, which meet the requirements for the Risk-Ranking methodology.

ASME OM Code, Appendix IV, paragraph IV-3410, states that PAT shall be performed within three refueling cycles or 5 years, whichever is longer following implementation of Appendix IV for pre-2000 plants.

ASME OM Code, Appendix IV, paragraph IV-3410, states that PAT shall be performed for post-2000 plants prior to plant startup or during plant startup activities.

Mandatory Appendix IV requires establishing Performance Assessment Testing (PAT)

PATs are necessary to evaluate “AOV functional margin” as defined in paragraph IV-2000, “Supplemental Definitions,” which states:

the increment or percentage by an AOV is available as tested capability exceeds the thrust/torque load required to operate the AOV under worst-case operating conditions.

Test parameters may be determined from data obtained during testing and are important to monitor (e.g., tracking and trending) to ensure functional capability.

Parameters should include but are not limited to bench set, spring preload, spring rate, full stroke time, valve travel, measured torque or thrust, and seat loading.

Mandatory Appendix IV, Paragraph IV-3410, Performance Assessment Testing (PAT)

For pre-2000 plants, an initial PAT shall be performed within 3 refueling cycles or 5 years, whichever is longer following implementation of Appendix IV to assess Functional Margin.

Post-2000 plants shall perform this testing prior to plant startup or during plant startup activities.

Testing activities that were performed as part of the plant’s Legacy AOV Program can be used to satisfy PAT requirements of paragraph IV-1400(a).

PAT is required prior to maintenance activities concurrently scheduled to support tracking and trending.

The PAT interval for each AOV shall not exceed 10 years.

Mandatory Appendix IV, Paragraph IV-3000, General Testing Requirements

Performance Assessment Test

Stroke Time Test

Fail Safe Test, if applicable.

Leak Testing in accordance with ISTC-3600 and ISTC-5000, as applicable

Position Verification Testing

Note: PAT will be performed under the AOV Program at Palo Verde Generating Station, while the remaining tests are already performed under the current Surveillance Testing Program.

Program Development Plan at Palo Verde Generating Station

AOV Categorization – Completed

KVAP 4.3 Software and calculations completed for Category 1 AOVs

Contracted Kalsi Engineering to revise procedures for data acquisition using Teledyne FS3 diagnostics and performance assessment of test evaluation as discussed in paragraph IV-6000.

Guidance will be developed to analyze and evaluate the functional margin in accordance with paragraph IV-6400

The evaluation process will provide reasonable assurance of actuator margin meeting the acceptance criteria at present and during the PAT interval as required by paragraph IV-3410. This includes ensuring positive functional margin will be maintained over the next scheduled test interval.

Installation of KVAP 4.4 is projected by the end of 2025 or early 2026.

Procedures are projected for completion by spring of 2026 to allow for testing administrative processes.

The process is expected to be operational by the end of 2026 in preparation for implementation of ASME OM Code, Mandatory Appendix IV.

NextEra Energy Redundant Valve Positioner Design

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Abstract

Institute of Nuclear Power Operations (INPO) Event Report 22-4 identified an adverse trend in feedwater-related scrams at nuclear power plants. Of the feedwater-related related scrams from July 2021 to July 2022, five events were attributed to single point vulnerability (SPV) recognition/mitigation and three were related to parts quality. A root cause analysis originating from a reactor trip at the Turkey Point nuclear power plant identified that the Steam Generator Level Control Systems in the NextEra Energy fleet have SPVs present in the existing designs. One of the most predominant SPV identified is the positioner for the Main Feedwater Regulating Valves (MFRVs). This paper walks through the steps where NextEra Energy established and implemented a solution to eliminate the SPV associated with the MFRV positioners by installing redundant auto-swapping digital valve positioners.

1. Introduction

NextEra/FPL Engineering developed a design where redundant digital valve positioners automatically swap from the primary/controlling to the backup utilizing a discrete/auxiliary switch configured to de-energize a relay, thus powering a solenoid valve to swap the pneumatic outputs. Similar approaches have been implemented at other utilities where the plant Distributed Control System (DCS) controls a solenoid valve downstream of dual positioners which requires a digital modification to the DCS to function. The NextEra design is unique where the on-board diagnostics of the digital positioner is utilized (as opposed to DCS) to actuate an auxiliary switch on the positioner which then powers a relay and solenoid valve to automatically swap from a degraded positioner to a healthy positioner, thus avoiding a reactor trip. The design is stand-alone and does not rely on DCS to function.

Design Overview

Dual Fisher series DVC6200 positioners utilize discrete/auxiliary switches on the positioner that are configured to open upon receipt of a travel deviation; therefore, de-energizing the coil of a latching relay. When the latching relay opens, it powers a solenoid valve (i.e., positioner swapping solenoid) with 120 volt alternating current (VAC) that automatically redirects the positioner output pressures from the primary (aka Positioner 1) to the backup positioner (aka Positioner 2).

Travel deviation is defined as the difference between the control signal (%) supplied to the positioner from the controller compared to valve travel (%) over a specified period of time. It is

one of the alerts generated by the positioner on-board diagnostics from user defined parameters that are enabled and set during the detailed setup with the Valvelink computer or HART/TREX communicator.

A latching relay is needed since the positioner swapping solenoid needs to maintain power until it is manually reset by the 3-position selector switch. When a travel deviation alert is not present, the auxiliary switch contact on the positioner returns to the closed position. If the latching function is not present, the positioners would potentially experience multiple automatic swaps back and forth and a degraded condition could go unnoticed.

By design, the primary positioner (Positioner 1) will automatically swap to the backup (Positioner 2). When Positioner 2 is in control, it will swap to Positioner 1 upon receipt of a travel deviation or loss of power. When an automatic swap occurs, redundancy is lost and the controlling positioner becomes an SPV until the system is restored.

The positioner swapping solenoid valve is locally controlled by a 3-position selector switch mounted on the door of the electrical enclosure mounted on the panel. The normal alignment for this switch is in the mid-position which aligns the circuitry to automatically swap from Positioner 1 to Positioner 2 upon receipt of a travel deviation. The switch positioned to the left disables automatic swapping and the solenoid remains un-powered aligning Positioner 1 instrument air output to the MFRVs. The switch positioned to the right energizes the swapping solenoid and the instrument air flowpath is aligned with Positioner 2. In the event of an automatic swap-over, the 3-way switch must be first positioned to the left to reset the electrical components and then taken back to the mid position to restore the alignment to enable the automatic swap.

The status of the positioners is displayed by four indicating lights (red 1, blue, red 2 and white) installed on the door of the electrical enclosure. The backup positioner status is monitored by using a blue indicating light controlled by the positioner auxiliary switch on Positioner 2 switch and a k-relay. The blue light illuminated indicates a healthy Positioner 2 without a travel deviation and goes dark upon receipt of a travel deviation above 10 percent for 20 seconds or loss of control power. The red 1 (left) light indicates that the swapping solenoid is de-energized and the flowpath to the valve is from Positioner 1. The red 2 (right) light indicates the swapping solenoid is energized and the flowpath is from Positioner 2. Finally, the white light indicates the presence of 120 VAC power. There is a red push button located at the bottom that resets the blue light and k-relay circuit upon loss of control power or a travel deviation to Positioner 2.

When in operation, the normal display of the indicating lights will show red 1 light ON (Positioner 1 normal), blue light ON (Positioner 2 ready with no travel deviation) red 2 light OFF (positioner swapping solenoid valve not energized) and white light ON. When the circuit is aligned for an automatic swap, a travel deviation alert on Positioner 1 opens the positioner auxiliary switch which automatically swaps the instrument air flowpath/control from the Positioner 1 to Positioner 2. The red 2 light will come ON and red 1 light will go OFF.

Similarly, a travel deviation alert on Positioner 2 opens the positioner auxiliary switch which shuts OFF the blue light along with de-energizing the swapping solenoid and causing the Red 2 light to extinguish. Also, 3-way instrument valves are installed to manually bypass the positioner swapping solenoid and remove the reliance on the electrical components to maintain the flowpath from Positioner 2.

To facilitate disconnecting Positioner 1 online while maintaining the control loop circuit to Positioner 2, a maintenance jumper is installed under procedural guidance. In the event of a failed Positioner 1 or 2, a pre-calibrated spare will be installed in its place. Once Positioner 1 is restored, the maintenance jumper will be removed and normal alignment can be restored. Positioner 2 can be removed without affecting the primary control loop circuit, so a jumper is not necessary for Positioner 2 removal.

When the system is in its normal alignment, a failure of any component associated with the automatic swap or Positioner 2 will not affect operation of Positioner 1. The swapping solenoid is normally de-energized and a loss of 120 VAC power will not have an impact on a healthy and properly operating Positioner 1.

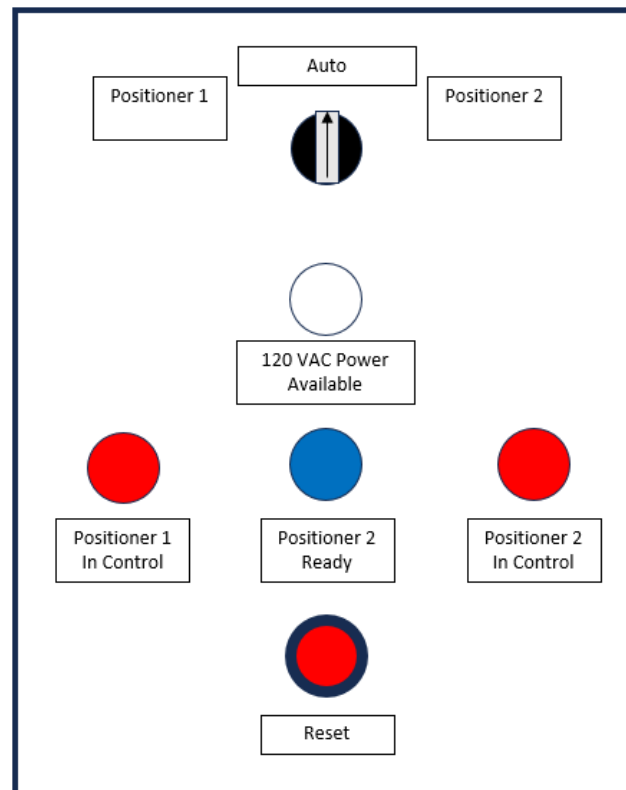


Figure 1 Typical Control Panel Arrangement

The common design approach supports standardized maintenance and operating procedures for the fleet. The consistency of design promotes efficient maintenance across our fleet where issues can be managed and resolved from multiple sites. Similarly, using a uniform panel layout establishes continuity between fabrication, troubleshooting and operation. The emphasis on interchangeable parts in the common design allows for inventory to be stocked and traded among all sites.

2. Materials and Methods

The design and implementation consisted of the following:

- 1) Performed proof testing of the design
- 2) Prepared a detailed Failure Modes and Effects Analysis (FMEA)
- 3) Reviewed the conceptual design with all the sites
- 4) Identified a vendor to fabricate the panels
- 5) Prepared Engineering Change Packages (ECs) for installation at all sites
- 6) Prepared and performed Factory Acceptance Tests (FATs) for each panel
- 7) Installed the positioner panels at all sites
- 8) Performed Site Acceptance Tests (SATs) and startup monitoring
- 9) Established a basis for travel deviation setpoint recommendation
- 10) Developed recommend actions upon receipt of a travel deviation

2.1 Performed proof testing of the design

A spare actuator for the Turkey Point Feed Reg valve was used with two remote mounted Fisher DVC 6200s to validate the design as shown in Figure 2. The travel sensors and arrays were mounted on the actuator with instrument tubing routed to the positioners and actuator. A 4-20 milliamp (mA) control loop was then set up to drive the positioners. A 24 volt direct current (VDC) circuit was established to connect to the positioner discrete switch to power relays and indicating lights. Finally, a 120 VAC circuit was made to power the solenoid valve and remaining indicating lights.

Once everything was configured and connected, actuating the solenoid valve coincident to a travel deviation alert was successfully demonstrated early on. However, it was then realized that HART communication with two positioners on the same control circuit presented challenges. The Valvelink computer connected to the first positioner that had a heartbeat. This was resolved by installing an isolator to separate the two control circuits. The electrical circuit design was finalized by identifying the correct selector switch, latching relay, k-relay, power supply, and combination of indicating lights.



Figure 2 Proof Testing Setup

2.2 Prepared a detailed Failure Modes and Effects Analysis

One of the most critical elements of the design was to ensure that no new failure modes were being introduced while controlling on the primary positioner. The FMEA showed that any new failures were isolated to the backup positioner. The analysis looked at each component identifying the component function, failure mode, cause/failure mechanism, effect on train or system, and method of detection. The FMEA review resulted in several changes to the original design for optimum configuration.

2.3 Reviewed conceptual design with all the sites

This was a first of a kind endeavor since NextEra/FPL centralized many of the engineering functions for the nuclear fleet at the Jupiter West office. Since NextEra Fleet Engineering had the lead on this project, 30 percent and 90 percent reviews of the Engineering Change packages were performed with the stakeholders from each site for alignment. While a standardized design was being pursued, each site had unique requirements that needed to be considered. One example is that the St. Lucie nuclear power plant has double-acting positioners and actuators on their Feed Reg Valves while the remaining sites have single-acting. Along with the actual differences between each site's Feed Reg Valve setup, there

were also specific requests to be included in the design. All feedback was considered to ensure the stakeholder needs were met.

2.4 Identified a vendor to fabricate the panels

It was decided to use a vendor for the panel fabrication. This approach eliminated the need to generate Work Orders along with maintenance having to supply the labor for fabrication. Using a vendor ensured consistency and quality in the construction. Further, it greatly simplified the procurement process by eliminating the need to procure all the individual parts as opposed to the completed panel.

NextEra provided the design details as shown in Figures 3 and 4 along with the materials list. The vendor assumed the responsibility of finding all the suppliers. They were able to meet our tight schedule demands.

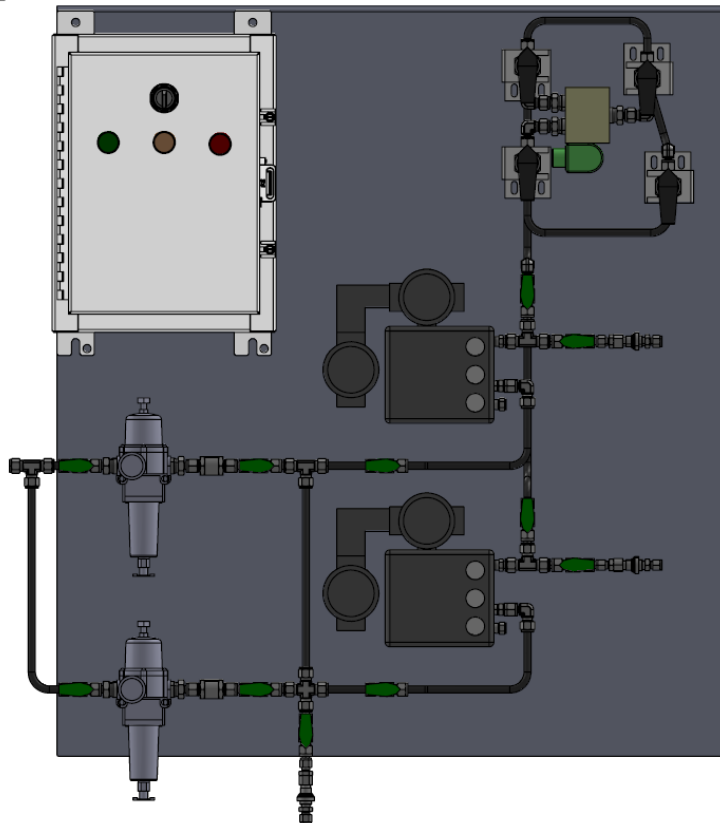


Figure 3 Conceptual Drawing for Single Acting Positioner

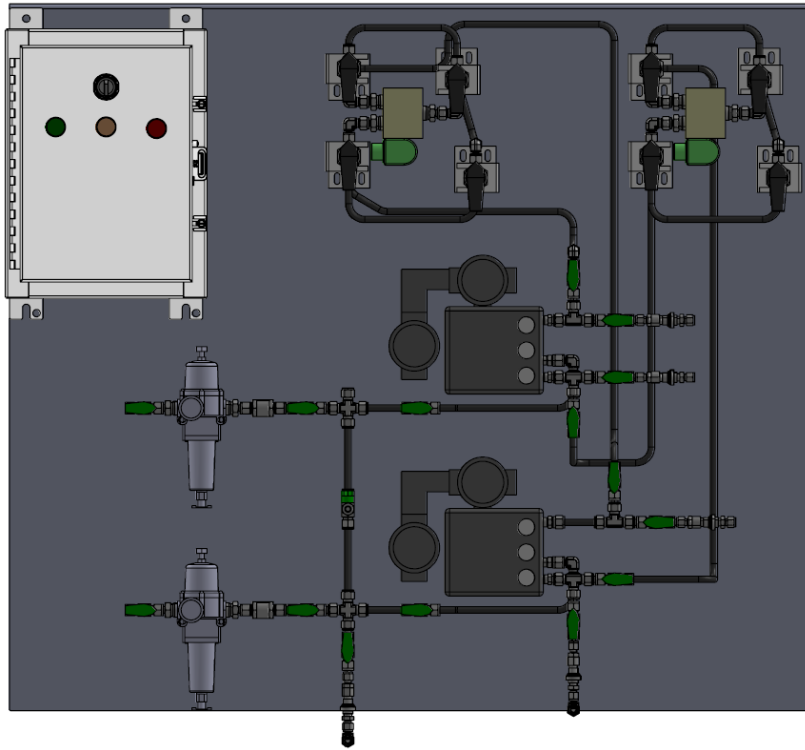


Figure 4 Conceptual Drawing for Double-Acting Positioner

The vendor fabricated the panels in their Birmingham, Alabama, facility. The panels were completely assembled and wired with the exception of the positioners. The positioners were bought and installed separately by NextEra to maintain compliance with cyber security requirements.

This approach also streamlined the receipt inspection process as all the panels were initially shipped to our Integrated Supply Chain (ISC) Technical Services facility in Rivera Beach, Florida. The Factory Acceptance Testing was a part of the receipt inspection.

2.5 Prepared Engineering Change Packages (ECs) for installation at all sites

NextEra uses the Nuclear Energy Institute (NEI) standard design change process. ECs were prepared for each site. Once the first EC was prepared, it served as a template for all subsequent design change packages associated with this effort. This simplified the preparation of the remaining ECs since about 80 percent was applicable to all sites.

2.6 Prepared and performed Factory Acceptance Tests (FATs) for each panel

Comprehensive FATs were developed to ensure the panels functioned as designed. The testing was performed by the design team along with ISC Tech Services. The testing validated all the identified failures which were designed to initiate an automatic swap.

Scenarios where a loss of 120 VAC power, loss of 24 VDC power, loss of air, and loss of travel sensor signal were all developed and performed. Another scenario was to have both positioner outputs aligned with the actuator to simulate leaking solenoid valve. Finally, a positioner swap-out was successfully performed with the valve and controlling positioner remaining in service. Maintenance and Operations personnel from the sites were present during testing to gain first-hand knowledge of the equipment.



Figure 5 FAT Setup

2.7 Installation of the positioner panels at all the sites

Once the FATs were completed, the positioner panels were then shipped to each site for installation. The panels were then bolted in place with 120 VAC and instrument air routed to each as detailed in Figure 6. Each site had a different valve and actuator setups, so unique travel sensor mounting techniques were implemented for each setup as shown in Figure 7.

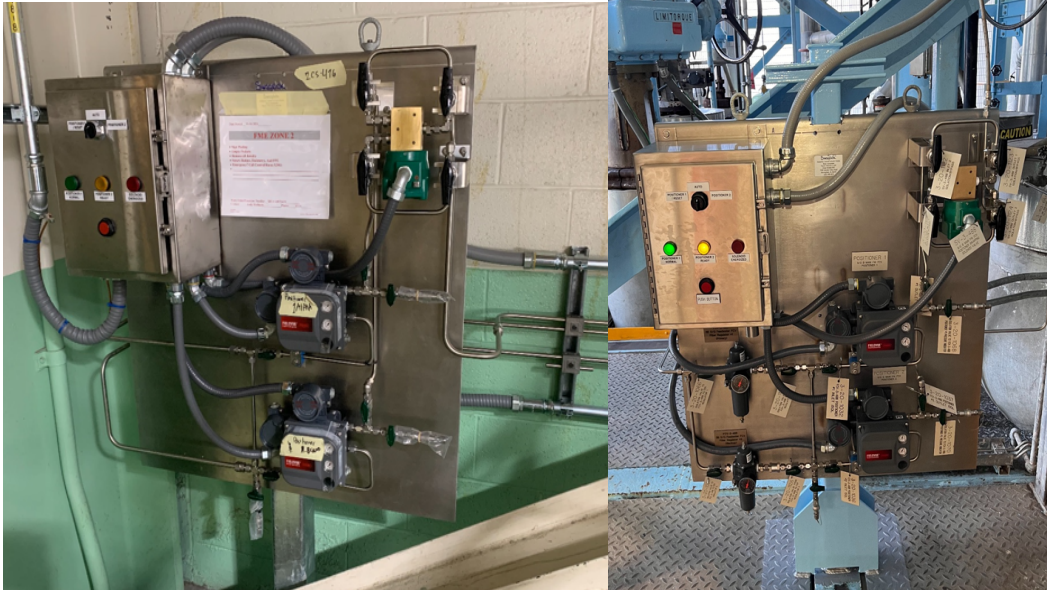


Figure 6 Point Beach and Turkey Point Installation

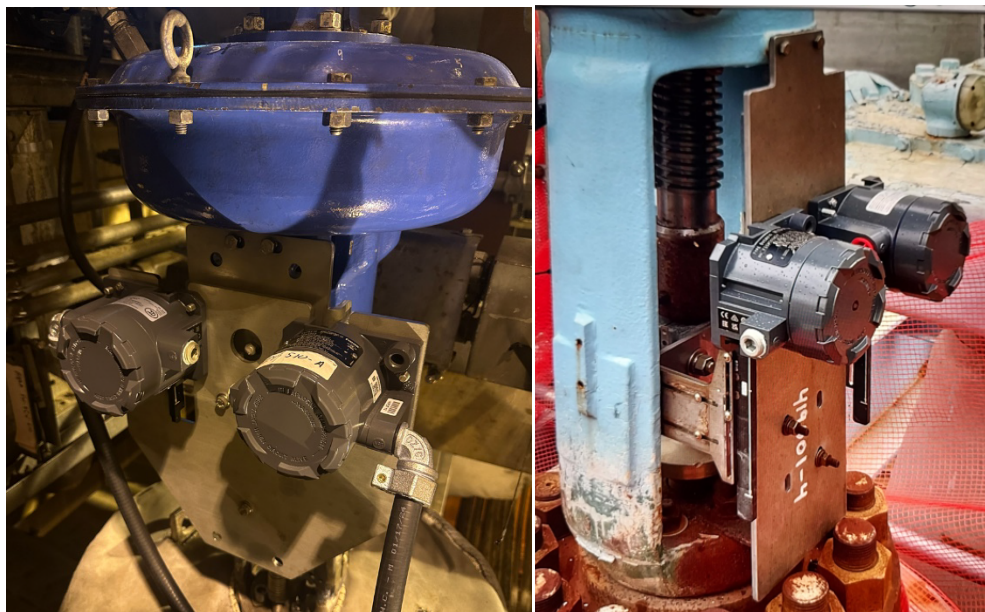


Figure 7 Travel Sensor Mounting

2.8 Performed Site Acceptance Tests (SATs) and startup monitoring

The site acceptance testing consisted of reperformance of a portion of the factory acceptance tests along with validation of the loop calibration. It ensured a proper connection and setup prior to turnover to the plant. Once the panels were placed in service, Valvelink data were collected at several intervals during power ascension on both the primary and the backup positioner to confirm proper operation. One parameter of primary interest was the amount of travel deviation present on the backup positioner.

2.9 Basis for Travel Deviation Setpoint Recommendation

When selecting the travel deviation setpoints, factors to consider are a premature swap-over which will cycle Operations and Maintenance unnecessarily to determine the cause and a swap-over that occurs too late in the event which may result in a reactor trip. Whereas neither is desired, the scenario with less risk is a premature swap-over. The default settings for travel deviation are 5 percent for the alert point with 10 seconds for travel deviation time. Considering the above, the default settings might not be optimum when using travel deviation to initiate an automatic positioner swap. Catastrophic failure will likely result in a large travel deviation over a short period of time. A 10-second delay coincident to a catastrophic failure will result in the valve traveling to the closed or near closed position with a significant level transient in the affected steam generator. As such, 5 seconds of a continuous deviation is more appropriate for this approach. For percentage of deviation, 5 percent is too low and may trigger an unnecessary swap-over and a value of 10 percent is more representative of the characteristics of a catastrophic failure of Positioner 1.

For Positioner 2, the amount of deviation will be the same as Positioner 1, but the deviation time will be longer. If the deviation time is set the same as Positioner 1, the Positioner 2 light will extinguish coincident with the swap-over. That said, Positioner 2 will be set at 20 percent at 10 seconds. These settings will still capture a degraded positioner but should not lock in prematurely.

Under all aspects of operation including power ascension/descension, pump starts, blowdown adjustments, etc., a positioner panel that is functioning properly will be able to respond within these parameters without a premature swap-over.

Each site in the fleet ran scenarios in the simulators as an additional check to validate travel deviation swap-over settings. Since the final settings for the travel deviation setpoints were ultimately determined by the sites, it was decided to make the setpoint more aggressive at two sites.

2.10 Recommended actions upon receipt of a travel deviation

In the event of a swap-over, the Valvelink computer will be connected to Positioner 1 to determine the cause of the swap. During the commissioning of the positioners, the triggered

profile function was enabled. This function is an onboard diagnostic feature which allows up to 4 variables including travel, travel setpoint, travel deviation, input setpoint, supply pressure, actuator pressure A, actuator pressure B, etc. to be collected and saved once the trigger conditions are met. Enabling the triggered profile function will automatically collect/save data on travel deviation for these positioners. The DVC 6200 positioners memory can save up to 15 minutes of triggered profile data. If the triggered profile data review shows a gradually increasing deviation and Positioner 1 functioned properly up to the swap, the deviation percentage setpoint can be adjusted once it is concluded that it is healthy. If the triggered profile data show an abrupt step change in travel deviation, then Positioner 1 may have to be replaced before returning the system back to the normal alignment.

