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Proceedings of the Eleventh NRC/ASME Symposium on Valves, Pumps, and Inservice Testing

Held at Hilton Washington DC/Rockville Hotel
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Abstract

The 2011 Symposium on Valves, Pumps and Inservice Testing, jointly sponsored by the Board of Nuclear Codes and Standards of the American Society of Mechanical Engineers and by the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic and regulatory issues associated with inservice testing programs at nuclear power plants, including the design, operation and testing of valves, pumps and dynamic restraints. The symposium provides an opportunity to discuss improvements in design, operation and testing of valves, pumps and dynamic restraints that help to ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives to be discussed regarding the improvement of testing programs and methods for valves and pumps at nuclear power plants.

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Disclaimer and Editorial Comment

Statements and opinions advanced in the papers presented at the Eleventh NRC/ASME Symposium on Valves, Pumps and Inservice Testing are to be understood as individual expressions of the authors and not those of either the American Society of Mechanical Engineers or the U.S. Nuclear Regulatory Commission. The papers have been copy edited and recast into a standard format. By consensus, Metric units have been used as an expression of current industry practice with English units also indicated where possible.

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Exploring Alternatives to Snubber Sample Plan Testing

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Abstract

This paper explores the possibility of alternatives to snubber sample plan testing currently required at all US nuclear power plants. The existing requirements often result in emergent scope expansion that can significantly impact outage duration, accumulated dose, and costs. In addition, the emergent scope may also result in risk management issues due to the potential impact on operational systems or trains. Alternatives to these plans that eliminate or reduce the unplanned scope expansions are available, and some may even provide a higher degree of population reliability.

Many plants incorporate preventive maintenance and condition monitoring programs under the umbrella term of Service Life Monitoring. In many instances these programs are extensive and provide a heightened degree of population reliability such that the continued use of sample plan testing is redundant. Examples of these programs are explored in this paper as potential alternatives to sample testing. These may include rebuild programs, in-place verification programs, or other preventive maintenance or service life programs that provide sufficient reliability data to replace the sample testing programs.

Introduction

Introduction Testing of snubbers has been a requirement for nuclear power plants in the US since the early 1980’s. Testing requirements were initially contained in individual plant licensing commitments and took many forms, but all involved some variation of a statistically based sample of the snubber population. Generally the test plans also involved some degree of randomness in the sampling technique used. One key aspect of every plan was a requirement to extend the testing into additional (usually random) samples for each unacceptable snubber identified. Sampling and testing continued until a certain mathematical formula was satisfied or all snubbers were tested. This testing requirement remains in effect today in various forms.

Current sample plan testing has other drawbacks in addition to the scope expansion. Sample testing as performed can identify a population once it has degraded to a certain point, and through scope expansion can “clean up” a population. This satisfied the original intent to identify and correct existing problems. But such testing provides only a snapshot picture in time. Drawing conclusions with regard to future reliability is beyond the scope of the statistics involved. The testing is not a good reliability tool, in that it is neither predictive nor preventive in nature. As plants age, better tools are needed to maintain and enhance reliability.

Background

Testing of snubbers is a requirement for US plants as detailed in Title 10 of the Code of Federal Regulations (10 CFR) Part 50.55a rulemaking. In simplest terms, the rulemaking requires that licensees test snubbers in accordance with the ASME Section XI and OM Codes, or else seek regulatory relief to perform equivalent testing under some other program. Many plants test snubbers in accordance with their Technical Specifications or Technical Requirement Manuals (TRMs) using such relief.

Snubber testing was originally required by regulators in response to numerous concerns identified during the late 1970’s and early 1980’s. Test requirements were included in Standard Technical Specifications, and were often modified somewhat for individual plant specifications. However, in all cases some statistical sample of installed snubbers is required to be tested, with expanded sampling required for any unacceptable snubbers found. With few exceptions, testing must be performed each cycle.

Generally, the sample plans used for snubber testing are one of two options available, the 10% Plan or the 37 Plan. Although some variations of these plans are used in accordance with plant specific licensing documents, these are the two most common plans. For the purposes of this document, these two plans as outlined in the OM Code are used for discussion and comparison.

When using the 10% Plan, a sample of snubbers equal in number to 10% of the sampled snubber population is initially selected for functional testing. The sample is to be representative of the tested population based upon the significant features of snubbers within the population and based upon the ratio of snubbers of each feature within the overall population as well. The plan also includes an option to include snubbers that are concurrently scheduled for seal replacement or similar activities.

In the event of finding an unacceptable snubber in the initial sample, a supplemental sample must be tested for each unacceptable snubber identified. Supplemental samples must be at least one-half the size of the original sample. Additional supplemental samples must be tested for any unacceptable snubbers found in supplemental tests as well.

Under the 37 Plan, a sample of 37 snubbers is chosen from the population. The sample snubbers are chosen entirely at random. In the event of an unacceptable snubber, an additional sample of either 18 or 19 snubbers must be selected for each such case. Additional samples are also chosen randomly for each subsequent failure.

Under both plans there are options to focus testing using Failure Mode Grouping. In addition, under the 37 Plan, one supplemental random sample must be tested from the overall population for each Failure Mode Group identified and tested.

As seen above, the randomness of the snubbers selected for testing varies between the plans. However, there is a random element of selection involved in both processes. In addition, the use of Failure Mode Grouping introduces a selection process that, while not entirely random, is not predictable prior to beginning the test campaign.

Concerns

The concerns with regard to sample testing requirements generally fall into two areas. One area of concern involves issues related to the emergent and unscheduled work scope that results from supplemental testing requirements. The other area of concern relates to weaknesses and limitations of the sample testing methodology as an effective reliability tool.

Emergent Work Scope Issues

As noted previously, sample testing often results in supplemental samples that can only be identified as emergent work. The actual snubbers selected for supplemental tests are dependent upon the conditions associated with the original as-found unacceptable snubber (or snubbers) and any identified extent of condition concerns. Failure modes and causes must be identified for the original snubbers before additional snubbers to be tested can be selected based upon that information. This can result in significant concerns with regard to outage scheduling, costs, and dose.

In today’s environment, outage activities are scheduled very tightly and managed in great detail. Emergent work scope that has not been carefully planned beforehand can result in a cascade effect of delays that impact unrelated areas of work. Such delays inevitably result in additional costs. More significant, perhaps, is the impact to operational scheduling. Supplemental scope will often include snubbers located on systems or trains which have already seen their outage maintenance windows closed. The removal of those snubbers for testing presents operational challenges as it may affect system availability, require operability assessments, or result in entering Technical Specification Required Actions.

Likewise, unpredictable scope expansion can result in a direct increase in manpower requirements and associated labor costs. Additional personnel may be needed to perform the added snubber scope. The emergent scope may require significantly more scaffolding or other support activities than the original scope. In addition, personnel required to continue working on the emergent scope are unavailable for other scheduled tasks, resulting in further delays or a need for even more additional personnel.

Hand in hand with the increased labor costs, the additional personnel involvement will result in increased dose exposure. More person-hours expended in completing the field work results in more cumulative dose. Added to that is the possibility that at least some of the emergent scope will include snubbers in higher dose areas or areas where no additional shielding was planned. Overall the dose due to expanded testing scope can be significant.

Obviously some impact of a supplemental testing scope can be mitigated with contingency planning. But since the exact scope of additional work cannot be identified ahead of time, contingency planning is often guesswork. Many of the above listed factors will inevitably result in significant difficulties.

Reliability Effectiveness

The second major area of concern is not as directly measurable as the scheduling, cost, and dose impacts noted above. This area of concern centers on the weaknesses and limitations of the sample testing methodology with regards to maintaining the snubber population reliability. As noted previously, sample testing of snubbers was initially required in response to a significant number of concerns noted during the early years of the nuclear power industry. The intention of the sample plan testing was to provide an immediate measure of the population reliability at the time of testing. As such, the sample plans proved effective at identifying “bad” populations and cleaning them up through the supplemental testing process. Statistically speaking, for large populations the 37 Plan is especially effective for this purpose.

However, this testing provides only a statistical snapshot of a population at the time of testing. As such, the tests are not truly predictive – one cannot extrapolate future results from a given test campaign. Sample testing as practiced today can identify a significantly degraded or “bad” population once it reaches a certain level of degradation, and may restore a population by testing a large percentage of the snubbers in it. But this typically only occurs through a large number of unacceptable snubber tests and large scale supplemental testing. In other words, sample testing does a good job of identifying that you have a problem once it occurs, but is not reliable in telling you that the problem is approaching. Sample test data is very limited in usefulness with regard to trending results, as it serves mostly as a “go/no-go” gauge. As such, from a component reliability viewpoint it is simply a measure, and a “reactive” rather than a “proactive” tool.

There are also some weaknesses inherent within the existing sample plan methodology. As a statistical tool, a sample is generally expected to be representative of a larger but homogeneous parent population. As currently allowed in industry testing requirements, snubber populations sampled are of a widely varying degree of homogeny. Many samples are representative by ratio of the multiple types of snubbers in the total population, but they vary greatly in type and design. While the relevance of this difference is statistically arguable when using the sample as a point in time measure of the population condition, it is certainly a major weakness in any attempt to forecast any meaningful data from the results.

Need For Alternatives

The underlying basis for component testing is to verify function and to assure reliability. In the case of large groups of components, such as snubbers, it is generally unrealistic to test each individual component. Therefore a method is needed to provide some reasonable assurance of reliability that can be extrapolated to an entire population of similar components. In the case of snubbers, existing regulatory and code requirements attempt to do this through the combination of testing and service life monitoring. As noted previously, snubbers first became a component of interest due to many real and perceived issues identified in the early stages of the nuclear power industry. In response, the focus of early requirements was centered upon testing, with the identification and correction of “bad” populations as the primary goal.

Due to that focus, both regulatory and code guidance devote the majority of emphasis and detail on the sample testing process. This process is expounded in great detail over multiple pages of code and licensing documentation. On the other hand, service life monitoring is barely mentioned by comparison – with generally a simple paragraph or two stating that such monitoring is required. This contrast in emphasis has often led to a perception of Service Life Monitoring as a “by the way” program. In fact, for a significant number of operating plants the “Service Life Monitoring Program” in place consists simply of tracking the sample testing results and assuming that the data corroborates their assumed service life values as long as they do not result in 100% testing. Almost without fail, the vast majority of resources allocated to snubber programs are solely for the purpose of completing the required sample testing.

Thus it has come to pass that the entire industry focuses on the testing of snubbers as the primary requirement and most important aspect of a snubber program, losing sight of the underlying basis of maintaining population reliability. For this reason, alternatives to the existing sample testing methodology are needed that will enable resources to be reallocated to fulfilling this basis through effective monitoring and preventive maintenance programs that serve to be measures of effectiveness as well as predictive in nature.

Potential Alternatives

Obviously, any viable alternative to the sample testing requirements would have to provide a current measure of reliability as well as addressing both preventive and predictive aspects of reliability. The optimum solution would be a program that could accomplish those goals while eliminating or at least reducing the amount of emergent work scope required by the program.

There are currently no such alternatives available to the industry. While Code Case OMN-15 provides a methodology for extending the required frequency of testing, it still relies on a sample testing process that includes potential emergent scope. And though the use of the Code Case requires a service life monitoring program, there is little guidance as to how that is accomplished or how to measure its effectiveness.

It would appear that the best approach to develop such an alternative program is to expand on programs already in place, adding elements to enhance the programmatic capabilities to meet the needs described previously. Elements required to replace the emergent and random aspects of sample testing would have to include the following:

- Verification of functionality
- Addressing the entire population
- Sufficient data trending to identify adverse trends and corrective actions prior to a conservatively estimated end of life

Programs using this approach would obviously have to have extensive service life monitoring or condition monitoring programs. While these programs can also be costly, they can be designed such that unacceptable snubbers found under those programs are addressed using pre-planned corrective action processes that avoid the emergent scope aspect (Unless significant generic issues are found, in which case normal extent of condition requirements would have to be applied). Following are some examples of potential approaches. Effective programs may use similar approaches either alone or in combination to result in the most efficient program for a given population. The examples included herein are not all inclusive. There are a number of alternatives and variations that may apply to specific cases. The key element is to be able to verify the population reliability to at least the same degree as sample test, without the added burden of extensive unplanned scope expansion.

Rebuild Programs

A number of plants already implement a variety of snubber rebuild programs. As a minimum, plants with hydraulic snubbers must have a program in place to replace seals on a scheduled basis due to the expected seal life. But a number of plants have much more extensive programs, including mechanical snubber rebuilds. Some of these programs involve a systematic rebuilding of all snubbers at a very conservative frequency. If all snubbers are rebuilt on a conservative time frame, sample testing with provisions for emergent scope may be proven to be redundant and unnecessary.

As an example, Plant Alpha may institute a program where 100% of their mechanical snubbers are rebuilt on a frequency of 15 years. The generic manufacturers suggested service life for the snubbers was originally 40 years, but industry experience has proven that to be somewhat non-conservative. Based upon industry experience significant age related degradation is expected to be seen after 25 years. The plant established the rebuild program many years ago, and since then has completely cycled through the population at least once. As part of the rebuild program examination of internal parts is performed and any degradation indications are evaluated and trended. In addition to the rebuilding program, random testing under a sample plan is also performed each outage. Since implementing the rebuild program no test failures have been recorded.

By industry consensus, the rebuild frequency used is conservative. Information from the rebuild data shows that no significant age related degradation has been noted on a general basis. Based upon these facts and the fact that the entire population is covered by the program, the random outage testing has proven to be redundant and unnecessary to verify the reliability of the population. An argument could be made that there is no need to continue such testing. The addition of Service Life Monitoring testing may serve as an enhancement to the rebuild program to provide further confidence, but that testing could be performed on samples chosen well ahead of time using a planned approach with no need for random scope expansion as a result of isolated incidences.

Service Life Monitoring Programs

An extensive Service Life Monitoring Program by itself may be sufficient to provide confidence in population reliability. An effective program would include some degree of functional testing of snubbers, using some appropriate selection criteria and frequency. If that testing, combined with other service life monitoring aspects, covers the entire population over a reasonable period of time, then that data could be used to extrapolate conclusions to the entire population. Such conclusions would render the need to perform sample testing to verify reliability as unneeded.

Again, the testing required to reach such conclusions may be extensive, but it could be planned scope that would not normally be expected to result in emergent outage work. Much of service life monitoring testing and corrective actions could be performed in non-outage periods. The goal of such a program would be to collect sufficient data as to identify any significant population-wide concerns well before such concerns are an immediate issue.

Condition Monitoring Programs

Similar to Service Life Monitoring, Condition Monitoring actively assesses the reliability of each component, rather than extrapolating data. If such a program sufficiently addresses the entire population over a reasonable time period (and is repeated on an appropriate frequency), then the actual monitoring of the populations functionality can preclude the need for testing. An example of such a program would be one where all mechanical snubbers in a population are manually exercised on a periodic basis.

Such stroking of mechanical snubbers by trained personnel serves not only to verify functionality, but also as a valid and recommended preventive maintenance activity that extends the life of the snubber. By applying this method to an entire population, the reliability of the population is verified to a greater degree than can be accomplished with sample testing that includes only a small portion of the snubbers. If this activity is completed on a sufficiently frequent basis, there would be no need to perform statistical based testing. This program could be combined with service life testing to obtain additional trending data to be used in a more predictive manner with regard to life expectancy. This program would provide assurance of reliability as well as early indications of significant issues. The scope of the work performed would be such that extent of condition concerns would require additional scope only in the most extreme situation.

Rotational Testing

Another potential method to address population reliability is to perform testing on a rotational basis, where the entire population is tested over a finite period of time. This would likely be more appropriate for plants with small populations. An example might be a plant with a population of 100 snubbers. This plant may choose to test 25% of the snubbers each cycle on a rotating basis, thereby testing 100% of the snubbers over a 4-cycle period. Although they are testing more than the normal 10% each time, they could make a case for not expanding scope for 1 or 2 unacceptable snubbers – as long as they could show sufficient corrective actions and trending is performed. This program would be an effective reliability and service life program, with no significant need for emergent outage scope.

Implementation of Alternatives

In the current licensing environment, snubber testing is performed either in accordance with site specific licensing requirements or in accordance with ASME Code requirements. Therefore, in order to implement an alternative methodology, either a relief request or code change would be required. Although any licensee is permitted to request relief, the current focus within the industry is to move towards more consistency among snubber programs. It would appear then that the best approach to implement change would be through a revision to the code itself. Although it is noted that code changes are often modeled on a "pilot" relief request, any individual plant relief would likely be too specific to serve as a basis for a generic code change.

Most likely the best approach to incorporating any alternative to testing into the OM Code would be through a code case. This type of alternative represents a shift in philosophical focus for inservice testing as currently presented in the code, so such a code case would require a significant amount of justification and documentation. The wording would have to be generic enough to cover the multiple possible alternatives, yet specific enough to clearly delineate requirements regarding reliability measures and corrective actions. Although this represents a significant effort, this is possibly a worthwhile undertaking for an ISTD task group as an enhancement to the code.

Conclusion

There are many burdens associated with sample testing of snubbers and the emergent scope expansion that is often required. These burdens include outage schedule impacts, added costs, increased dose, and potential operational challenges. Alternatives to the sample testing methodology are possible that could reduce or eliminate these burdens while at the same time maintaining the ability to measure and maintain population reliability. Although individual plants may choose to pursue regulatory relief to implement an alternative specific to a given program, the best approach appears to be an effort to produce an ISTD code case to provide generic alternative guidance. Such alternatives would greatly benefit many plants individually, and overall could serve to increase the ability of the industry to focus on true component reliability improvement.

References

1. ASME OM Code (multiple editions)
2. ASME Section XI (multiple editions)
3. 10 CFR 50.55a rulemaking

Nuclear Power Plant Dynamic Restraints (Snubbers) Inservice Examination and Testing

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

Abstract

This paper discusses recent issues related to inservice inspection (ISI) and testing of dynamic restraints (snubbers) at U.S. nuclear power plants. These issues were identified during the U. S. Nuclear Regulatory Commission (NRC) staff review of ISI and testing snubber programs and relief requests, and applicable operating experience. This discussion includes information that could have generic applicability in the implementation of effective snubber programs at U.S. nuclear power plants.

Introduction

The NRC staff has encountered a number of snubber inservice inspection (ISI) and testing issues since the Tenth NRC/ASME Symposium on Pumps, Valves and Inservice Testing in 2008. This paper discusses (1) Title 10 of the Code of Federal Regulations (10 CFR) 50.55a requirements for snubber inservice inspection and testing programs at nuclear power plants; (2) Mandatory subber inservice examination and testing program updates; (3) Use of Relief Request alternatives in lieu of the ASME Code requirements; (4) Voluntary Use of Later Editions and Addenda to the American Society of Mechanical Engineer (ASME) Code; (5) Snubber Programs and their Bases; (6) General documentation and their submittal requirements for the snubber inservice examination and testing programs; and (7) Use of the10 CFR 50.59 processes to change the NRC authorized relief request alternative related to inservice examination and testing of snubbers. Some current staff positions and actions in these areas are also discussed. This discussion includes information that could have generic applicability in the implementation of effective inservice inspection and testing snubber programs at U.S. nuclear power plants.

Regulatory Requirements for Snubber Inservice Examination and Testing Programs at Nuclear Power Plants

The regulations in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(b) describe the Codes and Standards that have been approved for inclusion in 10 CFR 50.50a, including the effective edition and addenda of the ASME Boiler and Pressure (B&PV) Code and the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

10 CFR 50.55a(g) contains the ISI requirements that licensees must use when performing ISI of components (including supports). 10 CFR 50.55a(g)(4) states, in part, "Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, components (including supports) which are classified as ASME Code Class 1, Class 2, and Class 3 must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of editions of the ASME B&PV Code and Addenda."

Snubbers are part of component "supports." Supports are widely used to support various safety or non-safety related piping systems or components in the nuclear power plants. The most widely used supports are (1) Rigid Supports; (2) Rod-Hanger Supports; (3) Spring- Hanger Supports; and (4) Snubbers. Therefore, the regulations in 10 CFR 50.55a(g)(4) require that ASME Code Class 1, 2, and 3 snubbers meet the ISI and testing requirements of the ASME B&PV Section XI or OM Code, as incorporated by reference in 10 CFR 50.55a(b).

10 CFR 50.55a also requires inservice examination and testing of snubbers because it incorporates by reference the ASME B&PV Code, Section XI, "Rules for Inservice Inspections of Nuclear Power Plant Components," requirements contained in Article IWF-5000, "Inservice Inspection Requirements for Snubbers, and the ASME OM Code requirements in Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants." The inservice examination and testing of snubbers has been a requirement in Article IWF-5000 since Article IWF was first

issued in the Winter 1978 Addendum to ASME B&PV Code, Section XI. The 2005 Addendum and earlier editions and Addenda of Section XI, of the ASME B&PV Code, Article IWF-5000, provide the requirements for the examination and testing of snubbers in nuclear power plants. Article IWF-5000 has been deleted in the 2006 Addendum of the ASME B&PV Code, Section XI. Subsection ISTD of the ASME OM Code has included provisions for the examination and testing of snubbers since it was first issued in 1990. Licensees have the option of using the ASME B&PV Code, Section XI or the ASME OM Code for snubber inservice examination and testing, if their applicable “Code of Record” is 2005 Addendum and earlier editions Addenda of Section XI, of the ASME B&PV Code.

10 CFR 50.55a(b)(3)(v) of the 10 CFR 50.55a(b) allows licensees using editions and addenda up to the 2005 Addendum of the ASME B&PV Code Section XI, to optionally use Subsection ISTD of the ASME OM Code, in place of the requirements for snubbers in Section XI. This part of regulations also states that snubber preservice and inservice examinations must be performed using the VT-3 visual examination method as described in IWA-2213, when using Subsection ISTD of the ASME OM Code. The NRC imposed the VT-3 visual examination requirement to ensure that licensees use an appropriate visual examination method for the inspection of integral and nonintegral snubber attachments, such as lugs, bolts, and clamps, when using Subsection ISTD.

Licensees that use the 2006 Addendum and later editions and Addenda to Section XI of the ASME B&PV Code must follow the requirements of Subsection ISTD of the ASME OM Code for snubbers because ASME removed the requirements for the examination and testing of snubbers from the scope of Section XI in the 2006 Addendum. 10 CFR 50.55a(b)(3)(v) does not invoke the VT-3 visual examination and testing requirement when licensees use the 2006 Addendum and later editions and Addenda to Section XI because ASME revised Figure IWF-1300-1 in the 2006 Addendum to Section XI to clarify that integral and nonintegral snubber attachments are within the scope of Section XI.

Recently the NRC issued new rulemaking for 10 CFR 50.55a. In this new rulemaking 10 CFR 50.55a(b)(3)(v) has been updated as follows:

“Subsection ISTD. Article IWF-5000, "Inservice Inspection Requirements for Snubbers," of the ASME B&PV Code, Section XI, must be used when performing inservice inspection examinations and tests of snubbers at nuclear power plants, except as conditioned in (A) and (B) below:

> (A) Licensees may use Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Power Plants," ASME OM Code, 1995 Edition through the latest edition and addenda incorporated by reference in paragraph (b)(3) of this section, in place of the requirements for snubbers in the editions and addenda up to the 2005 Addenda of the ASME B&PV Code, Section XI, IWF-5200(a) and (b) and IWF-5300(a) and (b), by making appropriate changes to their technical specifications or licensee-controlled documents. Preservice and inservice examinations must be performed using the VT-3 visual examination method described in IWA-2213.
>
> (B) Licensees shall comply with the provisions for examining and testing snubbers in Subsection ISTD of the ASME OM Code and make appropriate changes to their technical specifications or licensee-controlled documents when using the 2006 Addenda and later editions and addenda of Section XI of the ASME B&PV Code."

Mandatory Snubber Inservice Examination and Testing Program Updates

10 CFR 50.55a(g)(4)(ii) requires licensees to revise their inservice inspection (ISI) programs every 120 months to reflect the latest edition and addendum to Section XI of the ASME B&PV Code incorporated by reference into 10 CFR 50.55a(b)(2) that is in effect 12 months before the start of the new 120-month ISI interval. This Code is considered to be the "Code of Record" for the inspection interval.

Additionally, 10 CFR 50.55a(g)(4)(iv) notes that ISI of components (including supports) may meet the requirements set forth in subsequent editions to the "Code of Record" and addenda that are incorporated by reference in 10 CFR 50.55a(b), subject to limitations and modifications listed in 10 CFR 50.55a(b) and subject to Commission approval.

Use of Relief Request Alternatives in lieu of the ASME Code Requirements

Licensees are required to perform the ISI and testing of snubbers in accordance with ASME BPV Code, Section XI or the ASME OM Code and the applicable addenda as required by 10 CFR 50.55a(g) or 10 CFR 50.55a(b)(3)(v), except where the NRC has granted specific written relief, pursuant to 10 CFR 50.55a(g)(6)(i), or authorized alternatives pursuant to 10 CFR 50.55a(3). 10 CFR 50.55a(a)(3) states that licensees may use alternatives to the requirements of 10 CFR 50.55a(g) when authorized by the NRC if (1) the proposed alternatives would provide an acceptable level of quality and safety, or (2) compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

Currently, few licensees are using the ASME OM Code to meet the requirements of 10 CFR 50.55a for snubber inservice examination and testing, whereas most of the licenses are using a variety of licensee-controlled documents or procedures in lieu of the applicable ASME Code requirements. These licensee-controlled documents or procedures include the following:

1. Technical Specification (TS)
2. Technical Requirement Manual (TRM)
3. Final Safety Analysis Report (FSAR)
4. Updated Final Analysis Report (UFSAR)
5. Selected Licensee Commitment (SLC)
6. Licensee-Controlled Specification (LCS)
7. Equipment Control Guidelines (ECG)
8. Other Licensee-Controlled Procedures

Recently, the NRC staff has identified several instances in which nuclear power plants licensees have used a TRM, or other licensee-controlled documents and procedures, which do not meet requirements of their "Code of Record" for the ISI and testing of snubbers. These licensees have not requested approval to use these alternatives from the Commission. The NRC issued Regulatory Issue Summary (RIS) 2010-06, "Inservice Inspection and Testing Requirements of Dynamic Restraints (Snubbers)" on June 1, 2010 to remind all the licensees of the NRC's rules and regulations regarding snubber ISI and testing, in accordance with 10 CFR 50.55a(g), at nuclear power plants.

The NRC expects licensees to ensure that their snubber ISI and testing programs are in compliance with 10 CFR 55.55a(g) or authorized alternatives. If licensees discover that their programs are not meeting 10 CFR 50.55a(g) requirements or authorized alternatives, they should take appropriate actions to bring their programs back into compliance and ensure that non-compliant systems, structures and components are operable. In certain circumstances involving snubber programs at nuclear power plants that are not in compliance with NRC requirements, enforcement discretion has been provided by the NRC. The NRC's Office of Enforcement issued Enforcement Guidance Memorandum (EGM)-10-001, "Dispositioning Violation of Inservice Examination and Testing Requirements for Dynamic Restraints (Snubbers)," on June 1, 2010 to provide

NRC staff guidance for the disposition of certain 10 CFR 50.55a violations and the potential of granting enforcement discretion for the affected requirements. NRC expects that licensees of nuclear power plants, who were not meeting the 10 CFR 50.55a requirements for snubber inservice examination and testing as described in RIS 2010-06, should have entered any noncompliance into the corrective action system by December 01, 2010, and should have scheduled to correct the noncompliance by June 01, 2012 or submitted a relief request to NRC by June 01, 2011.

Voluntary Use of Later Editions and Addendas to the ASME Code

Licensees must conduct inservice examination and testing to verify the operational readiness of snubbers within the scope of the ASME Code in accordance with 10 CFR 50.55a(g)(4)(ii). In conducting these examinations and tests, licensees must comply with the provisions of the latest edition and addendum to the ASME Code, which 10 CFR 50.55a(b) incorporates by reference, 12 months before the start of the successive 120-month interval, subject to the limitations and modifications conditions listed in 10 CFR 50.55a(b).

After the initial 120-month interval, 10 CFR 50.55a(g)(4)(iv) notes that the inservice examination and tests of components (including supports) may meet the requirements set forth in subsequent editions and addenda of the ASME OM Code or ASME B&PV Code, Section XI that 10 CFR 50.55a(b) incorporates by reference, subject to NRC approval. This includes the examination and testing of snubbers. Licensees may use portions of editions or addenda provided that all related requirements of the respective editions or addenda are met. When requesting to use editions and addenda to the ASME OM Code or ASME B&PV Code, Section XI Code that have not yet been incorporated by reference, licensees must request authorization to use these later editions and addenda as an alternative to the regulations under 10 CFR 50.55a(a)(3).

The amount of written documentation needed for a request to use a later ASME OM Code or ASME B&PV Code, Section XI Code edition and addendum that 10 CFR 50.55a(b) incorporates by reference is significantly less than that of a request to use an alternative requirement. For example, licensees are not required to justify requests to use the later ASME OM Code editions and addenda that 10 CFR 50.55a(b) incorporates by reference. In contrast, when submitting an alternative request, licensees must provide justification that the proposed alternative would provide an acceptable level of quality and safety. If a licensee uses portions of a later ASME OM Code or ASME B&PV Code, Section XI edition and addendum, it must ensure that all related requirements of the respective editions and addenda are met. The licensee should discuss the related requirements in its letter to the NRC. The regulations do not specify when the licensee should submit the letter, only that it should submit the letter before it uses the later ASME OM Code or ASME B&PV Code, section XI edition and addendum. The staff issued Regulatory Issue Summary (RIS) 2004-12, “Clarification on Use of Later Editions and Addenda to the ASME OM Code and Section XI,” dated July 28, 2004, in order to clarify this matter.

Snubber Programs and Their Bases

Licensees are using TRMs or other licensee-controlled documents for snubber inservice examination and testing, in lieu of the ASME B&PV Code, Section XI requirements. TRMs or other licensee-controlled documents serve as bases for snubber programs and most of the snubber programs have similarities across the industry. Many licensees are in the process of updating their snubber programs as required by the ASME OM Code. Some licensees have already updated their programs to use ASME OM Code. The NRC staff has observed that some of the updated snubber programs are not consistent or complete. Some of the updated programs simply reference plant procedures for snubber examinations and testing without providing any details about sections, subsection(s) and/or paragraphs of the applicable ASME OM Code. Licensees should consult with the Snubber User Group (SNUG), when developing guidance for snubber programs and their bases, to help ensure consistency throughout the industry.

The updated snubber programs should contain at least the details and bases as documented in the TRM, or other licensee-controlled documents in alignment with the ASME OM Code. Bases documents have typically included a description of the methodology used in preparing the snubber programs. The bases document should clearly state where a list of each snubber is kept and how it is being maintained. Although not required by the regulation, the bases documents will help licensees ensure the continuity of their snubber programs when the responsibilities of personnel or groups change. A good bases document will also enable the plant staff to clearly understand the reasons that the snubbers are either in the program or not, as well as the basis for examination and testing. The bases document can also serve as a useful reference for reviews performed under 10 CFR 50.59 when changes are made to a facility.

General Documentation and Their Submittal Requirements for the Snubber Inservice Examination and Testing Programs

10 CFR 50.55a(g)(4) requires that, throughout the service life of a boiling or pressurized water-cooled nuclear power facility, ASME Code Class 1, 2, and 3 components (including supports) meet the ISI and testing requirements of the ASME B&PV Code, Section XI or ASME OM Code as incorporated by reference in 10 CFR 50.55a(b). The applicable ASME B&PV Code, Section XI, Article IWA-1000, “General Requirements,” and ASME OM Code, Subsection ISTA,

"General Requirements," provide the documentation and submittal requirements for inservice testing and examination of certain components in light-water nuclear power plants. Therefore, based on these requirements, licensees are required to submit their snubber examination and testing programs and their updates every 120 months.

(a) Documentation requirements for snubber programs when using the ASME B&PV Code, Section XI

IWA-1400(c) notes that owners, have the responsibility to prepare plans, schedules, and inservice inspection summary reports, and submit of these plans and reports to the enforcement and regulatory authorizes having jurisdiction at the plant site.

Article IWA-6000, Record and Reports, provides the requirements for preparation, submittal, and retention of records and reports.

(b) Documentation requirements for snubber programs when using the ASME OM Code

ISTA-3200(a) requires that plans for inservice examination and testing of snubbers shall be filed with the regulatory authorities having jurisdiction at the plant site.

ISTA-9000, Records and Reports, provides the requirements for preparation, submittal, and retention of records and reports.

Nonmandatory Appendix-A, and the Supplement to Nonmandatory Appendix-A describes voluntary guidance for licensees to develop snubber inservice examination and testing plans.

(c) Documentation requirements for snubber programs when using NRC authorized alternative TS, TRM or other-licensee-controlled documents in lieu of the ASME B&PV Code, Section XI, or ASME OM Code

NRC authorized relief to use TRMs or other-licensee-controlled documents, in lieu of the ASME B&PV Code, Section XI or ASME OM Code requirements for inservice examination and testing of snubbers, do not provide relief from submitting snubber programs to the regulatory authorities. Submittal is required by the applicable ASME B&PV Code, Section XI or ASME OM Code as noted in (a) and (b) above.

Licensees not meeting the requirements of IWA-1400(c) or ISTA-3200(a) must submit appropriate documents containing snubber inservice examination and testing plans and submit a request for relief to the NRC pursuant to 10 CFR 50.55a(a)(3). NRC staff will not perform a review of submitted snubber inservice examination and testing programs unless requesting alternatives or reliefs to Code requirements.

Use of the 10 CFR 50.59 Processes to Change the NRC Authorized Relief Request Alternative Related to the Inservice Examination and Testing of Snubbers

10 CFR 50.55a, “Code and Standards,” defines the requirements for applying industry codes and standards to boiling- or pressurized-water-cooled nuclear power facilities. Each of these facilities is subject to the conditions in paragraphs (a), (b), (f), and (g) of 10 CFR 50.55a, as they relate to inservice inspection (ISI) and inservice testing (IST).

Except where alternatives have been authorized or relief has been requested by the licensee and granted by the Commission pursuant to Sections (a)(3)(i), (a)(3)(ii), (f)(6)(i) or (g)(6)(i), 10 CFR 50.55a, requires, that the ISI of ASME Code Class 1, 2, and 3 components (including snubbers) shall be performed in accordance with ASME B&PV Code, Section XI, or ASME OM Code, including applicable addenda.

10 CFR 50.59 requires that licensees (1) evaluate proposed changes to their facilities for their effects on the licensing basis of the plant, as described in the Final Safety Analysis Report (as updated), and (2) obtain prior NRC approval for changes that meet specified criteria as having a potential impact upon the basis for issuance of the operating license.

In accordance with 10 CFR 50.55a, the NRC has approved alternatives and granted numerous reliefs from the ASME Code requirements. Once relief is granted, the alternative approved for the relief request becomes a part of the licensee’s snubber programs and regulatory requirements. Therefore, changing from one alternative or relief to another would require NRC approval. In no case should licensees use the 10 CFR 50.59 process to supersede or overwrite a previously authorized relief request, since 10 CFR 50.55a requires these alternatives to ASME Code requirements be authorized by the NRC.

Most of the licensees' snubber examination and tests requirements are included in their TSs, TRMs, or other licensee-controlled documents. The TRM requirements and other licensee-controlled documents are controlled using the criteria in 10 CFR 50.59. In the case of snubber inservice examination and testing, the NRC has authorized the use of the TRM snubber examination and testing requirements or other licensee-controlled documents requirements for snubber examination and testing, in lieu of the ASME Code requirements, at numerous operating plants through the 10 CFR 50.55a relief process.

Recently the NRC has learned that a licensee used the 10 CFR 50.59 process to revise the snubber inservice examination and testing requirements of the TRM. The requirements contained in this TRM were approved by the NRC to be used as an alternative to the ASME Code requirements. The use of an alternative as authorized by the NRC becomes a regulatory requirement; thus changes to these requirements must be reviewed and approved by the NRC staff pursuant to 10 CFR 50.55a(a)(3).

Nuclear Energy Institute (NEI) Procedure, NEI 96-07, Revision 1, "Guidelines for 10 CFR 50.59 Implementation," notes that licensees activities which are controlled by regulation (e.g. 10 CFR 50.55a), take precedence over the 10 CFR 50.59 requirements. NEI 96-07, Revision 1 was endorsed by Regulatory Guide (RG) 1.187. Similarly, RG 1.187, Section D, "Implementation," notes that 10 CFR 50.59 cannot be used in those cases in which a licensee proposes an acceptable alternative method for complying with the specified portion of the NRC's regulations. Licensees are encouraged to use caution when revising or changing programs or procedures referenced in an approved relief request or TRM. Any changes or updates that supersede or overwrite an alternative or relief authorized in a relief request must be approved by the NRC unless the requirements of the ASME Code can be met. Utilization of the 50.59 process to change the requirements of an approved relief request is not appropriate.

Conclusion

The purpose of this paper is to make licensees aware of a number of snubber inservice examination and testing issues that the NRC staff has encountered since the Tenth NRC/ASME Symposium on Pump, Valve and Inservice Testing in 2008. The Flowchart, Appendix-I, "Use of 10 CFR 50.55a Regulatory

Requirements for Development of Snubber Inservice Examination and Testing Program," is attached for quick reference to regulations applicable to snubbers inservice examination and testing at nuclear power plants. Licensees who believe that some of the items discussed are applicable to their facilities may wish to review their current ISI and testing programs for snubbers and modify or update their programs, as appropriate.

References

NUREG/CP-0152, Vol. 7, "Proceedings of the Tenth NRC/ASME Symposium on Valve and Pump Testing," July 2008.

U.S. Code of Federal Regulations, Domestic Licensing of Production and Utilization Facilities, Part 50, Chapter I, Title 10, "Energy," Section 50.55a, Codes and standards.

NUREG-1482, Revision 1 "Guidelines for Inservice Testing at Nuclear Power Plants."

Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments."

Nuclear Energy Institute Procedure, NEI 96-07, Revision 1, "Guidelines for 10 CFR 50.59 Implementation."

American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components.

*American Society of Mechanical Engineers (*ASME)/*American Nuclear Standards Institute* (ANSI) Operation and Maintenance of Nuclear Power Plants (OM), Part 4 (OM-4), 1987 Edition with OMa-1988 Addenda.

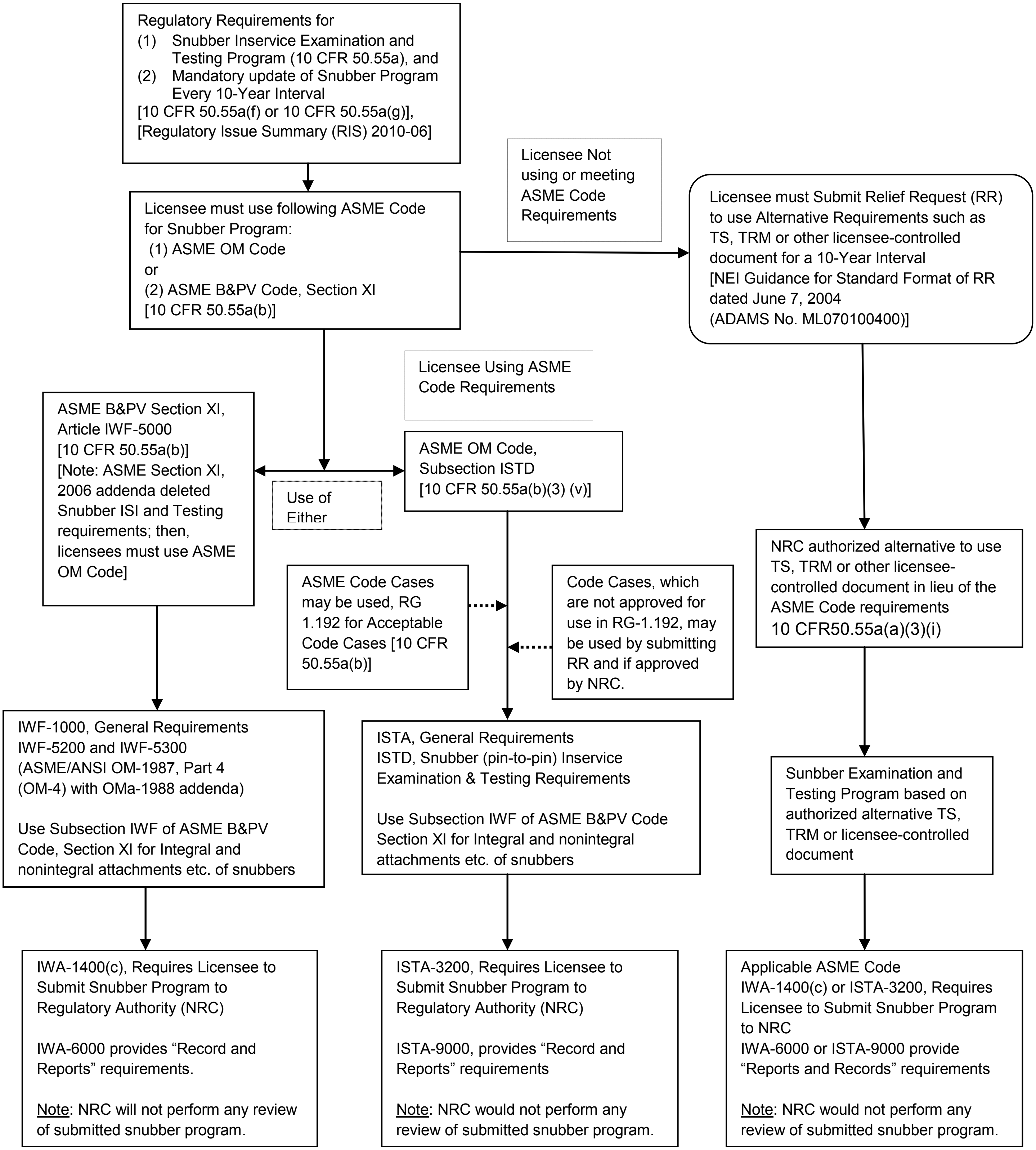
ASME/ANSI, *Code for Operation and Maintenance of Nuclear Power Plants*, 2004 Edition: with 2005 addenda and 2006 addendas

Regulatory Issue Summary (RIS) 2010-06, "Inservice Inspection and Testing Requirements of Dynamic Restraints (Snubbers), dated June 1, 2010 (ML101310338).