3. Conclusions

This design has been successfully implemented at six of the seven operating units (sixteen of eighteen total panels) in the NextEra/FPL fleet. St Lucie Unit 1 will have the remaining two installed during their Fall 2025 outage. Since all NextEra/FPL sites do not have distributed control systems at all the sites capable of providing the auto-swapping capability, this methodology was a good fit by using the standard/common design approach. With NextEra performing the engineering and testing in-house, a \$5.1MM savings in design development costs were realized.

4. Operating Experience (OE)

For the panels that have been in service since the fall of 2024, they have performed reliably with minimal issues. The following OE has occurred:

Turkey Point

During the operator rounds, Turkey Point discovered the positioner 2 ready light to be off. In addition, the Positioner 2 output gauge was reading 0 pounds per square inch gage (psig). Positioner 2 data was collected with a TREX communicator and discovered an existing 2.1 percent travel deviation when at 100 percent power. During commissioning of the panels, it was decided to use a travel deviation alert setpoint of 4 percent for 8 seconds vs the 10 percent for 20 seconds. The 2.1 percent travel bias prematurely triggered the travel deviation alert. Regarding the 0-psig output, the positioner is trying to move the valve closed since the setpoint is less than the travel which is an expected condition considering the circumstances. It was concluded that the backup positioner remained capable of providing precise control of the valve if an automatic swap occurred and the condition was indication only.

Seabrook

During the operator rounds, Seabrook discovered all the indicating lights to be off with the exception of the White 120 VAC Power Available indication. Troubleshooting found a blown 3A fuse for the 120 VAC circuit along with a failed 120 VAC to 24 VDC power supply. In addition, it was determined that two wires were incorrectly landed inside the panel. The impact of the incorrectly landed wires was an off normal combination of lights being extinguished consistent with a blown fuse and failed 120 VAC to 24 VDC power supply. Positioner 1 remained in control but the ability to swap to Positioner 2 was lost. The failed 120 VAC to 24 VDC power supply and fuse were both replaced, and the panel was restored back the normal alignment.

Point Beach

Coincident to collecting Valvelink data for a quarterly online health check, an automatic swap from Positioner 1 to Positioner 2 occurred. The investigation found that a travel deviation was not the cause for the automatic swap. Based on the review of the Valvelink data, it was decided to restore the alignment with Positioner 1 in control with the 3-way selector switch in Auto. The panel was successfully restored, and the valve/actuator/positioner has been controlling as expected. The cause of the automatic swap was not determined. Performance of the quarterly online health check has been suspended. If the Valvelink or TREX communicator is to be connected in the future, consideration will be given to temporarily disable automatic swapping capability by positioning the 3-way selector aligned to Positioner 1. This should prevent any unanticipated swaps in the interim until the cause is determined. It is noteworthy to mention that during the swap, Operations did not note any change in steam generator level.

REFERENCES

1. INPO Event Report 22-4 (IER L4 22-4), Adverse Trend in Feedwater-Related Scrams. Issue Date October 11, 2022
2. Nuclear Energy Institute IP-ENG-001, Standard Design Change Process

The Future of Air Operated Valve Online Monitoring, a Vision

Fred Setzer

Electric Power Research Institute

The presentation, The Future of Air Operated Valve (AOV) Online Monitoring – A Vision, delivered at the 15th ASME/NRC OM Code Symposium, explored the evolving landscape of valve performance management in nuclear power plants. Operational events involving valves remain a leading cause of reliability challenges, compounded by workforce changes and underutilization of available technologies. The session emphasized the need for condition monitoring to detect degradation before failure, optimize performance, and reduce maintenance risks associated with random failures, which dominate valve failure modes.

Key objectives include implementing cost-effective monitoring strategies, leveraging ASME OM Code credit for operational demand strokes, and transitioning from time-based maintenance to predictive approaches. The presentation reviewed current monitoring options—wired diagnostics, wireless solutions, and discrete sensors—highlighting their limitations and cybersecurity considerations. Emerging strategies, such as low-cost sensor integration with plant PI systems, promise continuous data collection and improved decision-making without impacting operability.

Future directions focus on replicating offline diagnostics online, enabling on-demand monitoring, and updating industry guidance for analog-to-digital transitions. By aligning research, technology adoption, and workforce proficiency, the vision aims to enhance reliability, reduce outage costs, and improve safety in nuclear operations.

Pumps

Track Chair:
Betsy Moenkedick
Southern Nuclear Company

The Evolution of Pump Inservice Testing

Thomas Ruggiero

Professional Engineer, ASME Fellow, OM Standards Committee Member

The American Society of Mechanical Engineers (ASME) Operation and Maintenance of Nuclear Power Plants, Division 1, OM Code: Section IST (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 separate standard. At that time, IST for pumps was specified in ASME BPV Code, Section XI, Subsection IWP. After the 1986 Edition of ASME BPV Code, Subsection IWP requirements were moved into the OM Code as OM Part 6. There was a period on time when OM was referenced by ASME BPV Code, Section XI, and there was a committee for Subsection IWP as well as OM Part 6. That was cumbersome and inefficient. OM subsequently became a code, and pump IST requirements were placed in OM Subsection ISTB.

For the most part, IST was developed after many nuclear power plants were designed, and even built. This meant that, in several cases, there was no provision specifically to allow testing. For pumps, that typically meant that there wasn't a full flow test loop. The desire was that no backfits were to be required to comply with IST requirements.

The ASME committee understood testing a pump on low, even minimum, flow was meaningless for trending data. The committee developed a Comprehensive pump test that in addition to requiring a higher test flow rate, included oil analysis, as well as motor current. After some time, the oil sampling was removed in that it was considered maintenance and not testing, and the motor current requirement was removed because the position at that time was that it was a test of the motor that was outside of the scope. Vibration measurement was retained as some committee members considered it was a better predictor of pump condition than hydraulic performance.

While this was happening, the NRC staff sent a letter to ASME that is typically referred to as the Richardson Letter. Among other things, the letter specified that IST for pumps would better assess the condition of the pumps by installing greater accuracy instrumentation on the test line. For many plants, this was the minimum recirculation line. Over the course of time, the committee was able to obtain agreement that if a centrifugal pump was tested "back on its curve" then the increased instrument accuracy would be meaningless. This was the genesis of what we now call Comprehensive Pump testing.

The NRC staff had three open issues that prevented endorsement. These were (1) the test flow rate needed to include maximum credited flow rate, (2) the high-end acceptance criteria tolerance for flow rate, and (3) Group B tests. These issues were resolved as follows:

While a design flow verification test was not the intent of the Code, the compromise position was the addition of the flow verification test.

The percentage of flowrate on the high end for the required action range was revised. The complication here is that acceptance criteria, as well as instrument accuracy, differ for the quarterly versus the comprehensive tests.

Group B test is to ensure that the pump can start and come up to its reference point.

The OM Code committee has revisited going beyond the deterministic testing approach. One result of this is the inclusion of condition monitoring for pumps.

Now, ASME has issued the OM-2 Code for IST in the new generation of nuclear facilities. The OM-2 Code has no pump categories and is in a more logical format than the OM Code. The committee is currently reformatting the OM Code to the OM-2 format and including some improvements. There is another presentation during this symposium that presents the plan for the OM-1 project.

Subcommittee for Pump Testing Presentation

Melvin L. McGaha
Iddeal Solutions, LLC

The 15th NRC/ASME OM Code Symposium will examine issues from the perspective of the ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code). All aspects of the OM Code are open for presentation and discussion including Code development, implementation, regulation, and future improvements, ideas, or concepts. Attendees include those engaged in Inservice Testing (IST) from the Operations, Engineering, Maintenance, Licensing, as well as Manufacturers, Consultants, and Designers involved in any facet of IST activities involving pumps, valves, and dynamic restraints (snubbers) used at nuclear facilities.

As Chairman of the Subcommittee for Pump Testing Requirements for the ASME OM Code, I have developed a presentation outlining the changes made for the 2022 Edition of the ASME OM Code. The purpose of this presentation is to provide the changes associated with Subsections ISTB and ISTF of the 2022 Edition of the ASME OM Code. Most if not all of the changes were associated with four major Records and Ballots that were processed through the OM Code process and approved by the Board of Nuclear Codes and Standards.

These changes included Record #18-1672, for OMN-22 incorporation into Subsections ISTB and ISTF. Also, Record #20-2355 provides changes associated with vibration measurement, ranges, etc., to bring the ISTB and ISTF vibration requirements more in line with Predictive Maintenance (PdM) requirements, used in nuclear power plants. In addition, Record #20-2354 included changes to broadband unfiltered measurements to an overall value, without filtering of velocity and displacement. Record #18-1784 updated requirements for “Pumps in Systems Out of Service” to “Pumps Out of Service” as a means to focus the pump testing requirements on the Component rather than the overall System. This presentation will also explain the changes and provide details of the changes, as well as describe the program impacts for nuclear power plants.

ASME Code Pumps and Vibration: A Case for Going Beyond Code Requirements

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ABSTRACT and INTRODUCTION

This paper is meant to familiarize those new to nuclear power of how the industry developed its maintenance practices and achieved high-capacity factors. It is also meant as a reminder for those that have been in the industry for a long time of the history, scientific studies, and transitional period that resulted in current maintenance practices. This paper also seeks to implore plant management not to succumb to the temptation of re-implementing time-based maintenance in the interest of budget stability. Random failures will still occur at the same rate no matter how often you refurbish that pump, and the site will have to deal with increased infant mortalities. Make sure your Predictive Maintenance Programs have adequate resources and continue to provide the early warning of equipment health issues that is so central to our modern maintenance philosophies.

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) is setup to monitor system, structure, and component (SSC) performance to allow for the determination of operability. It is not focused on plant operational efficiency or detection of degradations at an early stage for optimal maintenance planning. By design, it does not address the opportunity to identify failure modes that will lead to operability issues later in development. Addressing efficiencies in plant operation has been the province of equipment reliability programs. Assessments of plants by the Institute of Nuclear Power Operations (INPO) and the U.S. Nuclear Regulatory Commission (NRC) often include reviews of equipment reliability programs, but these assessments have reduced the focus on Condition-Based Maintenance in recent years since implementation of the Nuclear Promise.

The current ASME OM Code for vibration data collection on safety-related pumps in nuclear power plants primarily relies on overall vibration measurements. However, these measurements are insufficient for effective condition monitoring of components. Overall vibration values provide a limited view, often missing early signs of equipment degradation. Advanced vibration analysis techniques, such as Fast Fourier Transforms, time waveform analysis, and high-frequency enveloping, offer a more comprehensive understanding of equipment health, enabling early detection of potential issues. This paper argues that the ASME OM Code must evolve to make allowances for, and encourage, these advanced techniques, ensuring higher reliability and safety in nuclear power plant operations. Embracing advanced vibration measurements is crucial for maintaining the integrity and performance of critical components, and the ASME OM Code should reflect this necessity.

SUMMARY

The requirements for vibration data collection on safety-related pumps in nuclear power plants have a long history that follows developments in the field of vibration analysis for equipment monitoring. Inservice testing of pumps was first implemented in ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, Subsection IWP, in 1974. By the late 1970's, vibration monitoring requirements in Subsection IWP which were codified as part of Nuclear Plant Inservice Testing (IST) Programs in Title 10 of the *Code of Federal Regulations*, Part 50, Section 55a, "Codes and standards," (10 CFR 50.55a), paragraph (g). The IST requirements for pumps, including vibration monitoring requirements, were removed from ASME BPV Code, Section XI, Subsection IWP, in 1988 and moved to the newly created ASME OM Code (Part 6 initially, now Subsection ISTB). The NRC incorporated by reference the new ASME OM Code in 10 CFR 50.55a in 1999.

Throughout all these changes in the applicable code, requirements for vibration monitoring evolved as the field of vibration analysis grew and understanding of pump health monitoring increased. The Code monitoring requirements changed over time such as the shift from using units of displacement monitoring to units of velocity. Equipment calibration requirements shifted as the transition from analog to digital instruments occurred. Requirements in monitoring frequency shifted as pump runtime was considered. However, one thing has remained steadfast over time, the requirement to use simple overall vibration values for trending and alarming in determining pump health.

During the 1990's, understanding of vibration behavior in rotating equipment proliferated. Nuclear power plants in the U.S. began transitioning from a time-based maintenance approach to a condition-based maintenance approach to equipment reliability. The profession of "Vibration Analyst" became a mainstream career in industry with training and certification structures. By the year 2000, most power plants had a vibration analyst on staff as part of a Predictive Maintenance Team and were employing advanced analysis techniques of Fast Fourier Transforms, time waveform analysis, high frequency enveloping, and other tools to detect equipment health issues and to plan maintenance. These capabilities became mainstream and were regularly applied to safety-related and balance-of-plant equipment in the pursuit of greater equipment reliability.

The ASME OM Code gave a nod to these greater analysis capabilities when the 2012 Edition of the Code was released, which added a new capability under the ISTB Corrective Actions section. The ability to use analysis of pump performance in lieu of mandatory increased frequency testing when Code-specified action levels were exceeded.

The 2012 Edition of the OM Code made the robust analysis of vibration data for pumps in the IST Program more important. The existing OM Code may only still require trending of basic overall values, but the value of going well beyond the Code requirements and embracing modern vibration analysis capabilities were now discussed in the Code itself.

Most nuclear power plants have transitioned to a condition-based maintenance (CBM) approach to equipment reliability on their IST safety-related pumps for reasons described in the Background section of this document. A big part of embracing a CBM philosophy necessitates maintaining qualified vibration analysts on staff and collecting routine dynamic and comprehensive vibration data.

Detecting equipment degradation well before Code IST vibration action levels are exceeded became common place in the 1990's and early 2000's. Concerningly, for the last 10 to 15 years, sites and fleets have seen a reduction of knowledgeable personnel and analytical capability. Retirements of highly trained vibration and predictive maintenance analysts have accelerated, leaving many sites with less qualified and proficient staff than was common just a few years ago. CBM/PdM analysis programs are much leaner than they were at the height of adoption, and expertise to perform complicated advanced analysis is no longer available at many sites. Some plants have reverted to reliance on basic overall vibration limits for discovery of equipment degradation. Departures of qualified analysts with no backup available have become common. Code compliance vibration monitoring is a minimum level of effort for equipment reliability, but it is not the state of the art in early detection of equipment health issues.

ASME Code requirements for vibration monitoring and its influence on the history Condition-Based Maintenance Philosophy adoption in the U.S.

Background:

The transition to a Condition-Based Maintenance Strategy from Time-Based Maintenance started in the 1980's. Several factors aligned in the early 1980's to accelerate the adoption of monitoring for degradation rather than periodic intrusive inspections and parts replacements.

- The Three Mile Island Kemeny Commission Report – subsequent reorganization of the NRC and heightened focus on improving equipment reliability.
- Growing awareness of multiple large studies on equipment reliability and Reliability Centered Maintenance Philosophies being adopted in the airline industry. These studies revealed that a large percentage of failures are random in nature, unaffected by time-based maintenance practices.
- The inclusion of performance monitoring requirements, including vibration monitoring, in the ASME BPV Code, Section XI (IWP) in the 1970's and the refinement of vibration monitoring criteria in the late 1980's with the creation of the ASME OM Code.
- Official endorsement and inclusion of the ASME Codes in NRC regulations required vibration monitoring and performance trending on safety-related equipment in nuclear power plants.
- The Electric Power Research Institute (EPRI) Publications on Vibration Program development and efforts focused on Predictive Maintenance Technologies beginning in 1986 as part of EPRI Eddystone Monitoring and Diagnostics (M&D) Center.
- Monitoring using dynamic data, more than just overall values, allows for identification of failure modes

Table 1 Research Studies on Equipment Reliability

SCOPE OF STUDY→ FAILURE PROFILE (NOTE 1) ↓		UAL: US Airlines	Broberg: Swedish Airlines	MSDP: Major System Development Programs [Military]	SUBMEPP: Submarine Maintenance Engineering, Planning and Procurement	SSMD: SIMA (Shore Intermediate Maintenance Activity) Submarine Maintenance Division
		Aircraft Components	Aircraft Components	Naval Vessel Components	Naval Vessel Components	Electronic Components
TIME-BASED	A 	4%	3%	3%	2%	6%
	B 	11%	8%	23%	29%	~7% (<1%)
	C 	5%	4%	3%	17%	0% (<1%)
RANDOM	D 	7%	11%	6%	9%	0% (<1%)
	E 	89%	92%	77%	71%	~93%
	F 	68%	66%	29%	6%	33%
NOTE 1: The symbol lambda (λ) represents the failure rate.						
NOTE 2: MDSP and SUBMEPP experienced more age-related failures due to sea water related corrosion.						

United Airlines Study (1968)

The United Airlines (UAL) study was the first large well-structured statistical study of airline equipment reliability with surprising findings:

- Most equipment failure modes are random and unaffected by time-based maintenance intervals.
- The ubiquitous “Bathtub Curve” depicting the way equipment wears and fails was only applicable to very simple mechanical systems or materials subject to known aging effects such as elastomers or corrosion.
- Scheduled overhauls have little effect on the overall reliability of a complex item unless the item has a dominant failure mode.
- For complex components, there is no effective form of scheduled periodic maintenance.
 - 77 to 92 percent of the total failure modes of complex machines are random.
 - Time-based maintenance activities do not address random failure modes and contribute to refreshing infant mortality failure modes.

Broberg (1973)

The Swedish Airline Study was similar to the UAL study.

- Study published results consistent with the UAL study with similar findings.

MSDP Studies (1983)

Naval Vessel study.

- Found more age-related issues due to corrosion-related failures which were defined as end-of-life in the extreme environment. 17 percent of failures were end-of-life failure modes compared to 2 percent for UAL.
- Random non-age-related failures predominated.

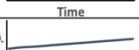
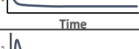
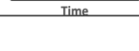
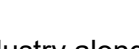
SSMD (1993)

Naval Electronics components study. RCM Handbook

- Found that electronic components are even more subject to random failure modes than mechanical components.

Study results affected the maintenance philosophy of the Nuclear Power Industry throughout the 1990's and 2000's.

Table 2 Failure Curves - Failure Profiles for Maintenance in Industrial Facilities [3]

	Failure profiles	Characteristics	Examples
Age related failures	A 	Associable to mechanical devices with low quality manufacturing process or mechanical devices with a necessary initial settling period.	Machines from late 18th to early 19th century.
	B 	Mechanical devices	Reciprocating-engine cylinders, turbine-engine compressor blades, all parts of the airplane structures.
	C 	Mechanical devices installed in adverse environmental conditions, devices installed out of the design work conditions.	Air filters or Salvage Air Valves in submarines.
	D 	Structures and wearout elements	Automobile bodies, tires, brakes, airplane structures, ship vessels, pressure vessels, etc.
Random failures	J 	complex devices with high stress work conditions.	High pressure relief valves
	K 	Complex devices or machinery with a well balanced design.	Gyro compass, multiple sealing high pressure centrifugal pump.
	L 	Electronic components, complex components after corrective maintenance.	Computers, notebooks, PLCs, etc.
	M 	Complex industrial machinery and industrial installations.	Whatever industrial plants taken into the account the commission stage.

The nuclear power industry along with many other industries began embracing the study results in the 1980's and began transitioning away from a time-based maintenance approach wherever possible.

This necessitated the implementation of a robust condition-monitoring philosophy to mitigate the random failure modes that predominate complex equipment.

EPRI embraced a Condition-Based Maintenance Philosophy in developing the Preventive Maintenance Basis Database (PMBD) first issued in 2000. This database now serves as the starting maintenance basis for a large majority of the U.S. nuclear fleet.

The nuclear power industry had been performing vibration monitoring on safety-related pumps since the early 1980's due to the requirements in the ASME Code. This helped facilitate the transition to a condition-monitoring approach to maintenance a fairly simple one in nuclear stations as the stations were already familiar with the concept and had equipment on-hand to perform vibration monitoring and performance monitoring of more components and staff familiar with its use. The implementation of Predictive Maintenance Programs has proliferated. By the early 2000's, most nuclear power plants in the U.S. and Canada had created Predictive Maintenance teams and fully adopted a Condition-Based Maintenance philosophy for safety-related and BOP [balance of plant] rotating equipment and were also applying the philosophy to any component where existing monitoring technologies could be used to detect and mitigate existing failure modes. EPRI issued multiple publications focused on implementation of Predictive Maintenance (PdM). INPO also issued multiple good practice publications on implementation of PdM and began including assessment of PdM programs in periodic plant assessments.

Industry conferences with a focus on CBM and Vibration Analysis became ubiquitous in the 1990's. Case histories presenting detection of degradation in rotating equipment including IST pumps with advanced vibration analysis well before overall vibration trends indicated a problem are common. The following is an example case history of the use of vibration analysis to detect degradation before overall vibration amplitudes were affected, and OM designated alarm levels were triggered.

Example Case History: (presented at EPRI Condition-Based Maintenance User Group, circa 2004)

Machine Details:

- Component: Pressurized Water Reactor (PWR) High Pressure Safety Injection Pump, 600 horsepower (HP) Horizontal Multi-stage barrel pump, 3580 revolutions per minute (rpm).
- Bearings: Motor - Sleeve bearings, Pump – Non-Drive End (NDE) = Back-to-back Angular Contact ball bearings, Drive End (DE) = Deep Groove ball bearing.
- Flow: Best Efficiency Point (BEP) = 500 gallons per minute (gpm). Full Runout Flow: 775 gpm at 2500 pounds per square inch gage (psig). Min-recirc flow: 75 gpm
- Coupling: gear type - greased

Event:

The pump in question is a safety pump that is normally idle such that it is categorized as Group B in the ASME OM Code. At the time this case history was documented in the late 1990's, the Group designations of the Code were not in place and the pump was fully tested with vibration data collected every 3 months. The pump was tested every 3 months at minimum-flow and Full Flow tested every 18 months. Due to the quarterly vibration collection being at minimum flow, the normal vibration on the pump is near 0.3 inches per second peak (ips pk) (7.6 millimeters per second (mm/s)). The ASME OM Code acceptable normal range limit is set at 0.325 ips pk with a maximum vibration limit at 0.7 ips. Vibration frequencies produced by the pump are predominately at 4x and 5x running speed frequency (this pump has impellers with 4 and 5 vanes). This 4x and 5x vibration is considered normal due to the low flow during quarterly tests causing a poor flow angle between the impeller vane tips and the diffuser. Full Flow vibration is also typically at about 0.3 ips pk and is primarily at 5x running speed due to the flow being near run-out conditions causing a similar poor flow angle. Vibration at the best efficiency point (500 gpm) is normally less than 0.1 ips pk (2.54 mm/s) with very little vane passing vibration.

During a planned mid-cycle outage, vibration data were collected during full flow IST surveillance, and the overall value trend was normal and in line with previous values. Since the pump was part of a robust PdM program, it was subject to full vibration analysis for all data collected. Analysis of the vibration spectrum noted a significant change in the frequencies present. A large 3/4x frequency had appeared on the outboard (NDE) radial measurement points, and 5x (vane pass) vibration was much lower than normal (Figure 1).

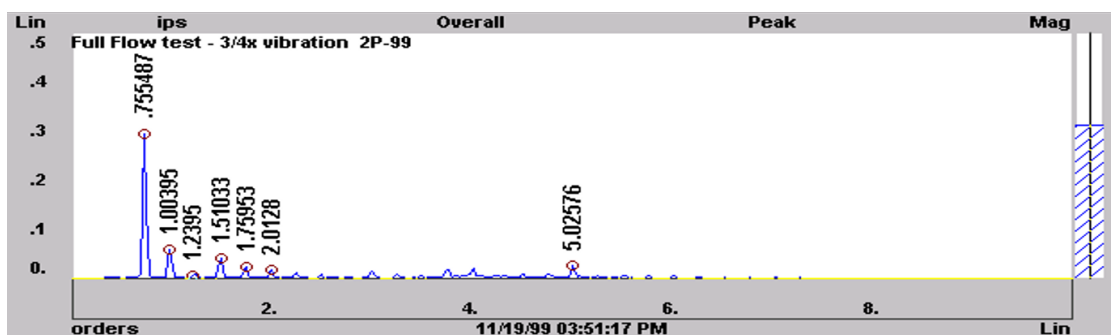


Figure 1 3/4x vibration at full flow

Management and the system engineer were notified of the change, and further testing to confirm the anomalous data was scheduled.

The pump was run at a lower flow of 630 gpm (closer to best efficiency point) and was run again at full flow of 775 gpm with additional vibration data collected.

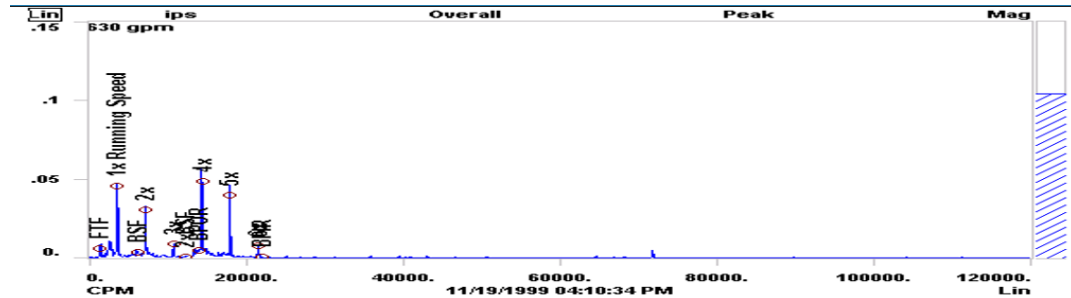


Figure 2 vibration at lower flow nearer BEP (no 3/4x)

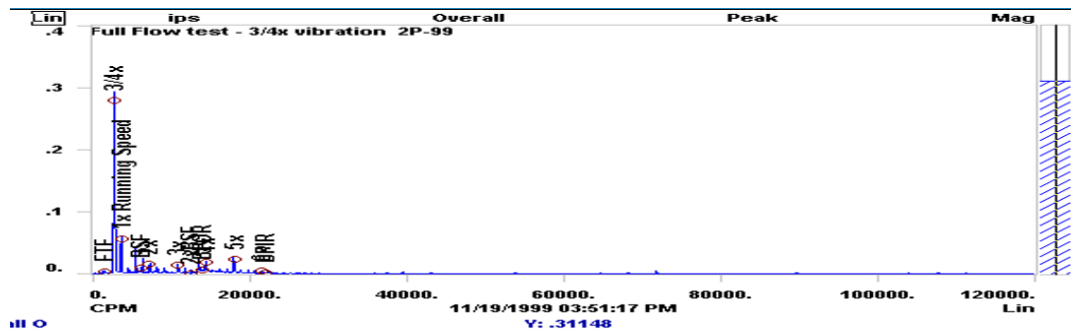


Figure 3 3/4x vibration at full flow

As can be seen from the plots above, the 3/4x vibration was absent at the lower flow, but was still present at full flow. Further analysis showed no indications of a rub or impacting in the time waveform.