Enforcement Guidance Memorandum- EGM-10-01, “Dispositioning Violation of Inservice Examination and Testing Requirements for Dynamic Restraints (Snubbers), dated June 1, 2010 (ML101390020).

Regulatory Issue Summary (RIS) 2004-12, “Clarification on Use of Later Editions and Addenda to the ASME OM Code and Section XI,” dated July 28, 2004 (ML042090436).

Flowchart - Development Inservice Examination and Testing Program for Snubbers*



Regulatory Requirements for
(1) Snubber Inservice Examination and Testing Program (10 CFR 50.55a), and
(2) Mandatory update of Snubber Program Every 10-Year Interval
[10 CFR 50.55a(f) or 10 CFR 50.55a(g)],
[Regulatory Issue Summary (RIS) 2010-06]

Licensee must use following ASME Code for Snubber Program:
(1) ASME OM Code
or
(2) ASME B&PV Code, Section XI
[10 CFR 50.55a(b)]

Licensee must Submit Relief Request (RR) to use Alternative Requirements such as TS, TRM or other licensee-controlled document for a 10-Year Interval
[NEI Guidance for Standard Format of RR dated June 7, 2004
(ADAMS No. ML070100400)]

ASME B&PV Section XI, Article IWF-5000
[10 CFR 50.55a(b)]
[Note: ASME Section XI, 2006 addenda deleted Snubber ISI and Testing requirements; then, licensees must use ASME OM Code]

ASME OM Code, Subsection ISTD
[10 CFR 50.55a(b)(3) (v)]

NRC authorized alternative to use TS, TRM or other licensee-controlled document in lieu of the ASME Code requirements
10 CFR50.55a(a)(3)(i)

ASME Code Cases may be used, RG 1.192 for Acceptable Code Cases [10 CFR 50.55a(b)]

Code Cases, which are not approved for use in RG-1.192, may be used by submitting RR and if approved by NRC.

IWF-1000, General Requirements
IWF-5200 and IWF-5300
(ASME/ANSI OM-1987, Part 4
(OM-4) with OMa-1988 addenda)

Use Subsection IWF of ASME B&PV Code, Section XI for Integral and nonintegral attachments etc. of snubbers

ISTA, General Requirements
ISTD, Snubber (pin-to-pin) Inservice Examination & Testing Requirements

Use Subsection IWF of ASME B&PV Code Section XI for Integral and nonintegral attachments etc. of snubbers

Sunbber Examination and Testing Program based on authorized alternative TS, TRM or licensee-controlled document

IWA-1400(c), Requires Licensee to Submit Snubber Program to Regulatory Authority (NRC)

IWA-6000 provides “Record and Reports” requirements.

Note: NRC will not perform any review of submitted snubber program.

ISTA-3200, Requires Licensee to Submit Snubber Program to Regulatory Authority (NRC)

ISTA-9000, provides “Record and Reports” requirements

Note: NRC would not perform any review of submitted snubber program.

Applicable ASME Code
IWA-1400(c) or ISTA-3200, Requires Licensee to Submit Snubber Program to NRC
IWA-6000 or ISTA-9000 provide “Reports and Records” requirements

Note: NRC would not perform any review of submitted snubber program.

* Flow Chart is for guidance only. For complete details, see 10 CFR 50.55a

ISTD Requirements

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Abstract

The American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code), Subsection ISTD, describes the preservice and inservice examination and testing requirements for dynamic restraints (Snubbers). This Code was originally published as an American National Standards Institute (ANSI) standard (OM-4) in 1982. Since that time the OM-4 Code has been revised and improved over the years. For the first time OM-4 was published as Subsection ISTD in the ASME OM Code in 1990, which has been also revised and improved over the years and is published in its latest version in the ASME OM Code, 2009 edition. The OM-4 document has been referenced for many years within the ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inspection of Nuclear Power Plant Components. Specifically, the snubber inservice inspection and testing requirements were referenced as ASME/ANSI OM, Part 4 (OM-4), located in Section XI, Article IWF-5000. While the snubber examination requirements were referenced in IWF-5000, there were many owners who asked for relief from the Section XI referenced requirements using similar requirements located in owner's Technical Specifications (TS) or owner controlled technical requirement manuals (TRM), relief was granted in order to avoid overlapping boundaries between the ASME OM requirements and the Section XI requirements. This has resulted in a wide range of program approaches and differing snubber inspection and testing programs.

With the publication of the 2006 addenda to the Section XI Code, the requirements previously located in Article IWF-5000 were deleted. When Section IWF-5000 was deleted, the requirements for examination and testing of snubbers as required by 10CFR50.55a would now point to the ASME OM Code, Subsection ISTD. Since there is now be only one requirement within the ASME Code for snubber examination and testing requirements, it is anticipated there will be fewer relief requests when owners prepare updates to their snubber

examination and testing programs. Therefore, when owners prepare their ten year inservice testing (IST)/inservice inspection (ISI) program updates that incorporate the 2006 addenda of the Section XI Inspection Code, the snubber requirements will be required to be in accordance with the ASME OM Code, Subsection ISTD. This edition of the ASME OM Code is referenced in the NRC Rulemaking published in Federal Register on June 21, 2011 (Federal Register, Vol. 76, No. 119, page 36232-36279). From this point forward, owners are required to meet the requirements of the ASME OM Code, Subsection ISTD, for snubber examination and testing requirements when they update their ISI or IST programs otherwise 10 CFR 50.55a requires to submit relief request to NRC to use alternative in lieu of the ISTD requirements.

Since this will be a change in requirement, owners may be asking some of the following questions. What is the difference between our existing program requirements and those included in the ASME OM Code, Subsection ISTD? Will this change the way the current snubber examination and testing program is implemented? How much effort will be required to make this program change? Although this paper will not provide specific guidance for the implementation of the ISTD Code, it will generally describe the requirements of Subsection ISTD and identify typical areas where changes may be required to existing snubber examination and testing programs.

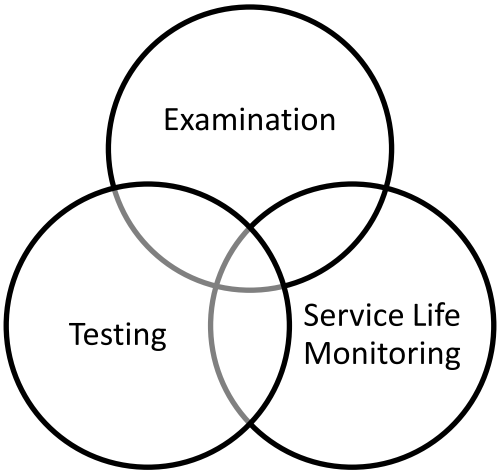
Introduction

Subsection ISTD Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubber) in Light-Water Nuclear Power Plants is included as part of the ASME OM Code. Therefore when users state they are adopting the ISTD Code, they are also adopting the general section of the ASME OM Code, titled, ISTA, General Requirements. It is within Subsection ISTA of the OM Code that the general requirements that apply to snubber examination and testing programs as well as other IST programs can be found. For example, paragraph ISTA-3200(a) requires IST plans to be filed with the regulatory authority having jurisdiction at the plant site. This will now apply to snubber program plans. Further guidance on submittal of test plans can be found in Non-Mandatory Appendix A.

ISTA-1100 establishes the scope of snubbers to be included in the snubber program. There are some additional general requirements found within ISTD that are snubber specific which are not included in ISTA. Therefore, in order to implement ISTD, one must satisfy both the specific and general requirements of

ISTD as well as the general requirements of ISTA. Within the general requirements sections are included such things as applicability, definitions, owner responsibilities, examination boundaries, transient dynamic events, supported component or system evaluations, and snubber repair/replacement requirements. It is noted that although snubber examination and testing requirements are no longer appear in Section XI, IWF-5000, both repair and replacement actions are required to be in accordance with Section XI as referenced in ISTD-1500 and ISTD-1600.

Within ISTD there are three main elements that together establish the basis of the snubber examination and testing program. All three elements must be properly implemented in order to conform to the requirements of the ASME OM Code, Subsection ISTD. These three elements are:

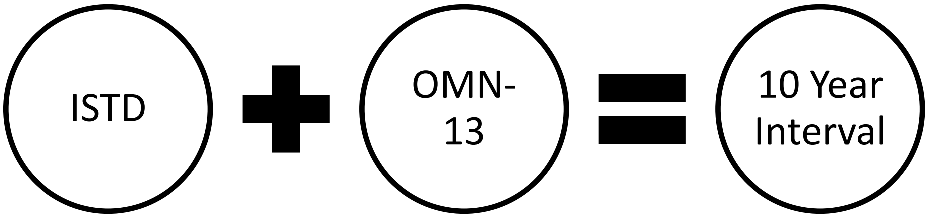


Examination

Visual Examination of snubbers is the first leg of the ISTD Snubber Program. The examination requirements for snubbers are found in Section ISTD-4000. Within this section are both preservice and inservice examination requirements. The preservice examinations confirm proper installation of the snubber and that the snubber will restrain load. For operating plants, there may be a new snubber design or location where preservice requirements must be addressed. The inservice examination requirements commence after power operation and are performed on a schedule determined in accordance with ISTD-4252 and the application of Table ISTD-4252-1. Visual examinations are required with a maximum interval not to exceed 48 months, or every other refueling outage. This frequency may vary depending on the results of the previous examination interval. If the results include several visual examinations that are determined to be unacceptable, then the next examination interval could be reduced. On the other hand, in the case of only a few unacceptable examinations, the interval could be extended up to the maximum as noted in ISTD Table 4252-1.

ISTD Table ISTD-4252-1 is essentially identical to the table which was included in Generic Letter (GL) 90-09 issued by the NRC addressing the extension of snubber examination intervals. Most snubber programs are using the approach of GL 90-09 and that frequency table for visual examinations so the change to move to ISTD in this area is not significant. Further guidance on the use of ISTD Table ISTD-4252-1 can be found in Non-Mandatory Appendix G.

In addition, there is also an approved Code Case, OMN-13, which allows the extension of the visual examination interval beyond as specified in Table ISTD-4252-1, to a maximum of once every ten years after the prerequisite requirements of the OMN-13 Code Case have been satisfied. While using OMN-13, at any time during an examination interval the cumulative number of unacceptable snubbers exceeds the applicable valves from Column B in Table ISTD-4252-1, the current examination interval shall end (more details see OMN-13). In order to use this Code Case the existing snubber program must meet all the requirements of the ISTA and ISTD Code.



As defined by ISTD-4220, the snubber population may be considered as one population or may be divided based on accessibility categories for visual examination purposes. This may differ slightly from some owner controlled programs which may have allowed separate groupings by area rather than by accessibility. When moving a snubber program into ISTD space, this should be checked.

The boundary for examination as defined in ISTD-3110 is from pin to pin inclusive. ISTD does not cover the attachments to the building structure or the piping. This may differ from the previous owner controlled or TS controlled program where the structural attachment and piping attachment might also be included in the examination program as part of the ISI Program. These structural attachments remain in the Section XI component support ISI examination program under present code requirements. Coordination with the ISI program manager is required to ensure that the structural attachments have the proper examinations performed. Some plants keep the inspections under the snubber program using VT-3 qualified individuals to complete the work. ISTA-1500(e) requires the owner to use qualified individuals which may or may not be VT-3 qualified.

One provision defined under ISTD-4240 visual examination requirements allows the re-categorization of an unacceptable snubber to be considered acceptable after the completion of an acceptable functional test. This test must demonstrate snubber operational readiness and confirm the unacceptable condition did not affect the snubber’s operational readiness.

Testing

Functional testing of snubbers is the second leg of the ISTD snubber program. The testing requirements for snubbers are found in Section, ISTD-5000. Within this section are both preservice and inservice testing requirements. The preservice tests confirm proper operational readiness of the snubber before installation in the plant. This may be satisfied using the manufacturer’s test performed at the factory, or it could be satisfied with a functional test performed by the owner just prior to installation of the snubber. The inservice testing requirements begin after plant power operation and are performed once every fuel cycle as stated in ISTD-5200, however, testing may begin no earlier than 60 days before a scheduled refuel outage as stated in ISTD-5240. The sample testing required under ISTD is intended to capture a snapshot in time to determine the overall condition of the snubber population.

The functional testing must utilize one of the two test sampling plans identified in ISTD-5260. The two plans identified are the 10% plan and the 37 plan. Generally the 10% plan is used for a population size less than 370 snubbers and the 37 plan is used for populations larger than 370 snubbers. The initial sample size using the 10% plan is 10% of the snubber population identified for each Design Test Plan Group (DTPG). The 37 plan requires an initial sample of 37 of the population identified for each DTPG. Further guidance on use and strategy for choosing one of the two sample plans can be found in the Non-Mandatory Appendices D and E.

Design Test Plan Groups

Snubbers may be grouped in various DTPG's according to the criteria outlined in ISTD-5250. The purpose of this grouping is to combine snubbers of like design, application, size, or type. There is some strategy involved in establishing the initial DTPG groupings due to additional testing being determined by test failures within each DTPG group. The size of the sample is a function of the size of the group while using the 10% plan. ISTD-5253 requires a separate DTPG for large equipment snubbers attached to steam generators or reactor coolant pumps on pressurized water reactors.

Examples:
Population size 900 mechanical snubbers of various sizes, however, same manufacture.

Example 1:
Grouping – one DTPG
Use 37 test plan – initial sample size is 37 snubbers.
Use 10% plan – initial size is 90 snubbers.

Example 2:
Grouping – two DTPG's, small snubbers = 150, all others = 750
Use 37 test plan on large sizes – initial sample size is 37 snubbers.
Use 10% plan on small sizes – initial size is 15 snubbers

Depending on which of the approaches above is used, there would be a different result in expanded testing scope requirements if test failures were identified. Whichever test plan is chosen, once the testing begins it must be continued through until the end of testing and must be concluded in accordance with ISTD-5330 for the 10% plan or ISTD-5430 for the 37 plan.

Test parameters are identified in ISTD-5210. An activation test is required for all snubbers, both hydraulic and mechanical. For hydraulic snubbers, a release rate test is also required as applicable to the snubber design. For mechanical snubbers, a drag force measurement is required. Tests are to be performed in both the tension and compression directions. ISTD does not identify acceptance criteria for these tests as they will be dependent upon the design criteria used for each plant. ISTD-3210 requires tests to be performed at sufficient loads to verify these test parameters.

Inservice tests must be performed in the “as found” condition to the fullest extent possible as stated in ISTD-5221. This prohibits any preconditioning to improve the condition of the snubber to bias the test results prior to performing the as found test. The purpose of the inservice test is to determine if the snubber is in fact ready to operate if it is called upon to do so. ISTD allows options to use various test methods to accomplish this test, e.g., bench test, in-place test, subcomponent test, indirect measurement, and qualitative tests. These differing approaches are described under ISTD-5220 and ISTD-5230. Additional information on test parameters and methods can be found in Non-Mandatory Appendix H, Test Parameters and Methods. If a hydraulic snubber is tested without the application of a load to the snubber piston rod, then per ISTD-6400, the snubber fluid must be evaluated and piston seal integrity verified.

All test failures must be evaluated to determine the cause of the failure (ISTD-5271) and potential damage to the supported system or component (ISTD-1800). Test failures trigger requirements to perform additional testing until the equations (ISTD-5331 or ISTD-5431) of the test plan used are satisfied. When failures are identified and there is a distinguishable failure mode determined, a failure mode group (FMG) may be established. The benefit of establishing an FMG may allow limiting the additional testing to the group of snubbers identified to be the same FMG. Owner controlled programs may not have the ability to define an FMG for continued testing as is available in the ISTD Code. All snubbers placed in the same location as a previously failed snubber test, must be subjected to a retest during the next fuel cycle as stated in ISTD-5500. There may be some confusion over this requirement in some programs. However, it is the location that is suspect, not the specific snubber. Therefore, if a snubber is removed from service due to an unacceptable inservice test and then refurbished before being installed in a new location, that snubber will not require a retest during the next fuel cycle.

Service Life Monitoring

Service Life Monitoring (SLM) is the third leg of the ISTD snubber program. Although all owner controlled snubber programs will have an element of examination and some type of testing, they may be lacking in the documentation of an effective service life monitoring program as required by ISTD. Most programs monitor performance of their snubbers from a reactive viewpoint. When there is a problem, it is addressed. Or, they establish a seal life for hydraulic snubbers and replace seals before they expire calling that “Service Life Monitoring”. ISTD-6000 outlines a proactive approach that predicts service life in order to take appropriate action in advance of encountering a problem. When moving to an ISTD snubber program, there is usually significant work to be done in the area of service life monitoring. Programs may consider service life by performing some kind of maintenance on snubbers, but they fail to document a service life strategy and approach toward maintaining a healthy snubber population. In developing an effective service life monitoring program, the owner must consider alternatives and develop his own strategy to maintain the health of the snubber population.

Whatever the service life monitoring approach taken, it needs to be documented. ISTD provides certain prerequisites for an SLM program and additional information in Non-Mandatory Appendix F. Initially, ISTD-6100 requires the prediction of a service life for each snubber based upon manufacturer’s recommendation or design review. Sometimes service life is confused with the design life of a snubber. ISTD-2000 defines service life as the period of time an item is expected to meet the operational readiness requirements without maintenance. Even though there is substantial documentation published to the contrary, many plants still consider the service life of the basic mechanical snubber to be 40 years. This may be true for some environments, but definitely not for other environments. A good SLM program will take the environment into consideration when establishing the service life of the snubber.

Each fuel cycle the service life for all snubbers is to be evaluated and adjusted if necessary based upon technical data gathered from snubbers which have seen service in the plant (ISTD-6200). ISTD-6300 requires an evaluation to determine the cause of snubber failures with consideration given to reestablishing the service life based upon that evaluation.

Due to differing plant conditions, there may be some snubbers that are evaluated more often than required by either of the sample plan testing programs. For example, areas where a mechanical snubber experiences excessive vibration may reduce the expected service life of the snubber from 20 years to 10 years. Or, when a hydraulic snubber is located near a high temperature heat source, the seals and fluid may reach the end of their service life earlier than expected. If the normal cycle to work through a snubber population is 15 years, then these snubbers will not come up for testing before the service life is exceeded.

When service life testing is performed early to address this type of issue (ISTD-6500), the results of such testing do not require testing of additional snubbers as would be required by ISTD-5320 or ISTD-5420. However, appropriate corrective action must be taken based on an evaluation of the failure. Performing SLM testing may be a prudent practice to gain additional information about the performance of the snubber population. However, many snubber program owners have difficulty scheduling optional testing that is not required by Code or TS due to schedule or budget concerns.

There are numerous approaches and strategies that can be implemented to establish an effective SLM program. Non-Mandatory Appendix F provides additional insights that might guide the program owner to establish this strategy.

Conclusion

The ASME OM Code, Subsection ISTD, defines the requirements necessary to establish a comprehensive snubber examination and testing program. ISTD allows the program owner significant latitude to shape the actual snubber program; however, the essential elements of ISTD; 1) Examination, 2) Testing, and 3) Service Life Monitoring must all be considered to be equally important in order to reach the goal of a successful snubber program. The transition from an owner controlled snubber program to an ISTD compliant program can usually be made without significant pain once there is a solid understanding of the essential elements of the ISTD Code.

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10 CFR 50.55a rulemaking (Federal Register, Vol. 76, No. 119, page 36232-36279, dated June 21, 2011)

Session 2(a): Valves I

Session Chair: Kevin G. DeWall, Idaho National Laboratory

A Study on an Analytical Approach with Fluid-Structure Interaction Technology for the Design of High-Temperature Check Valves in Nuclear Power Plants

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Abstract

A check valve is located on the water feed pipe connected to the steam generator in nuclear power plants. It is required that the performance test of a check valve at a high temperature and pressure should be performed based on American Society of Mechanical Engineers (ASME) QME-1, “Qualification of Active Mechanical Equipment used in Nuclear Power Plants,” for the practical use in nuclear power plants. This paper investigates the design technology considering design characteristics and the high temperature/pressure test of the check valve which is one of the important components in a nuclear power plant. In this research, the functionality and structural integrity is verified by experiment and analytical approach, such as the simulation of closing time and the analysis of stress and fatigue. The functionality is investigated under a reverse flow during an accident event. The test setup consists of the practical prototype of a check valve with the material of ASME SA217-WC9 and support equipment consisting of a Tank, Sensors, Rupture disc, computer, and feed pipe. The structural integrity is associated with the stress and fatigue life under the loading conditions such as fluid pressure, end-loading, and thermal expansion. The structure analysis is performed based on Fluid Structure Interaction (FSI) technology providing the integrated solution of the coupled structural-fluid physics. The fluid part is first solved based on Computational Fluid Dynamics (CFD) modeling to calculate the fluid pressure on the solid casing structure. Then, the structure part is resolved based on the Finite Element Method (FEM) to compute displacement and stress under the pre-calculated fluid pressure and other loads such as end-loading and thermal expansion. Finally, the fatigue analysis is applied to compute the fatigue life for the closing duration of a check valve by utilizing the stress data derived from the previous structure analysis.