A Failure Modes Analysis (FMA) was inconclusive as to the possible cause. 3/4x vibration is very unusual and normally occurs in conjunction with other sub-harmonics (such as 1/4x, 1/2x, etc.) in the presence of severe rubs, which had been ruled out by waveform analysis.

Investigation into the pump history is always part of any good anomaly investigation and a review of pump history found the pump rotating element was new. The pump had been rebuilt 6 months previously as part of a time-based refurbishment strategy. No issues or abnormal wear were found during the refurbishment. The post-maintenance testing (PMT) full flow vibration was normal after the refurbishment, and quarterly vibration data were normal leading up to the mid-cycle outage when the change in vibration was noticed during the full flow test.

The 3/4x vibration was so unusual, the FMA team recommended the pump be disassembled and inspected. Convincing management of the need for inspection required detailed explanation of complicated vibration concepts and advocacy from both the PdM Engineer and System Engineer because the pumps overall vibration was not above any code alarm limits. Overall value trends were normal.

During disassembly, the flow balance drum, located near the first impeller, on the outboard (NDE) of the pump was found loose and spinning on the shaft. The balance drum setscrews were missing, with only rust discoloration in the screw holes.

A review of the previous rebuild material sheets found that carbon steel setscrews had been used in the balance drum during the previous rotating element replacement instead of the stainless-steel screws recommended on the material sheet in the Technical Manual. The carbon steel screws had corroded in the highly borated water environment and completely disappeared over the 6 months between refurbishment and detection of the vibration change.

Continued operation with the loose balance drum spinning on the shaft would have eventually resulted in severe damage to the pump. The loose balance drum had the potential to affect internal pump geometry.

Takeaways:

- Material selection is important!
- Overall amplitude trending is not sufficient to detect all degradations and is not ideal for early identification of problems. Spectrum analysis by a trained analyst for changes over time is critical for early detection of degradation.
- Post Maintenance Testing will not always assure good health of the machine long term.
- Convincing management of the need for significant maintenance when overall trends are normal is difficult and requires skill in explaining complicated vibration analysis concepts.
- The fact that this issue was not detected during minimum flow quarterly testing corroborates the ASME Group A vs. Group B testing philosophy which places emphasis on data collection during comprehensive testing at flows closer to design best efficiency point.
- The issue was caused by human error, installing the wrong set screws, but ultimately, this failure was caused by the time-based maintenance strategy, which disassembled a pump operating in good condition and introduced a new failure mode. If the pump had been subject to a condition-based maintenance philosophy, this issue would not have been induced, and significant man-hours and dose would have been saved by avoiding a refurbishment and a 2nd subsequent rebuild.

Condition-Based Maintenance conferences are full of presentations making the same point as the above case. Examples include:

- Detection of degradation of bearings in both motors and pumps before degradation begins affecting overall values with required alarm limits set by the OM Code.
- Detection of coupling degradations with no change to overall value trends.
- Monitoring of higher frequency ranges on auxiliary feedwater (AFW) and reactor core isolation cooling (RCIC) Terry Turbines to detect degradations that do not manifest as overall value changes in velocity trends.
- Detection of gear issues which manifest as high frequency vibration that does not initially affect overall vibration trends.

Example Case History: (presented at EPRI Condition-Based Maintenance User Group, circa 2007)

Machine Details:

- Component: GE Vertical Motor (Safety Related Service Water), 600 HP Vertical Motor driving a deep draft vertical service water pump, 1780 rpm.
- Bearings: Non-Drive End (NDE upper bearings) = Face to back Angular Contact ball bearings 7330, Drive End (DE) = Deep Groove ball bearing.



Figure 4 Vertical Motor

Three vertical service water motors at a PWR nuclear power plant were experiencing bearing degradation on an average of every 4 years. The short bearing life was due to a design with the bearing load near the maximum static and dynamic load ratings. These are very smooth running vertical motors with required vibration data on a quarterly frequency in accordance with ASME OM Code. The overall value trend shown in Figure 5 below encompasses a period of over 20 years showing 4 detected bearing degradations, all of which were detected well before values reached alarm limits.

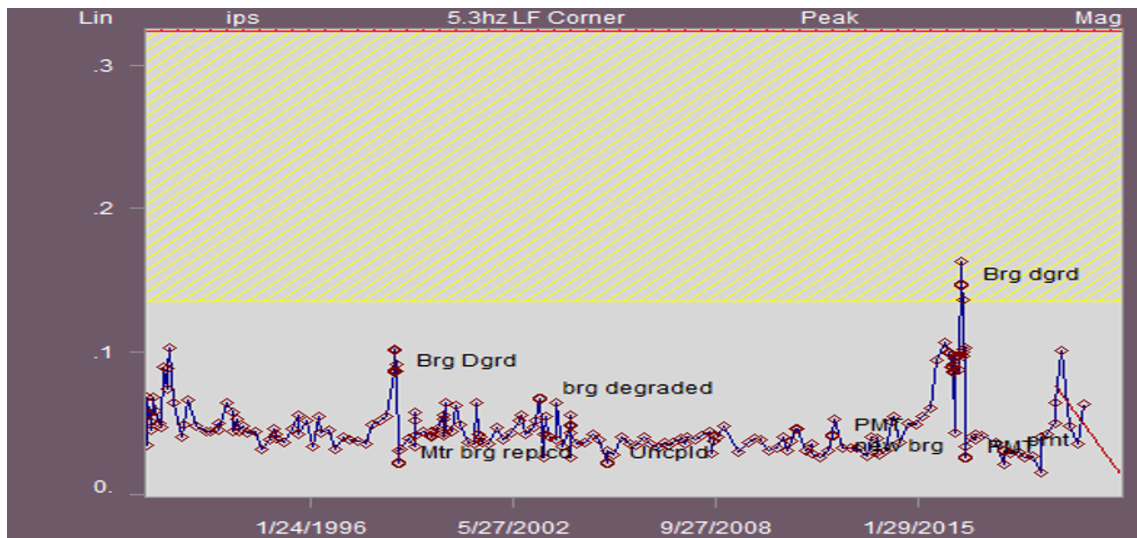


Figure 5 20-year vibration trend

Note that most of the bearing degradations were identified and repaired long before vibration amplitudes reached an alarm limit and sometimes before a rise in overall amplitude was obvious. This was accomplished by regular review and analysis of spectral and waveform data by a trained analyst. The goal of predictive maintenance is to identify issues to allow scheduling repair, and avoiding perturbation of the station work schedule with emergent maintenance.

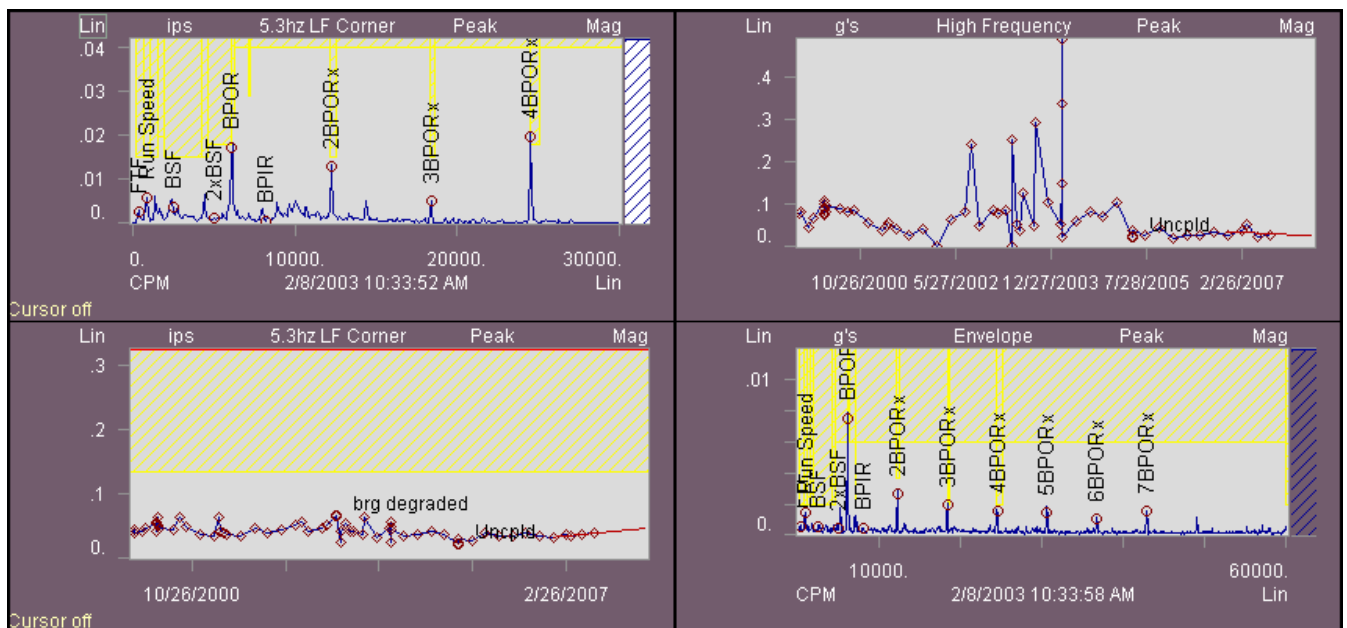


Figure 6 Vibration trend and spectral data

Figure 6 depicts a bearing degradation that was detected and repaired with no obvious change in the overall vibration trend. The FFT spectrum and envelope spectrum clearly show bearing faults. Figure 7 is a picture of the removed bearing with significant spalling damage on the race.



Figure 7 Damaged Bearing

Takeaways:

- Overall amplitude trending is not sufficient for early identification of problems. Spectrum analysis by a trained analyst for changes over time is critical for early detection of degradation.
- Depending on overall amplitude to trigger Code alarm limits would result in disruption to the station work schedule due to the need for immediate action once the level is reached.

Closing

The last 20 years have been challenging for the nuclear industry in terms of competition, cost control, knowledge retention, and resource scarcity. Efforts in the mid-2000's to slow the expanding costs in the nuclear industry resulted in the 2007 Nuclear Promise, which had an amazing impact on nuclear competitiveness in energy markets. But these efforts had a downside. Many non-Code programs, including Predictive Maintenance Programs, were removed from "official" program status and are no longer subject to assessments by internal or outside organizations. Health reporting of the program was no longer required and a slow

Cost Category	2012 Costs (\$/MWh)	2022 Costs (\$/MWh)	Realized Reductions
Fuel	\$9.15	\$5.37	\$3.78 (41.4%)
Capital	\$14.01	\$6.46	\$7.55 (53.9%)
Operations & Maintenance	\$28.05	\$18.36	\$9.69 (34.6%)
Total Generating	\$51.21	\$30.18	\$21.03 (41.1%)

removed from "official" program status and are no longer subject to assessments by internal or outside organizations. Health reporting of the program was no longer required and a slow

reduction in resources ensued. INPO Good Practice publications on Predictive Maintenance were retired, and PdM programs were no longer included in periodic INPO assessments. Many PdM programs have transitioned from a staff of 3 or more analysts (at a single unit site) in the early 2000's down to 1 person and the remaining analyst is typically responsible for all PdM technologies (such as vibration analysis, oil analysis, thermography, etc.). Most fleets no longer have a designated fleet lead for PdM. Several sites have experienced retirement of their highly experienced vibration analyst without another experienced backup to step into the role. Many plants have advanced analysis equipment such as multi-channel vibration trouble shooting equipment on the shelves with no one left who knows how to use it.

This trend is concerning in an industry that transitioned to a Condition-Based Maintenance philosophy over the course of 30 years. The gains in capacity factor and equipment reliability over that time are intricately tied to the change in maintenance philosophy, and the maintenance philosophy is highly dependent on having highly qualified analysts looking at data and identifying issues early enough to avoid perturbation of work schedules. Many time-based refurbishment tasks on critical equipment such as IST pumps were retired in favor of the higher equipment reliability gained from robust condition monitoring.

The requirements in the ASME OM Code for vibration monitoring were directly influenced by the knowledge revealed in reliability studies showing the majority of failure modes in pumps are random.

The current Code requirements have changed significantly from the early requirements in ASME BPV Code, Section XI, Subsection IWP, but the requirements still represent only a minimum effort required to identify degradation before unanticipated failure can occur. Going beyond those requirements has been a hallmark and triumph of the industry with historically unprecedented equipment reliability to show for it. ASME support for vibration analysis well above and beyond minimum Code requirements has been manifested in several ways.

- Deviations from the Code acceptance criteria often implement predictive maintenance analysis as part of the alternative.
- Alternative requests to the NRC for deviation from Code alarm limits for smooth running pumps (<0.05 ips pk) often specify the pumps must be subject to additional advanced analysis from a predictive maintenance program.
- ASME OM Code Case OMN-29, Pump Condition Monitoring Program, was approved. This code case outlines multiple advanced monitoring technologies for use in pump testing, including vibration analysis.
- The ability to use analysis in evaluating vibration above alarm limits in lieu of doubling the test frequency has been part of the OM Code since 2012.

This paper is meant to familiarize those new to nuclear power as to how the industry developed its maintenance practices and achieved high-capacity factors. It is also meant as a reminder for those that have been in the industry for a long time of the history, scientific studies, and transitional period that resulted in current maintenance practices. This paper also seeks to implore plant management not to succumb to the temptation of re-implementing time-based

maintenance in the interest of budget stability. Random failures will still occur at the same rate no matter how often you refurbish that pump, and the site will have to deal with increased infant mortalities due to the time-based intrusive maintenance. Make sure your Predictive Maintenance Programs have adequate resources and continue to provide the early warning of equipment health issues that is so central to our modern maintenance philosophies.

ACKNOWLEDGEMENTS

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ISTB Pump Periodic Verification Testing and Implementation Guidance

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ABSTRACT

As Chair of Subcommittee on Pumps (ISTB) of the American Society of Mechanical Engineers (ASME) Operation and Maintenance of Nuclear Power Plants, Division 1, OM Code: Section IST (OM Code), and an Inservice Testing (IST) Consultant developing revised IST Basis Documents and program plans for IST Programs, I have developed an implementation issue paper to assist nuclear power plant licensees with the requirements of Pump Periodic Verification Test (PPVT) Scope and Implementation for the 2020 and 2022 Editions of the ASME OM Code. This paper was developed based on Pump Periodic Verification Test requirement implementation and as part of the 2020 Edition of the OM Code, as well as the 2022 Edition.

This paper will discuss issues related to IST implementation for PPV, and the impact on the plant's current Comprehensive Pump Testing requirements, as well as outside support (from plant staff) that may be needed to identify the test parameters. First, the entire pump population within the IST Program has to be screened in order to determine which pumps have specific design-basis accident flow rates in the Owner's credited safety analysis (e.g., technical specifications, technical requirements program, or updated final safety analysis report (FSAR)) for inclusion in the PPVT program. Second, the pumps that are selected to be within the PPV Scope requirements need to have the accident analysis flow rates determined based on the licensing documents for each site. The credited flow rates may be listed in the FSAR or within Technical Specifications and in some cases within the Technical Requirements Manual (TRM), or within Accident Analysis calculations for the site. Additionally, the design requirements based on the purchase specifications had to be known to identify the Design Flow Rate to meet the requirements for Comprehensive pump test procedures in the current intervals for each site.

There were significant changes from standard comprehensive testing requirements in the 2004 Edition through the 2006 Addenda of the ASME OM Code. Current programs implementing the 2004 Edition through the 2006 Addenda of the OM Code are required to perform Comprehensive Testing from 80 percent to 120 percent of the Design Flow Rate. The comprehensive pump test requirements were changed in the 2012 Edition of the OM Code to allow for comprehensive testing at an Owner-specified test flow.

However, for the updates our company has worked on for the last 12 years, we have found that most plants do not alter the Comprehensive Test parameters for the new interval for the pumps that are within the PPV scope. This goes back to the 2012 Edition of the OM Code requirements for the ASME OM Code, Appendix V. This presentation will show you what is required for compliance with the PPV scope for the 2020 and 2022 Editions of the OM Code and what tasks are required during your 10-year Interval Update.

BACKGROUND

Appendix V was added to the ASME OM Code with the 2012 Edition. As part of the Purpose (Scope), this Mandatory Appendix establishes the requirements for implementing a PPV test. As discussed in ASME OM Code, Subsection ISTB, paragraph ISTB-1400(d), the Owner shall establish a PPV test program for certain applicable pumps (with design accident flow rates credited in the accident analysis) that are tested in accordance with the ASME OM Code, Subsection ISTA, paragraph ISTA-1100. As an Owner, each site has to review the safety functions of the pumps included in the IST program and review the FSAR, Technical Specifications and TRM (as applicable) to evaluate these pumps and determine if the pump has a specific design-basis accident flow rate in the credited safety analysis (e.g., technical specifications, technical requirements program, or updated safety analysis report) for inclusion in the PPV program.

Each plant should have established Comprehensive Pump Flow Rates within ± 20 percent of Design Flow Requirements, as part of ISTB-3300(e)(1) *“Reference values shall be established within $\pm 20\%$ of pump design flow rate for the comprehensive test”* to meet the 2004 Edition through the 2006 Addenda (or in some cases the 2004 Edition). In most cases, the design flow rate should be higher than the accident analysis flow rate. The discharge or differential pressure (dp) is the key to PPV requirements. As part of the 2012 and 2017 OM Code requirements, each plant had to reconcile Appendix V to the ISTB Comprehensive Testing. For the 2020 and 2022 Editions, the plant has to reconcile Comprehensive Testing to ISTB PPVT requirements. Identifying the highest accident flow rates and highest discharge pressure or differential pressure required for the PPVT is the key to satisfying these requirements, going forward.

In order to address issues with flow rates, two defined flow rates are to be discussed. The term “Design Flow Rate” comes from the actual pump design and is discussed in the 1995/1996 Edition/Addenda through the 2004/2006 Edition Addenda of the ASME OM Code, Subsection ISTB. The “Design Flow Rate” came from the actual pump design specification or was listed in FSAR tables as part of the licensing and design basis of each plant. As part of these Code Editions/Addenda, pumps were required to be tested every 2 years at ± 20 percent of the “Design Flow Rate” as part of the Comprehensive Pump Testing Requirements. In the 2012 Edition of the ASME OM Code, Subsection ISTB, the requirement to test the pump at ± 20 percent of the “Design Flow Rate” has been removed and the plants are no longer required to test at this flow rate.

However, Pump Periodic Test Requirements require a PPVT per the ASME OM Code, Subsection ISTB, paragraph ISTB-1400(d) if the current testing is not binding of the Accident

Analysis Flow Rates and associated Differential Pressure (or Discharge Pressure for Positive Displacement Pumps). As part of the 2020/2022 Editions, the ASME OM Code, Subsection ISTB, paragraph ISTB-1400(c) was revised to state “*establishing a comprehensive pump test flow rate for each pump.*” The ± 20 percent of the “Design Flow Rate” was removed from the ASME OM Code, Subsection ISTB. Paragraph ISTB-2000, “Supplemental Definitions,” specifies the definition of “*comprehensive pump test flow rate*” as follows:

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.

DISCUSSION

This PPV program consists of those pumps credited in the accident analysis for accident mitigation by providing flow during the accidents within the analysis. In most cases, these pumps are Engineered Safety Feature (ESF) powered and part of the Emergency Core Cooling System (ECCS) for each plant. Comprehensive flow rates have been established to meet the requirements from previous editions and addenda of the OM Code. A solid basis for inclusion or exclusion from the Periodic Verification has to be developed, even if your current Comprehensive Testing is at the Design Basis Accident Flow Rate. Also, as part of your analysis for the development of PPV Testing, the actual test has to verify a pump can meet the required differential or discharge pressure as applicable, as its highest design-basis accident flow rate. The key element here is the discharge or differential pressure. In many cases, the design-basis accident flow rate will be listed in the FSAR or Technical Specifications, but the required differential or discharge pressure may not be easily retrieved. In some cases, it may be necessary for the Owner to determine the discharge pressure or differential pressure through analysis or calculations to establish the acceptance criteria. Do not confuse Design Flow Rates with Accident Analysis Credited Flow Rates. These are normally two different values. The accident flow rate should be lower than the design flow rate.

In some cases, where a Pressurized Water Reactor has a dry header for Containment (or Building Spray for B&W Nuclear Steam Supply System) Spray System, or does not have a full flow test loop for Containment Spray return to the Refueling Water Storage Tank (or Borated Water Storage Tank), the required differential pressure or discharge pressure at the highest accident flow rate may not be achievable without significant plant modifications. Also, in some cases, it may be hard to recreate the test conditions to simulate the accident scenario because the Reactor Coolant piping would experience a guillotine shear and the differential pressure would be so low, a correlation may be required, as not to damage plant equipment during the test.

For most Boiling Water Reactor (BWR) designs, full flow testing is available and many plants actually perform Comprehensive Testing on a quarterly frequency. In these cases, the highest flow and discharge/differential pressure have to be identified and added to the test procedures, unless the Comprehensive Test is bounding for PPVT. In many cases, the Comprehensive Pump testing may be binding for the Pump Periodic Test Program and no actual PPVT is

required. In those cases, the acceptance criteria have to be listed in the IST Basis Document and the evaluation documented that indicates the comprehensive test procedure that bounds the PPVT requirement.

CURRENT EVENTS

When the 1995 Edition of the ASME OM Code was implemented by U.S. nuclear power plants, there were some challenges for the Pressurized Water Reactor (PWR) designed plants in relation to achieving the ± 20 percent Design Flow Rate for Containment Spray Pumps. At this point, each PWR should have determined that 80 percent of the Design Flow Rate was not obtainable, or in some cases, the 80 percent may have been obtainable but the Accident Analysis Flow Rate may not be.

In previous intervals, the licensee of North Anna Units 1 and 2 obtained relief from the NRC based on their Outside Recirculation Spray (ORS) pumps being below Code required flow rates. The Comprehensive Tests could not reach the 80 percent of the Design Flow Rate and in 2020, the request was revised to include Appendix V (2017 Edition of the OM Code). These ORS pumps are tested with a 4-inch recirculation line. The request was updated to include the new requirements in Mandatory Appendix V of the ASME OM Code. Guidance provided in Section 5.10 of NUREG-1482 was followed. In NUREG-1482, Revision 3, Section 5.10, *“Alternative to ASME OM Code Comprehensive Pump Testing Requirements”* (now updated as Revision 4), the NRC staff stated the following:

The Comprehensive Pump Test was developed with the knowledge that some pumps, such as containment spray pumps, cannot presently be tested as required at the required high flow rates because of system design limitations. Consequently, subparagraph ISTB-3300(e)(1) requires licensees to establish reference values within $\pm 20\%$ of the design flow for CPT.

The request was a carryover from the previous interval where the design flow rate could not be obtained.

With the changes made in the 2012 Edition for ISTB, the ± 20 percent requirement is no longer part of Subsection ISTB of the OM Code. The 2012 Edition of the OM Code revised ISTB-3300(e)(1) to state “Reference values shall be established at the comprehensive pump test flow rate for the comprehensive test.” When implementing the 2012 Edition or a later edition of the OM Code, the site no longer has to perform a comprehensive test within 20 percent of the Pump Design Flow Rate. A point in the pump curve that is optimum to performance can be selected and trended, as long as a new reference point is established and maintained throughout the interval, as to allow for adequate trending. In some cases, pump curves are used for testing, and Code Case OMN-16, Revision 2, still includes the ± 20 percent of pump design flow rate requirement for the comprehensive pump test shown as a requirement in paragraph 16-3300(d). If your site is not using OMN-16 or OMN-18 (which also includes the ± 20 percent of pump design flow rate requirement for the comprehensive pump test) to perform pump testing, you no longer have to perform the comprehensive pump test within 20 percent of the Design Flow Rate.

However, based on the accident flow rate and discharge/differential pressure requirement of Subsection ISTB (and Appendix V for the 2017 Edition), you may want to continue the setup you have for comprehensive testing and enhance the test by verifying the pump periodic verification test (PPVT) (or Appendix V for 2017 Edition) requirements are within your current comprehensive test procedure acceptance criteria.

Each site has to perform either a comprehensive pump test AND a PPVT or steps can be added to the current comprehensive pump test to establish the PPV test parameters (dp/discharge pressure and flow). The pump periodic verification test does not require vibration measurements nor does it establish a timeframe for how long the pump must maintain these values. If feasible, you would just alter the parameters to include the PPVT values toward the end of your comprehensive test. In some cases, if your pump is tested above the PPVT flow and discharge pressure/dp, you can bound your PPVT requirement within your Comprehensive Pump Test. Footnote 1 of Appendix V in the 2012 Edition of the ASME OM Code 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.

For many BWR design plants, full flow testing is performed quarterly using Code Case OMN-18, or per paragraphs ISTB-5000(a) and (b), when a Group B or A test is required, a comprehensive or preservice test may be substituted. The difference here is OMN-18 allows for the use of a modified Group A Test where the lower end of the acceptance criteria can be as low as 0.90 for flow or dp, and the comprehensive pump test limit is 0.94 for flow and 0.93 for dp (2012 OM Code, Table ISTB-5121-1). If the lower end of the criteria is used, Code Case OMN-18 should be used. Some of the BWR plants that have been updated to the 2012 or 2017 Editions of the OM Code have been able to take credit for the comprehensive pump test performed quarterly. One site in particular had detailed calculations for flow and differential pressure that made Appendix V adoption much easier. BWR plants licensed after the TMI event have marginal concerns for Appendix V implementation.

For PWR plants moving into the 2017 Edition of the OM Code, a good example of transitioning to the Appendix V requirements creating issues occurred for the IST Program at Oconee. Oconee's Fifth IST Interval is performed in accordance with the 2004 Edition through the 2006 Addenda of the ASME OM Code. As part of the Comprehensive Pump Test requirements for the Building Spray Pumps (B&W PWR design), the pumps are tested at 750 to 765 gallons per minute (gpm) because there are significant pump performance assumptions that are not adequately covered by testing at a higher gpm alone. The Updated Final Safety Analysis Report (UFSAR) Section 6.2.1.1.3.2 and UFSAR Table 6-26 require a 900 gpm flow rate for long term recirculation (accident analysis flow rate). The Injection Flow rate from the Borated Water Storage Tank is about 700 gpm. With the comprehensive pump reference value allowance of ISTB-3300(e)(1) of the 2006 Addenda of the ASME OM Code within ± 20 percent of pump design flow rate, a flow based on 900 gpm less 20 percent is 720 gpm. With testing performed at 750 to 765 gpm, the flow rate for comprehensive is considered to meet the 2006 Addenda

requirements. However, when the Appendix V requirements are imposed for the 900 gpm flow rate, without a full flow test loop to achieve this flow rate, a request can be created and submitted to the NRC.

ADDITIONAL ISSUES

For some plant designs, the NSSS supplier may have to perform some analysis to correlate your accident analysis flow rates along with differential pressure or discharge pressure, in order to identify what those requirements are as it applies to your analysis. In other words, with the guillotine shear of your largest Reactor Coolant System (RCS) piping, the differential pressure is drastically reduced for the accident scenario (Large Break LOCA). Depending on the physical location of your pump and the elevation of the RCS piping at the break, many assumptions have to be in place and a calculation may be required to determine what those numbers will be. In some cases, the analysis may be part of a flow model that requires further analysis. Those numbers may not be readily available within your design and licensing basis for your plant.

There are instances where sites are working with Westinghouse to identify the compliance requirements associated with ASME OM Code, Subsection ISTB, for a pending IST Program Update. If your plant has an Interval Update coming up in the next few years, you may want to start looking at your accident analysis flow rates and differential pressure values in preparation for the implementation requirements with the new Code of Record.

In most cases, the IST Vendor supporting your IST Interval Update will not be able to provide you the analysis determinations you may need to support your update. The Vendor can locate and/or identify the numbers from the FSAR, Technical Specifications or Technical Requirement Manual, but in many cases, the flow may be listed within a Table, but the differential pressure may not be listed or is not found in your analyses. An engineering analysis or calculation would be required to determine the highest differential pressure for the various scenarios in the accident analysis. Many years ago, working as an IST Engineer at DC Cook Nuclear Plant, in order to obtain the maximum accident flow rates for check valves in the ECCS injection loops for Safety Injection and Residual Heat Removal (RHR) systems, an extensive amount of research was required. For DC Cook design, where the systems were piggy-back alignment for long term recirculation, there were 14 tables within the accident analysis with flow rates. It may be necessary to start looking for these numbers for PPV Requirements long before the start of your interval. It may also require involvement from the NSSS vendor to support your identification of highest flow rate and highest discharge pressure or differential pressure to establish your test parameters. You may find these values unattainable without plant modifications, and a request submitted to the NRC could be required.

SUMMARY

The purpose of this paper is to share experiences gathered while implementing the 2012 and 2017 Editions of the ASME OM Code as it applies to the challenges of Appendix V on the Design and Licensing Basis of your facility, as well as application of Subsection ISTB requirements for the 2020 and 2022 Editions of the OM Code. While the comprehensive flow

rate can be changed when implementing the 2012 and newer editions, from the ± 20 percent of the "Design Flow Rate," to a more manageable rate of flow (where the pump is known to operate acceptably), I have found that after 10 to 20 years of testing within 20 percent of the "Design Flow Rate" many plants are reluctant to change their comprehensive pump test procedures. The lack of change could be for a number of factors. One factor is believed to be the effect it has on the Operations Department and the learning curve associated with pump testing. Also, with up to 20 years of trending values from previous comprehensive tests, it is easier just to continue to use those reference values already established. Since the plant has been testing all of the IST Pumps every 2 years to the comprehensive values, it may be easier just to add the PPV Test values to the current comprehensive pump test procedure as long as plant design and analysis support this approach.

This paper also was written to inform Owners to be aware of challenges you may face with Containment Spray or Building Spray Pumps that are not equipped with a full flow test line. If your site has a full flow test line, there may be no issue or concern. However, if your discharge or differential pressure is not easily identifiable in your FSAR or Technical Specifications, you may want to start looking at developing calculations and associated analyses to create/identify those numbers and then see if you can verify those numbers during an actual test.

BIOGRAPHICAL SUMMARY

The author, Melvin L. McGaha, is a Senior Project Engineer for Iddeal Solutions, LLC. As a Project Engineer, Mr. McGaha manages the Inservice Testing Projects assigned to him and his team of IST Engineers, including Inservice Testing Program Interval Updates. Over the last 25 years, Mr. McGaha has been involved in IST Program Updates for ANO Unit 2, Indian Point Unit 3 (twice), ANO Unit 1, Grand Gulf Nuclear Station, River Bend Station, Susquehanna Steam Electric Station, Browns Ferry Nuclear Plant (twice), Sequoyah Nuclear Plant (Bases), Watts Bar Nuclear Plant (Bases), Donald C. Cook Nuclear Plant (twice), Shearon Harris Nuclear Power Plant, Catawba Nuclear Station (twice), Brunswick Nuclear Generating Station, Indian Point Unit 2, H.B. Robinson Nuclear Generating Station, Oconee Nuclear Station, South Texas Project, Prairie Island Nuclear Power Plant, Enrico Fermi Nuclear Generating Station, Davis Besse, for a total of 37 Units updated (approximately 40 percent of the US Nuclear Fleet). Mr. McGaha has also provided site support for Inservice Testing at Indian Point 3, DC Cook, Quad Cities, HB Robinson and James A. Fitzpatrick Nuclear Plants. Support for the Corporate Office of TVA was provided in 2012 for the update of 3 Units at Browns Ferry Nuclear Plant and 95-003 issues as well as review of previous intervals for extent of condition. Mr. McGaha also provided site support as Project Manager for Local Leak Rate Testing at Limerick, Peach Bottom, and LaSalle Nuclear Sites during refueling outages. Mr. McGaha is a Member of the ASME OM Standards Committee, Chairman of the Subcommittee for Pump Testing (ISTB), Member of the Subcommittee for General Requirements (ISTA), and Chairman of the Regulatory Interface Task Group (RITG). Mr. McGaha has a total of 46 years' experience in commercial nuclear power.

Check Valves

Track Chair:
Domingo Cruz
APS/Palo Verde Generating Station

Phased Array Sectorial Scanning (Pass) to Determine Valve Operational Readiness

Jesse Delgado

Industrial Inspection and Analysis

This presentation provided a description of a method for applying advanced Ultrasonic phased array techniques to establish the operational readiness of safety and non-safety-related valves using three valve type examples. The phased array sectorial scanning (PASS) techniques take advantage of accessible areas of the valve to introduce and steer sound waves in the direction of internal component assemblies. A time encoded process is used to permanently capture data from the sound waves propagating through the bonnet or body into the water and interacting with the valve internals. Data analysis is then performed to determine dynamic or static behavioral characteristics of the valve internals and location measurements of key components. The initial data collection can be considered a baseline and subsequent PASS test data sets can be used for historical trending and monitoring of the valve's condition over the valve's life cycle.

Approval for Mechanical Agitation of Pressure Isolation Valve Testing

Russell D. Wells

Senior Program Manager
Nuclear Fleet Licensing
Tennessee Valley Authority

This presentation discusses a nuclear industry first-of-a-kind inservice testing (IST) alternative request to allow the use of mechanical agitation for troubleshooting certain pressure isolation valves (PIVs) that fail to meet the allowed leak limit in the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code). PIV testing is performed during startup from a refueling outage. If one of these PIVs fails and cannot pass at a higher pressure, without this alternative request, there is no remedy other than to repair or replace the valve as required ASME OM Code, Subsection ISTC, paragraph ISTC-3630(f). There is no other corrective action allowed by the ASME OM Code. In some cases, mechanical agitation has been necessary to get the valve to seat well enough to achieve an acceptable leakage rate. Mechanical agitation is a troubleshooting tool rather than a repair method. Review of the ASME OM Code and industry operating experience search revealed a U.S. Nuclear Regulatory Commission (NRC) Non-Cited Violation in 2019 at the Turkey Point Nuclear Plant regarding the unacceptable use of mechanical agitation for preconditioning. This resulted in Tennessee Valley Authority's (TVA's) determination that the use of mechanical agitation, in lieu of corrective maintenance and valve closure with no additional closing force applied, would require a request for an alternative to the requirements of ASME OM Code Subsection ISTC, paragraph ISTC-3630. This presentation discusses the efforts required to develop and obtain NRC authorization of this alternative request.

Valves

Track Chair:
Dharmesh Patel
Southern Nuclear Operating Company, Inc.

Appendix J Leak Rate Changes Between Test and Accident (Pa) Pressures

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ABSTRACT

Evaluation of expected leakage change is described for conditions where Title 10 of the *Code of Federal Regulations*, Part 50, Appendix J, leak testing occurs at test pressures greater than accident (Pa) pressure for valve applications where pressure tends to increase the seat load. The OM Code [1] provides guidance for test pressures less than accident pressure and allows the licensee to adjust the leakage results up to the functional maximum differential pressure (DP) value. By contrast, many licensees are testing at a higher test pressure than the accident pressure (Pa) and the OM Code does not provide guidance on how to address this scenario. This presentation will offer a technical discussion on the topic and what can be done to evaluate expected valve leakage changes at Pa conditions when the test pressure is greater than Pa for instances where pressure tends to increase the seat load.

Evaluations are performed for various valve types and designs to determine the expected changes in seat stress and load for valve installations where flow/pressure tends to increase seat load. An assessment is provided to determine if increased leakage can be expected at the lower accident pressures. Verification leakage testing at both Pa and the higher Local Leak Rate Testing (LLRT) test pressure are recommended where there is uncertainty in the analytical evaluation.

INTRODUCTION

Background and Technical Approach

Local leak rate testing (LLRT) is performed to satisfy U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR Part 50, Appendix J [2, 3] requirements and is conducted according to ANSI/ANS 56.8, Containment System Leakage Testing Requirements [4]. For this evaluation, the applicable scope are valves where a higher DP results in increased sealing, such as a check valve.

Leakage depends on many variables, including seating surface finish (waviness and roughness), seat materials, seat contact width, and seating load. Higher seat loads would tend to decrease the size of microscopic flow passages at the seating interface and diminish the size of the leak passage.

The approach used for gate and globe valves is to evaluate the reduction in seat load from LLRT DP to Pa DP to determine if the size of the leak path is likely to enlarge to such the point where measured leakage will increase. For tapered plug valves the total sealing force (sum of upstream and downstream seat load) is evaluated within the range of LLRT test pressures. For swing and piston (lift) check valves the approach is to determine the reduction in seating stress

for soft-seated designs and the increase in leak path area for metal seated designs. A combination of analysis, industry data, and supporting test data (if available) are used.

NOMENCLATURE

C_L	Leakage coefficient, Flow Rate/ $\sqrt{DP}$
C_{L1}	Leakage coefficient at condition 1, Flow Rate/ $\sqrt{DP}$
C_{L2}	Leakage coefficient at condition 2, Flow Rate/ $\sqrt{DP}$
DP	Differential pressure, psi
$DP1$	Differential pressure at condition 1, psi
$DP2$	Differential pressure at condition 2, psi
DP_{max}	Differential pressure greater than DP_{test} , psi
DP_{test}	Test differential pressure, psi
LLRT	Local Leak Rate Testing
L	Leakage rate based on seat leakage coefficient and differential pressure across the interface, Flow Rate
L_1	Leakage rate at condition 1, Flow Rate
L_2	Leakage rate at condition 2, Flow Rate
L_{test}	Tested leakage rate at DP_{test} , Flow Rate
L_{max}	Calculated leakage rate at DP_{max} , Flow Rate
P_a	Maximum expected containment accident pressure, psig
P_{test}	LLRT test pressure, psig

SCOPE

The applicable scope are valves where a higher LLRT differential pressure results in increased sealing, such as a check valve or globe valve with flow over the seat.

APPROACH AND METHODS

Generic Leakage Evaluation

Leakage depends on many variables, including seating surface finish (waviness and roughness), seat materials, seat contact width, and seating load. Fortunately, LLRT valves are proven to meet acceptable leakage criteria under the tested conditions, which provide assurance that the seating surfaces are in good condition and that minimum seat loads (pounds per inch (lb/in)) required to achieve sealing have been obtained.

For valves where "...service pressure will tend to diminish the overall leakage channel opening, as by pressing the disk into or onto the seat with greater force," ASME OM Code, Subsection ISTC, paragraph ISTC-3630 [1] allows use of the following formula to estimate the leakage. L_{test} , is the measured leakage at a test differential pressure of DP_{test} , L_{max} , is the calculated leakage at DP_{max} , where DP_{max} is higher than DP_{test} .

$$\frac{L_{max}}{L_{test}} = \sqrt{\frac{DP_{max}}{DP_{test}}} \quad \text{Equation 1}$$

This equation conservatively assumes the microscopic leak flow passages at the seating interface providing the flow resistance remain constant in size with increasing seal load due to a higher-differential pressure condition. It also assumes the leakage is proportional to the square root of the test differential pressure. Higher pressure would tend to decrease the size of microscopic flow passages at the seating interface as shown in Figures 1 and 2.

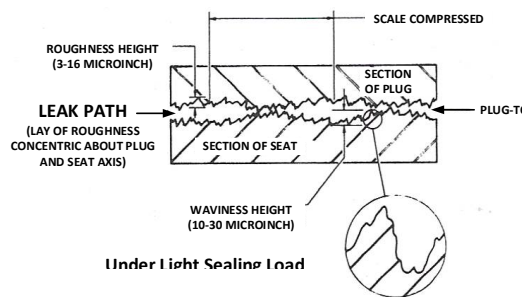


Figure 1 Illustration of Lightly Loaded Seat Interface [5]

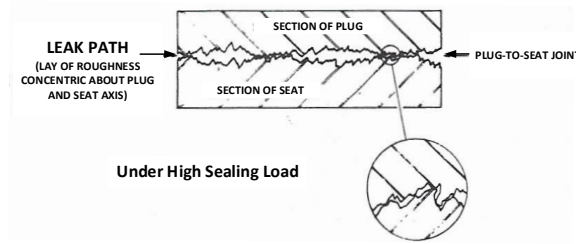


Figure 2 Illustration of More Highly Loaded Seat Interface [5]

In this analysis, the seat load decreases with decreasing test differential pressure. The amount of seat load decrease is limited to the portion of seat load produced by differential pressure and not from other contributions such as actuator or spring force and wedging.

For a given leak flow path, the leakage, L , is proportional to the square root of the differential pressure according to ISTC-3630 [1]. A leakage coefficient proportionality constant, C_L , is given to relate the square root of the pressure differential to the leakage flow rate.

$$L = C_L \cdot \sqrt{DP} \quad \text{Equation 2}$$

Over the small change in test air pressure, any physical properties of the air test fluid associated with C_L would be relatively constant (air density, etc.) such that only the change in leak flow passage size is important. Therefore, leakage at Condition 1 and Condition 2 can be determined as follows:

$$L_1 = C_{L1} \cdot \sqrt{DP1} \quad \text{Equation 3}$$

$$L_2 = C_{L2} \cdot \sqrt{DP2} \quad \text{Equation 4}$$

To maintain the same leakage (i.e. $L_1 = L_2$) at test DP condition 1 (DP1) and test DP condition 2 (DP2), the following relationship between the leakage coefficient, C_L , and DP is obtained:

$$\frac{C_{L2}}{C_{L1}} = \sqrt{\frac{DP1}{DP2}} \quad \text{Equation 5}$$

Using Equation 5, if the LLRT test DP changed, for example, from 16.5 psi to 9.0 psi then the leakage coefficient can increase by 35 percent before the measured leakage at the lower DP2 would increase from the measured leakage at the higher DP1. If the relationship between leakage flow rate and DP were linear or squared (DP^2), as suggested by some references. For compressible fluid, the predicted allowed change in leakage coefficient would be larger. Therefore, it is conservative to assume a square root relationship.

Motor-Operated Wedge Gate Valves

During LLRT, sealing load is applied by mechanical wedging and differential pressure (DP). Mechanical wedging load is produced by the applied force acting on top of the gate (or wedge), the wedge angle, and friction at the disk-to-seat surfaces. A higher applied stem force increases the mechanical wedging load. DP load is proportional to the DP and the area over which the DP

acts. A higher DP results in a higher DP-applied seat load. For motor-operated valves (MOVs), the seat load due to mechanical wedging is much greater than that due to the LLRT DP as illustrated in Figure 3.

The approach for this analysis is to evaluate the reduction in total sealing load due to changing the DP from DP_{test} to P_a to determine if this reduction is expected to increase the measured leakage.

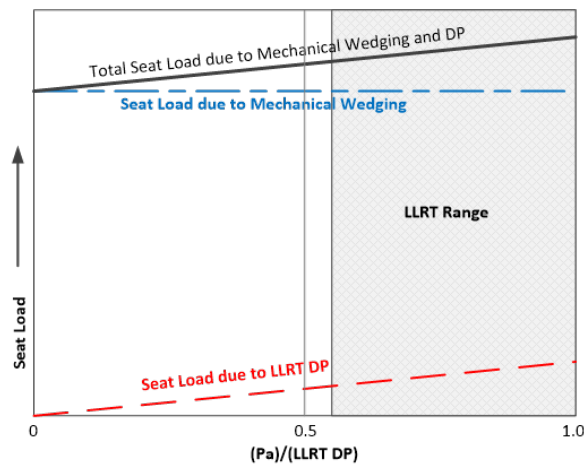


Figure 3 Illustration of Total Seat Load for MOV Wedge Gate Valves

$$LLRT\ DP + Mechanical\ Wedging\ Seat\ load = Total\ Seat\ Load$$

Plug Valves

Tapered plug valves have a conical metal plug inserted into a polymer body sleeve with an interference fit to form a seal. As the plug rotates 90° from close to open the plug port aligns with the body sleeve port to form a rectangular flow passage. As the plug rotates 90° back from open to close, the plug port rotates away from the sleeve port leaving the solid portion of the plug wall in contact with the rectangular body sleeve port. Differential pressure applied to the valve increases the seat load on the downstream seat and reduces the upstream seat load, although very slightly over the LLRT DP range as illustrated in Figure 4. However, for the low LLRT DP the net sealing load between the two seats remains the same such that overall leakage is not expected to increase from the higher to lower LLRT DP conditions.

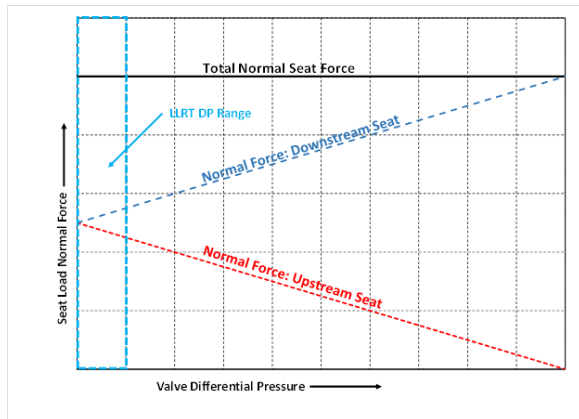


Figure 4 Tapered Plug Valve Seat Force vs DP

Downstream Normal Seat Force + Upstream Normal Seat Force = Total Normal Seat Force

Swing Check Valves

There are both soft-seated and metal (or hard)-seated swing check valves typically within the applicable population for evaluation. Swing check valves rely primarily on differential pressure to form a seal along with some weight (or gravity) force. The approach for soft-seated and metal-seated valves is as follows:

Soft-seated swing check valves

1. Determine the peak and average seat contact stresses based on the seat load at the higher and lower LLRT pressures. Verify that the peak seat contact stress is higher than the differential pressure to ensure a positive sealing margin at that pressure.
2. Determine the percent O-ring or soft seal compression. Verify that the sealing load at the higher and lower LLRT pressures provide adequate O-ring compression to ensure sealing.

Metal-seated check valves

1. Determine the percentage increase in the leakage flow area with the decrease in the seat load due to the reduction from the higher to lower LLRT test pressure.
2. A negligible change in the leakage flow area shows that the leakage flow resistance (and corresponding leakage flow coefficient, C_L) change is well below 35 percent for an example 16.5 psi LLRT DP and a 9.0 psi Pa DP. The leakage flow coefficient needs to change greater than 35% to have higher measured leakage at the lower LLRT test pressure (See Equation 5).

Lift/Piston Check Valves

Lift/Piston check valves have a plug with seat load applied by an internal spring. The spring is sized to provide a certain cracking pressure in the under-seat flow direction. In the opposite flow direction, the spring and differential pressure close the valve and provide a sealing load. Most lift/piston check valves have soft seats. Low modulus soft seats require less seat load to form a seal than high modulus metal seats since the material more easily fills small surface asperities that form leak passages. The approach for lift/piston check valves is like that used for the swing check valves as described previously.

Manual and AOV Globe Valves with Metal Diaphragms

Manual globe valves and Air Operated Valves (AOVs) with dish-shaped metal diaphragms are often included within LLRT scope which seal against the internal line pressure. Stem packing, if present, acts as a secondary seal. Based on examination of typical metal-diaphragm sealing valves, pressure applied over-the-seat with the valve in the closed position will act equal and opposite on the plug and diaphragm seal such that the test pressure is effectively balanced and there is no significant change in seat load as a function of LLRT test DP (see Figure 5).

Therefore, the test pressure balances equally (seat force downward versus metal-diaphragm force upwards) and higher test pressure will not increase the seat load for these valves.

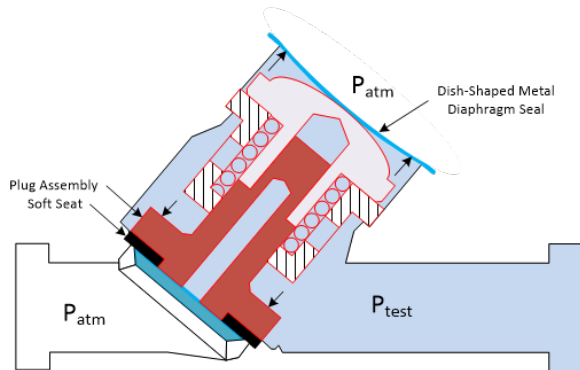


Figure 5 Metal Sealed Diaphragm Valve Pressure Balance

AOV Globe Valves

Like gate valves, sealing load for AOV (and Manual) globe valves is applied by mechanical wedging and differential pressure (DP). Mechanical wedging load is a function of the applied force acting on top of the plug, the plug angle, and friction at the disk-to-seat surfaces. DP load is a function of the DP and the area over which the DP acts. For AOVs, the seat load due to mechanical wedging is much greater than that due to the LLRT differential pressure.

The approach for this type of analysis is to evaluate the reduction in total sealing load due to decreasing the LLRT test DP to determine if an increase in the measured leakage is expected. The minimum recommended seat contact force per linear inch of mean seat joint circumference for metal seats from reference [5] is used to help make the determination as to whether the reduction in test pressure results in an expected increase in seat leakage.

Solenoid-Operated Globe Valve

Solenoid-operated valves typically have a pressure equalizing port in the disc that connects the under-seat side of the disc to the valve bonnet as shown in Figure 6. Reviewing several manufacturer's drawings, the scaled dimensions show that the seat diameter is estimated to be equal to the disc stem diameter. This results in a zero unbalanced area for the disc making the seat load independent of the DP load in either direction (flow under-the-seat or flow over-the-seat). In the valve closed condition, the seat load is applied by the spring preload and the plug weight. Therefore, the seat load will remain the same under the reduced LLRT pressure.

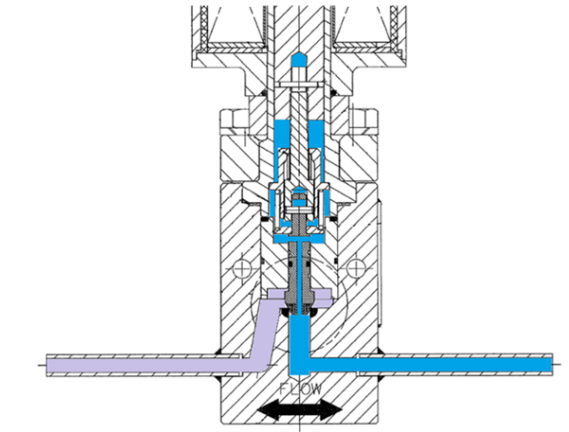


Figure 6 Balanced Disk Solenoid Valve Showing Upstream and Downstream Pressure

RESULTS AND CONCLUSIONS

The analysis results show that increased measured leakage is not expected if the test pressure were reduced from DP_{test} to Pa psig.

Hard-seated check valves were found to have low seating stresses and a significant decrease in seat load from DP_{test} to Pa conditions. Although the results based on calculations and engineering judgment show that leakage is not expected to increase for these valves, a check valve from a sample group was tested to support the calculation-based conclusions. Test results were favorable and showed no increase in leakage.

REFERENCES

1. ASME Operation and Maintenance of Nuclear Power Plants, ASME OM-2022.
2. Code of Federal Regulations, Title 10, Part 50.55a, Codes and Standards.
3. Code of Federal Regulations 10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors*.
4. ANSI/ANS-56.8-1994, American National Standard for Containment System Leakage Testing Requirements.
5. Instrument Society of America, ISA Handbook of Control Valves, 2nd Edition, 1976.
6. Electric Power Research Institute 3002008055, Evaluation Guide for Valve Thrust and Torque Requirements., Palo Alto, CA: 2016.
7. Emerson Automation Solutions, *Control Valve Handbook*, Fifth Edition, 2017.