Introduction

A check valve is a mechanical device used in a wide variety of applications that normally allows fluid (liquid or gas) to flow through it in a single direction. The check valve is also regarded as one of the fundamental components widely used in safety systems of nuclear power plants (NPP). Figure 1 depicts an example of a check valve in a nuclear power plant. Practically, a check valve mounted on a flow line is generally used to protect a centrifugal pump and the related equipment, establish a flow direction, and maintain a pressure state during an operational mode change in the nuclear power plant. The check valve in a nuclear safety system also takes a role to supply sufficient fluid for safety feed and auxiliary feed in Design Basis Accident scenarios. Additionally, the check valve can often be exposed to severe temperatures and pressures due to operating conditions in the nuclear power plant. The failure of check valves can result in the undesirable effects such as water hammer [Reference 1], over-pressurization, and damage to the flow system. Therefore, the check valve in NPPs should be designed to operate normally under severe operational temperatures and pressures and obtain the required reliability of the standard codes such as ASME QME-1. Additionally, the check valve should be well designed with sufficient sealing and shall protect against water hammer in normal operational mode [References 2, 3]. However, it is not convenient to totally fulfill the requirements of the standard codes only by experimental testing. Thus, the analytical approach can be a fine alternative method to support check valve design. The advanced analysis technology of the Fluid Structure Interaction (FSI) method is a promising approach that provides an integrated solution of multi-physics problems including thermal fluid dynamics and structural dynamics. Unfortunately, this advanced analytical approach is uncommon in NPP and this paper will demonstrate the advantages the FSI design method for NPP mechanical equipment analysis.

In this research, a study on an analytical approach for simulation of the check valve was performed based on the FSI method, which describes the integrated phenomena of thermal fluid flow and structural deformation. The numerical models of the fluid and structure parts in the check valve were constructed based on Computational Fluid Dynamics (CFD) and Finite Element Analysis (FEA). These numerical models were also verified with the experiment data and then the analyses were performed under loading conditions considering the effects of fluid pressurization, end-loading, and thermal expansion, which were required for the qualification of the check valve for nuclear power plant use according to ASME QME-1. As a result of analysis, the valve stress and life cycles were obtained and evaluated.

Check Valve Experimental System

The test check valve system for a reverse flow was prepared as shown in Figure 2. This apparatus was composed of the surge tank, test check valve, pipe line, pool, rupture disk, various measurement systems, personal computer for storage of a measured signal data, etc. The test check valve system generates a reverse flow in the check valve through a pressure difference between the tank and rupture disks. The direction of reverse flow is from the tank to the rupture disks, which is caused by lowering pressure between two rupture disks. Therefore, the check valve is operated from the open to the closed state.

Figure 3 depicts the experimental instruments for measurement of some data such as pressure, position, vibration characteristics, and strain. The strain gages were attached to the expected weak points on the surface of the piston for evaluation of the deformation and stress.

Numerical Analysis and Results

This research investigated the advanced analysis technology of the FSI method for a more reliable approach to evaluate the integrated results of pressure, temperature, deformation, and stress in the structure of a check valve. FSI occurs when fluid flow generates forces on a solid structure, causing it to deform and potentially perturb the initial fluid flow. In this study, a one-way coupling method for FSI simulation was used by ANSYS software since the fast fluid flow almost dominated the structure behavior in the check valve. The numerical models of fluid and structure regions were constructed based on CFD and FEA. Figure 4 shows mesh generations of two numerical models for CFD and FEM analysis and Table 1 summarizes main features of each models such as solution, algorithm, property, node & element numbers, and element shape in the table. The numerical model was verified with the experiment data.

The fluid region was first resolved by the three dimensional incompressible steady flow analysis with the Raynolds-Averaged Navier-Stokes and continuity equations in ANSYS. The turbulent model was the k-e model with wall function and the tetra element was used for mesh generation. Boundary conditions were defined by imposing the design pressure (8.9 megapascals [MPa]) at the right side of the check valve in Figure 4 (a) as the inlet boundary and atmosphere pressure at the left side as the outlet boundary. The pressure and velocity of the fluid region were solved by CFD analysis with boundary conditions at the open state of the check valve. The plot results of pressure and velocity are shown in Figure 5. The pressure was concentrated on the base region due to the impact of high velocity water. This pressure distribution data was used as a loading condition on the internal surface of the structure region in the following FEM structure analysis.

The structure region was also solved by the three dimensional static analysis in ANSYS simulation using the pressure data of the CFD analysis results. The high order hexa-element was dominantly used for the mesh generation in Figure 4 (b). This FEM structure model included three types of load conditions. The first load condition was defined by imposing fluid pressure distributions in the open and closed states on the internal surface of the check valve. The second load condition was applied by an end-loading condition which is defined in the functional qualification requirements for active valve assemblies for nuclear power plants in ASME QME-1. The equivalent moment load was used for the end-loading condition. The third load condition was defined by considering the thermal expansion from temperature gradients. Thermal expansion can be an important design factor since a check valve is operated at a high temperature during plant operation. Before the static structure analysis with thermal expansion was completed, thermal conduction analysis was performed to obtain the temperature distribution in the structure region. A geometric boundary condition was defined by imposing the fixed support at both end sides of the check valve.

Figure 6 shows the deformation and stress contour results obtained under the first loading condition. The maximum deformation and stress coincided closely in the border area between the piston part and pipeline. Figure 7 depicts contour results obtained under end-loading and thermal expansion with fluid pressurization. The maximum stress occurred at the similar position in all load conditions of fluid pressurization, end-loading, and thermal expansion. The result shows the maximum stress is approximately 155 MPa in the end-loading condition. This stress level did not exceed the allowable stress of the steel material. To support this analysis, thermal conduct analysis was carried out in advance to obtain the temperature distribution shown in Figure 8.

A check valve often changes from an open to a closed state during plant operation. This repeated loading causes premature failure in the material by fatigue. The fatigue can be evaluated by the stress-life (S-N) method that is widely used in design applications. This S-N approach is based on fatigue curves of stress versus number of cycles such as S-N curve shown in Figure 9. For fatigue evaluation, the mean and amplitude stresses were calculated by using the stress result from FEM structural analysis. The alternating stress level was obtained based on Goodman diagram [Reference 5], and its life cycle was determined by interpolation in S-N curve of Figure 9. Finally, the result of the life cycle according to loading conditions is shown in Table 2. This life cycle level was qualified to satisfy a conservative cycle (2,000) of the standard code and specification.

Conclusion

This research investigated the FSI analytical method for the simulation of a check valve. The numerical models of the fluid and structure regions in the check valve were solved based on CFD and FEA. The results of the FSI analysis showed the fluid pressure from CFD and the stress distribution from the FEM. The analysis results, with certain loading conditions, provide contour stresses comparing the effects of fluid pressurization, end-loading, and thermal expansion. Finally, the material fatigue was computed from the stress data of the previous static analysis. Therefore, it is hopeful that this design approach by using FSI method is a beneficial guide to solve multi-physics engineering problems of nuclear equipments.

Acknowledgement

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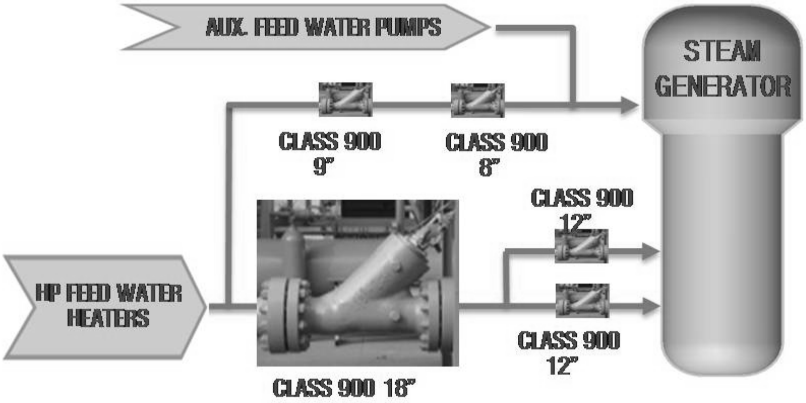


Figure 1. Check valve mounted on the line in a nuclear power plant

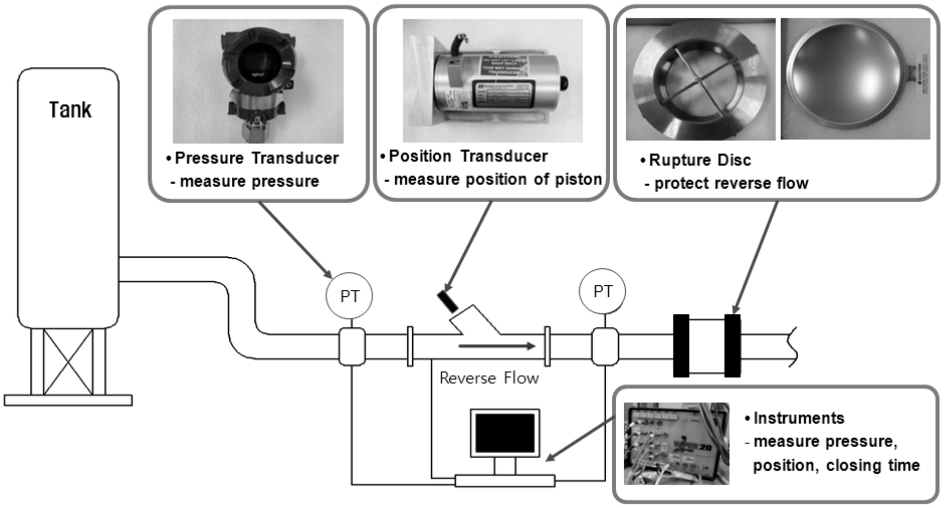


Figure 2. Schematic of a test check valve system for a reverse flow simulation

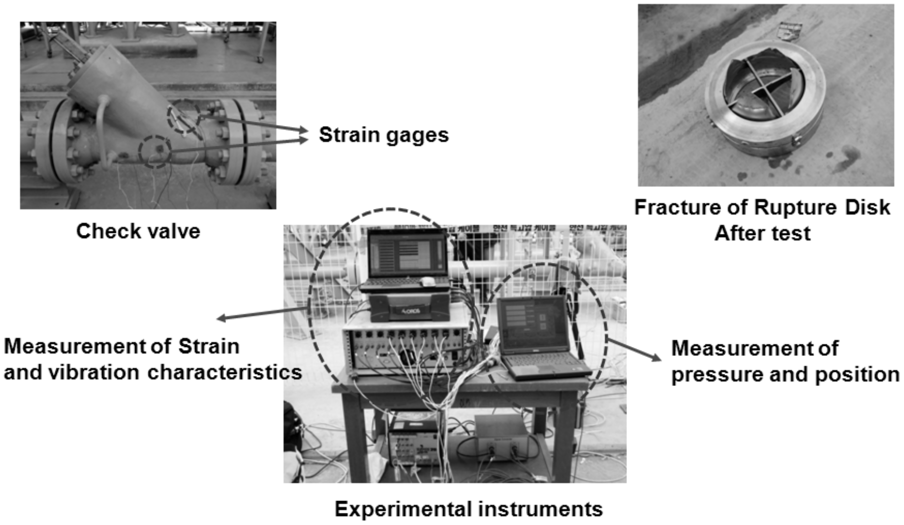
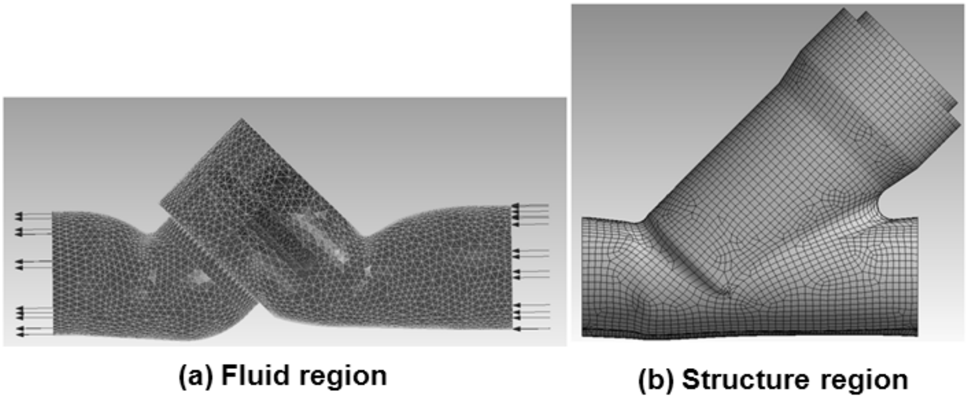


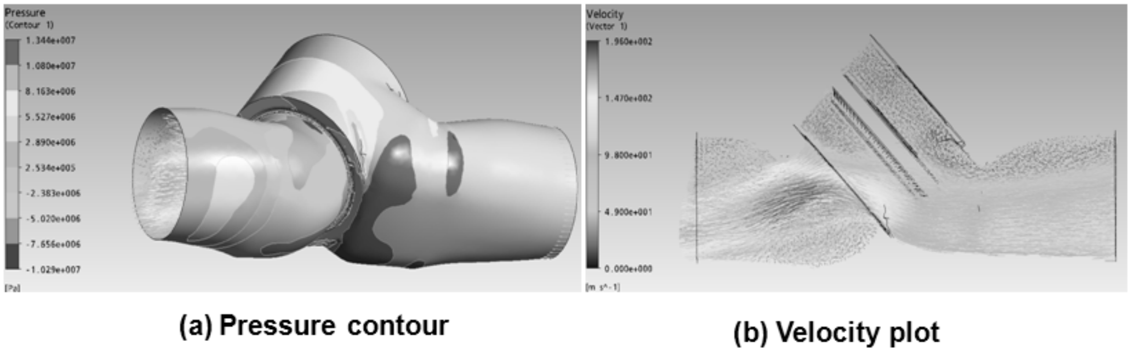
Figure 3. Experimental instruments for data measurement



(a) Fluid region

(b) Structure region

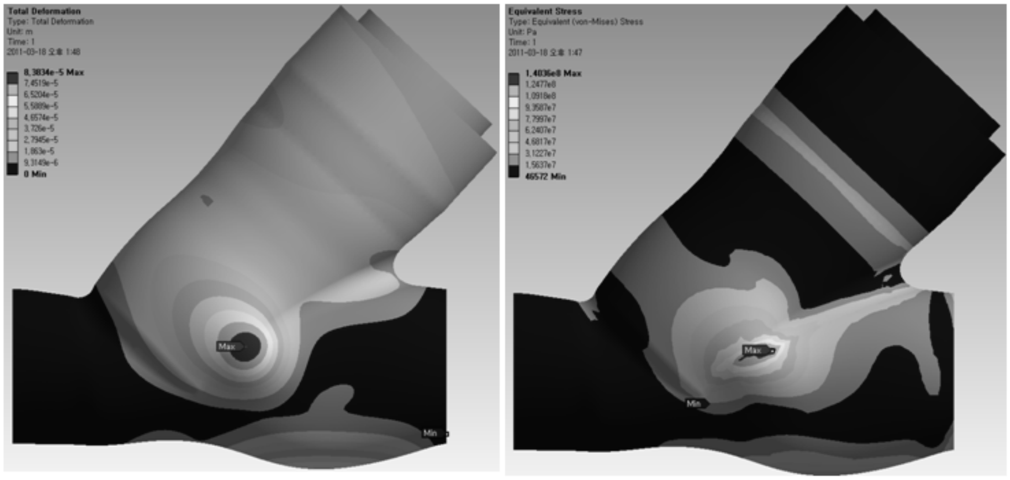
Figure 4. Mesh generation used for CFD and FEM analysis



(a) Pressure contour

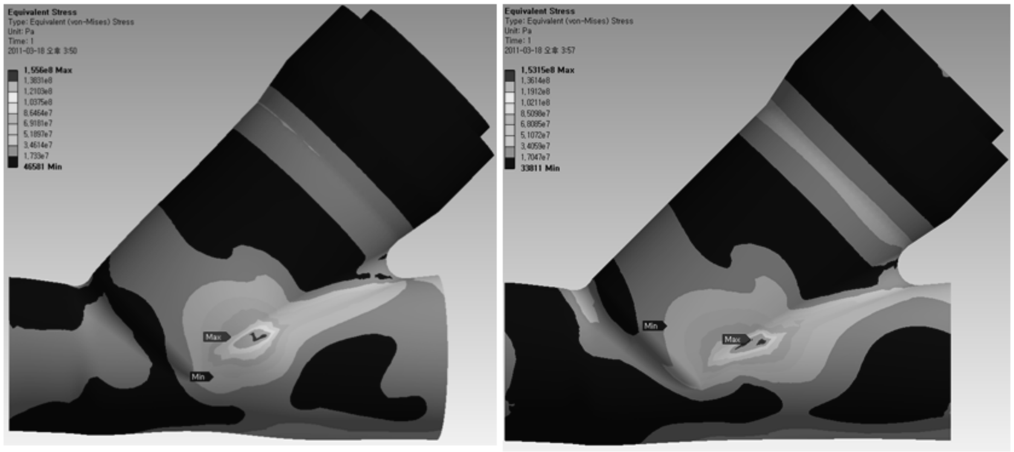
(b) Velocity plot

Figure 5. Plot results of CFD analysis at the 100% open state



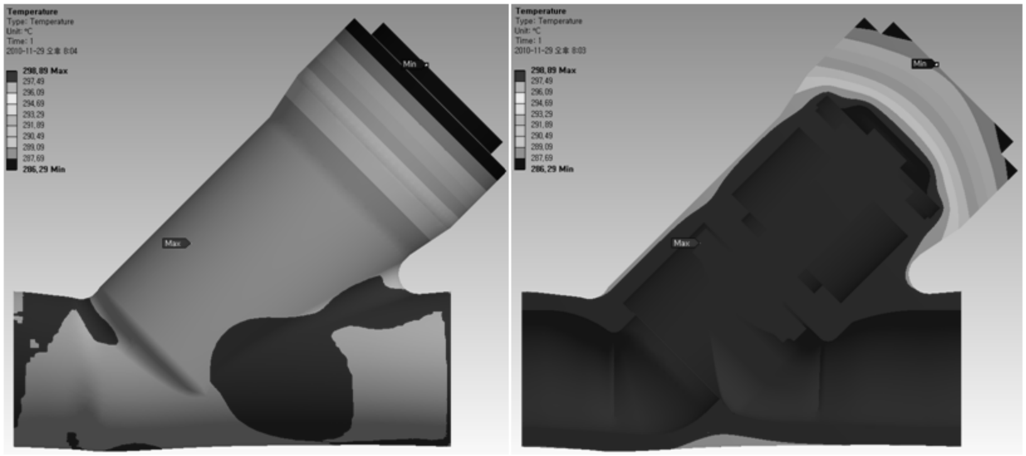
(a) Total deformation **(b) Equivalent stress**

Figure 6. Contour results with fluid pressure load



(a) Stress in End-loading **(b) Stress in Thermal expansion**

Figure 7. Stress contour in end-loading and thermal expansion with fluid pressure load