A Method for Addressing the Cold Differential Test Pressure (CDTP) for ASME Relief Valve Set Pressure Testing

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and

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Abstract

A Cold Differential Test Pressure (CDTP) is of concern for a pressure relief device which is postulated to perform its pressure relief function at a temperature other than the temperature it is bench set, which is typically at a room temperature of less than 80°F [26.7°C].

American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix I, Sections I-4110(e), I-4120(e) and I-4130(e) require that either ambient temperature conditions be simulated or that a correlation between the devices operational/relieving temperatures and the testing ambient temperature condition be established, in order to assure proper adjustment of the device. This includes not only the temperature of the environment surrounding the device, but the temperature of the media which the valve will discharge. ASME OM Code, Appendix I, Sections I-4310 and I-4320 also provide additional requirements when utilizing correlations.

Bench set pressure testing performed at elevated external ambient and elevated internal fluid temperatures is not only difficult and costly, but can be hazardous to test personnel. As a result, it is preferred to conduct bench set pressure testing at other than the elevated temperatures expected during operational or accident conditions, which then requires the application of a correlation factor(s). Correlation factors can sometimes be supplied by the valve's vendor; however, the data/documentation behind said vendor correlation factors may not be sufficient for meeting today's regulatory requirements. The Owner in such case may then commission their own independent testing to either verify the vendor's correlation factors, or simply perform their own testing to determine applicable correlation factors for compliance with Code requirements, but that has proven to result in an economical burden in many cases.

What this paper attempts to do is provide the Owner with a model for determining which relief devices should have a CDTP correlation applied and when one is not necessary. This guidance has been formulated utilizing information that has been previously provided in numerous Electric Power Research Institute (EPRI) Technical Reports and Plant Reliability Data Initiative Group (PRDIG)/ Plant Reliability Data User Group (PRDUG) (PRDIG/PRDUG) PowerPoint presentations.

What is CDTP?

Cold Differential Test Pressure (CDTP) is defined in ASME PTC 25-2014, "Pressure Relief Devices," as:

The inlet static pressure at which a pressure relief valve is adjusted to open on the test stand. This test pressure includes corrections for service conditions of superimposed back pressure and/or temperature.

Utilities need to assure that a separate Superimposed Back Pressure correction factor is not applied if they are utilizing a vendor supplied CDTP correction factors which already contains a correction for Superimposed Back Pressure.

With that said, factoring in a valve's Superimposed Back Pressure (when known) is a fairly straight forward process that all utilities are assumed to be performing. The remainder of this paper is written to address the temperature constituent of CDTP.

Acknowledgements and References

Being the current secretary of the ASME OM Subgroup on Pressure Relief Devices, gave me access to a number of industry representatives whom I have contacted concerning temperature related CDTP. Below is a list of the organizations those individuals represent:

EPRI

Sid Cammeresi-Retired-Furmanite

Curtiss-Wright Target Rock

Emerson Automation Solutions (formerly Pentair Valves and Controls)

NWS Technologies

General Electric

Element Materials Technology (formerly NTS) – Huntsville

Individuals from these organizations provided me with input ranging from their own opinions which they have been developed through years of service, to technical presentations and technical EPRI documents. The Technical Reports and Presentations that I have utilized are listed below:

- EPRI Technical Report, 1003508 (Final Report, December 2002), "Method for Assessing Temperature Effects on Relief Valve Set Points," Project Manager John Hosler. (Reference 1)

- EPRI Technical Report, 1006934 (Final Report, April 2002), "Relief Valve Thermal Analysis – Development of a Transient Thermal/Mechanical Model of a Crosby Relief Valve," Project Manager John Hosler.
- Power Point Presentation presented by C. Dowd to one of the annual PRDIG/PRDUG meetings, circa 2001 titled, "Effects of Inlet Fluid Temperature on Valve Set Pressure."
- Power Point Presentation presented by John Hosler (EPRI) and Dr. Alan Bilanin (CDI) to PRDUG in January 2002, titled, "EPRI Temperature Correlation Project Update."
- Power Point Presentation presented by John Hosler (EPRI) to PRDUG in January 2003, titled, "EPRI Temperature Correlation Project Update."

Note: SRVUG, which stands for the "Safety Relief Valve Users Group," has taken the place of PRDIG/PRDUG. PRDIG stood for "Pressure Relief Device Interest Group," and PRDUG stood for "Pressure Relief Device Users Group."

Purpose

Using the documents, presentations and guidance from my colleagues and other industry professionals, this paper will attempt to:

1. Summarize how temperature affects the set pressure on relief valves.
2. Put into context when the application of a temperature dependent CDTP should be utilized in set pressure testing.
3. Create a defensible CDTP Position that can be utilized by the utility.

Discussion on How Temperature Affects Relief Valve Set Pressure

There are essentially two different temperature inputs that can affect relief valve set pressure. The ambient temperature that the valve performs in and the temperature of the inlet fluid that the valve is in contact with and relieves.

Testing has shown that the ambient temperature has a much more significant effect on relief valve set pressure than inlet fluid temperature effects.

Ambient Temperature is defined per ASME OM Code, Mandatory Appendix I, as:

The temperature range of the environment surrounding a pressure relief device at its installed plant location during the phase(s) of plant operation for which the device is required for overpressure protection.

So what are these temperature effects.

- Increased ambient temperatures reduce the springs K factor and can expand bonnet components which can result in a decreased lift pressure on the order of 6.0 to 7.0

percent associated with temperature increases from 70 to 350 °F [21.1 to 176.7 °C] Ref. 1 (i.e., approximately 1.2 percent for every 50 °F [10 °C] increase in temperature).

- Increased inlet fluid temperature changes are relatively small (on the order of 1.0 to 2.0 percent) for an increase in temperature from 70 °F to 350 °F [21.1 to 176.7 °C], but can be either positive or negative depending on the convective heat losses from the valve. (e.g., geometry, air flow, etc.) Ref. 1 (i.e., approximately 0.26 percent for every 50 °F [10 °C] increase in temperature).

It needs to also be noted that these correlations provided in the above are not necessarily “linear,” and while believed to be representative of all similarly constructed relief valves, are based upon a limited test sample.

However, it is more than just the calculated temperature that needs to be considered.

Ambient Temperature and Time

We not only have a Normal Operating Ambient Temperature, but we have an Accident Ambient Temperature. There may be multiple Accident Temperatures, dependent upon which Accident is taking place and depending upon at what point during the Accident this valve may be required to perform its safety-related relieving function.

For example, if Normal Operating Temperature (NOT) is 125 °F [51.7 °C] and Peak Accident Ambient Temperature is 600 °F [315.6 °C] (Steam Line Break), it is going to take “time” for the new Ambient to heat up the relief valve. In addition, the Accident temperature is not going to be a constant 600 °F, it is going to be dropping as a function of time. With this knowledge, one then needs to consider whether this relief valve will be functioning at the start of the accident or at some time “x” into the accident? In other words, if one would simply apply the Peak Accident Temperature CDTP to a relief valve, the result would more than likely be that this valve would not lift when required.

Multiple Accident Ambient Temperatures

In your evaluation, one needs to consider whether the valve may need to operate during different accident conditions (e.g., a main steam line break and an accident that involves a control rod drop or ejection). If I apply a CDTP to the relief valve based upon the ambient temperatures in the room following a steam line break, this valve may not open when expected/required during a control rod drop or ejection event.

Fluid Inlet Temperature and Time

The same type of argument that is being applied to the ambient temperature and time discussion can also be made here regarding fluid temperature. During Normal Operating Conditions, the fluid temperature seen by a relief valve may not be the accident fluid temperature. As a result, there are a couple of “time components” that may need to be

applied. How long does it take for the fluid to reach the accident temperature and how long would it then take for the higher fluid temperature to heat the valve internals and affect the set pressure?

In addition to these Ambient Temperatures, Inlet Temperature and Time factors, one must use some “Engineering Judgement,” when determining when a temperature dependent CDTP should even be considered/applied.

If the bench set “test” temperature is 70 °F [21.1 °C] and the Accident Ambient Temperature is 100 °F [37.8 °C], need a thermal CDTP be applied? I would say no because if you utilize a “rule of thumb” that there is a 1.2 percent reduction in set pressure for every 50 °F [10 °C] in temperature increase, and you are dealing with a 125.0 pounds per square inch gage (psig) valve, the temperature you would want to cold set this valve at is

$$(125 \text{ psig}) \left(1 + \left[(0.012) \left(\frac{(100 - 70)}{50} \right) \right] \right) = 125.9 \text{ psig}$$

Compare that to the standard Acceptance Criteria of +/- 3.0 percent (i.e., 121.25 to 128.75 psig), it can be argued that the CDTP change is fairly insignificant, and possibility not even measurable when testing consists of a human eye watching an analog pressure gauge. Does a 0.9 pound per square inch (psi) CDTP change deserve consideration when you have a 7.5 psi acceptance criteria range?

Now consider this question when considering a higher set pressure.

For a 400 psig valve, an Acceptance Criteria of +/- 3.0 percent, provides an range of 388 to 412 psig, where the application of a “rule of thumb” CDTP for an elevated ambient temperature would increase the bench set pressure to 402.9 psig. Does a 2.9 psi CDTP change deserve consideration when you have a 24.0 psi acceptance criteria range?

Now, let’s consider the inlet fluid temperature effects on both the above 125 and 400 psig valve examples. Let’s say in the above examples that the fluid temperature is 550 °F [287.8 °C]. And let’s assume that this temperature will cause the set pressure to also drop. Looking at the 125 psig valve.

$$(125 \text{ psig}) \left(1 + \left[(0.0026) \left(\frac{(550 - 70)}{50} \right) \right] \right) = 128.12 \text{ psig}$$

for fluid temperature alone. Add that to the Ambient CDTP and you get

$$125.0 + 0.9 (\text{ambient}) + 3.12(\text{fluid}) = 129.02 \text{ psig.}$$

Is this worth the application of a CDTP?

But if the fluid temperature associated with this 125 psig valve is only 100 °F [37.8 °C], the fluid CDTP constituent drops to only 0.19 psig, which when added to the ambient temperature CDPT results in a total CDTP of 126.09 psig, arguably still fairly insignificant to necessitate the required application of a CDTP.

Caution, there is more than just the overpressure protection to consider. There are inventory loss concerns that need to be addressed in your engineering evaluations.

Method for Determining when a Thermal CDTP need be Applied

Currently, ASME OM Code, Appendix I, paragraphs I-1320(c)(1) and I-1350(c)(1) essentially state that the As-Found acceptance criteria for set pressure testing is the greater of either the Owner's established set-pressure acceptance criteria or +/- 3.0 percent. While some Owners have instituted stricter As-Left set pressure criteria, many have not. In other words, some utilities allow for a +/- 3.0 percent As-left criteria to be adequate for installation.

This in itself can lead to future As-Found testing failures if the "good practice" of adjusting the valve's As-Left set pressure closer to the center of the acceptance criteria's range is always not performed.

For example, if the As-Found and As-Left acceptable range of a 400 psig relief valve is the same 388 to 412 psig, and the worker when performing the As-Left measures a 389 psig set pressure and allows this valve to be re-installed, the chances are very good that this valve, if known to drift low, will fail when it's next tested. While it may be assumed that the "good practice" of adjusting the As-Left set pressure to be close to the center of the acceptable range is always performed, time pressure/procedural instruction/experience of the craft has resulted in this "good practice" not always being implemented.

As a result, some utilities have made it a requirement that all As-Left set pressure acceptance criteria shall be +/- 1.0 percent (with exceptions for some lower pressure relief valves, e.g. < 70.0 psig), thus proceduralizing the "good practice" and reducing the probability of a future As-Found set pressure test failure.

For Owners that adopt this tighter, more restrictive, As-Left set pressure acceptance criteria, it is proposed that an ambient CDTP need only be applied to a valve's bench set pressure if the working ambient temperature is greater than 83.3 °F [28.5 °C] above the bench set pressure temperature. This would be done utilizing the 1.2 percent decrease in set pressure per every 50 °F [10 °C] increase in ambient temperature condition "rule of thumb" determined through the testing as earlier described. This essentially utilizes the 2.0 percent savings that is provided by adopting a more restrictive 1.0 percent As-Left set pressure criteria.

Again assuming that this As-Left set pressure criterion is adopted, it is proposed that an inlet fluid CDTP only needs to be applied to a valve's bench set pressure if the working inlet fluid temperature is greater than 385 °F [196.1 °C] above the bench set pressure fluid temperature. This would be done utilizing the 0.26 percent change in set pressure per every 50 °F [10 °C]

increase in inlet fluid temperature “rule of thumb” determined through the testing as earlier described. This essentially utilizes the 2.0 percent savings that is provided by adopting a more restrictive 1.0 percent As-Left set pressure criteria.

Note that these two criteria must be **COMBINED**, when applicable.

In addition, one must remember that the inlet fluid effect could be either positive or negative.

So in summary, if the postulated combined ambient temperature and inlet fluid temperature, set pressure change could add up to greater than 2.0 percent of the valve’s set pressure, on relief valves for which the Owner has adopted an As-Left set pressure criteria of 1.0 percent or less, a thermal CDTP must be applied.

Determination of the Proper Thermal CDTP

For valves in which the postulated combined temperature set pressure change could add up to greater than 2.0 percent, there are a number of different ways in which a thermal CDTP can be determined. Some methods are more precise than others, but precision in the “near term” may need to be sacrificed until time and funding is available for the most precise method to be utilized. Starting with the most precise method.

- **CDTP determination via Testing**

If the utility does not have their own facility, such as the Seabrook Nuclear Plant, there are a number of third-party vendors which have the ability to perform CDTP testing at various ambient and fluid inlet temperatures.

- **Utilization of Vendor CDTP Values**

Some valve manufacturers supply their relief valves with CDTP values. If it can be verified that the vendor has control of, or maintains the data used to create these CDTP values and that the data support the calculated values, then the vendor CDTP criteria can be applied.

- **Application of “Rule of Thumb” CDTP Criteria**

While the “Rule of Thumb” criteria described in this discussion is based upon a limited population of valve testing (as compared with all known valve styles/manufactures currently being utilized), and with the knowledge that the CDTP is not always linear, when one knows that there is a high potential of the temperature conditions causing a change in set point over 2.0 percent of the required set point, the application of a “correction factor,” based upon empirical knowledge, in the conservative direction, will provide additional assurance that the valve will perform its safety-related function during design basis events.

The application of a “Rule of Thumb” CDTP is only a temporary solution to be utilized until either the Vendor CDTP values can be verified or until physical testing can be performed which then calculates a valve-specific CDTP.

The 2.0 percent criterion is chosen as a cut off, along with the utilization of a 1.0 percent As-Left set pressure, so as to reduce the probability of the valve's set point of being greater than 3.0 percent from its design-basis set point.

Process for Determining if a Thermal CDTP Needs to be Applied

The following example is based upon the Reactor Coolant Pump (RCP) Thermal Barrier Cooler Thermal Relief Valve, which exists in a 3-Loop Westinghouse Pressurized Water Nuclear Power Plant.

It is within this determination process where assumptions are being made and documented. For example, this Westinghouse 3-Loop valve identified as RV-3-722A is an RCP Thermal Barrier Cooler Thermal Relief Valve, which per its specification sheet has a normal operating temperature of 100 °F [37.7 °C], and a relieving temperature of 550 °F [287.8 °C]. Below is a screen shot of a portion of the valve's specification sheet.

1	TAG NUMBER		RV-3-707		RV-3-715		RV-3-722A		RV-3-722B		RV-3-722C	
2	LINE NUMBER											
3	SEAT TYPE											
4	DESIGN TYPE											
5	BONNET											
6	BODY											
7	MATERIAL		CS		CS		CS		CS		CS	
8	SIZE INLET * OUTLET *		3 4		3 4		3/4 1		3/4 1		3/4 1	
9	END CONNECTION TYPE		FLANGE		FLANGE		FLANGE		FLANGE		FLANGE	
10	ORIFICE DESIGNATION *		L		L		SPEC		SPEC		SPEC	
11	TRIM MATERIAL											
12	SEAT & DISC											
13	GUIDE & RING(S)											
14	SPRING											
15	ACCESSORIES											
16	CAP & NO LEVER											
17	LEVER PLAIN PACKED		NO NO		NO NO		NO NO		NO NO		NO NO	
18	GAG											
19	BALANCED BELLOWS		YES		NO		NO		NO		NO	
20	OTHERS											
21	BASIS OF SELECTION											
22	CODE											
23	OTHER											
24	SERVICE CONDITIONS											
25	FLUID RADIOACTIVITY		WATER NO		WATER NO		WATER NO		WATER NO		WATER NO	
26	REQUIRED CAPACITY & UNITS GPM		460		850		20		20		20	
27	MOL. WT. OR SP. GR. @ F.T.											
28	VISCOSITY @ F.T.											
29	PRESS. PSIG. NORM. RELIEVING		30 54		50 200		50 2485		50 2485		50 2485	
30	TEMP. °F NORM. RELIEVING °F		100 100		100 150		100 550		100 550		100 550	
31	CONSTANT BACK PRESSURE PSIG		5		0		0		0		0	
32	DEVELOPED BACK PRESSURE PSIG		40		0		0		0		0	
33	SPRING SET PRESSURE PSIG		54		200		2485		2485		2485	
34	OVERPRESSURE - %		25%		25%		10%		10%		10%	
35	ORIFICE AREA											
36	CALCULATED SQ. INS.											
37	SELECTED SQ. INS.											
38	MANUFACTURER		CROSBY		CROSBY		CROSBY		CROSBY		CROSBY	
39	MFG'S ASS'Y DWG. NO.		H-40434-21		H-51036		H-50914-1		H-50914-1		H-50914-1	
40	WESTINGHOUSE OUTLINE DWG. NO.											
41	IDENTIFICATION NO.		3-RV32LWB		3-RV32LW		3/4-RV38SW		3/4-RV38SW		3/4-RV38SW	
42	SPECIAL REQUIREMENTS											
SPEC. SHEET NO. 1 OF 12 E-SPEC. NO. 676257			NOTES: * INDICATES DATA TO BE FURNISHED ** PER SPEC.									

In some of the earlier referenced EPRI sponsored testing, they found that it would take 90 minutes or more for valves component temperatures to equalize when subjected to elevated Ambient conditions. It was also found that it might take 6 to 7 hours for a valve's component temperatures to equalize once subjected to elevated inlet fluid conditions. If it is found that this 550 °F [287.8 °C] is an accident temperature that occurs at T=1 minute, and at T = 30 minutes, the temperature is down to 350 °F [176.7 °C], then the 550 °F [287.8 °C] would be the incorrect temperature to utilize when making the "Rule of Thumb" calculation, even if the design basis event (DBE) does not predict conditions where this valve would need to relieve pressure until 45 minutes into the accident.

In other words, if this valve has a NOT inlet temperature of 100 °F [37.8 °C], then a failure occurs that changes the inlet temperature to 550 °F [287.8 °C] at T=0, the full inlet fluid temperature effect will not be seen until hours into the event, although the valve may be called up to relieve only minutes into the event. These types of assumptions will need to be documented in each evaluation.

Let's continue working through this example using same relief valve from a 3-Loop Westinghouse Plant, RV-3-722A.

Again using the valve specification sheet shown above for valve RV-3-722A, the Normal Operating Temperature is 100 °F and relieving is 550 °F.

This RCP Thermal Barrier Cooler Relief Valve is located inside containment. Failure of the Thermal Barrier Cooling Coil during normal operation would result in Reactor Coolant System (RCS) entering the Component Cooling Water (CCW) line which is protected by this relief valve. Failure of the Thermal Barrier Cooling Coil alone will not cause this relief valve to lift as the valve's set point is 2485 psig, less than the RCS Normal Operating Pressure (NOP) of 2235 psig. This valve is only designed to lift when the RCP Thermal Barrier Cooling Coil is intact and the Thermal Barrier CCW piping inside containment is isolated, with heat continuing to be added through the Thermal Barrier Cooling Coil to the trapped CCW water in the isolated piping.

Per the site's Environmental Qualification (EQ) document, you will find that the maximum temperature that would occur inside containment would be that following a Main Steam Line Break (MSLB), peaking at 321 °F, dropping to 315 °F after 35 seconds, dropping to 280 °F after 200 seconds. For a Loss of Coolant Accident (LOCA), the highest temperature would be 281.2 °F at 652.2 seconds (about 11 minutes) post-LOCA.

So what temperatures (both Ambient and Fluid Inlet) should be applied to RV-3-722A in determining whether a CDTP should be applied?

Per the referenced 2002 PURDUG (Ref. 4) Powerpoint, Seabrook test No. 6 which utilized a 353.8 °F inlet fluid temperature and a 350 °F ambient temperature, it took 20 minutes of the valve being subjected to these increased temperatures for the set pressure to drop 10 psig from 450 to 440 psig.

RV-3-722A normally experiences 50 psig and relieves at 2485 psig. The ambient temperature that RV-3-722A would be subjected to would be less than the Seabrook Test 6, both in severity and duration. The inlet temperature that RV-3-722A would be subjected to would be higher than the Seabrook Test 6 (550 °F vs 350 °F), but one needs to take into account how the inlet temperature effects provide (1) only a small percentage of set point change as compared to ambient temperature effects, and (2) take place over time, not immediately.

RV-3-722A is a thermal relief valve which would theoretically open when the isolated fluid reaches the valve's set point which would occur at 550 °F. The valve would lift once 550 °F was reached and would have not been able to sit and "soak" at 550 °F, so the effects of an increased inlet fluid temperature on the set pressure would be reduced. Once the valve's initial

lift, burping out a volume of CCW water, the valve will presumably not lift again as no more water will be added to the isolated section of piping. On the other hand, with the valve soaking now at 550 °F, the set pressure of the valve could drop 62.0 psig assuming the “Rule of Thumb” factor described above and possibly drop to 2423 psig and possibility lift again.

$$(2,485 \text{ psig}) \left(1 - \left[(0.0026) \left(\frac{(550 - 70)}{50} \right) \right] \right) = 2,423 \text{ psig}$$

The loss of additional CCW water as a result of a temperature-induced lower set point is however inconsequential as it is only the fluid which is trapped in an isolated section of piping.

Taking this a step further, if the thermal barrier cooling coil were to then fail after cooling water isolation, heat up, set pressure reduction, this valve’s set pressure would still be above the RCS NOP of 2235 psig. (Note also that if cooling water had been isolated initially as the result of a Containment Isolation Signal, more than likely Operations would have already been in the process of shutting down the reactor and RCS pressure would be less than NOP.)

Now suppose that instead of an inlet fluid negative set pressure effect, a high inlet fluid temperature resulted in a positive set pressure effect, raising the set point from 2485 to 2547 psig, which is greater than the “design rating” of the piping that is being protected (i.e., 2500 class). But is a 47 psig over the 2500 class rating something to be concerned with if the hydro pressure associated with a 2500 class pipe at 550°F was over 5000 psig? (Ref. https://ebgflow.com/pressure_class.php) It shouldn’t be.

Again too, factoring in the “time” element, the soak time would not have been at a full 550 °F. If a soak of 250 °F is assumed, the increase in set pressure due to inlet fluid temperature would be to only 2508 psig. (Again, if the hydrostatic pressure of this piping over 5000 psig, we should be ok.)

Now to look at only the valve’s ambient temperature possible inputs, if the valve is challenged at the start of the accident, the valve would not have been subjected to the increased accident ambient temperature for a sufficient amount of time to affect the valve’s set point beyond the normal operating ambient temperature of 100 °F, then a CDTP need not be applied (100 minus 75 °F < 83.3 °F above the bench temperature described earlier).

If instead this valve is assumed to be required to function at some time into the accident, after having been subjected to accident ambient temperatures in excess of 200 °F, which may be plausible, a thermal CDTP will need to be applied.

In most likelihood, it would be analyzed that a thermal CDTP need not be applied to RV-3-722A as any ambient and/or inlet temperature effects would have a minimal effect on the valves set point during the time frame in which this valve would be required to function following a design basis event.

Note in this example for which a Westinghouse 3-Loop site is utilized, the below illustrates how peak RCS pressures occur during the first few minutes of an accident, before increased accident ambient/inlet temperatures can affect the valve's set point.

- Site Specific UFSAR Figure 14.1.15-6 and Table 14.1.15-3 show RCS pressure above 2960.2 psia after 112.6 seconds for a Loss of Load (LOL) Anticipated Transient Without Scram (ATWS).
- Site Specific UFSAR Figure 14.1.15-2 and Table 14.1.15-2 show RCS pressure peaking at 3174 psia after 89.2 seconds for an Loss of Normal Feedwater (LONF) Anticipated Transient Without Scram (ATWS).
- Site Specific UFSAR Figure 14.1.10-3 shows RCS pressure below 2485 after 25 seconds for a total loss of external electrical load, peak RCS Pressure case.

Relief Valves in Other Plant Locations

Every site will need to evaluate their relief valves based upon their own site-specific conditions. Sites primarily located in the southern US have major portions of their systems exposed to the outdoors, in areas where an MSLB will not have the same thermal impact as at those sites in the north where the majority of components are enclosed.

At the Westinghouse 3-Loop specific site being used in this example, per the referenced EQ document, during a LOCA, the ambient temperature in the Containment Spray (CS) pump room will increase from 104 °F to 158 °F. In the SI pump room, the ambient temperature will increase from 104 °F to 176 °F. During normal operation the RHR Pump Room may reach 138 °F for a short duration during plant cooldown evolutions under some plant conditions. These lower accident temperatures are due to a lot of the plant equipment being exposed to the outside such that the effects of an MSLB would not heat up the inside of the buildings like for those sites located in colder climates.

Conclusions/Considerations

So what does the above exercise/discussion make us realize?

- While some sites may not apply temperature based CDTP to their relief valve bench set pressure testing, the differences may be so minimal that strict compliance with the words in ASME OM Code, Mandatory Appendix I, may have little mathematical significance when it comes to reasonable assurance that the relief valve will be able to perform its safety-related function during a Design Basis Accident. But before a position like that can be officially stated, each IST relief valve will need to be looked at to determine what the actual working Ambient Temperatures and working inlet Fluid Temperatures maybe obtained, with all assumptions being documented.
- Realizing that CDTP corrects for both temperature and backpressure, we must ensure that backpressures are not being applied twice at plants which are currently utilizing vendor or third-party CDTP.