(a) External distribution **(b) Internal distribution**

Figure 8. Temperature distributions in thermal expansion

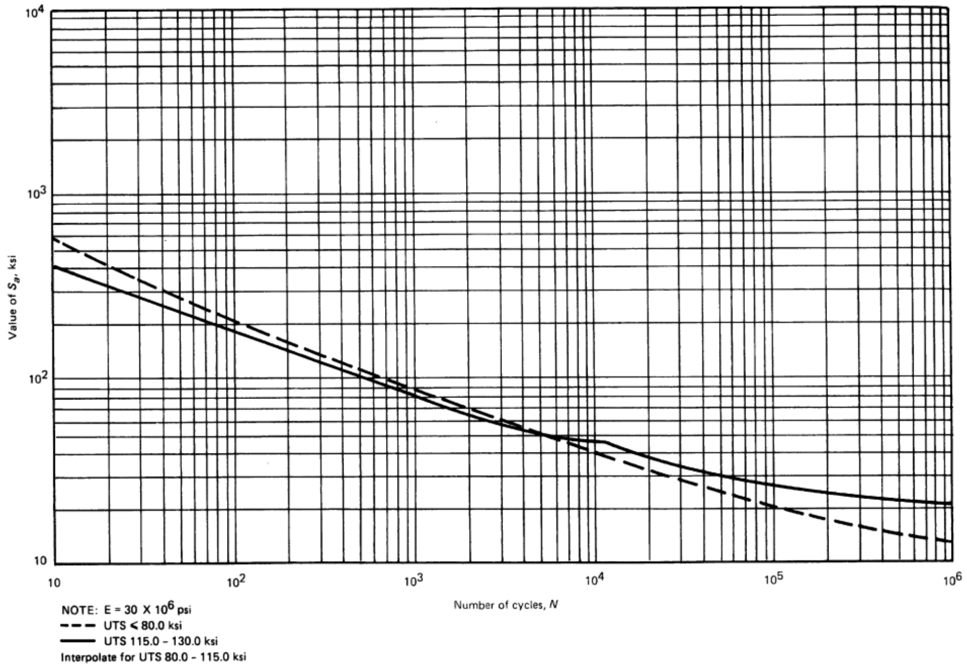
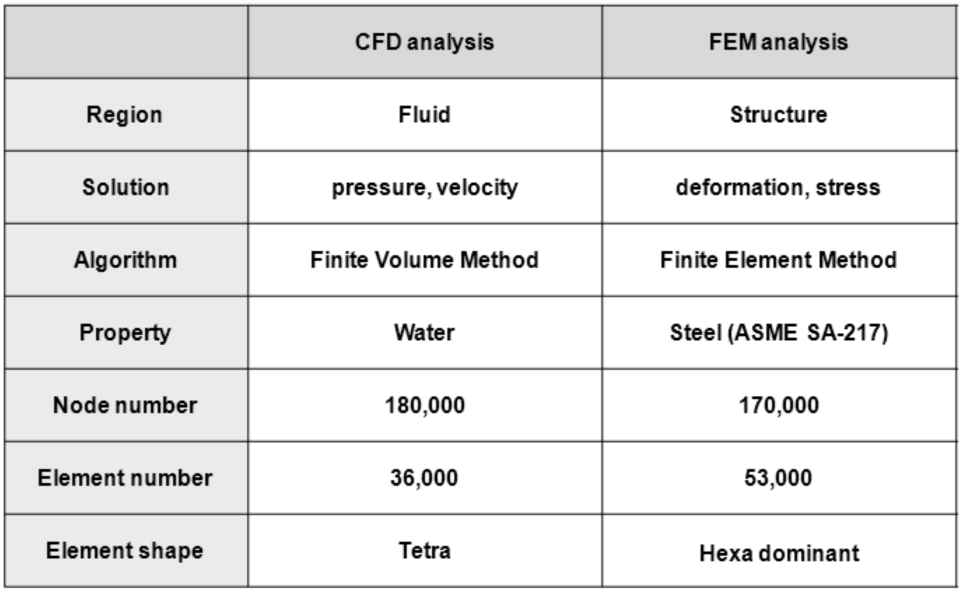


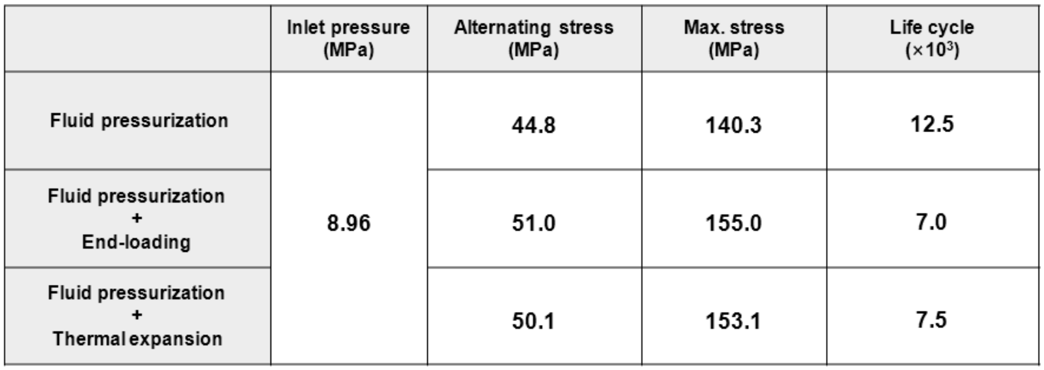
Figure 9. Typical stress life (S-N) curve [6]

Table 1. Features of CFD and FEM numerical models



	CFD analysis	FEM analysis
Region	Fluid	Structure
Solution	pressure, velocity	deformation, stress
Algorithm	Finite Volume Method	Finite Element Method
Property	Water	Steel (ASME SA-217)
Node number	180,000	170,000
Element number	36,000	53,000
Element shape	Tetra	Hexa dominant

Table 2. Life cycles according to loading conditions



	Inlet pressure (MPa)	Alternating stress (MPa)	Max. stress (MPa)	Life cycle ($\times 10^3$)
Fluid pressurization	8.96	44.8	140.3	12.5
Fluid pressurization + End-loading		51.0	155.0	7.0
Fluid pressurization + Thermal expansion		50.1	153.1	7.5

Systematic Evaluation of Significant Check Valve Application to Improve Reliability and Enhance In-Service Test Performance and Plant Availability

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Abstract

This paper presents an assessment of the performance of Borg/Warner (B/W) check valves installed at the Palo Verde Nuclear Generating Station (PVNGS). The objective was to systematically review the recent performance of the PVNGS Borg/Warner swing check valve population to develop a basis for improving its reliability. The range of valve sizes and different potential contributory failure causes identified necessitated the application of a proactive programmatic approach versus a piecemeal reactive approach.

This evaluation highlighted not only the uniqueness and importance of the large Borg/Warner check valve population to the three PVNGS operating units, but also underscored the importance of carefully considering remedial actions due to the immediate and expensive impact of unsustainable solutions. The Borg/Warner valve population had performed reliably for the first 10 operating cycles, suggesting that the design was not inherently defective. However, "running the valve to surveillance test failure" was not an option, given the valves' location inside containment and its low usage, and the associated rash of unreliability that challenged plant Operations, as it manifested predominantly as a failure to pass local leak rate tests in Mode 3 during startup. These failures were attributed mainly to two reasons: accumulation of deposits in narrow clearances, which limited articulation at sliding surfaces, and improper reassembly related to valve internal dimensional relationships and design features.

Maintenance personnel responded vigorously to the challenge of managing this "field fit up valve" population of valves by developing an elaborate (90-page) valve assembly procedure and a test and measurement apparatus to compensate for the complexity of reassembly. Before this program was completed, a second initiative was launched to introduce sweeping changes that would reduce the internal clearances of the valve based on "optimized" dimensional data purchased from the valve vendor. The rigorous maintenance procedures include mechanisms to detect vendor quality issues and eliminate maintenance errors. However, such intricate processes are inherently expensive

and not sustainable in the long term, given the reality of subject-matter experts' turnover and variance in outage crews, creating a potentially unresolved production risk.

This paper discusses various options for improving the reliability of the PVNGS Borg/Warner valve population that will enhance plant safety and availability, and minimize avoidable challenges to Operations and burdens to control-room operators, as well as unexpected impacts on operation and maintenance (O&M) budgets and outage schedules.

Introduction

The Palo Verde nuclear generating station has 68 Borg Warner (BW) swing check valves installed in the emergency core cooling systems (ECCSs) of each of its three identical operating pressurized boiling-water reactor units. Over time, these 204 originally installed and now obsolete valves are proving to be increasing unreliable for sustaining plant operations, and with age, they have become burdensome to maintain. Palo Verde initiated a project to develop a sustainable and cost-effective approach to improve the reliability of this large population of check valves, to reduce burdens on the control-room operators, and minimize unexpected impacts on O&M budgets and outage schedules. The goal was to develop a strategy to alleviate undefined production risks and O&M costs stemming from intermittent local leak rate test (LLRT) failures during startup, and possible future loss of specialized valve expertise.

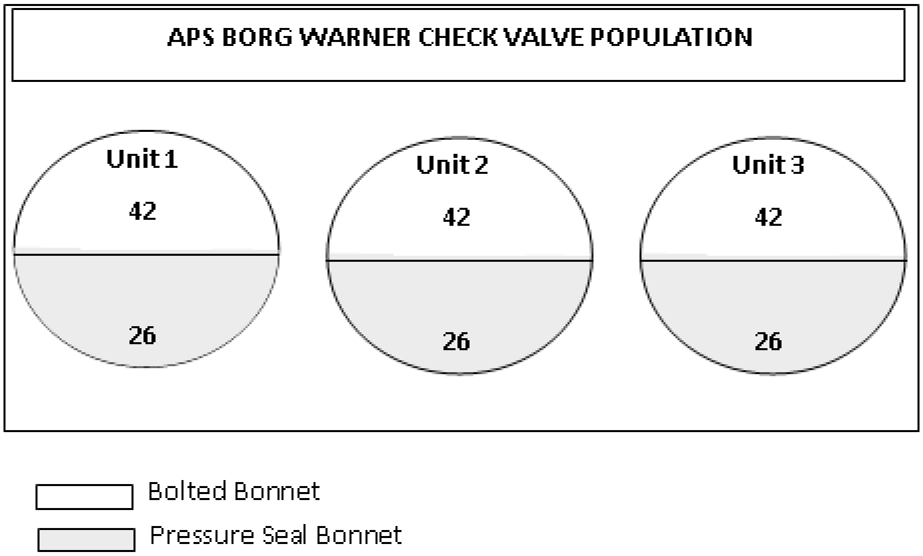

Figure 1: Each unit at Palo Verde has 38 BW safety-related swing valves in the safety injection (SI) system and 30 valves in the chemical volume and control system (CVCS).

The Design Problem

The 204 swing check valves installed at the Palo Verde are all of the bonnet-hung design and range in size from 3 to 24 inches (Figure 1). Some of these valves are of the bolted bonnet design (Figure 2), while the rest are of the pressure-seal bonnet design (Figure 3). Palo Verde nuclear station is unique in having such a large population of these valves in its ECCS systems, although some valves of this style are installed at other U.S. power stations.

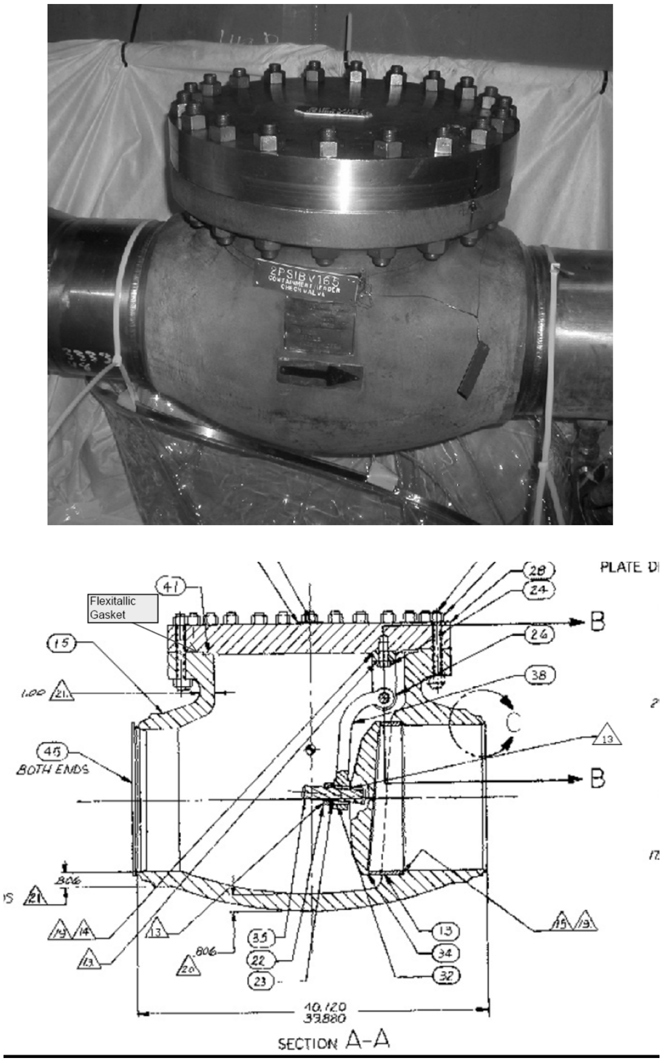

Figure 2: Typical bolted-bonnet BW swing check valve

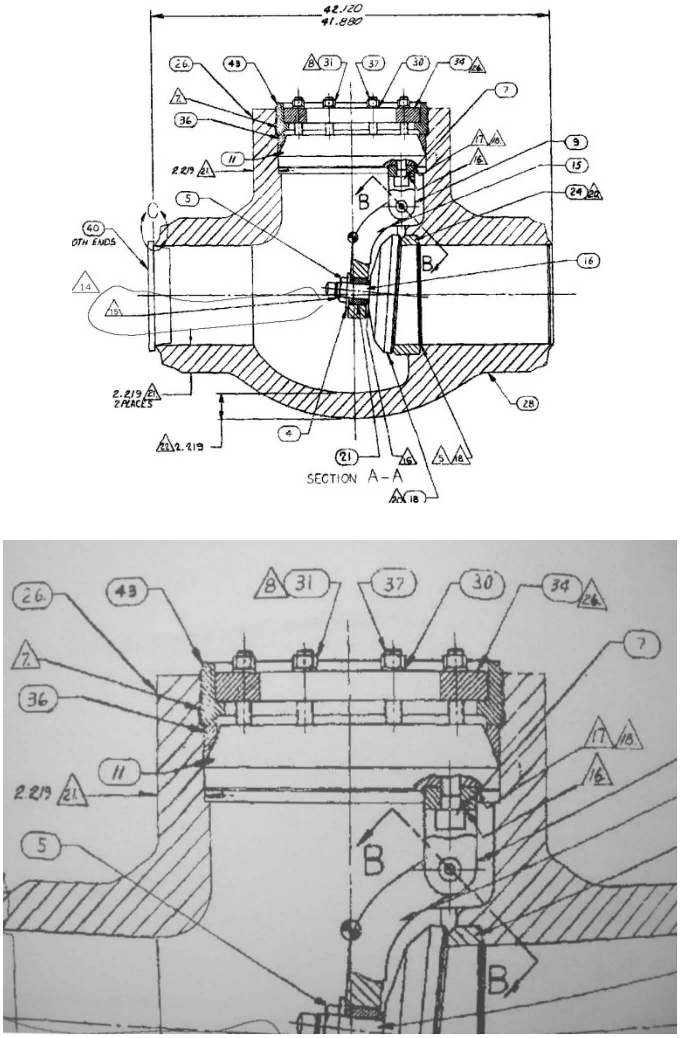

Figure 3: Typical pressure-seal bonnet BW swing check valve

The central problem stems from the inability to visually observe and adjust the position of the disk assembly relative to the body seat once the valve is assembled. The disc hangs from the bonnet, and the valve seat is welded to the body, so there are numerous factors that affect the final position of the disc with respect to the valve seat, including the fact that the position of the bonnet itself with respect to the body is not well defined. This last problem is further exacerbated in valves with a pressure-seal bonnet where the disk assembly is apt to move as the bonnet is hot torqued and secured in its final position. This requires carefully controlling a large number of internal dimensions to achieve the right geometric relationships that will ensure a proper disk-to-valve-body seat contact (Table 1). The inherent variability in these dimensions and their influence on assembly requires specialized valve expertise and disproportionately resource-intensive procedures and tooling to work the valve.

Table 1: Examples of dimensions that vary
(* indicates dimensions that significantly influence assembly)

Bonnet Assembly	Body
Bonnet thickness*	Height of seat centerline* from top of body
Clevis height*	Seat angle* with respect to vertical
Hinge-pin diameter	Seat angle with respect to horizontal
Hinge-pin hole diameter, location in clevis*	Seat offset* with respect to seating surface
Bushing ODs, IDs	Seat width*
Swing-arm length*, hole diameter / thickness at disc stud*, material	Diameter of seating surface* (both horizontally and vertically)
Spherical bearing height*, diameter, chamfer (some have one side)	Height of seating surface*
Disc diameter*, thickness	Height of ledge where bonnet initially seats (pre-assembly)
Location* / diameter of stud hole in disc*	Seat hard face thickness
Disc stud to disc weld size, quality	Location and size of diametral chamfer between retainer threads and sealing area
Disc gap size*	

When originally installed, these bonnet assemblies were custom fit to their bodies by the vendor. As seen in Table 2, the majority of these originally installed valves performed reliably for the first ten operating cycles. But the valves' reliability hinged on the implicit assumption that each bonnet assembly would never leave its original body. This, however, was an unsustainable condition because of the valves' location in containment and the need to minimize time at the valve to minimize as low as reasonably achievable (ALARA) exposure required that the disk assemblies be switched. Once the link between a bonnet assembly and its mating valve body was lost, problems in these field-fit up valves multiplied rapidly.

Table 1: Operating history of a sampling of valves over 12 inches in the population of BW swing check valves, indicating the refueling outage (Rx) when a valve required rework

System	**RC Loop Check Valves**				**Safety Injection Tank Discharge**				**SI Injection Header**			
Valve ID	217	227	237	247	215	225	235	245	540	541	542	543
Unit 1	R6	R10		R11	R11	R10	R10		R4	R10		R11
Unit 2	R10		R11		R10	R11	R10	R11	R11	R11		
Unit 3					R9	R8	R10					

This problem became a wider concern when highlighted by NRC Information notice No. 89-02, *Malfunction of Borg Warner pressure seal bonnet check valves caused by vertical misalignment of disk* (Reference 1) which described the risk of the top of the disk getting caught under the top of the seat (Figure 4). BW/IP CFRN-9301 10 CFR Part 21 report concerning 3-in. and 4-in described the potential for the disc of specific model valves (which Palo Verde did not have) to over-articulate and become wedged against the seat, preventing a closure (Reference 2). Such disc cocking and wedging under the seat could result from an excessive gap between the swing arm and the disc stud washer caused by excessive weld buildup at the disc to stud weld.

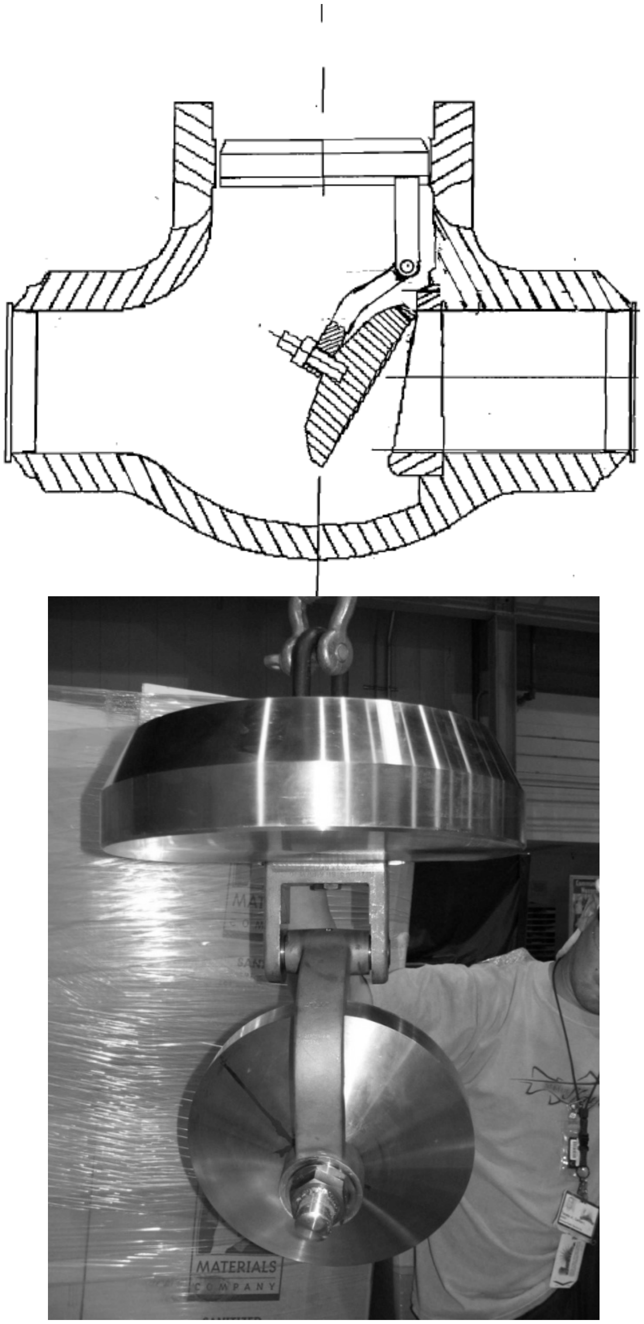

Figure 4: Depiction of the top of the disk getting caught under the top of the seat and a photograph of the bonnet hung disk assembly

During normal operation, these valves remain closed throughout the entire fuel cycle. This increases the likelihood for magnetite released by the system to deposit in the nooks and crannies and over time make the sliding and rotating joints stiff and arthritic. The added requirement for these valves to meet LLRT requirements in Operating Mode 3 during startup means that each failure automatically delays startup and often results in the plant returning to a cold shut down to allow for a valve inspection and repair.

Cost of Unreliability

The ongoing valve unreliability is reflected in high O&M costs driven by a number of contributing reasons including:

- High cost of some replacement spare parts which rival the cost of a new valve.
- Extended outages and lost generation resulting from delaying startup to inspect valves that fail in Mode 3 and require returning to Cold shutdown (Mode 6).
- The resource intensive nature of routine maintenance (90 page valve inspection and assembly procedure)
- Given that the RCS/SI valves are in high dose areas, ALARA-intensive in-situ valve body seat repairs.
- Burden to control room operators to continually depressurize systems affected by a leaking valve.