- If CDTPs are currently being utilized, it needs to be verified that the temperatures for which the CDTP is calculated are actually representative of the temperature conditions that the valve will be required to perform in. In other words, if the vendor supplies a CDTP based upon the peak LOCA ambient temperature which only exists during the first few minutes of the accident, not accounting for the soak time necessary for the valve's material properties to change, the application of the CDTP could actually result in the valve being As-Left set pressure high, beyond its required criteria

Below is a template for a possible Technical Position that may be used in addressing the application of CDTP at one's site.

Application of a Thermal Cold Differential Test Pressures (CDTP)

ASME OM Code, Mandatory Appendix I, requires that either the ambient temperature of the operating environment in which the relief valve must perform its safety-related function **shall** be simulated during the set pressure test or that a "certified correlation procedure" is utilized which assures that the valve's acceptance criteria are met.

At (-add your site here-), all Class 1 Relief Valves, and PWR Main Steam Relief Valves are tested at Ambient Temperature conditions with "ambient" defined as:

The temperature range of the environment surrounding a pressure relief device at its installed plant location during the phase(s) of plant operation for which the device is required for overpressure protection. [ASME OM Code, Mandatory Appendix I, section I-1200]

Class 2 and 3 relief valves are, depending upon the site, either tested at Ambient conditions or are tested at conditions that may necessitate the application of a thermal CDTP as documented in evaluation (TBD).

Per ASME PTC 25-2014, the Cold Differential Test Pressure is:

The inlet static pressure at which a pressure relief valve is adjusted to open on the test stand. This test pressure includes corrections for service conditions of superimposed back pressure and/or temperature.

The remainder of this Site/Fleet Position is written to address only the temperature, or "thermal" constituent of the CDTP.

Based upon the analysis documented in (-add reference here-), a CDTP need only be applied to a valve that has a working Ambient Temperature greater than 83.3 °F above the bench set temperature and/or has a working inlet fluid temperature greater than 385 °F above the bench set inlet fluid temperature, or when the combined possible change from the required set pressure is greater than 2.0 percent of the set pressure, assuming that the valve is As-Left set at +/- 1.0 percent of the valve's required set pressure.

It is of course preferable that all valves are tested at their Ambient (both surrounding and fluid inlet) temperatures, but safety and economic concerns prohibit this ability.

CDTP correlations provided by either the valve's vendor, or a third party may be utilized provided the valve vendor or third party can also supply the data from which these correlations were calculated and that these calculations have been reviewed and accepted by Site/Fleet Engineering.

Lacking acceptable valve vendor or third-party CDTP correlations, the Site/Fleet will impose interim CDTP values based upon the evaluation contained in *(-add reference here-)*. These interim CDTP values are calculated as follows:

For Ambient Temperature Conditions

If the valve's working Ambient temperature is greater than 83.3 °F above the bench set pressure ambient temperature, a 1.2 percent increase in set pressure will be applied for every 50 °F above the bench set pressure ambient temperature.

If the valve's working Ambient temperature is within 83.3 °F of the bench set pressure ambient temperature, no CDTP constituent need be applied.

For Inlet Fluid Temperature Condition.

For fluid inlet temperatures greater than 385 °F above the bench set pressure fluid inlet temperature, a 0.26 percent increase or decrease (whichever is most conservative for the valve's specific situation) in set pressure will be applied for every 50 °F above the bench set pressure fluid inlet temperature.

If the valve's working Inlet Fluid Temperature Condition is within 385 °F of the bench set pressure inlet temperature condition, no CDTP constituent need be applied.

Combined Ambient Temperature and Inlet Fluid Temperature Effects

As described by the analysis contained in *(-add reference here-)*, working Ambient and working Inlet Fluid Temperature effects are additive, and must be considered.

For example, if the working Ambient temperature is 80 °F above the bench set Ambient temperature, and the working Inlet Fluid Temperature is 370 °F above the bench set inlet fluid temperature, the combined thermal effect may be greater than 2.0 percent of the valve's set point value, which will therefore require that a CDTP be applied.

As described in *(-add reference here-)*, both the working Ambient Temperature and working Inlet Fluid Temperature may not simply be those maximum values listed in the design documents. Set Point temperature affects are "time" related/dependent. Therefore, an evaluation needs to first be performed for each valve or group of valves to determine what those temperature values are before they can be compared to the 83.3 °F/385 °F "Rules of Thumb."

It is the Site/Fleet goal that all interim CDTP are eventually replaced by either vendor or third-party CDTPs or replaced with Site/Fleet calculated CDTPs determined through actual valve testing performed at (-add Site Facility here-).

Biographical Summary

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Refined OM Requirements Drive Operational Efficiencies

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ABSTRACT

American Society of Mechanical Engineers (ASME) Operation and Maintenance (OM) valve test requirements are general, creating opportunities for site-specific refinements that unlock operational benefits. In 2024, Palo Verde submitted alternative requests under Title 10 of the *Code of Federal Regulations*, Part 50, Section 50.55a (10 CFR 50.55a) paragraph (z) to reduce valve test frequencies and eliminate acceptance criteria. The Palo Verde Generating Station justified an acceptable level of quality and safety for:

- Once-per-cycle exercise testing of normally closed valves with an active safety function to close.
- Removing the lower stroke time acceptance criterion for select solenoid-operated valves (SOVs).

Plant design, component design, and vendor documentation provided the basis. Risk insights and component operational uses further support the analysis. If approved, the alternatives will reduce IST Program overhead, though specific benefits are not quantified. Future opportunities for site-specific requests may be available in safety-related air-operated valves (AOVs) with a fail-safe function and Group A pumps supporting continuous or intermittent plant operations.

Keywords: valve, test, testing, ASME OM, alternative request, 10 CFR 50.55a

NOMENCLATURE

10 CFR 50.55a(z), "Alternatives to codes and standards requirements."

AOV: Air-operated valve

ASME OM or OM Code: ASME OM (2012 Edition), *Operation and Maintenance of Nuclear Power Plants*

CDF: Core Damage Frequency

FMEA: Failure Modes and Effects Analysis

IST: Inservice Testing

LERF: Large Early Release Frequency

NRC: U.S. Nuclear Regulatory Commission

RAI: NRC Request for Additional Information

SOV: Solenoid-operated valve

VRR: Valve Relief Request. The Palo Verde naming convention for relief requests under 10 CFR 50.55a(f)(6)(i) and alternative and hardship requests under 10 CFR 50.55a(z).

1. Introduction

The alternative request process described in 10 CFR 50.55a(z) presents an opportunity to refine ASME OM requirements to meet site-specific needs. Leveraging knowledge of system requirements, component design, and operational uses, Palo Verde devised a strategy to maintain an acceptable level of quality and safety while reducing the frequency of tests and evaluations required by ASME OM. The NRC requested additional technical rigor for these proposals by asking clarifying questions in pre-submittal meetings and through formal requests for additional information. This feedback enabled Palo Verde to enhance its proposals, producing a mutually beneficial change to the station's testing requirements. The proposals enable Palo Verde to protect public health and safety while gaining operational efficiencies.

2. Results and Discussion

In May 2025, the NRC authorized two alternative requests allowing Palo Verde Generating Station to reduce valve test frequencies and remove acceptance criteria from certain SOVs. These first-of-a-kind alternative requests are plant-specific adaptations of OM Code requirements. The station has historically used alternative requests to address instrumentation that cannot meet OM Code requirements. These new requests show plant-specific insights for component and system operation can be used to reduce operational burden while maintaining an acceptable level of quality and safety. Safety evaluations for Alternative Requests VRR-02 and VRR-03 are available via the NRC ADAMS system, Accession Numbers ML25127A214 and ML25127A174, respectively.

Alternative Request VRR-02 requires once-per-cycle exercise testing of fail-safe valves that are normally in their safety position. In contrast, the ASME OM Code requires a quarterly test frequency for these valves. VRR-02 produces operational efficiency by allowing Palo Verde to test components less often. This saves time and effort in the scheduling, printing, briefing, performing, and documenting of nuclear test records.

Alternative Request VRR-03 requires only the upper stroke time acceptance criterion for select SOVs that historically use a reference value. In contrast, the ASME OM Code requires a tolerance band around SOV stroke time reference values. The band defines the upper and lower acceptance criteria that, when exceeded, suggest abnormal performance and require evaluation. VRR-03 produces operational efficiency by allowing Palo Verde to accept a wider range of stroke times as acceptable performance. This saves time and effort because the station does not need to re-test and evaluate rapid stroke times that cannot indicate component degradation.

VRR-02 and VRR-03 demonstrate that nuclear power plants can leverage plant-specific insights to refine the IST Program requirements to their advantage. The OM Code carries prescriptive requirements for testing. Palo Verde has historically used the relief request and alternative

request provisions in 10 CFR 50.55a when updating to a new code of record during decennial updates. The requests address long-standing issues of plant configuration, such as:

- Installed minimum recirculation flow measurement that does not meet instrument accuracy requirements for quarterly safety injection pump testing.
- The absence of inlet pressure gages on diesel fuel oil transfer pumps.

In contrast, VRR-02 and VRR-03 enhance operational efficiency by reducing test frequencies and refining test acceptance criteria.

Palo Verde personnel pivoted from compliance mindset to a design mindset to develop VRR-02 and VRR-03. Personnel responsible for IST programs primarily focus on data processing, component trending, basis maintenance, performance evaluations, and responding to updated regulatory requirements. Developing site-specific test strategies requires shifting to a design mindset, in which engineers identify problems, propose solutions, research, test, and iterate.

VRR-02 and VRR-03 were developed through a check-and-adjust process that aligns with a design mindset. The process includes:

1. Insight. Identifying improvement opportunities, analogous to defining a problem.
2. Investigation. Research to understand requirements, capabilities, and scope of the insight. This informs the proposed solution and prepares the technical basis for regulatory interface (pre-submittal meetings and/or formal submittal of the alternative request).
3. Feedback. Regulators review the proposal, asking clarifying questions and challenging the technical basis to ensure an acceptable level of quality and safety.
4. Refinement. Perform additional research to answer regulator questions and provide comprehensive technical basis.
5. Iteration. Regulatory review is iterative because plants must satisfy all questions to demonstrate an adequate technical basis for acceptable quality and safety.
6. Final approval and implementation. NRC issues a safety evaluation. Station revises procedures and program documentation to align with the approved alternative request.

3.1 VRR-02 Development

While implementing supplemental indication strategies in 2018-2019, Palo Verde engineers learned that some valves were not regularly operated except for exercise testing. The station's main steam isolation valve bypass valves are normally closed with a fail-safe function to close. The valves open to equalize pressure across the main steam isolation valves during plant start-up, however this non-safety function was rarely used. As active valves, they were exercised quarterly. Engineers believed quarterly testing was excessive for these specific valves, and suspected that other normally closed, fail-closed valves might also be exercised more often than warranted based on their application.

Research revealed a scope of 28 normally closed valves with a safety function to close and no safety function in the open position. These AOVs and SOVs appear in six systems, including safety injection, main steam, nuclear sampling, and chemical and volume control. Palo Verde evaluated and determined the valves were designed, operated, and controlled to ensure their safety functions. A draft technical basis was developed to state:

- The valves are in their closed safety position unless established procedures are used to open them for testing or for specific plant evolutions. After use, the valves are closed by the same procedures.
- Valve closure via control room hand switch is equivalent to fail-safe testing. The hand switch removes power (air or electricity) allowing passive closure by an internal spring. Therefore, any operational use of a valve during the operating cycle confirms the valve's ability to close as required.
- OM Code allowances for cold shutdown and refueling outage testing provide a precedent for testing active valves once per cycle. Palo Verde already applies these rules for select AOVs and SOVs.

Regulators' feedback on the VRR-02 concept demonstrated more detail was needed to assure an acceptable level of quality and safety. Regulators provided two rounds of feedback. First, in a June 2024 pre-submittal meeting, regulators requested additional information on performance and maintenance history, risk, duration in the open position, and operational methods to verify valve closure after use. Palo Verde researched these questions, revised its argument, and formally submitted the request in October 2024.

The pre-submittal feedback drove Palo Verde to refine its technical argument for the reduced test frequencies. Insights included:

- Test period extension had an acceptably small impact on risk. Nine of 28 valves were potential contributors to core damage frequency (CDF) and large early release frequency (LERF), yet the aggregate impact of testing at 18 months instead of quarterly was less than permitted under NRC Regulatory Guide 1.174. The remaining 19 valves are excluded from the station's risk model because they have no impact on CDF and LERF.
- Only 7 percent of corrective maintenance work orders have come from IST performances in the past few years. Most valve issues are identified by non-IST activities (operations, maintenance, and other tests and inspections) and are corrected before they result in IST performance issues.
- The valves' active function determination is consistent with guidance in NUREG-1482. Some valves are operated only for testing (main steam isolation valve bypass valves), while others have operational uses during the cycle. Reactor drain tank containment isolation valves are cycled regularly for tank level maintenance. Containment power access purge valves are held open to support containment depressurization. The active function is appropriate because the valves may be called upon to close when out of their safety position to support plant operations.

In February 2025, the regulators issued two RAIs requesting further details on administrative controls and methods of assessing operational readiness. To answer the RAIs, Palo Verde identified each operating procedure governing the valves, and identified the operations department guides and administrative requirements that ensure component deficiencies are entered into the corrective action program.

In May 2025, Palo Verde achieved final approval when NRC issued a safety evaluation authorizing the basis for the reduced test frequencies. The safety evaluation states, "The NRC staff has determined that the testing approach described in Alternative Request VRR-02 provides reasonable assurance that the subject valves will be operationally ready to perform their safety functions for the duration of the alternative request."

3.2 VRR-03 Development

Palo Verde engineers evaluating SOV performance had an insight that the lower stroke time acceptance criterion could not provide evidence of degradation. At Palo Verde, some SOVs use a reference value. The valves occasionally stroked faster than allowed by the ASME OM Code acceptance criteria. Evaluations of these performance deviations pointed to the absence of a minimum design-required stroke time and the vendor failure mode and effects analyses.

Research showed vendor information and industry guidance supported the insight that rapid stroking does not indicate SOV degradation. Palo Verde evaluated and determined the lower acceptance criteria threshold had no basis for any of the station's 46 IST SOVs per unit. A draft technical basis for all SOVs was developed to state:

- Vendor failure modes and effects analyses (FMEAs) and troubleshooting guides showed only failures that would increase stroke time. Failure mechanisms include indication issues (failure to illuminate, or failure to extinguish), electromagnetic failures (lack of magnetic field strength, insufficient voltage, and lack of power), or mechanical issues (internal binding, failed internal spring, or foreign material). There were no failure modes that would cause a valve to stroke faster.
- EPRI's Solenoid Valve Maintenance Guide [1] finds SOV performance degrades only by increasing stroke times. It shows the mechanisms of stroke time failures also cause failure-to-operate events. The analysis provides no examples of failure modes that exhibit decreasing stroke times. SOVs that stroke "too fast" are showing improved performance capability, not degradation.
- ASME OM Code, Subsection ISTC, paragraph ISTC-5152(c) sets a precedent for managing SOV performance. It states, "Valves that stroke in less than 2 sec may be exempted from subpara. ISTC-5152(b)." ISTC-5152(c) establishes no lower stroke-time threshold for select valves based on performance, an acknowledgement that evaluating performance below a certain threshold provides no additional safety assurance.

Feedback from the regulators showed more information was needed to support the request. During a pre-submittal meeting in June 2024, the regulators asked for a list of the applicable valves, explanation of the valves' performance and maintenance history, and discussion of how stem-disc separation or valve sealing capability might relate to shorter stroke times.

In October 2024, Palo Verde formally submitted VRR-03 with the following additions:

- A list of four valves per unit that used a reference value and acceptance criteria, or had the potential to do so based on operating experience. All other Palo Verde SOVs have historically applied the < 2 second stroke-time criterion per ISTC-5152(c).
- Corrective maintenance history discussion showing no evidence of maintenance in response to rapid stroking. Since 2020, 54 percent of the 24 corrective maintenance work orders were for increasing stroke times and failure-to-stroke events. The remaining scope of work orders supported IST program management or addressed seat leakage, which is not reasonably detectable via stroke time.
- Operating experience review and explanation of valve design to show the valves are not susceptible to stem-disc separation.

In May 2025, the NRC authorized Palo Verde's VRR-03 alternative with no RAls. The safety evaluation states, "Together with the ASME OM Code requirement in paragraph ISTC-5151 for monitoring abnormal or erratic SOV operation, the NRC staff finds that the proposed alternative provides an acceptable level of quality and safety, based on SOV operating experience, design, and vendor and industry guidance, for the remainder of the current IST program interval."

3. Conclusion

VRR-02 and VRR-03 show the alternative request process in 10 CFR 50.55a(z) allows nuclear plants to calibrate IST requirements based on site-specific insights and operating experience. Palo Verde is deriving value from reduced test frequencies and removal of SOVs' lower stroke time acceptance criterion because it adopted a design mindset. The station employed knowledge of system requirements, component design, and operational practices to develop novel approaches to valve testing. The NRC supports these efforts by ensuring alternative requests capture the technical rigor necessary to protect public health and safety. In summary, the alternative request process enables nuclear plants to develop testing regimes that support operational efficiencies.

REFERENCES

- [1] Electric Power Research Institute, NP-7414, *Solenoid Valve Maintenance Guide*, 2003.

The QME to OM Functional Testing Connection for MOVs, AOVs, and Check Valves

Mark Rain
Flowserve

This presentation examined the functional qualification, and production valve testing conducted under a valve manufacture's American Society of Mechanical Engineers (ASME) QME-1 Standard, "Qualification of Mechanical Equipment Used in Nuclear Facilities," program and how those transition into the Owner's testing requirements of the QME-1 Standard and Operation and Maintenance (OM) Code. This presentation discussed the functional tests, which are flow tests conducted under QME-1 that may be completed on similar types or a like valve design. It detailed what functions are verified or parameters developed in the functional flow testing of the test valve(s), which may be used to support analytical models. It discussed what fluids, flow rates, pressures, and temperatures should be used in the QME-1 functional testing. It presented what manufacturing tests are completed on each individual production valve built and, finally, it discussed what testing is completed during the QME-1 post-installation verification tests performed by the Owner. Design basis verification tests, preservice tests, and/or inservice performance assessment testing required under the ASME OM Code will be compared to the QME-1 testing. It discussed what overlap may exist, and whether credit can be taken for tests completed under the QME-1 program for the OM program. It examined what flow conditions are required to be imposed during the OM Code's functional testing. The QME-1 Standard and OM Code use terms such as "full-flow," "applicable flow," and "representative flow," and the meanings and differences for each flow terminology and where they are used were examined. The presentation discussed the purpose of each flow test and what functionality will have been explicitly verified for each specific valve, a like valve (same size, class, material, type, etc.), or a similar parent valve; and what uncertainties or margins are required for a parameter that cannot be explicitly measured or verified on an installed valve. Similarities and differences in terminology and testing requirements for air-operated valves (AOVs), motor-operated valves (MOVs), and check valves were examined with possible gaps in each program.

Requirements for Testing of Additional Relief Valves Following Valve Failure: Tested by When?

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Abstract

American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix I, provides the Inservice Testing (IST) Program requirements for the testing of pressure relief devices utilized in water-cooled nuclear power plants. Following the failure of a valve's As-Found set pressure test, the ASME OM Code (to be hereafter simply referred to as the "Code") requires the testing of additional valves from the same group (if they exist), but does not stipulate a time frame in when these additional valves need to be tested by.

While some users may attempt to infer "test by" requirements from other sections of ASME OM Code, Mandatory Appendix I, it is this author's position that the Code neither provides hard requirements for when the testing of additional safety/relief valves need to be completed by, nor should it provide those hard requirements. Hard limits as to when additional testing must be completed by should be determined through the application of the Owner's Corrective Action Program.

Once a relief valve has been identified as having failed its required Code test, there are numerous possible scenarios that will have a direct bearing as to when any additional valves need to be tested. The complexity of this determination does not lend itself to be delineated by Code language. The author's basis for his position is contained herein.

Introduction

Users rely upon the Code to tell them what to do, how to do, and when to do various activities when it comes to the testing of numerous components which meet the scoping criteria of the Code's ISTA-1100. If your valve's stroke time is measured to be outside of the calculated Acceptance Criteria limits of ASME OM Code, Subsection ISTC, your valve is then "per the Code," inoperable. If your pump's flow rate is measured to be outside of the Code's Subsection ISTB calculated Required Action Range, "per the Code", your pump is inoperable.

Once inoperability of a component is determined by the Code, the plant's Technical Specifications or other site operational documents/requirements are used to determine what

steps must then be taken to restore the component/system to operable status to allow for the continued operation of the plant. The Code will identify the inoperable condition, and may impose additional actions to be taken when a component is approaching an inoperable condition, but it is the responsibility of the plant/Owner to determine what immediate actions need to be taken following the determination of inoperability.

Unfortunately, in some people's opinion, one area where the Code does not provide clear-cut guidance on when "additional actions" need to be performed by is following the failure of an IST Relief Valve Set Pressure Test.

Pressure Relief Device Testing

Typically, when IST performs a Relief Valve Set Pressure test, the valve has either been removed from its system and the system is either out of service, waiting for the valve to be tested and re-installed, or a spare replacement valve has already been installed in the removed valve's location with the system having been returned to service. In these cases, if the valve being tested fails to meet its set pressure testing criteria, there is no component "inoperability" that the plant must then address using its Technical Specifications or other documentation requirements, there are only additional actions which are prescribed within the Code that need to be performed. Namely, the testing of additional, similar (as defined within the Code through the "grouping" definition) relief/safety valves in an effort to determine whether the testing failure identified is a lone failure or whether it is an indication of a systemic problem. In other words, could there be similar relief valves currently installed in an operating system that may not be able to perform their safety-related function?

The question is then, "When must these additional relief valves be tested by?"

An answer to that question is currently not contained within the ASME OM Code.

What the Code Says and Why

Some individuals will argue that based upon how the Code establishes "shall be tested by" criteria for other circumstances or situations, that the same "shall be tested by" requirement is *implied* for the testing of additional relief valves following an IST set pressure test failure. For example, when dealing with Classes 2 and 3 pressure relief valves (except for Pressurized Water Reactor (PWR) Main Steam Safety Valves), if one replaces only a partial complement of valves in a "group" with pretested spares, those removed valves shall be tested within 3 months of removal from the system or the resumption of electric power generation whichever is later. [see I-1350(b)(1)] Some take away from this 3-month requirement that "3 months" need also be applied to the time period in which the expansion valves must too be tested by. This is not the case.

The same for I-1350(b)(2), which requires that if a full complement of valves is removed and replaced with pretested spares, these removed valves shall be tested within 12 months of removal from the system.

These 3-month and 12-month restrictions are in place not as a response to the identification of a valve failure, but in response to the unknown ability as to whether or not the removed valves would have been able to perform their own safety-related overprotection function.

Furthermore, if either the 3-month requirement for testing the removed partial complement of valves or the 12-month requirement for testing the removed full complement of valves were not met for whatever reason, that would not mean that any of the valves currently installed were inoperable. Neither would it mean that the valves removed had been inoperable. Failure to meet either of these two requirements would simply mean that compliance with the Code, and then by association, compliance to 10 CFR 50.55a was not met, which is a problem on its own.

Site Corrective Action Program

A good conservative engineering practice would of course be to perform any additional, required tested as soon as possible. Whether that means prior to further electric power generation or prior to returning the train/system to service or some other criteria is up to the utility to decide, not the Code.

This is where the site's Corrective Action Program comes into play.

There are many factors, outside of the Code's purview, that should be used to determine when the required ASME additional testing must be performed by.

Let us look at a couple of scenarios.

A relief valve has been removed from its system, installed on a test bench, and has failed its as-found set pressure test. How did it fail? What does "fail" mean? Let's say that this valve has a set pressure of 600 pounds per square inch gage (psig), with a +/- 3.0 percent acceptance criteria which means that the valve needs to "pop" somewhere between 582 to 618 psig in order to meet its Code as-found testing requirement. This valve is in a group of 6 valves.

When tested, this valve lifted at 580 psig. It failed low. The site must now per the Code test two more valves in the group. When must the site test these two additional valves by? What is the urgency in this instance? At this point with what little information is given in this example, a definitive numerical number of days in which these additional tests must be performed by cannot reasonably be determined.

If any of the other remaining, currently installed valves in the "group" were to be assumed to have drifted 20 pounds below the valves nominal set pressure, (i.e., only 2 pounds below the established lower acceptance criteria) what would be the effect of a premature lift be on the system's ability to perform its safety-related function?

This is where the site's Corrective Action Program will need to be used in making the determination as to the urgency for when these additional valves need to be tested by. I suspect that a drift low of 2 pounds below the 3 percent acceptance criteria would not create the same urgency as what one would have if the valve lifted 80 pounds below the 3 percent

acceptance criteria, which could lead to a loss of inventory situation especially if any of these other valves in the group still installed have drifted low to the same degree.

Also, more urgent would be if the valve tested, instead of lifting 2 pounds below the 3 percent acceptance criteria would have failed to lift until a pressure of 700 psig was reached, which would perhaps result a pressure boundary failure of the valve's system.

Another question to consider when determining urgency within the Corrective Action Program is what was the As-left set pressure of this valve that failed low? What if this nominal 600 psig valve's as-left set pressure was only 585 psig? Acceptable, but on the low end of its acceptable band. Failure was then a result of the set pressure dropping only 5 psi. If we then learn that the other 5 installed valves in the group had As-left set pressure between 599 and 601 psig, and that they had been installed for a similar amount of time, assuming a similar drift, they would still be in Code tolerances.

It is this type of Corrective Action Program Evaluation that would need to be performed to determine the urgency in which any additional valves need be tested by. The Code does not, and in my opinion should not, go into any greater detail than already exists in ASME OM Code, Mandatory Appendix I, paragraphs I-1320(c)(3) and I-1350(c)(3).

Additional Considerations

As stated in paragraphs I-1320(c)(3) and I-1350(c)(3), the Code requires that the Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria. Until the failed relief valve is disassembled and inspected by a qualified individual, that evaluation cannot be adequately performed. Results from this evaluation, or even "partial" evaluation, need to be factored into the Corrective Action Program's additional testing "urgency" determination.

Was the valve installed in a system that handles raw river water or clean RCS water?