In addition to the above tangible costs, there exist intangible costs of future unreliability to this large population of obsolete valves in the ECCS systems of all three units. A common cause problem found in any one of the larger obsolete safety valves that requires a valve replacement poses the risk of extended unavailability at one or more units. This extended unavailability allows time for the engineering required to identify suitable replacement alternatives and the long lead time for delivery of replacement valves. At the high cost of lost generation, such a delay of even a few weeks would grow to a substantial sum. Other lesser but perhaps more likely intangible costs would be driven by:

- Loss of specialized valve fit up expertise through retirements and competition for suitable outage crews to rework valves,
- Maintenance induced errors generated by complex procedures and shorter outages, and
- Added management and regulatory oversight generated by the perception of unresolved reliability issues.

Table 3 attempts to capture the direct and indirect operation and maintenance costs related to hypothetical repairs.

Table 3: Pro forma operation and maintenance cost of hypothetical repairs estimated by plant staff

	Maintenance type	Shifts	Hours	No. of men	Man Hrs	Direct Cost $35/hr.(est.)
ROUTINE PREVENTIVE (PM)/CORRECTIVE MAINTENANCE (CM)						
1	Valve disassembly and inspect – including recording of critical dimensions Larger valves require rigging (12–14 inch) - Small valves under 10-inch	1	12	2	24	$840 45,000 25,000
2	Valve Replacement (plug and play), assuming availability of replacement assembly - Larger valves require rigging (10–14 inch)	1-2	12-24	2	48	$1,680
3	Seat Work to repair seal areas Larger valves require scaffolding/rigging (≥12 in.) - Small valves ≤ 12 inch	 2 1	 24 12	 3 2	 72 24	 $2,520 $840
4	Decontamination	2	24	2	48	$1,680
5	Reworking bonnet assembly	1	12	2	24	$840
6	Reworking spherical bearing Cut nut at welded stud, code weld, inspect, Re-lap seat and reassemble	3-4	36 - 48	2	96	$3,360
7	Other – regardless of size – Radiation Physics Coverage (2hrs), Engineering (2 hrs), Welders (4hrs), Planning(4hrs) @ $40/hr		12	1	12	$480
8	Spares and cost of carrying inventory					
ESTIMATED COST OF PM (1) Larger valves require rigging (12 – 14 inch) $45,000 - Small valves under 10-inch $25,000						
ESTIMATED COST OF CM (1+2+3+4+5+6+7) Larger valves require rigging (12 – 14 inch) $55,000+ spares - Small valves under 10 in. $30,000+ spares						
COST OF APPARENT-CAUSE ANALYSIS/ROOT-CAUSE ANALYSIS						
9	ERCA/CRDR @ $40/hr		40	10	400	16,000
COST OF ALARA						
10	ALARA High dose (inside shield wall) e.g., loop checks 160–180 mRem/person/ 8-hr shift Medium dose (inside containment outside shield wall) – 20–30 mRem/person/ 8-hr shift					

	Low Dose (outside containment) e.g., CVCS checks – 10 mRem/person/ 8-hr shift					
COST OF LOST PRODUCTION						
11	Lost generation during seat work /occurrence spare					$1,000,000
12	Time to power down after an UNSAT IST leakage test in Mode 3 or 4 and subsequent power up					$1,000,000

Plant Response

In the recent past, Palo Verde has conducted a number of corrective-action reviews to study this sporadic unreliability and identify common causal effects. As part of its component programs (References 3-8) Palo Verde investigated included:

1. Bonnet-hung disc hinge assembly prevents a visual verification of proper disc alignment on the body seat once the bonnet is installed in the valve body.
2. Spherical bearing introduced to provide extra play of the disc/hinge connection (to ensure self-alignment).
3. Weld at the disc stud to disc—that can interfere with the spherical bearing.
4. Weld on disc stud threads.
5. A 5° seat angle and axial location of the valve seat relative to the opening at the top of the valve.
6. Metal-to-metal seats—more difficult to seal at low pressures.
7. Pressure seal requires a hot torque that can result in stresses on hinge arm stretched between a pressurized disc and a rising bonnet (i.e., uneven lifting of bonnet under line pressure can result in a loading of the hinge arm).
8. Materials of construction:

a. Washer	315 CRES
b. Nut	ASTM A194, grade 8M
c. Ball (spherical bearing)	Stellite #6B
d. Swing arm	17-4 PH material (AMS 5398)
e. Stud	ASTM A276, Type 316A
f. Disc	ASTM SA182, Type 316

These studies pointed toward two key common factors: (i) improper reassembly related to internal dimensional relationships and design features, and (ii) accumulation of magnetite deposits in narrow clearances and loss of articulation. These studies, when narrowed to individual valves or subsets of valves, also attributed the failures to various other potential contributory causes, some of which were validated by physical evidence and robust technical basis, while others were not. Table 2 lists the range of potential contributory factors identified by plant staff over the years.

Palo Verde maintenance engineers launched an effort to understand the correlation between variances in various internal dimensions and proper valve fit up. This effort has culminated in a 90-page valve inspection and assembly procedure [3] and a number of specialized assembly tools to improve the reliability of this population of valves. Palo Verde also launched a dimensional optimization program to “tighten up clearances.” For this, the plant procured optimal dimensions and geometric relationship data for key components (Figure 5). These dimensional changes were applied programmatically to the entire population to reduce internal clearances based on “optimized” data.

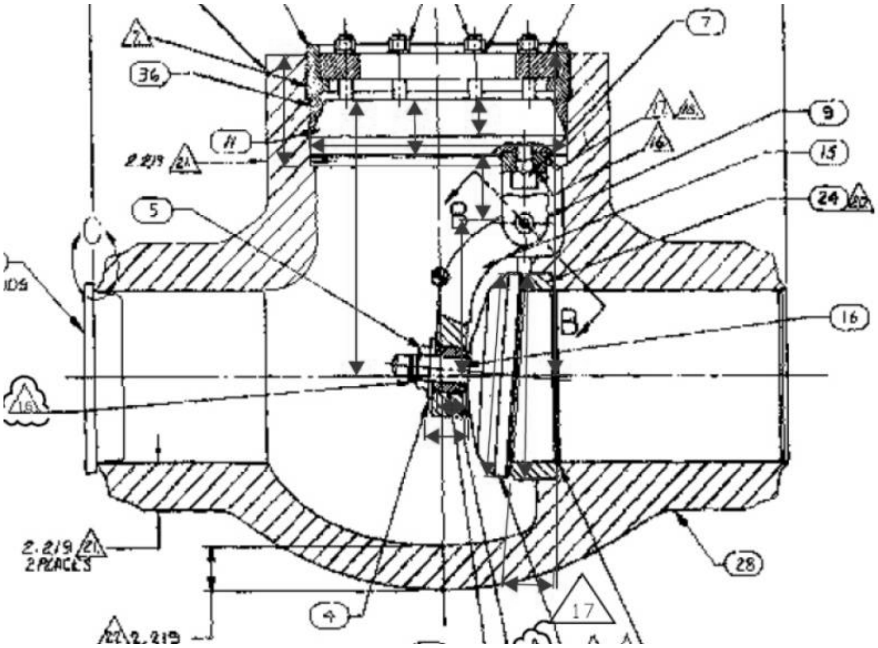

Figure 5: Examples of variable dimensions that significantly influence assembly

New disassembly practices require qualified check-valve inspectors to verify freedom of movement of the disc hinge-arm assembly (Figure 6), by checking for (i) rotation at the spherical bearing (disc yaw), (ii) gimbal or articulation at the spherical bearing (disc pitch and roll), and (iii) rotation at the hinge pin (ability of hinge arm to swing open or close). Excessive disc gimbal can cause the disc to cock to an extent that it catches under the seat during closure. Disc rotational or articulation stiffness, caused by the accumulation of deposits or mechanical binding, can prevent the disc from being properly positioned on the valve seat when the disc closes from an open position. For proper reassembly, personnel must therefore carefully maintain and verify a number of dimensions, such as the radial gap between the hinge arm and the disc stud, the axial gap between the hinge arm and the disc, and the hinge arm and the washer for any given axial position of the hinge arm, height of the disc stud to disc weld, height of the shoulder in the disc stud relative to the height of the spherical bearing, OD of the disc washer relative to the hinge-arm bore, and perpendicularity and eccentricity of concentric dimensions. It is this level of attention to detail that makes valve reassembly cumbersome and specialized. The time required to perform such intricate steps and checks does affect ALARA, given that the RCS/SI valves are in high dose areas.

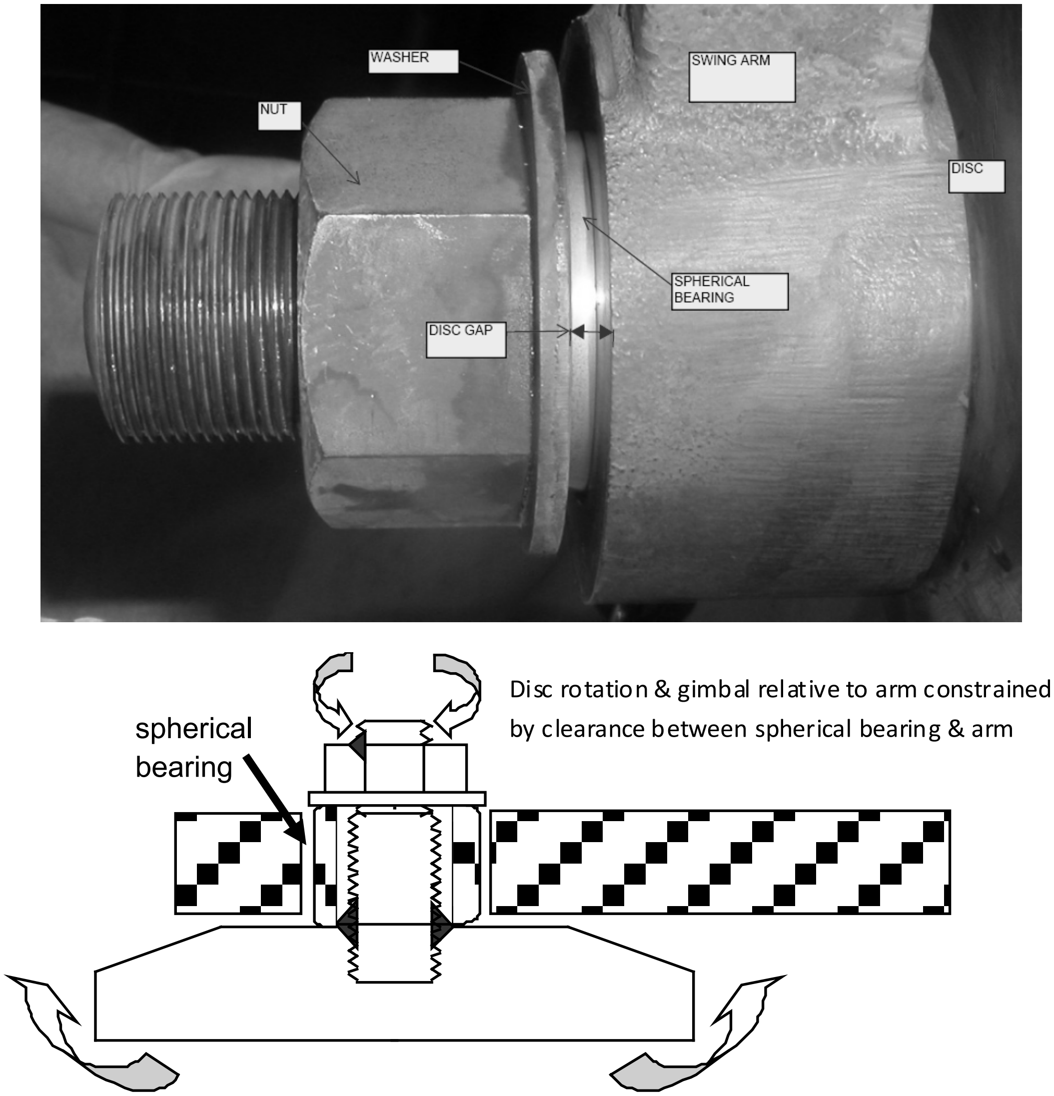

Figure 6: A reduced clearance between the disc and the hinge arm impairs the disc's ability to articulate freely to seal against the body seat.

The newly developed geometric relationships, elaborate procedures, specialized tooling, and the new vendor-developed acceptance criteria were expected to solve the problem. But the tight clearances actually may have resulted in valves becoming arthritic faster in the presence of the magnetite deposits. Despite the noteworthy efforts and expense, this population of valves continues to exhibit sporadic unreliability.

Table 2: Sampling of potential contributory factors suggested in CRDRs

Test Procedures	**Application**
Insufficient DP during IST testing	High dose area (1 or 2 man-rem; 10 days to get parts out of shop)
Manufacturing Defects	Infrequent usage (except for valves in charging system)
Spherical bearings installed upside down	Loose parts concerns
Large disc-to-stud weld	**Maintenance Induced**
Bonnet bore out of round—Grafoil seals	Uneven lifting of bonnet under line pressure—loading the hanger
Valve seat angle out of plane 5° vs. 12°	Excessive seat lapping—seat cocked sideways
Axial projection of seat	Limited interchangeability of disk assembly
Seat cocked sideways	**Vendor Guidance Induced**
Hanger arm-disc post holes bored off center	Lack of consistency on tolerance and dimensions
Hanger arm casting voids	Generalized vendor inspection guidance insufficient
	Tack weld

Technical Approach

Given the plethora of contributory factors suggested, the range of valve sizes and styles, the wide variance in internal geometry, the standby safety function of these valves, and the ongoing high O&M costs involved, the present evaluation focused on a broad strategic approach instead of a narrow, piecemeal approach of modeling individual valves. Furthermore, it was recognized that, more than just being a challenging technical problem, the ongoing operational uncertainty made this equally a production risk management and economic problem. The substantial direct and indirect costs of replacing the 204 valves en masse also underscored the need for a rigorous holistic review.

The first phase of this study consolidated the best available information and plant experience on the population that had been gleaned over the years. This effort consisted of compiling valve operating history, maintenance records, root-cause analyses, and reliability improvement initiatives, as well as a discussion with plant domain experts involved with maintaining this valve population. The next phase of the study critically reviewed previous root-cause evaluations and categorized the findings based on the supporting physical evidence and rigor of evaluation. This involved a review of selected plant Component Repair and Disposition Reports (CRDRs) and an examination of which corrective actions and programs had worked and which had not.

This study was able to compartmentalize the role of various contributory factors stemming from system, valve design, and maintenance constraints, as well as from the unintended consequences of improvement initiatives.

Solution Strategy

The above findings helped reframe the problem into three groups.

- Group A — Valve problems that were well understood and for which the underlying sources of unreliability were demonstrably eliminated based on a well-defined technical solution
- Group B — Valve problems that were well understood but could be not be eliminated and had to be managed
- Group C — Problems that are not completely understood based on available information and studies.

Recommendations, Solutions, Path Forward

To implement the above solution strategy, one must first determine whether a specific problem is well understood or not; therefore, it is essential to determine the root cause and assess the reliability of this determination. Once this is done, the solution that best fits each target group can be implemented.

- Group A — For issues that are being eliminated:
    - Stay the course while continuing to validate solutions
    - Where possible, streamline valve procedures to simplify maintenance and optimize inspection frequencies.
- Group B — For issues that cannot be eliminated, the options that should be evaluated include:
    - Where possible, streamline valve procedures to simplify maintenance and optimize inspection frequencies.
    - Selectively maintain spare sets of internals for each problem valve body (e.g., where replacement valves will be equally susceptible to system-induced unreliability).
    - Prepare design engineering packages to order replacement valves for targeted applications, judiciously selected using a probabilistic analysis.
    - Procure and maintain a supply of ready-to-install replacement “parachute” valves to prevent an extended outage at one or more units. This would include valve applications that have required repeated seat rework, or identified by in-service inspections as requiring a body replacement, or valves with long procurement lead times.
- Group C — Rigorously evaluate valves whose failure modes are not completely understood, to place them in Group A or B and to guide expensive replacement decisions.

Conclusions

While the case study presented in this paper focused entirely on a population of Borg Warner swing checks, the underlying concepts for ensuring continued future reliability with aging, obsolete equipment has broader applicability. With the vast majority of units securing operating-life extensions, it will become increasingly important to examine sustainable strategies to manage aging, obsolete equipment to ensure plant safety and economic viability. The significant financial impact of equipment replacement decisions underscores the need for a rigorous technical evaluation and proactive procurement of strategically selected “parachute” components. This will provide an approach that balances the call to maintain aging equipment using technically defensible and proven solutions against the need to replace known bad actors with improved technology without introducing any new problems.

References

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Practical Approaches to Gain Operability Margin of Safety Related Gate and Globe Valves

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Abstract

Generic Letter (GL) 96-05 required licensees to develop a program to demonstrate that safety related motor operated valves (MOVs) are capable of performing their design basis functions [3]. The Joint Owners Group (JOG) consisting of Boiling Water Reactor (BWR) and Pressurized Water Reactor (PWR) Owners Groups undertook a comprehensive testing program lasting approximately 6 years to characterize age-related degradation in safety related MOVs. To address GL 96-05, the JOG had plants perform differential pressure testing on various motor operated valve designs as part of the periodic verification program to determine any evidence of age-related degradations on safety related MOVs. At the end of the testing, the JOG produced a topical report, MPR-2524-A, documenting the results of the tests that covers the following: classification basis of industry safety related valves depending on the potential for age-related degradation, the threshold coefficient of friction of valve materials, and margin determination [4]. The JOG topical report proposed an implementation schedule of 6 year for plants to comply with the JOG program. The Nuclear Regulatory Commission (NRC) issued a Safety Evaluation that states that the topical report is an acceptable industry response to GL 96-05 for valve age-related degradation [6]. Since the issuance of the NRC safety evaluation, plants that committed to the JOG program have established programs to implement the JOG document. Among the elements of the program implementation are valve categorization, design basis calculations to confirm operability, and design changes and modifications, if required. In implementing the JOG program document, the primary goal is ensuring that the valves are operable and will perform their safety related functions. A secondary and equally important goal of plant evaluations is striving to get sufficient operability margin to reduce the periodic test frequency of the valves. Westinghouse, as a valve manufacturer and a Nuclear Steam System Supplier (NSSS), has provided support to a number of plants in their JOG implementation process. While the

majority of the work we do has been on Westinghouse designed valves, we have supported other non-Westinghouse valve evaluations. In doing so, several technical approaches have been used to gain margin for our customers ranging from purely analytical approaches to valve modifications or a mixture of the two. In this paper these approaches will be discussed. Practical, cost effective, approaches based on experience gained from plant support on gate and globe valve evaluations are presented.

Introduction

For years the valve industry was not challenged by design standards to meet performance requirements. Vendor experience with the specification and application often guided design acceptance. In the author's opinion, the Three Mile Island Unit 2 (TMI-2) accident in 1979 initiated industry-wide interest in valve operability assessment to address the operability of safety related valves in the nuclear industry after the TMI-2 accident. Following that event, the nuclear industry, with regulatory oversight, embarked on understanding what it takes to have good, reliable, valves for safety related applications. In nuclear power plants, the majority of power operated safety related valves provide either open or flow isolation functions during plant operation including postulated accident scenarios. Figures 1, 2, and 3 illustrate the three main valve groups typically used. As shown in Figure 1, gate valves use gates to affect flow isolation, the globe valves use a plug to provide flow isolation, and butterfly valves use symmetric discs to do the same. Over the years the NRC has used regulatory mechanisms to ensure that safety related valves perform their safety related functions. In Bulletin 85-03 the NRC required licensees to ensure that MOV switch settings are properly set and maintained so that valves can operate under all design basis conditions [1]. In GL 89-10 the NRC required licensees establish a program to demonstrate that motor operated valves are capable of performing their safety related functions during accident conditions. At the closure of GL 89-10, GL 96-05 was issued which required licensees to develop a program to demonstrate that safety related MOVs are not susceptible to age-related degradation and are capable of performing their design basis functions. The JOG consisting of BWR and PWR Owners Groups undertook a comprehensive testing program lasting approximately 6 years to characterize age-related degradation in safety related MOVs. To address GL 96-05, the JOG had 98 participating plants perform differential pressure testing on 176 motor operated valve designs from many vendors as part of the periodic verification program to determine if there is any evidence of age-related degradations on safety related MOVs. The focus was on the determining the thrust and torque values required by the valves and not on the actuators. The tested valves covered many suppliers and Westinghouse gate valves were one of the designs dynamically tested in the JOG program. At the end of the testing, the JOG produced a topical report, MPR-2524-A, documenting the results of the tests. Two of the principal parameters identified in the report that govern valve thrust and torque are the coefficient of friction of the sliding or rotating surfaces in the case of gate valves and butterfly valves, and area factor in the case of globe valves. In this paper, we concentrate primarily on gate and globe valves because margin determination and how margin can be recovered is most commonly affected by the JOG report. While this paper focuses on gate and globe valves, some of the issues discussed can be extended to butterfly valves.

Valve Operability

A valve is operable when the actuator thrust or torque exceeds the opening and closing thrust or torque at the design basis conditions taking into account the structural integrity of the valve and the actuator and any associated uncertainties. For gate valves, the JOG established the threshold disk-to-seat coefficients of friction (COFs) for plants to use for different material pairs and operating conditions. The JOG prescribed threshold coefficients for gate valves are significantly higher than the traditional values recommended by the valve suppliers and which were used to size the valve actuators in operating plants. The higher threshold coefficient of friction has been a source of consternation to the valve suppliers because they do not believe that their actuators were improperly sized and to the end users (i.e., the utilities) because that requires resizing the plant actuators and reconfirming whether or not the valves are still operable.

In addition to the increase in valve COF, there are other factors noted in the JOG report that affect valve operability which include uncertainties associated with both actuators and valve design covering such areas as; switch repeatability, actuator spring pack relaxation, rate of loading, etc. The increase in valve COF combined with the increase in uncertainties considered by the JOG report results in reduced margin on MOVs, which is functionally defined as:

$$Margin(\%) = \frac{Adjusted\ Actuator\ Output\ Thrust - Adjusted\ Required\ Thrust}{Adjusted\ Required\ Thrust} \times 100 \qquad (1)$$

Divide the right hand numerator term by the Adjusted Required Thrust in the denominator.

$$Margin(\%) = \left\{\left(\frac{Adjusted\ Actuator\ Output\ Thrust}{Adjusted\ Required\ Thrust}\right) - \left(\frac{Adjusted\ Required\ Thrust}{Adjusted\ Required\ Thrust}\right)\right\} \times 100 \qquad (2)$$

Equation 2 can be simplified to:

$$Margin(\%) = \left\{\left(\frac{Adjusted\ Actuator\ Output\ Thrust}{Adjusted\ Required\ Thrust}\right) - 1\right\} \times 100 \qquad (3)$$

The adjusted actuator output includes uncertainties which cover:

- Test equipment accuracy
- Torque switch repeatability
- Rate-of-loading
- Spring pack relaxation
- Stem lubrication degradation

The uncertainty inputs come from various sources. Test equipment accuracy comes from the test equipment supplier. Torque switch repeatability data comes from the actuator manufacturer (e.g., Limitorque). The rate of loading comes from the plant or another industry source based on performing multiple static and dynamic tests on the same valve to isolate the rate of loading. The spring pack relaxation comes from the actuator manufacturer. The stem lubrication degradation is based on plant experience.

Rewriting the Adjusted Required Thrust in its component parts:

$$Adjusted\ Required\ Thrust = \left((Required\ Thrust)(1 + All\ Uncertainties)\right) \qquad (4)$$

Because All Uncertainties are taken into account in the Required Thrust:

$$Adjusted\ Actuator\ Output\ Thrust = Actuator\ Output\ Thrust \qquad (5)$$

Substituting Equation 6 and 7 into Equation 5:

$$Margin(\%) = \left\{\left(\frac{Actuator\ Output\ Thrust}{(Required\ Thrust)(1 + All\ Uncertainties)}\right) - 1\right\} \times 100 \qquad (6)$$

Equation 1 and Equation 6, though written differently, are equivalent. The JOG document MPR-2524-A, recognizes that individual plants could apply the uncertainties either to the required thrust or to the actuator output or the combination of the two, as long as there is no double counting.

For a gate valve the required thrust is

$$T = VF * \Delta P * A + F_{Packing} + F_{SE} \tag{7}$$

Where:

VF = *Valve Factor*
ΔP = *Pressure Drop Across the Valve*
A = *Effective Disc Area*
$F_{Packing}$ = *Packing Force*
F_{SE} = *Stem Ejection Load (can be neglected in the opening direction for conservatism)*

The valve Factor (VF) is defined as

$$VF_{Closing} = (COF)/[\cos(T)-(COF)*\sin(T)] \tag{8}$$

$$VF_{Opening} = (COF)/[\cos(T)+(COF)*\sin(T)] \tag{9}$$

Therefore, it is clear from the JOG document that the word “Adjusted” denotes the inclusion of uncertainties such as; rate-of-loading, test equipment inaccuracy, torque switch repeatability and, spring pack relaxation to both Actuator Output Thrust and Required Thrust. In order to make the calculation clearer this paper applies all of the Uncertainties to the Required Thrust Value; this way the Actuator Output Torque is unmodified. Either approach, Equation 1 or 2 yields the same results.

Why Margin?

Margin confirms not only operability and no concern for age-related degradation but also provides a matrix for static testing of the valves in accordance with MPR-2524-A. Table 1 illustrates the risk-margin matrix showing the distribution of static test frequency based on risk margin values [4]. For example, a high risk valve with high margin can be statically tested every 6 years and one with low margin must be tested every 2 years. Similarly, a low risk valve with high margin can be tested every 10 years and one with low margin must be tested every 6 years. Table 1 shows that the higher the margin for any valve the more years the static test frequency can be extended, which translates to more savings for the plant by reducing maintenance costs and personnel dose.

Table 1: MOV Static Test Frequency Criteria

Risk Ranking[1]	PV Test Interval (years) for…		
	Low Margin (≤ 5%)	**Medium Margin (5% < 10%)**	**High Margin (≥ 10%)**
High Risk	2	4	6
Medium Risk	4	8	10
Low Risk	6	10	10

[1] – Based on Plant Risk Ranking

Margin Improvements

As shown in the above equations (Equations 1, 2, 3 and 6), margin is not only governed by the required thrust or torque but also by the uncertainties. Both margin and uncertainties are additive and therefore minimizing their respective contributions increases margin. As a valve designer, Westinghouse was faced with providing supporting evaluations to plants that have Westinghouse designed MOVs in their safety systems. Customers have made many different types of requests covering structural integrity, weak link analysis and margin improvements. Over the years of supporting plants in design basis calculations and margin assessment improvements, a number of practical options to gain margin have emerged. Table 2 summarizes practical approaches that have evolved over the years of our support including MOV evaluations. The goal of margin improvement is to make necessary analytical and design improvements to arrive at an acceptable overall margin to serve the needs of the plant. This may require hardware changes in some cases.

Table 2: Approaches to Gain Margin

Area of Improvement	How it affects margin	Basis/Justification	Expected Margin
Sliding Surface Coefficient of Friction	The COF is the main factor that affects the required thrust or torque. See equations.	Reduction of COF is permitted when there is a qualifying basis for the reduction in accordance with MPR 2524-A.	COF reduction by 20% results in a margin improvement of 10.5%.
Stem to Stem Nut Coefficient of Friction	The stem to stem nut friction affects the translation of motor torque to thrust.	The reduction can occur if the plant data support the reduction.	A reduction in stem to stem nut COF from 0.2 to 0.15 increases margin by 25%.
Actuator Rerating	Actuator capability provides the basis for margin assessment.	A number of Limitorque actuators have been rerated for higher capability by Kalsi and Westinghouse (See Note 1).	Depending on the rating program used, the gain can be up to 60%.
Degraded Voltage	Degraded voltage affects the actuator capability as the output varies proportionately to voltage squared (AC Motors).	For conservatism, some analysts assume that the valve is subject to degraded voltage. Sometimes it is not. Need to verify susceptibility to degraded voltage.	Deletion of degraded voltage improves margin by 36%.
Valve setting from torque limiting to position limiting	Valves can be set either by torque limiting or position limiting. Position seating reduces uncertainties significantly.	The vendor must have the capability to provide the position seating guidance.	Position seating margin improvement can be in the range of 20%
Use of the actual Differential Pressure	A conservative differential pressure across the valve that does not reflect the actual differential pressure reduces margin.	Performing system calculation that confirms the actual differential pressure across the valve reduces the conservatism.	Using the actual pump pressure for example; 2500 psi instead of the dead head of 2700 psi improves margin by 10%.
Spring Pack Limits	In some cases the margin or lack of it is driven by the limits of the installed spring pack.	Evaluate if the actuator can have a higher spring pack load limit.	An increase in spring pack load improves margin.

Gear ratio Change	Thrust output of the actuator is directly proportional to gear ratio. The higher the gear ratio the higher margin potential.	Provided that the reduced speed of operation is acceptable and the structural limit is acceptable.	Increased margin depends on the ratio of the gear ratios.
Temperature Effect (AC)	High temperature affects motor actuator output. See Limitorque Technical Update 93-03	Evaluate and use the actual environmental temperatures of the MOV.	The margin improvement between 104°F and 356°F can be as high as 30%.
Temperature Effect (DC)	High temperature affects motor actuator output	Evaluate and use the actual environmental temperatures of the MOV.	The margin improvement between 150°F and 340°F for 100 ft-lb at 250 volts DC is 24% using Limitorque guidelines [5].
Structural Weak Link Analysis	In some cases the structure may limit the set-up window and the overall margin.	Review conservative criteria or even change material to increase structural limit.	The amount of margin depends on the extent of improvement in material properties gained by the change.
Direction of Flow of globe valves	Typically, the maximum thrust is assumed in the calculation of globe valve thrust requirements because it is not of clear how the valves are installed (i.e., over the seat or under the seat).	If the actual flow direction is known the actual equations governing the valve operation can be modeled.	The margin improvement can be substantial.
Packing Load	Typically, the rule of thumb packing load is 1000 lbs per inch of stem is used.	Determine actual packing load from diagnostic testing and apply it.	The margin improvement in low differential pressure applications can be substantial.

Note 1: To request more information on Limitorque actuator re-rating programs please contact:

Westinghouse Electric Company; Nuclear Engineering Marketing, 1000 Westinghouse Drive, Cranberry Twp., PA 16066
or
Kalsi Engineering, Sugarland, Texas

Conclusion

This paper has discussed how MPR-2524-A defines margin and why margin is important for operability assessment and static test frequency to demonstrate operational readiness. The paper has also presented various approaches the authors have used to gain margin on MOVs. It is noteworthy to point out that, of the all the approaches presented, the use of COFs lower than the threshold values is the most challenging in that it relies completely on the availability of substantial differential pressure tests, which most suppliers do not have. To use a lower COF, a qualifying basis evaluation in accordance with MPR-2524-A is required. It is recommended that the utility MOV engineer that is considering this approach should check with their valve suppliers to determine if such data exists to support the GL 96-05 evaluations.

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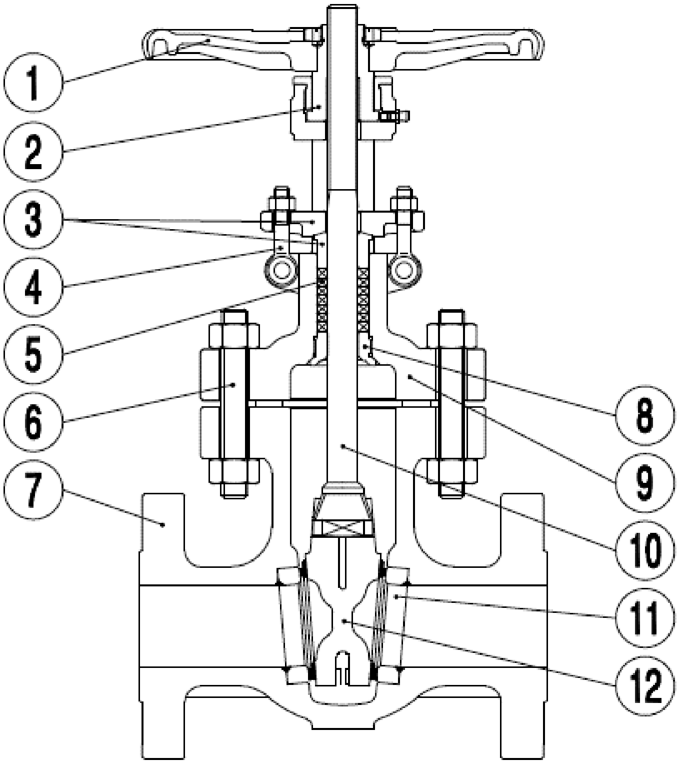
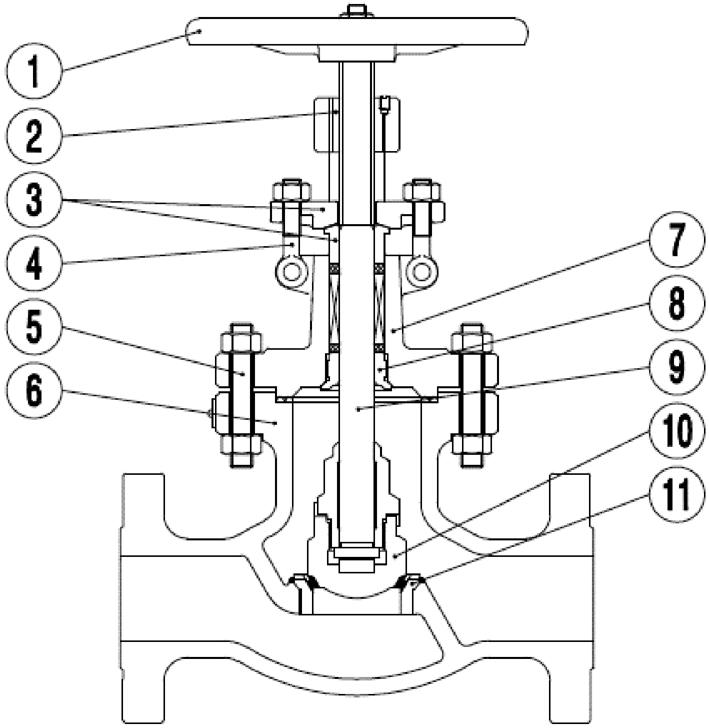


IT.	DESCRIPTION
1	HANDWHEEL
2	YOKE SLEEVE
3	GLAND FLANGE
4	GLAND EYE BOLT
5	PACKING
6	BONNET BOLT
7	BODY
8	BONNET
9	BACK SEAT
10	STEM
11	SEAT RING
12	WEDGE

Figure 1 – Typical Manual Gate Valve



IT.	DESCRIPTION
1	HANDWHEEL
2	YOKE SLEEVE
3	GLAND FLANGE
4	GLAND EYE BOLT
5	BONNET BOLT
6	BODY
7	BONNET
8	BACK SEAT
9	STEM
10	DISC
11	SEAT RING

Figure 2 – Typical Manual Globe Valve

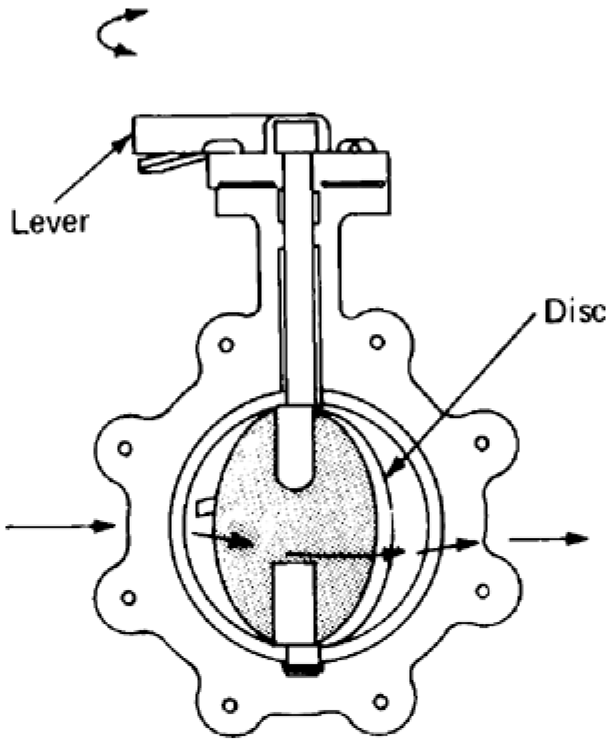


Figure 3 – Typical Manual Butterfly Valve

Online Valve Monitoring Helps Shell Achieve Goals at the Ormen Lange Gas Plant in Norway

Stan Hale
Score Atlanta, Inc.

Abstract

Located on Nyhamna Island on the west coast of Norway, the Ormen Lange Gas Plant is the source of 20% of the natural gas imported into the United Kingdom. The gas is transported via the Langeled subsea pipeline across the North Sea from Nyhamna to the Easington Gas Terminal near the mouth of the River Humber on the UK's East coast. A/S Norske Shell operates and maintains the Ormen Lange plant.

Ormen Lange is one of the world's most advanced gas processing plants but is operated by a skeleton crew. In fact, Shell's goal for the facility is to operate and maintain the plant with as few people as possible. In order to accomplish this, online condition monitoring systems are employed to monitor virtually everything that moves in the plant including pumps and compressors, control valves, certain structures, and critical shutdown isolation valves. A stated goal for the plant is that 70% of the maintenance budget and maintenance spending should be based on the results of condition monitoring. This lofty goal carries some element of risk since critical components cannot be allowed to run to failure. Any disruption in supply from Ormen Lange during the winter months causes significant perturbations in the gas markets and affects prices across Europe. Therefore, equipment condition must be accurately reflected by the monitoring systems and maintenance performed at the moment it is needed.

This paper shall discuss the condition monitoring approach for the 41 most critical shutdown isolation valves at Ormen Lange. The population of critical valves includes a mix of single and double acting pneumatic and hydraulic gate, ball, and flow control valves. These valves are instrumented with strain gages, pressure transducers, and acoustic leakage sensors. The sensor data is continually streamed to a data acquisition system that combines other important data pulled from the plant's distributed control system (DCS) such as command signals, limit switch signals, and upstream and downstream system pressures to create a complete picture of what is occurring at the valve during operation. Acceptance criteria for key parameters such as thrust or torque output at various

points in the cycle, stroke time, leakage, and other critical measures are automatically evaluated by the valve monitoring system after each cycle and icons in the system display software provide a visual indication of current valve condition.

The monitoring approach is essentially the same as having a motor-operated valve (MOV) or air operated control valve (AOV) diagnostic system continually attached to these valves at all times. In our nuclear plant world, the analysis is akin to evaluating Generic Letter (GL) 89-10 data every time a valve cycles, in effect, allowing the valve to test itself and call someone when something changes for the worse. Score Atlanta has been assisting Shell in evaluating the on-line results and performance of these critical valves for the past 3 years. The data is accessed with the right permissions from computers on the Shell network or remotely through the internet and the normal valve signature analysis process is used where needed to evaluate condition. The approach taken at Ormen Lange illustrates how industries around the globe are leveraging the lessons learned from over 25years of valve testing in the nuclear power industry by adopting systems that make valve diagnostics and condition monitoring a permanent and critical element of safe operations and effective plant maintenance.

Background

Following the introduction of the early MOV and AOV diagnostic systems in the mid-1980s, the effectiveness and benefits of valve condition monitoring and signature analysis were widely discussed in industry forums such as the American Society of Mechanical Engineers (ASME)/Nuclear Regulatory Commission (NRC) Pump and Valve Symposium, various Electric Power Research Institue Valve Symposiums, MOV and AOV Users Group meetings, and at other nuclear industry conferences. The early success of diagnostic systems for valves has also been well chronicled in numerous industry publications and a wealth of information is available on the internet for those seeking information on valve diagnostics and condition monitoring. The ASME code committees have also made adjustments to the various codes and code cases to get the most out of valve diagnostic and signature analysis techniques used as alternative methods for in-service testing of valves in nuclear power plants.

The leading valve diagnostic system and service suppliers have also marketed every process industry in every corner of the globe where improved valve performance is desirable. Because of the high cost and absence of regulatory pressure, adoption of valve diagnostics has not been as wide spread in other industries when compared to nuclear. However, that trend is changing at a fast pace. The move toward valve diagnostics and condition monitoring has moved fastest in the offshore oil & gas industry on the Norwegian side of the North Sea.

The initial adoption of valve diagnostics for the most critical valves on offshore platforms by Norwegian oil companies was not initially encouraged by the Norwegian Petroleum Directorate which is responsible for offshore regulatory compliance. However, after several years of experience with on line data acquisition and analysis, the current expectation among operators is that critical valves must be monitored at some level.

By 2003, at least a dozen Norwegian offshore platforms were monitoring critical isolation valves with on-line monitoring systems. Strain gages, hydraulic and pneumatic pressure transducers, and acoustic leakage detection sensors were producing a new level of confidence in valve performance. About this same time, engineers designing systems and components and planning maintenance and operating strategies for the Ormen Lange gas plant were searching for industry best practices related to valves.

In addition to valves, Ormen Lange has become synonymous with best practices in all areas of offshore oil and gas production. The gas field itself lies offshore and approximately 75 miles northwest of Kristiansund where the seabed is approximately 3,300 feet below the surface. There is no platform or other vessel on the surface above the wells as would normally be expected. The wells are completed subsea and the gas is piped through two 30” pipelines to the Ormen Lange plant on the remote Nyhamna Island. On the island, the gas is processed, compressed, and then piped 750 miles across the North Sea to the UK. Approximately mid way to the UK the pipeline crosses the Sleipner platform. Shell took over operation of the plant on December 1, 2007.

One over-riding strategy that helped guide the design and planning process was the need to minimize the number of people required at the plant for maintenance and testing activities. As a result, heavy use of condition monitoring systems for as many components and process systems as possible would be employed. The strategy was clear and detailed specifications were developed for the valve condition monitoring system and multiple suppliers competed in the bidding process.