Was the valve's failure a result of a parts problem? Application? Vibration? Corrosion? Was the valve dropped after it was removed from the system before it could be tested? I could list hundreds of possible factors which should be considered when determining when the expansion valves need to be tested by. The Code, in my opinion, is not the instrument that should describe "how" this determination/evaluation is to be performed. The Code simply states that based upon the evaluation, the Owner shall then determine if additional testing, beyond that already described in the Code, need be performed. The Owner's determination of when any additional testing needs to be completed by should be based upon the required evaluation, on a case by case basis, based upon the specific circumstances of the valve failure.

What if in this same group of 6 valves, you had already tested 5 valves in the month of April and they all pass, then in May, the sixth valve failed, do you need to re-test 2 of those freshly installed 5 valves the next day? Suppose that to do so would result in taking the associated systems/trains out of service, extending the existing maintenance outage or perhaps requiring a

new maintenance outage to be entered, resulting in a loss of both generation and revenue, or can a case be made within the Corrective Action Evaluation to hold off additional testing until the next available work window? (This determination will of course be made having factored in the reason for the valve's failure in the first place.)

This is yet another example of why the process for determining the 'must be tested by' date cannot practically be described within the structure of the Code, it must be made within the Corrective Action process.

So in summary, it is my opinion that the Code neither currently nor should in the future prescribe to the Owner when additional relief/safety valve testing needs to be performed by. The establishment of either a Code "hard limit" or "rule of thumb" criteria in my opinion would not be in the best interest of the industry. It is my position that the determination of when the testing of additional valves needs to be completed by should be made on a "case-by-case" basis by the Owner through their Corrective Action Process.

This presentation was written utilizing the 2022 Edition of the ASME OM Code.

Biographical Summary

Bret R. Collier is currently working for GSE Performance Solutions, LLC, and the owner of R C Engineering. He holds a BS degree in Nuclear Engineering from the University of Missouri-Rolla (1985), with over 39 years in the nuclear industry. Mr. Collier has been involved in Inservice Testing since 1996 and has served as the secretary of the ASME OM Code Subgroup on Pressure Relief Devices since 2006.

EPRI Safety Relief Valve Spring Compression Data Analysis

Nick Camilli

Electric Power Research Institute

This presentation summarized the Electric Power Research Institute (EPRI) study on the impact of performing multiple compressions on safety relief valve (SRV) springs prior to installation or during refurbishment. The practice of applying 10 compressions (“10x compressions”) has been debated within the industry as a means to reduce inherent manufacturing stresses and improve spring stability. Using archival data from 2020 to 2024, the study analyzed 59 springs—both new and inservice—across pressurizer safety valves (PSVs) and main steam safety valves (MSSVs). The results indicate that repeated compressions tend to improve consistency in spring rate performance, with the standard deviation decreasing significantly between the first 3 and last 3 sets of compressions. While improved repeatability was observed during compression testing, limited data prevented conclusions regarding long-term valve set-pressure performance. The findings support a flexible approach: compress springs until stable performance is achieved rather than adhering to a fixed number of cycles. Future work will focus on expanding the dataset and evaluating impacts on valve health and certification.

Motor-Operated Valves

**Track Chair:
William E. Densmore
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Appendix III – OMN-26 Implementation

Robert E. Brightup

Constellation Nuclear

American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix III, “Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants,” for Motor-Operated Valve (MOV) Programs includes the opportunity to utilize ASME OM Code Case OMN-26, “Alternate Risk-Informed and Margin Based Rules for Inservice Testing of Motor Operated Valves.” Many utilities are not availing themselves of the opportunities that Code Case OMN-26 provides to extend the Inservice Testing (IST) intervals associated with MOV Program valves. The presentation outlined Code Case OMN-26, including its origins, why the code case was developed, and its implementation. The presentation reviewed some of the concerns during the initial implementation of Code Case OMN-26, and the enhancement of the process as it has matured. The presentation focused on utilizing the Appendix III alternative paragraphs and how to justify establishing longer IST intervals, including intervals for MOVs stroked under design-basis conditions, without compromising equipment reliability. The presentation discussed the basic two-tier system of the Code Case OMN-26 performance evaluation, and the characteristics and trends to be considered before extending test intervals. With longer testing intervals come changes in preventive maintenance (PM) schedules, including actuator inspections and stem lubrication. The presentation discussed establishing appropriate intervals to optimize the time spent at the MOV and to minimize resource loading. The savings opportunities are real, as demonstrated by the scope and cost numbers realized by early adopters of Code Case OMN-26 IST intervals. The presentation helped utilities understand the advantages of implementing Code Case OMN-26, leading to reduced outage and online scope, reduced radiological dose, and measurable savings.

A Discussion on the Removal of Conditions on ASME OM Code Mandatory Appendix III

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Abstract

Title 10 of the *Code of Federal Regulations*, Part 50, Section 50.55a (10 CFR 50.55a) incorporates by reference the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code). Paragraph 10 CFR 50.55a(b)(3) places certain conditions upon the use of the ASME OM Code. If reviewed today, 10 CFR 50.55a(b)(3)(ii) places four conditions upon Motor-Operated Valve (MOV) testing prescribed in the OM Code's Mandatory Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants." Those conditions include a condition pertaining to MOV diagnostic test intervals, a condition pertaining to MOV testing impact on risk, a condition on MOV risk categorization, and a condition on MOV stroke times.

Starting in 2018, the ASME OM Code's Subgroup on MOVs worked diligently with the staff of the U.S. Nuclear Regulatory Commission (NRC) to modify the language in Mandatory Appendix III such that the conditions placed upon the standard could be removed. With the publication of the 2022 Edition of ASME OM Code, the language has been modified sufficiently to remove three of the four conditions.

This paper will discuss the process for changes to ASME OM Code, provide a brief description of the regulatory process for review and endorsement of the Code by NRC including the placement of conditions, provide a review on the four conditions currently found in 10 CFR 50.55a on Mandatory Appendix III, and discuss how the language in the 2022 Edition of OM Code has changed such that three of those four conditions can be removed in a future rulemaking of 10 CFR 50.55a.

Keywords: Mandatory Appendix III, MOV, 10CFR50.55a(b)(3)(ii), Diagnostic Test Interval, Testing Impact on Risk, Risk Categorization, Stroke Time Testing

Nomenclature

The following nomenclature is used within this paper:

AC Alternating Current

ASME American Society of Mechanical Engineers

BNCS Board on Nuclear, Clean Energy, Power, and Facilities Codes and Standards

CFR Code of Federal Regulations

DC	Direct Current
IST	Inservice Test
MOV	Motor Operated Valve
NRC	U.S. Nuclear Regulatory Commission
OM	Operation & Maintenance
OMB	Office of Management and Budget

1. Introduction

Rob Asghar from Forbes magazine has said that “writing-by-committee is in theory a fine thing, based on the notion that none of us is as smart as all of us. But in practice, none of us is as dumb as all of us, no matter the collective intelligence of the individuals involved.

Good writing-by-committee is virtually an impossibility. You could bring Mark Twain, Jane Austen, Miguel Cervantes, Toni Morrison and Leo Tolstoy into a room to write a novel together, but the only certainty would be that it would be a terrible one.

Still, writing-by-committee is a necessary evil.” [1]

And consensus standards like the ASME OM Code are no exception. The development of consensus standards requires the collaboration of individuals from all parts of industry. Government agency, special interest groups, manufacturers, and end-users need to come together to establish the rules and best practices to ensure mechanical equipment is designed, fabricated, assembled, and tested intentionally in ways that maximize the utility and longevity of the product. When that mechanical equipment is used to protect facilities from damage and destruction, equipment operators from harm, or the welfare of the public, the importance of the proper function of that equipment when called into service is paramount. Consequently, the standards used to ensure that mechanical equipment remains fully functional and operationally ready, must also be of the highest caliber.

The ASME OM Code is *the* consensus standard used to ensure pumps, valves, pressure relief devices, and dynamic restraints used in water-cooled nuclear power plants can perform their credited functions in support of shutting down a nuclear reactor, keeping the reactor shut down, or mitigating the consequences of a design basis accident. When nuclear power plants develop their maintenance and test programs, procedures, and guidelines in accordance with the ASME OM Code, the public is assured of their safety.

This paper will discuss the process for changes to the ASME OM Code, provide a brief description of the regulatory process for review and endorsement of the Code by the NRC including the placement of conditions, provide a review on the four conditions currently found in 10 CFR 50.55a on Mandatory Appendix III, and discuss how the language in the 2022 Edition of OM Code has changed such that three of those four conditions can be removed in a future rulemaking of 10 CFR 50.55a.

2. Development and Modifications to ASME OM Code

ASME standards cover a wide range of engineering applications, including pressure technology, power plants, elevators, construction equipment, piping, nuclear components, and more, essentially encompassing most mechanical engineering systems and components, ensuring safety and performance across various industries through standardized design and manufacturing practices. Standards are developed under the watchful eye of governing boards and each standard having a standard committee with a balanced interest group. Standard committees are charged with the responsibility to develop and maintain the content of the standards under their purview following an open consensus process.

Presently, ASME provides a system named C&S Connect where members of standards committees and their associated subcommittees, subgroups, working groups, and task groups can track the development of new standards, guides, and code cases or modification to existing works on electronic records¹. These electronic records include a description of the record, attachments to the record, as well as any committee correspondence which the committee, subcommittee, task group, or working group desires to track with the record. Descriptions of the record include the subject of the record, high level description of the proposal, and a summary of changes made to the record over time. Attachments are also placed in the record which include a copy of the item being proposed, whether that be a completely new document or a detailed comparison of the existing language and the newly proposed language in the case of modification of an existing standard, guide, or code case. Attachments to the record also include background files and a white paper describing the context and impetus of the proposed change.

Once records are established, balloting processes are executed which allow standards committees, subcommittees, subgroups, task groups, and working groups the ability to provide comment and/or vote (approve, disapprove, or disapprove with comment) on the acceptability of a proposed change. Each ASME standard can have a differing process for shepherding additions, modifications, and removal of requirement within standards. Processes of some standards require a global review and comment ballot by all other committees and subgroups reporting to the standards committee. Others require only targeted review and comment. The ASME OM Code's process is shown in Figure 1.

In any case, once the proposal has been fully balloted and approved by the standards committee, the proposal is reviewed by the board governing the standard. In the case of ASME OM Code, the governing board is the Board on Nuclear, Clean Energy, Power, and Facilities Codes and Standards, also known as BNCS. The board does not review the content of the record but must review the balloting process to ensure that consensus process was followed. This review includes a check of each ballot approving a change to ensure the following three criteria were met:

1. A balance of interest of eligible voting standards committee members was maintained.
2. Either no disapproval or disapproval with comments votes were cast on a first consideration ballot or that greater than a two-thirds majority of the standards committee approved the ballot on a recirculation ballot.
3. All comments made to first consideration ballots and recirculation ballots have been addressed.

¹ Standards committees, subcommittees, subgroups, task groups, and working groups may also use the C&S Connect system for balloting other administrative actions, such as membership actions, meeting minutes approvals, and the like.

The BNCS review of the standards ballots is initiated by the start of a new ballot in the C&S Connect system by the ASME OM Code Secretary. Once the BNCS ballot is approved, the approved changes or new documents are queued by the ASME OM Code Secretary until the time comes for transmittal to ASME's publisher for inclusion in the next edition of the standard. With the publication of the OM Code roughly every 2 years, it can take between 2 and 4 years for a modification to existing code language to be reviewed, voted on and published using the process.

3. U.S. Regulatory Process for Review and Endorsement

Circular A-119, issued by the Office of Management and Budget (OMB) of the Federal Government, is a policy document that directs federal agencies, including the NRC, to prioritize the use of voluntary consensus standards developed by private sector organizations when setting standards, rather than creating government-specific standards, unless absolutely necessary. Essentially, Circular A-119 encourages the NRC to participate in and leverage existing industry standards wherever possible to streamline regulations and reduce administrative burden. The National Technology Transfer and Advancement Act of 1995 codified existing policies in Circular A-119.

The NRC, like all federal agencies, is required to comply with Circular A-119, meaning they must actively seek out and utilize relevant voluntary consensus standards when developing regulations related to nuclear safety. The NRC should actively participate in the development of standards through relevant industry organizations to ensure that the standards are appropriate for their needs and effectively address nuclear safety concerns. By utilizing existing standards, the NRC aims to minimize the need to create new, agency-specific regulations, potentially streamlining the regulatory process and reducing administrative burdens on regulated entities.

The ASME OM Code is one of several consensus standards incorporated by reference into Title 10, Chapter 1, Part 50 of the U.S. Code of Federal Regulations, which covers Codes and Standards used in the Issuance, Limitation, and Conditions of Licenses and Construction Permits under the jurisdiction of the NRC. By listing the ASME OM Code in 10 CFR 50.55a(a)(1)(iv), the NRC endorses the use of the Code and requires that construction permit holders, operating permit holders or combined construction and operation license holders of commercial nuclear power plants conform to the requirements in these standards. Since issuance of their permits, licensee have been required to manage an inservice test (IST) program to maintain their safety-related pumps, valves, and dynamic restraints. The processes and procedures of these IST programs are required to be in conformance with those in the ASME OM Code with the additional conditions as imposed by 10 CFR 50.55a(b)(3). To ensure the highest assurance of public welfare, the requirements of the ASME OM Code will periodically change. This allows utilities to take advantage of the latest technology to ensure their equipment remains safe and reliable as well as reduces the cost to implement the programs. Accordingly, ASME will periodically publish new editions of the OM Code, which incorporate all of the changes accepted by the ASME OM Code Standards Committee and confirmed by the BNCS to have had an adequate consensus structure followed. Once published by ASME, the NRC has the mandate to review the standard and publish their findings using the Rulemaking Process.

The Rulemaking Process moves at the speed of government, which is to say, not very fast, but this is by design. A deliberate and measured process ensures equal and equitable access and time to each member of the public to voice their opinion. The Rulemaking Process requires the NRC to publish their initial opinion on the rules in the ASME OM Code and any additional

conditions they find fit to impose upon those rules to ensure the public's safety. Since members of the NRC actively participate in the development of the ASME OM Code, the initial rulemaking usually follows publication of the OM Code within six months. The public is then given roughly one year to review the initial rulemaking and submit any comments they may have on the NRC's acceptance or conditions. Following that public comment period, the NRC must then address each comment received, determine if their position should change based upon those comments, and finally issue a final rulemaking to incorporate by reference the latest edition of the ASME OM Code in 10 CFR 50.55a, with appropriate conditions, as noticed in the *Federal Register*.

4. THREE CONDITIONS REMOVED FROM MANDATORY APPENDIX III

Mandatory Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants," of ASME OM Code was first published in the 2009 Edition of the ASME OM Code. This edition was incorporated by reference into 10 CFR 50.55a along with the 2012 Edition of ASME OM Code in 2017. Paragraph 10 CFR 50.55a(b)(3)(ii) places four conditions upon MOV testing prescribed in the ASME OM Code, Mandatory Appendix III. Those conditions include:

- a condition on MOV diagnostic test intervals
- a condition on MOV testing impact on risk
- a condition on MOV risk categorization
- a condition on MOV stroke times

Each of these conditions are discussed in greater detail in the following subsections.

4.1 10 CFR 50.55a(b)(3)(ii)(A) MOV Diagnostic Test Interval

In the 2017 Edition of ASME OM Code, paragraph III-3310, "Inservice Test Interval," [2] had the following requirements for determining the inservice test interval, otherwise known as the time between inservice tests, for active MOVs.

The inservice test interval determination shall include the following:

- (a) The inservice test interval shall be determined in accordance with para. III-6640.
- (b) If insufficient data exist to determine the inservice test interval in accordance with para. III-6440, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer service interval.
- (c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per para. III-3400 may be used to satisfy this requirement.

Subparagraph (b) in paragraph III-3310 fails to define "sufficient" data. Due to a lack of a definition for what constitutes "sufficient" data to exist to determine an IST interval, the regulatory condition in 10 CFR 50.55a(b)(3)(ii)(A) requires licensees to evaluate the information obtained for MOV tests completed during the first 5 years or three refueling outages (whichever is longer) of the use of Appendix III to validate assumptions made in justifying a longer test interval. Specifically, condition 10CFR50.55a(b)(3)(ii)(A), "MOV Diagnostic Test Interval," states:

- (A) MOV diagnostic test interval. Licensees shall evaluate the adequacy of the diagnostic test interval established for MOVs within the scope of ASME OM

Cod, Appendix III, not later than 5 years or three refueling outages (whichever is longer) from initial implementation of ASME OM Code, Appendix III.

By placing this condition on the MOV diagnostic test interval, the NRC required domestic licensees to perform a review of every diagnostic test interval for every valve, or group of valves, within 5 years after entering their 10-year IST Interval in which they were required to follow the requirements of Mandatory Appendix III.

A review of III-3310(a) indicates that the inservice test interval must be determined in accordance with III-6400, "Determination of MOV Functional Margin." Paragraph III-6440, "Determination of MOV Test Interval," requires that the inservice test interval be set such that the MOV functional margin does not decrease below the acceptance criteria. Licensees have the liberty to set their own acceptance criteria for every active MOV or group of MOVs with the provision that the adequate functional margin (available actuator output – valve operating requirements, all taken during design-basis accident conditions) exists to satisfy the acceptance criteria for MOV Operational Readiness, that is to say functional margin must always remain a positive number.

In essence, these requirements in Mandatory Appendix III cause the licensee's IST program to be a living program in which MOV Inservice Test Intervals are continuously reviewed upon receiving new field data to ensure no new degradation mechanisms are influencing the functional margin calculation, such that active MOVs can be expected to remain operationally ready through their next regularly scheduled inservice test. Thus, condition 10 CFR 50.55a(b)(3)(ii)(A) has virtually no effect on plants which have a long established MOV program and already continually review their functional margin calculations and revise their inservice test intervals as required by the new field data as it arrives.²

Accordingly, when approached about revising the requirements in III-3310 such that condition 10 CFR 50.55a(b)(3)(ii)(A) could be removed from Mandatory Appendix III, the Subgroup on MOVs was able to marshal a change in those requirements with significant resistance. The 2022 Edition of ASME OM Code [3] reflects those changed requirements, now stating in III-3310(b):

- (b) If insufficient data exist to determine the inservice test interval in accordance with III-6400, the MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer inservice test interval. Not later than 5 yr or three refueling outages (whichever is longer) after initial implementation of this Appendix, the Owner shall evaluate the MOV diagnostic test interval per III-6440.

² This position is confirmed in the white paper which accompanied the modification to the requirements in III-3100(b). A section of the white paper reads "According to the white paper associated with this code change, "...Condition [10 CFR 50.55a(b)(3)(ii)(A)] primarily affects new plants. Current operating plants that have been performing diagnostic tests to address Generic Letter (GL) 89-10 and GL 96-05 have more than 5 years of test data and have reached optimum test intervals based on validated assumptions."

4.2 10 CFR 50.55a(b)(3)(ii)(B) MOV Testing Impact on Risk

In the 2017 Edition of ASME OM Code, paragraph III-3620, “Additional Exercising Requirements,” [4] had the following requirements for considering more frequent exercising of active MOVs.

The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

- (a) MOVs with high risk significance
- (b) MOVs with adverse or harsh environmental conditions or
- (c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

While subparagraph (a) of III-3620 in the 2017 Edition requires consideration of high-risk significance, the subparagraph fails to identify what high risk means. As such, the NRC felt it necessary to provide bounds defining what constitutes high risk significance. To do so, condition 10 CFR 50.55a(b)(3)(ii)(B) as placed upon the paragraph, which states:

(B) MOV testing impact on risk. Licensees shall ensure that the potential increase in core damage frequency and large early release frequency associated with the extension is acceptably small when extending exercise test intervals for high risk MOVs beyond a quarterly frequency.

By placing this condition on the additional testing requirements, the NRC effectively required licensees to consider the specific risks of core damage frequency and large early release frequency when determining how often they would exercise their active MOVs. Since this condition effectively bounds the consideration of high-risk activities to just increases in code damage frequency and large early release frequency, the inclusion of this condition directly into Mandatory Appendix III was met with little resistance. In the 2020 Edition of ASME OM Code, paragraph III-3620 [5] was revised to state:

The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

- (d) MOVs with high risk significance as required by para. III-3721
- (e) MOVs with adverse or harsh environmental conditions or
- (f) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

4.3 10 CFR 50.55a(b)(3)(ii)(C) MOV Risk Categorization

In the 2017 Edition of ASME OM Code, paragraph III-3720, “Risk-Informed Criteria,” [6] had the following requirement for considering risk insights into their active MOV program.

Each MOV shall be evaluated and categorized using a documented risk ranking methodology. This Appendix provides test requirements for high and low safety significant components (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

To those well versed in programs like the Joint Owners Group MOV Periodic Verification Program (also known as JOG), the classification of active MOVs using approved risk ranking

methodologies may seem like a forgone conclusion. In fact, as part of the NRC's review of a licensee's response to GL 96-05 [7], the NRC specifically ensured that each licensee's program utilized an approved risk-ranking methodology if risk insights were used. However, as written in the 2017 Edition of ASME OM Code, the requirement for using a risk-ranking methodology did not place any bounds on what that risk-ranking methodology needed to be. It only required the methodology be documented and that if it had more than two risk categories, then the valves in those intermediate safety significance categories needed to be treated as high safety or low safety significant valves. In a fantasy scenario, an Owner could have documented a methodology of a coin flip to make the decision whether a valve was of high or low safety significance.

Accordingly, the NRC placed condition 10 CFR 50.55a(b)(3)(ii)(C) onto III-3720 which states:

(C) MOV risk categorization. When applying Appendix III to the ASME OM Code, licensees shall categorize MOVs according to their safety significance using the methodology described in ASME OM Code Case OMN-3, "Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants," subject to the conditions applicable to OMN-3 which are set forth in Regulatory Guide 1.192, or using an MOV risk ranking methodology accepted by the NRC on a plant-specific or industry-wide basis in accordance with the conditions in the applicable safety evaluation.

Now since the overwhelming majority of licensees participated in the JOG program and were already utilizing risk-ranking methodologies which were accepted by the NRC on a plant-specific or industry-wide basis, when called upon to revise Mandatory Appendix III to reduce the number of 10 CFR 50.55a conditions placed upon it, the ASME OM Code's Subgroup on MOVs met no resistance at all in revising the language paragraph III-3720. In the 2020 Edition of the OM Code, paragraph III-3720 [8] was revised to read:

Each MOV shall be evaluated and categorized using a documented risk ranking methodology that has been accepted by the regulatory authorities having jurisdiction at the plant site. This Appendix provides test requirements for high and low safety significant component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

4.4 10 CFR 50.55a(b)(3)(ii)(C) MOV Stroke Times

In the 2017 Edition of ASME OM Code, paragraph III-3610, "Normal Exercising Requirements," [9] had the following requirements with respect to frequency and scope of normal exercising requirements of active MOVs.

All MOVs, within the scope of this Appendix, shall be full cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 months. Full cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full stroke exercising of an MOV is not practical during plant operation or cold shutdown outages, full stroke exercising shall be performed during the plant's refueling outage

For those who have watched the development of MOV programs and the codification of those MOV programs into the ASME OM Code, Mandatory Appendix III, this paragraph surreptitiously contained one of the largest benefits of moving to an Appendix III program: the elimination of stroke-time testing.

The vast majority of active MOVs within the commercial nuclear power industry today receive their motive force from alternating current (AC) motors. With their ability to draw more and more current to overcome load, AC motors do not experience the same drop in operational speed (when looked at in a macro scale) that direct current (DC) motors or other valve operators tend to experience. As such, the stroke-time testing required by ASME OM Code for active AC MOVs in editions prior to the 2009 Edition provided relatively little benefit to identify the start of any aberrant or anomalous behavior for the vast majority of those in-program valves. Any of those benefits pale in comparison to the relatively detailed analysis and evaluation of diagnostic test provided by inservice testing in accordance with the plant's MOV Program which was established as a commitment in response to GL 96-05. Therefore, when considering the cost-benefit analysis of stroke-time testing against the benefits of diagnostic testing, ASME OM chose to eliminate the stroke-time testing of MOVs and instead require the periodic verification of MOV functional margin using diagnostic testing. However, what those early drafters of Mandatory Appendix III did not anticipate was that another layer of nuclear oversight was also taking credit for quarterly stroke-time testing active MOVs: that is, Technical Specifications.

Consequently, when the NRC incorporated by reference the 2009 and 2012 Editions of ASME OM Code into 10 CFR 50.55a, a fourth condition was needed on the use of Mandatory Appendix III. In particular, 10 CFR 50.55a(b)(3)(ii)(D) reads as follows:

(D) MOV stroke time. When applying Paragraph III-3600, "MOV Exercising Requirements," of Appendix III to the ASME OM Code, licensees shall verify that the stroke time of MOVs specified in plant technical specifications satisfies the assumptions in the plant's safety analyses.

The subject of MOV stroke times and re-inclusion of the requirement to stroke-time test MOVs in conjunction with exercise testing received significant debate over several ASME OM Code meetings. Some members wanted to see changes made to paragraph III-3610 to indicate that if an MOV is referenced in the plant technical specifications, the Owner shall verify that the MOV stroke-time assumption in the plant's safety analyses is satisfied, such that the final condition on Mandatory Appendix III could be eliminated. Other members wanted to see action from those referring to OM Code MOV stroke-time testing to satisfy Technical Specification requirements by way of a separate regulation.

Review of ASME OM Code, Subsection ISTA, "General Requirements," paragraph ISTA-1100 provided insight into the discussion. Paragraph ISTA-1100 states:

Section IST establishes the requirements for preservice and inservice testing and examination of certain components to assess their operational readiness in water cooled reactor nuclear power plants.

Stroke-time testing of active MOVs provides no indication of operational readiness for most active safety-related valves in water-cooled nuclear power plants. Accordingly, the ASME OM Code Subgroup on MOVs ultimately chose not to modify the language in Mandatory Appendix III to allow the NRC to remove the condition. The condition will continue in perpetuity.

5. Conclusion

In aggregate, the ASME OM Code Subgroup on MOVs was able to modify the language in Mandatory Appendix III of the 2022 Edition of the ASME OM Code to allow removal of three of the four conditions in 10 CFR 50.55a(b)(3)(ii) placed upon the Appendix III in the ASME OM Code. At this time, the NRC has issued a final rulemaking that incorporates by reference the 2022 Edition of the ASME OM Code in 10 CFR 50.55a. The NRC indicates in 10 CFR 50.55a that the conditions in 10 CFR 50.55a(b)(3)(ii)(A), (B), and (C) do not apply to the use of the 2022 Edition of the ASME OM Code in IST programs at nuclear power plants. Once all licensees have updated their IST programs to follow the 2022 Edition (or later) of the ASME OM Code, the NRC is expected to remove conditions in paragraphs (b)(3)(ii)(A), (B), and (C) from 10 CFR 50.55a. Condition 10CFR50.55a(b)(3)(ii)(D) will remain for the foreseeable future.

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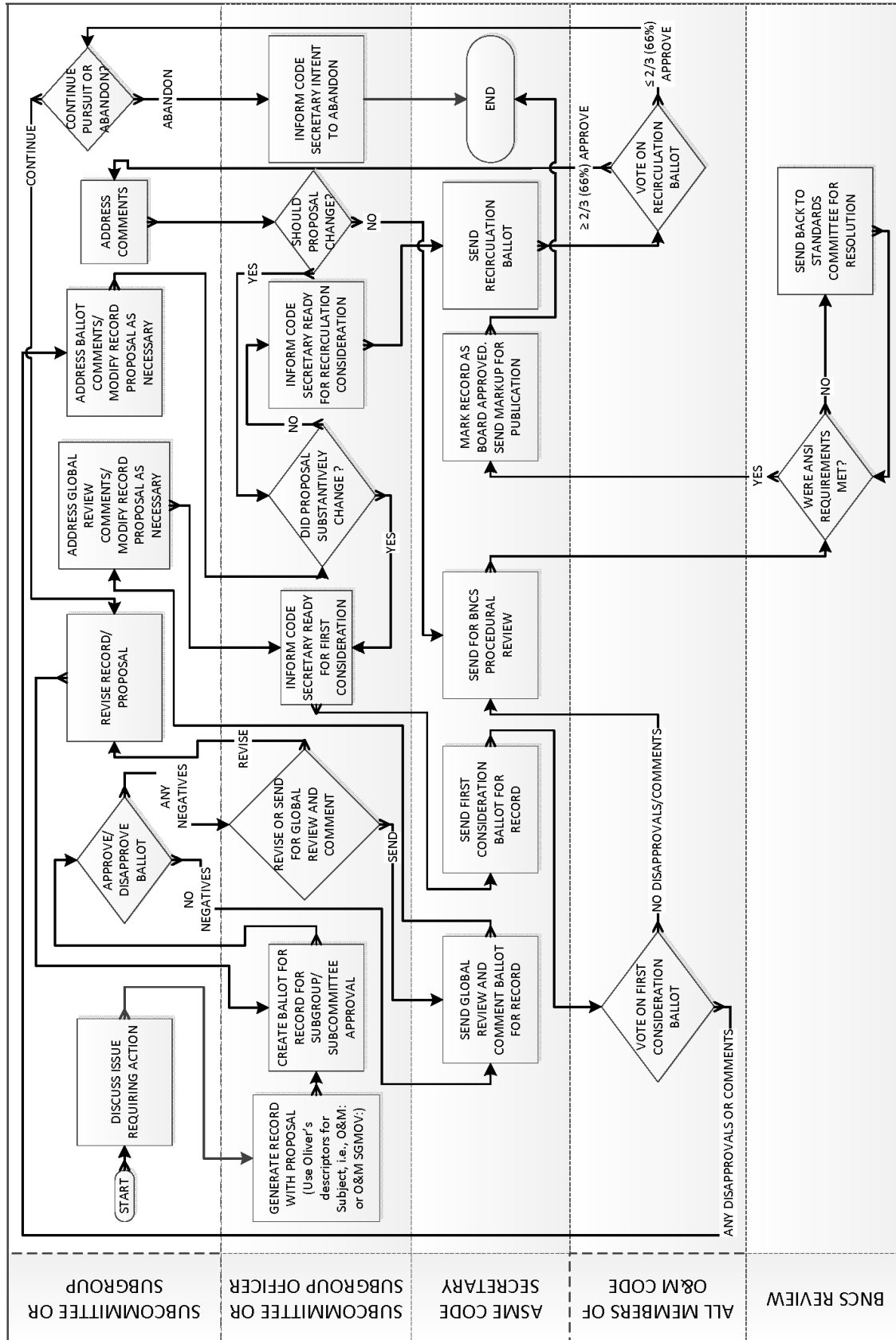


Figure 1 Operations & Maintenance Code Development Process

Cost-Informed Management of Motor-Operated Valve Programs

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APS/Palo Verde Generating Station

Tonopah, AZ

Abstract

Legacy-based motor-operated valve (MOV) programs have much to gain from relatively low-cost investments in modernizing requirements and adopting an aggregate metric for program implementation. In 2024, Palo Verde reduced its MOV testing burden more than 25 percent by re-evaluating diagnostic test periods and reassigning generic letter commitments to the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix III, “Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants.” “Burden” is a site-level metric with units of “tests per year.” This program-level summation of normalized test frequencies measures the implementation cost of regulatory compliance for MOVs. Program costs vary depending on adherence to the Joint Owners Group (JOG) MOV program requirements, equipment issues, and active program management. Cost-informed program management maintains high levels of safety because modern program requirements are built on industry operating experience.

Keywords: ASME, OM Code, Appendix III, MOV, motor-operated valve, JOG,

NOMENCLATURE

IST: Inservice testing

MOV: Motor-operated valve

JOG: Joint Owner’s Group

GL: Generic Letter

1. Introduction

Motor-operated valve (MOV) programs applying the Joint Owners Group (JOG) MOV Program requirements are more expensive to operate than those applying modern American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), requirements. In 2024, Palo Verde modernized program requirements enabling access to longer MOV test periods and reducing program burden by more than 25 percent. “Burden” is defined as the frequency of testing for an MOV subject to ASME OM Code, Mandatory Appendix III, “Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants.” Summing normalized test frequencies for all MOVs at a site provides a metric for the time and effort necessary to implement an MOV program. The metric provides a basis for comparison of impact

when modernizing MOV programs. The metric can provide a measure of MOV program performance over time.

2. Results and Discussion

JOG Program test periods are more restrictive than those allowed under ASME OM Code. For high-risk valves, JOG allows a maximum of 6-year test interval for high-risk/high-margin MOVs. For low-risk valves, JOG allows a maximum 10-year test interval. Low-risk JOG requirements align with Mandatory Appendix III, which allows a maximum 10-year test period for all valves. Plants have an incentive to test at longer intervals because it requires less effort than shorter test periods.

Palo Verde identified the opportunity to save effort with longer test periods because it applied both JOG and ASME requirements. Palo Verde's MOV Program incorporated both JOG and Mandatory Appendix III requirements. JOG requirements were adopted as a formal commitment to satisfy Generic Letter (GL) 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." ASME OM requirements were adopted starting in 1998 with OM Code Case OMN-1, "Alternative Rules for Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants," becoming Appendix III when the station adopted the 2012 Edition of the ASME OM Code for its fourth 10-year IST interval starting in January 2018. For each MOV diagnostic test, performance evaluations documented the acceptability of valve diagnostic periods per the JOG program provisions and ASME OM Code requirements, applying the more conservative criteria wherever applicable. The Mandatory Appendix III requirement was not based on risk, suggesting that high-risk valves could be tested at longer intervals provided that JOG program provisions could be removed.

Palo Verde applied a three-part approach MOV test period reduction to achieve more than 25 percent reduction in testing. The parts were worked in parallel. The station:

- Extended individual MOV test periods per JOG program provisions.
- Developed the concept of "burden" to capture the effects of test period extensions.
- Updated GL 96-05 commitments to Appendix III rather than the JOG program.

JOG Program Extensions

Palo Verde's initial testing reductions came from extending MOVs to the maximum justifiable test period. Several MOVs were not tested at their maximum justifiable periods. Some MOVs had been assigned to a 3-year test period per ASME OM Code, Mandatory Appendix III, paragraph III-3310(b), while others were using a period less than allowed by JOG with no clear basis. To resolve the issue, Palo Verde first extended MOVs with JOG Program provisions. Second, the station extended additional MOVs after GL 96-05 commitments were reassigned to Appendix III.

“Burden” Determination

To measure savings from test period extensions, Palo Verde developed “burden” to measure MOV program implementation effort. Burden is the normalized rate of testing for an MOV with units of “tests per year.” Normalized test rates can be summed across a unit or a site to determine an overall testing rate. These sums can be used to measure the effect of test period extensions.

Burden is salient in comparing the relative effort required to implement testing on MOVs with different test periods. An MOV with a 10-year test period has a burden of 0.1 tests per year, whereas an MOV with a 6-year test period has a burden of 0.17 tests per year. These rates show a 10-year MOV is 41 percent less burdensome than a 6-year MOV.

Normalized test periods can be summed across a unit or site to compare effort. For example, a hypothetical two-unit site with two MOVs per Unit A and Unit B.

- Unit A has both MOVs on 10-year test period. Its burden is 0.2 tests per year.
- Unit B has one MOV on a 6-year period and the other on a 10-year test period. Its burden is 0.27 tests per year.

Comparing the units, Unit A’s MOV program is 26 percent less burdensome than Unit B’s program. With this comparison, the hypothetical station would benefit from reducing the Unit B’s program burden via a test period extension. The site has a burden of 0.47 tests per year. Assigning both MOVs in Unit B to a 10-year period results in a 14.9 percent reduction in the site-level burden.

Palo Verde uses a site-level burden metric to quantify savings from MOV test period extensions. Prior to the test period extension effort, Palo Verde’s MOV program burden was 67.4 tests per year for 312 MOVs across the station’s three units. As of this writing, Palo Verde’s burden is 48.1 tests per year. This is a 28.7 percent reduction. This includes the effect of reassigning the GL 96-05 commitments to Appendix III.

GL 96-05 Commitments

Palo Verde updated its GL 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” and GL 96-05 commitments to credit the ASME OM Code, Mandatory Appendix III. NRC guidance on IST program implementation demonstrated this was possible. NUREG-1482, Revision 3, Section 4.2.13, states:

The staff considers that the implementation of Mandatory Appendix III for MOVs within the scope of the OM Code will meet the requirements of 10 CFR 50.55a(b)(3)(ii) provided the specified regulatory conditions are satisfied.... Licensees need to follow their commitment change process when updating their MOV program from the JOG final MOV test program to the new requirements of Mandatory Appendix III. [Recently issued NUREG-1482, Revision 4, includes the same sentences.]

These passages show (1) compliance with Mandatory Appendix III meets the 10 CFR 50.55a requirement to implement an MOV program, and (2) it is acceptable to update GL 89-10/96-05 commitments to Mandatory Appendix III. The guidance acknowledges Appendix III is equivalent to the JOG program for periodic verification of the design-basis capability of MOVs.

Outcome

Palo Verde has achieved significant savings in its MOV program implementation by modernizing requirements and taking a cost-informed approach to program management.

MOV Programs can add value by performing testing less often. Unlike other portions of OM Code, Appendix III gives stations control of test periods provided that MOV margin remains positive over the period. Test periods have a direct effect on the labor required to implement a program, and by extension the cost of implementing the program. Each test requires work orders, scheduling, planning, maintenance resources, and record archiving. The resources that implement each of these functions represent MOV program implementation costs.

Burden, as a metric, reflects changes in MOV test periods. It is useful in comparing program performance after extending valve test periods. Applied over time, it may also be useful in monitoring program effectiveness. MOVs assigned a 3-year test in response to maintenance will increase burden. MOVs extended beyond a 3-year period will reduce burden. Monitoring changes in burden over time could be used to trend program effectiveness in maintaining components that can support extended test intervals.

3. Conclusion

Nuclear plants can reduce MOV Program overhead by driving to reduce “burden.” Burden is the rate of MOV diagnostic tests performed per year at a site or station. Summing individual MOV burdens across a site or station provides a program-level burden metric, giving a measure of the cost of operating an MOV program. With this perspective, Palo Verde reduced its MOV program burden by nearly 25 percent in 2024 while maintaining compliance with the ASME OM Code, Mandatory Appendix III. The station reduced testing by ensuring MOVs were tested at the longest justifiable test periods and updating GL 89-10/96-05 commitments to access longer test periods available in Mandatory Appendix III. These changes maintain high levels of safety because they are rooted in ASME OM Code requirements developed by industry consensus and incorporated by reference into the NRC regulations.

Risk

Track Chair:
Daniele Ludovisi
Sargent & Lundy

10 CFR 50.69 Implementation Benefits and Practices

Kelli Voelsing

Nuclear Energy Institute

The Nuclear Energy Institute (NEI) made a presentation to highlight the collaborative industry experience of its members in implementing Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.69, “*Risk-Informed Categorization and Treatment of Structures, Systems, and Components (SSCs)*.”

The presentation highlighted the benefits of adopting a holistic 10 CFR 50.69 program. The presentation shared real-world case studies demonstrating safety benefits, and improved equipment reliability, in addition to the widely recognized cost savings and operational efficiency benefits. The presentation shared practical implementation experience from NEI members in terms of how risk-informed categorization, alternative treatment strategies, and performance monitoring is accomplished and how these activities are effective ensuring that SSCs continue to function as intended while providing flexibility to licensees. This discussion provided deeper insights into regulatory compliance, operational efficiency, and long-term sustainability of the 10 CFR 50.69 framework.

New Reactors II

Track Chair:
Augi Cardillo
NuScale Power

Overview of Natrium™ Demonstration Plant Implementation of ASME QME-1 for Qualification of the Control Rod Drive (CRD) Assembly

Thomas Kopriva
GE Hitachi Nuclear

The Natrium™ Plant will apply the American Society of Mechanical Engineers (ASME) QME-1 Standard, “Qualification of Active Mechanical Equipment Used in Nuclear Facilities,” and ASME OM-2-2024 Code, “Component Testing Requirements at Nuclear Facilities.” The applicable NRC Regulatory Guides will also be applied once they are defined and released. As a prerequisite, prior to their installation, components that are to be included in the Inservice Testing (IST) Program shall have been qualified by the ASME QME-1 Standard. In addition, the qualified life will be initially determined in accordance with the QME-1 Standard, Section QR, “General Requirements,” paragraph QR-5320, “Determination of Qualified Life.”

The Natrium control rod drive (CRD) driveline assembly is a subassembly of the CRD system that connects the upper mechanism of the system above the reactor head to the Control Rod Assembly (CRA) in the core. The driveline assembly is composed of three concentric shafts called the tension rod, sensing tube, and drive shaft. These parts and assembly of the CRD are classified as Safety-Related (SR), and are also considered Seismic Risk Significant (SRS) so will require qualification. In addition, parts and subassemblies of the driveline assembly shall be designed and analyzed using ASME *Boiler and Pressure Vessel Code* (BPV Code), Section III, Division 5 (III-5) HGB. However, the driveline assembly is not an ASME component; therefore, certification is not required.

The QME-1 Standard consists of four major sections: (a) Section QR: Qualification Requirements, (b) Section QDR: Qualification of Dynamic Restraints, (c) Section QP: Qualification of Active Pump Assemblies, and (d) Section QV: Qualification Requirements for Active Valve Assemblies for Nuclear Facilities. The CRD is neither a dynamic restraint, a pump, or valve. However, it is an active mechanical assembly whose function is required to ensure the safe operation or safe shutdown of the Natrium™ Demonstration Plant. The CRD specified safety-related functional requirements include positioning the control rods to change core reactivity and rapid insertion for rapid shutdown of the reactor (i.e., SCRAM). Guidance from QME-1, Section QR, and its nonmandatory Appendixes will be applied for the requirements and guidelines for the qualification of the CRD assembly to meet its specified functional requirements during operation, and during or after any postulated abnormal or accident conditions.

The IST program has not been determined for the CRD assembly. However, the ASME QME-1 Standard will be used to help determine IST activities. Specifically, as indicated by the draft ASME OM-1 Code, Section GR, the periodic and condition-monitoring frequencies specified in this Code may be adjusted based on recommendations for periodic IST activities that are included within the ASME QME-1 Qualification Report prepared by the manufacturer.

Overview of Natrium™ Demonstration Plant Implementation of ASME QME-1 and OM-2 Code

Matthew Laney
TerraPower

The Natrium™ Demonstration Plant (a TerraPower and GE-Hitachi technology) applies a graded approach per Nuclear Energy Institute (NEI) 18-04, Revision 1, “Risk-Informed Performance-Based Guidance for Non-Light Water Reactor Licensing Basis Development,” and NRC Regulatory Guide 1.233, Revision 0, “Guidance for a Technology-Inclusive, Risk-Informed, and Performance-Based Methodology to Inform the Licensing Basis and Content of Applications for Licenses, Certifications, and Approvals for Non-Light Water Reactors.” In this regard, the TerraPower Quality Assurance Program categorizes important to safety structures, systems, and components (SSCs) as safety-related (SR) or non-safety-related with special treatment (NSRST) based on their important to safety and risk-significant functions. The Natrium™ Plant will apply the American Society of Mechanical Engineers (ASME) QME-1-2023 Standard, “Qualification of Active Mechanical Equipment Used in Nuclear Facilities,” and the ASME OM-2 Code, “Component Testing Requirements at Nuclear Facilities.” The applicable NRC Regulatory Guides will also be applied once they are defined and released.

All important to safety valves will be qualified per the ASME QME-1 Standard, and will be scoped into the Natrium™ Plant Inservice Test (IST) Program per the ASME OM-2 Code. The Natrium™ Plant contains SR and NSRST pumps that will be qualified per QME-1; however, their functions do not require them to be scoped into the IST Program. The Natrium™ Plant does not contain any SR or NSRST dynamic restraint devices (DRDs) as defined by the OM-2 Code.

The Natrium™ Plant does contain SR seismic isolators that will be qualified per QME-1; however, these seismic isolators do not require inclusion into the IST Program based on their OM-2 definition and function. The seismic isolators will be included in the broader Natrium™ Plant Reliability and Integrity Management (RIM) Program under ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, Division 2, “Requirements for Reliability and Integrity Management Programs for Nuclear Power Plants,” and will be subjected to vendor-defined periodic test requirements.

Plant design engineers are still in the process of defining the SR and NSRST valves and their safety functions. The Natrium™ Plant contains passive safety features; therefore, valves fail to a safe position (fail-closed, fail-open, fail as-is) and do not require any back-up power to perform their important to safety function.

Pumps fail to a safe position and coast down upon loss of power. The Primary Sodium Pumps (PSPs) are vertical, mechanical centrifugal pumps which are attached to the Reactor Head (RH), sit within the Reactor Vessel (RV), and circulate the molten sodium into the Reactor Core (RC). They have SR functions. These pumps will have integrated instrumentation that will allow for in-situ performance monitoring. The maintenance program will utilize the integrated instrumentation to perform the periodic testing requirements and check for degradation. The

PSPs will be included in the broader Natrium™ Plant RIM program due to their pressure-retaining function.

SR and NSRST valves are expected to have some integrated instrumentation that will allow for some in-situ performance monitoring of the important to safety functions. However, it is expected that temporary instrumentation for periodic diagnostic testing will be required. Pressure relief devices (PRDs) will require temporary instrumentation for periodic diagnostic testing; however, the scope of PRDs is limited due to the passive design.

The Link between QME-1 and OM

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The American Society of Mechanical Engineers (ASME) published the QME-1 Standard, “Qualification of Mechanical Equipment Used in Nuclear Facilities.” The QME-1 Standard was developed from American National Standards Institute (ANSI) N278.1, “Self-Operated and Power-Operated Safety-Related Valves Functional Specification Standard,” and ANSI B16.41, “Functional Qualification Requirements for Power Operated Active Valve Assemblies for Nuclear Power Plants,” and was first published in 1994. The 2007 Edition of the QME-1 Standard was endorsed by the U.S. Nuclear Regulatory Commission (NRC) in 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,” and the QME-1-2017 Standard is currently endorsed by the NRC in Regulatory Guide 1.100, Revision 4. The latest edition is the QME-1-2023 Standard [with the QME-1-2025 Standard issued since preparation of this paper].

QME-1 has detailed instructions for Pipe Restraints (Snubbers), Pumps and Valves. The valve portion (Section QV) incorporates lessons learned from Generic Letter (GL) 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” and the resulting significant Motor-Operated Valve (MOV) programs at US nuclear plants. As a result, the qualification sequence of a Power-Operated Valve (POV), like a MOV, is:

- The Plant Designer clearly specifies the required function of the valve including system conditions and operating environment. QME-1 has a mandatory appendix stating what details must be specified at a minimum.
- The Valve Manufacturer analyzes their valve designs to determine what valves require testing. The Plant Designer will review the analysis and approve the test article selection.
- A Test Facility will test the valves under simulated seismic loads, end loads (if applicable), and perform high flow rate testing on a test article. Aging will be part of the testing, including the changes in friction over time of hardfacing.
- The Valve Manufacturer will use the test data to verify their analysis and then use the analysis to show function of the production valves, including the impact of machining tolerances.
- The production valves will have critical dimensions of the production valves measured prior to assembly to show they are within analyzed tolerances.
- The Valve Manufacturer will select and install qualified actuators to the production valves.
- The Valve Manufacturer will perform factory acceptance testing, including functional testing (with no or limited flow) on the production valves.

- The Valve Manufacturer will generate a report called the “Application Report.” This will detail the required function of the valve, how their valve design meets these requirements, and that the valve assembly is within adjustment prior to leaving the factory. It will reference qualification and analysis reports as required.
- The valve assembly will be installed in the plant.
- The valve will be flow tested at the plant and a “Post Installation/ IST Baseline” functional report will be generated.

Looking back at GL 89-10, each of these steps was extremely costly to perform at an operating plant.

- The valve function was not in the same document as the system conditions which was not in the same document as the environmental conditions. Significant effort was required to determine what each safety-related MOV had to do under what conditions.
- There were no analyses of the valve’s ability to perform its function. Analysis models had to be generated at significant cost.
- The qualification testing had focused on seismic qualification and not functional qualification. This required millions of dollars of flow testing at off-site test facilities and extensive flow testing in the plant.
- During testing, it was determined that friction coefficients of hard-facing change over time, leading to extensive additional testing to determine the conditions that lead to these changes and the stable friction coefficients over the life of a plant.
- The designed valve dimensions were generally unknown, and the vendor normally required payment to pull old drawings to obtain them.
- As-built dimensions were not known and many valves had no machining tolerances only statements like “to fit.” This led to disassembly and inspection of many plant valves, leading to longer outages and associated lost revenue.
- The actuator sizing had typically been performed to a generic sizing guideline, which was found to underestimate the actuator sizing requirements. Actuator replacement was a common result of GL8 9-10, which led to a revision of the seismic restraints of the system as heavier actuators were installed on the valves. Plant modifications lose revenue, cost significant amounts of money, and lead to ALARA (as low as reasonably achievable) radiological considerations.

The result was that MOV performance issue cost a dramatic amount of money to nuclear power plants for over a decade as the industry struggled to understand how to ensure their MOVs would function if called upon to mitigate an upset condition.

In recent years, the ASME OM code has started to add verbiage to valves other than MOVs which sound somewhat similar to the provisions of GL 89-10. For example, in ASME OM Code, Mandatory Appendix IV, “Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants,” reads: “Establish a performance assessment test acceptance criteria and technical basis for applicable AOVs that provide reasonable assurance the pneumatically operated valve is capable of performing its specified function(s)” (OM Code (2022 Edition) Section IV-1400(a))

This Section IV requirement has not led to as extensive programs as the GL 89-10 programs of the 1990s for MOVs, but it has led to similar issues with not having a single document clearly demonstrating that a particular AOV meets the requirements of the ASME OM Code, Mandatory Appendix IV, paragraph IV-1400(a).

For new plants (such as Vogtle Units 3 and 4), the QME-1 Application Report meets the provisions of GL 89-10 and all the requirements of sections of ASME OM Code similar to IV-1400(a). Retention of the Application Report is critical to answering the question of providing “reasonable assurance that... is capable of performing its specified function(s).”

The QME-1 Application Report does not just answer this one question. Over time, the IST baseline testing results will change. The test report and analysis behind the Application Report can be used to determine if these changes could be expected based on the analysis and qualification testing. Over time, the system conditions for the plant might change due to factors like Power Upgrades. If these change, the analysis behind the Application Report can be reviewed and updated, and it can be seen if the qualification testing is bounding to prove the AOV function. Over time, the valve internals will be inspected for damage and wear. The original measurements included in the Application Report can be used to determine what wear has occurred. The analysis report (which should be at least referenced in the Application Report) can point the way forward to determine the impact of any observed wear and the impact on the function to see if continued operation is justifiable. If restoration or part replacement is required, the Application Report and associated analysis can be used to determine the critical dimensions to achieve.

Finally, the Post Installation/ IST Baseline testing is an obvious direct link from Qualification to Operations. Because of the timing requirements of the ASME OM Code, additional IST testing might be required prior to plant start-up, but the baseline testing requirements of the ASME OM Code should NOT be required when an QME-1 component is installed, since this data should be generated as a last step in QME-1.

In summary, QME-1 will most likely be used for new plant construction for most US plants and has already been used at Vogtle Units 3 and 4 and many foreign plants in South Korea, China, and the Middle East. The documentation required for QME-1 is specifically designed to meet the requirements of the OM Code for performance assessments to provide reasonable assurance of function and IST Baseline testing. These documents and their references provide extremely valuable information for the life of the plant when it comes to extensive analysis, test data, critical dimensions and machining tolerances. As such, the documentation delivered from a QME-1 program should be carefully maintained and passed down to future generations so that this knowledge and data are maintained for the life of the plant.

Biographical Summary

Ralph D. Yeardley, PE, is a Senior Principal Engineer at Element Laboratories in Huntsville, AL, and has specialized in fluid and valve testing for over 25 years. He has been a member of the valve subcommittee and main committee of the ASME QME-1 Standard for over 15 years, and has been a member of the MOV subcommittee for the ASME OM Code for several years as well. Mr. Yeardley is a licensed Professional Engineer in the State of Alabama.

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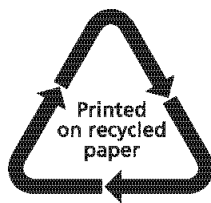
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