The V-MAP on line valve monitoring system was one of the systems selected to meet the condition monitoring goals of the Project.

One required feature of instrumentation used in the hazardous oil and gas environment involves assurances that electrical faults or instrument failures will not create enough energy to ignite a potentially explosive atmosphere in the immediate environment. Various strategies are used around the world to protect against potential ignition but the breakthrough for condition monitoring was the development, certification, and use of intrinsically safe circuits and devices. Intrinsically safe electrical circuits require very little power to operate and are designed such that normal operation, faults, and shorts cannot release enough energy or heat to ignite an explosive atmosphere.

A critical requirement of the Ormen Lange valve monitoring system was the ability to detect through-valve leakage after the valve closes. Through-valve leakage is one of the most important test parameters for the oil and gas industry and certain valves must be tested periodically to verify they will not leak when needed in an emergency. Broadband acoustic emission sensors are employed by V-MAP to detect the high frequency noise caused by very small leaks at high pressure. The leakage noise elevates the broad band emission output of the sensor and also creates an initial peak above 100 KHz that spreads in both directions from the peak when the amplitude increases as a result of increasing leak size.

The sensors and amplifiers used in the field provide the conditioned data in a format needed for automated recording in a safe area away from the valves. Much like the portable systems routinely used for periodic MOV and AOV testing in nuclear plants, the data acquisition units (DAUs) capture multiple channels of sensor data streaming from the acoustic emission sensors, the strain gages, and pressure transducers in the field. The DAUs stream the captured data in digital format from the sensors to a server in a remote location. Data from the plant control system is linked to the field data in the server via an OPC link. The plant data includes time stamps for initiation of the valve cycle, limit switch actuations, system pressure at the valve, and differential pressure across the valve when the valve is closed.

The V-MAP application running on the server provides automated analysis of the incoming data based on user defined limits in the software. When acceptance criteria are not met, the V-MAP user is alerted at his workstation when viewing the main V-MAP dashboard. The visual icons representing each valve change from green to red or yellow based on automated analysis of the data. During the early phases of operation the alarms were allowed to trigger with every cycle such that baseline performance could be established over a range of operating conditions. After 3 years of monitoring, the acceptance criteria for force or torque, cycle time, response time, and leakage have been adjusted to reflect the baseline performance at various operating conditions and to help evaluate changes over time.

Condition Monitoring Approach

As discussed above, the critical isolation valves at Ormen Lange include a mix of single and double acting pneumatic and hydraulic gate, ball, and flow control valves similar to globe valves.

Strain gages are attached to the valves to detect changes in actuator output or loads in the valve that may affect performance. The precise location of each gage was determined by finite element analysis (FEA). The FEA identified the best location for the gage and the appropriate conversion factors for converting strain to torque or thrust.

Since the actuators are hydraulic or pneumatic, pressure transducers are installed in the supply lines between the hydraulic control solenoids and the actuator cylinder. It is important to point out that the actuators and valves used at Ormen Lange are much larger than the typical nuclear plant valve. The isolation valves at the landfall accommodate the 30” pipeline from the subsea wells. The critical shutdown valves on the export side of the plant are 42” in diameter with a maximum gas pressure at the valve of 3,600 PSI. The hydraulic actuators for these large gate valves can easily apply greater than 250,000 pounds of force to the valve at the maximum hydraulic system pressure of 4,700 PSI.

The leakage criteria for each valve vary by valve and application but the typical acceptance criterion is .02 kilograms per second (Kg/sec) and .05 Kg/sec. The leakage criteria seem tight, but when converted to flow it would be over 100 liters per minute depending on the gas density. The acoustic sensors and signal processing used will detect a leak as low as .1 liters per minute.

The Ormen Lange plant was designed and built to the highest safety standards consistent with International Electrotechnical Commission (IEC) 61508 and 61511. IEC 61508 is applied during the design of safety critical systems to ensure that electrical, electronic, and programmable equipment are analyzed such that the risks caused by failure of systems or components to perform intended safety functions are minimized. IEC 61511 establishes requirements for the specification, design, installation, operation, and maintenance of a safety instrumented system, so that it can be confidently entrusted to place and/or maintain the process in a safe state.

To reach the desired level of safety at Ormen Lange, features such as partial stroke controllers for valves were installed in addition to the condition monitoring system. Partial stroke systems facilitate periodic exercising of valves that cannot be closed during operations. As a result, valves that must remain open for extended periods of time, such as those at Ormen Lange, can be partially cycled and monitored at some frequency. Both valve and actuator condition are monitored and evaluated after every full cycle and valves that remain open for production reasons can be partially closed in order to evaluate potential changes in performance. Since these valves may be cycled at any moment and multiple valves close at the same instant during shutdowns, it is not practical to capture the periodic test data with portable systems. Automated on-line data acquisition takes the human element completely out of the testing process and cycles/test opportunities cannot escape the continuous monitoring process. Even after the valve reaches the closed position, the acoustic sensors continue to stream data to the server where it is combined with system pressure information to assess the potential of a developing leak.

Strain gage devices and hydraulic transducers wait for the next cycle and the command signals from the control room trigger the software to look for activity at the valve. The automated analysis system looks at each parameter and decides when to alert the user.

Data Analysis and Results

The typical valve actuator at Ormen Lange is spring to close single acting hydraulic. However, there are also several double acting hydraulic and some pneumatic actuators. The hydraulic system operates at 4,700 PSI and solenoid valves route hydraulic pressure to the actuator to open the valve and they also release the pressure to allow spring closure.

The gate valves and actuators are both reverse acting, which means the valve stem is pulled upward or out to close the valve. When the stem is pulled upward or out of the valve, it lifts the gate (obtuator) to cover the orifice and shut off flow.

The gate is pushed down by the actuator to open. This creates a temporary orientation issue for an analyst familiar with the operation and signature characteristics of a typical gate valve used in a nuclear plant environment.

The backward looking signatures are easier to keep straight for a single acting spring close actuator because hydraulic pressure opens the valve and the release of hydraulic pressure allows it to close as the spring extends. One of the early analysis issues uncovered by the monitoring and signature analysis process was related to how fast a valve can close as it exhausts hydraulic pressure. The signature data revealed that for the typical actuator the hydraulic pressure required to start spring compression, which also starts moving the valve in the open direction, is 1,200 PSI. The springs reach full compression, which puts the valve in the full open position at approximately 1,750 PSI. However the hydraulic system pressure continues to increase to 4,700 PSI after the valve reaches the full open position. In order for the valve to close, the hydraulic cylinder must release sufficient volume to reduce the pressure from 4,700 PSI to 1,750 PSI before the spring can overcome the pressure force and start to extend which closes the valve. Flow restrictions were found which delayed the start of the closure process and extended the closure time for valves required to stroke within certain limits required by the safety analysis.

There were several different issues that caused the response time problem. In some valves, the size of the exhaust side tubing was increased so the volume could escape the actuator cylinder faster. In other cases, the hydraulic control blocks that contain the solenoid valves were replaced.

The strain sensor data is used to evaluate changes in running force on gate valves or torque on quarter-turn valves that would affect the available margin to operate the valve. Some minor changes in torque have been observed over the first 3 years but not to a level that would challenge the ability of these robust actuators. By evaluating the relationship between hydraulic pressure and force/torque from the strain gage, the analyst can assess changes in the valve and actuator and determine the location of the observed degradation.

The acoustic emission sensors used to monitor the valve for leakage after it closes are sensitive to very low level leakage down to .1 liter per minute. Because of the designs used, it is very rare that one of these valves will develop a significant leak and to date there have not been leaks that would challenge the acceptance limits discussed above. However, it is clear that some of these valves do develop very low level leaks from time-to-time that are self correcting.

These leaks which are detected by the system are typically a few liters per minute and can be corrected by simply cycling the valve. Debris might normally be expected but the gas is very clean by the time it reaches these particular valves. At this point they are simply monitored because when the valves close the plant or system will typically be headed toward shutdown and lower differential pressure across the valve. The cause of these low level intermittent leaks is not known but suspected to be related to how well the seats mate during closure under different operating conditions.

The valves with partial stroke control systems are exercised regularly and the data is automatically captured and evaluated by the system. Since the valves do not fully close, there is little diagnostic information about the condition of the valve gained from a partial stroke test. However, the partial stroke limit switches play an important role relative to stroke time. The amount of time required between the close command, the release of the solenoid, the valve starting to move, and then reaching the partial close limit is recorded and trended. Changes in these times could be indicative of changes in the hydraulic system, changes within the actuator or changes within the valve. The simultaneous recording of the strain and hydraulic pressure sensor data helps to isolate whether the change was due to changes within the valve or actuator.

All of the data is captured automatically without user intervention. The data is processed and analyzed and the results made available through the site network, the wider Shell network, and outside of the Shell network through the internet. The end result is continuous real time confidence in the condition of critical valves versus the unknown and often changing condition not detectable by periodic testing programs.

Growing Adoption in Oil & Gas

The growing adoption of on-line valve condition monitoring in oil and gas closely mirrors what occurred in the nuclear power industry when portable valve diagnostic systems were first introduced. In the early days of adoption by nuclear plants, the targets were problem valves known to directly affect safety or plant operations. In the Ormen Lange case, it is about getting the most out of the plant at the highest level of safety. This strategy has spread throughout the Norwegian oil and gas community and into other parts of the world as well.

V-MAP valve monitoring systems have been installed on offshore platforms in the North Sea and in the US Gulf of Mexico to monitor critical valves and known problem valves. Similar systems have also been installed on offshore platforms in the Malaysian waters of the South China Sea and most recently in the Tar Sands of Northern Alberta.

In the Tar Sands case, the initial targets are the 3 position coke shuttle valves operated by Rotork motor operators. These large ball valves create multiple flow paths which allow bitumen to flow into the coking tower from one pipe and out of the coking tower through another pipe. These valves are notorious problems that eventually lead to extended maintenance outages when they seize due to excessive build up of hydrocarbon products within the valve. The monitoring approach is to trend increases in the torque required to operate the valve over time and schedule maintenance before the actuator can no longer change the position of the valve. If the valve seizes with the tower full of bitumen it will harden and require extensive manual effort to remove so payback is achieved by avoiding the high cost of losing a coking tower in this fashion.

Considerations for Nuclear Plant Valve Testing

On line valve monitoring is not completely foreign to nuclear power plants in the United States. On line data acquisition was implemented for a small population of MOVs at the Pilgrim Nuclear Plant in the mid-90s as part of the GL 96-05 program. The data acquisition units are not linked to the outside world through the plant IT network as in the Ormen Lange example, but they contain sufficient memory to record the required data which is accessed locally by plant personnel. The data acquisition units are connected to strain sensors on the valve stem and current probes necessary to detect switch actuations are installed in the actuator switch compartment.

Unfortunately, on line valve condition monitoring did not gain traction as nuclear plants developed and implemented GL 89-10 or 96-05 MOV programs or the AOV programs that followed. As a consequence, plants have revisited valves at regular intervals to perform the periodic testing required by the MOV and AOV programs. The continual at-the-valve testing requires consideration in the outage planning process and additional testing resources are often required to install equipment and sensors on the valve in order to obtain the required data during the outage.

The many simultaneous outages across the nuclear industry during spring and fall refueling seasons continues to tax the various suppliers and demand for qualified testing resources often exceeds supply. Valves fail the test acceptance criteria from time-to-time and an unplanned corrective action is added to the outage workload which may also demand additional resources. The process of finding the appropriate qualified resources to perform the testing, performing the tests during the outage, adjusting the outage workload to accommodate emerging corrective actions, and risking extending the outage schedule due to availability of parts may not always represent the most efficient approach. These are the very issues that Shell wanted to avoid at Ormen Lange.

In the Ormen Lange case, the valves test themselves during each operation and the Shell engineer responsible for valve condition monitoring is not even located at the site. Valve testing is not a part of the outage and personnel qualified to perform valve testing are not required. Maintenance is instead a precise orchestra based on the data observed during operation.

Because of GL 89-10 and GL 96-05, strain gage sensors of some type are already installed on many nuclear plant MOVs and some AOVs. The addition of data acquisition devices that can connect field sensors to the plant network and to the outside world can be easily adopted at a lower cost than once expected. At-the-valve data acquisition units can communicate data using a dedicated valve condition monitoring network or the existing plant network directly to the valve program engineer's desk near real time. As a consequence, valves test themselves and all program testing requirements are completed as the valves cycle during normal operation or during the shutdown process. Like Ormen Lange, this online approach makes outages without at-the-valve MOV or AOV testing a reality.

One hurdle to nuclear plant adoption may be how to overcome the real-time stream of accurate information on valve condition while the plant is operating. In keeping with the highest standards of safety this is desirable. However, it can also give operators too much information and lead to unnecessary actions. This issue is also a concern in the oil and gas facilities where on line systems are currently used. Operations and maintenance personnel must be conscious of not blurring the line between the systems required to operate the plant and the condition monitoring systems required to maintain components such as valves. It must remain clear that an alarm in the condition monitoring system does not necessarily mean the component is not operable and this type of alarm should remain invisible to operators. However, an alarm in the condition monitoring system does alert maintenance and engineering that something is changing and it should be evaluated. Occasionally, there may be alarms in the system that after complete evaluation require immediate action.

Use of on line approaches with ASME Appendix 3 (OMN-1)

The ASME working group responsible for the OM codes related to the operation and maintenance of nuclear power plants and specifically the MOV working group continue to process inquiries related to implementation of Mandatory Appendix III of ASME OM-2009 (also known as OMN-1). Several formal and informal inquiries related to Appendix III relate to test frequency and grace for missed periodic tests.

Appendix III represents a change from the prescribed test intervals of GL 89-10 toward empirically derived frequencies based on test data from each valve or from groups of similar valves. The “every 2 years” of GL 89-10 and the variable intervals of GL 96-05 and the Joint Owners Group Program are relics of the past under Appendix III rules. The new approach of Appendix III requires nuclear plant licensees to consider margin, risk significance, performance trends, preventative maintenance schedules, and other factors that could affect performance when setting test frequencies for program valves. It is a highly data dependent and analytical process not too dissimilar from the IEC EN 61508 processes used to establish failure rates and diagnostic coverage of components that effect safety in oil and gas installations.

As plants adopt Appendix III, they will analyze existing data and set test frequencies based on the above discussion and factor those tests into future outage schedules. Since the average number of MOVs affected by Appendix III and GL 89-10 is approximately 100 per nuclear reactor and each MOV on potentially different schedules for testing or other program activities, the chances that one or more may be overlooked or a scheduled test requirement missed is a real concern which has already occurred for at least one plant.

Both of these issues and others are resolved by continuous monitoring of program valves and automated data analysis. However, since the software driven analysis can only be used to assess certain hard coded criteria such as running loads, available thrust or torque, total thrust or torque, and other key events, manual analysis by a skilled person or program engineer is still required at some frequency. As suggested by the overriding theme of Appendix III the manual, visual review of data would be based on the abundance of data generated by each operation over the life of the valve.

Disclaimer

The views discussed in this paper are those of the author and do not necessarily reflect those of any of the organizations discussed herein. The conclusions, interpretations, recommendations, or any opinion expressed above may or may not be completely the same as those of Score Group, Shell, the ASME MOV working group, or any other organization referenced in this paper but are based solely on the experience of the author relative to valve condition monitoring over the past 25 years in a range of industries.

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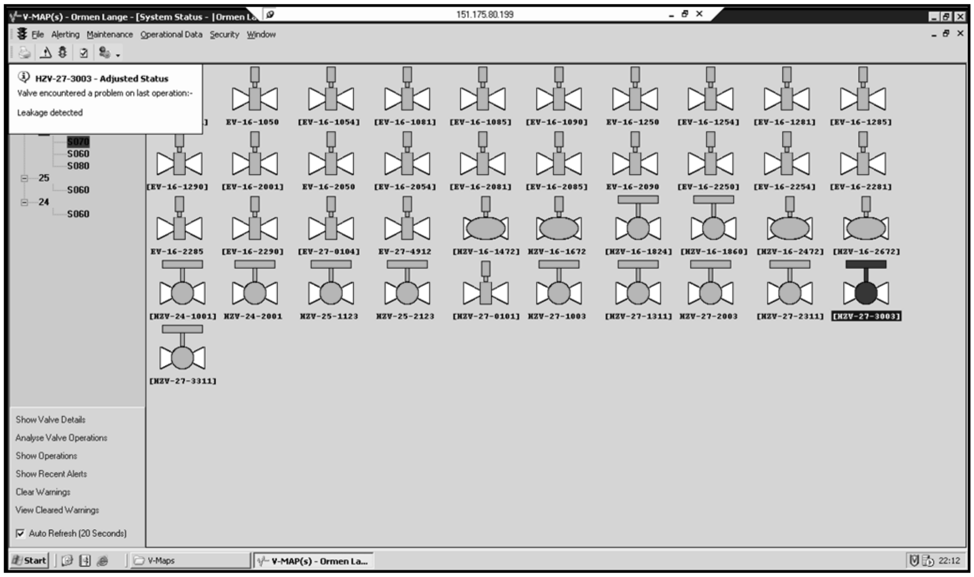
FIGURE 1
Ormen Lange Location

FIGURE 2
The Ormen Lange Plant on Nyhamna Island, Norway



HZV-27-3003 - Adjusted Status

Valve encountered a problem on last operation:-

Leakage detected

FIGURE 3
V-MAP Dashboard

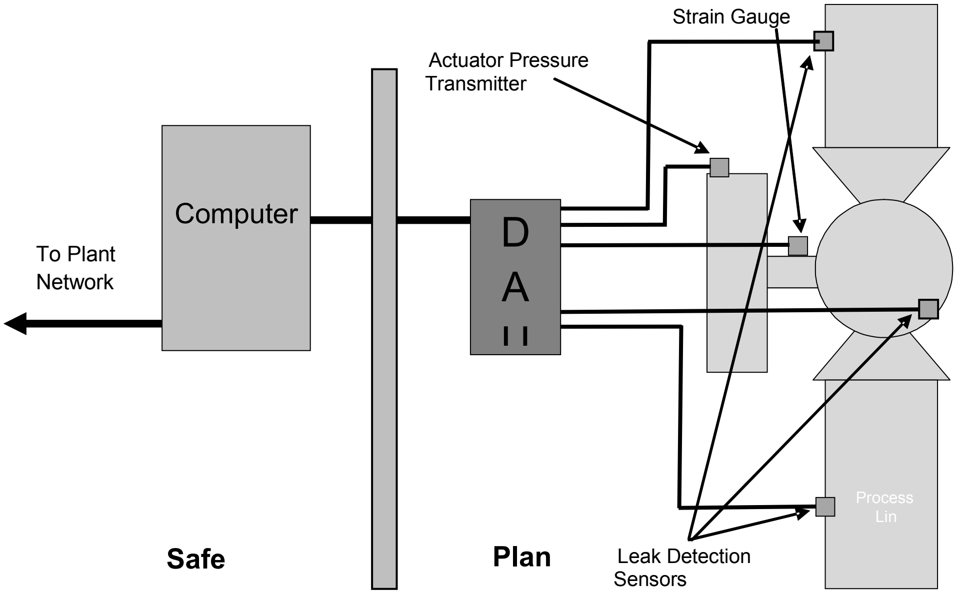


FIGURE 4
V-MAP Functional Diagram

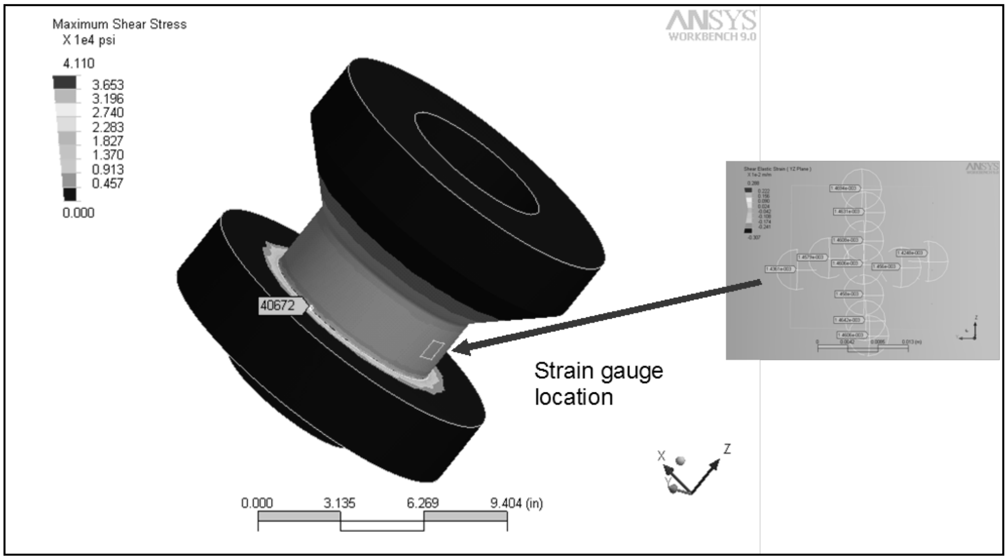


FIGURE 5
FEA of Ball Valve Mounting Stool

FIGURE 6
Installed Strain Gages

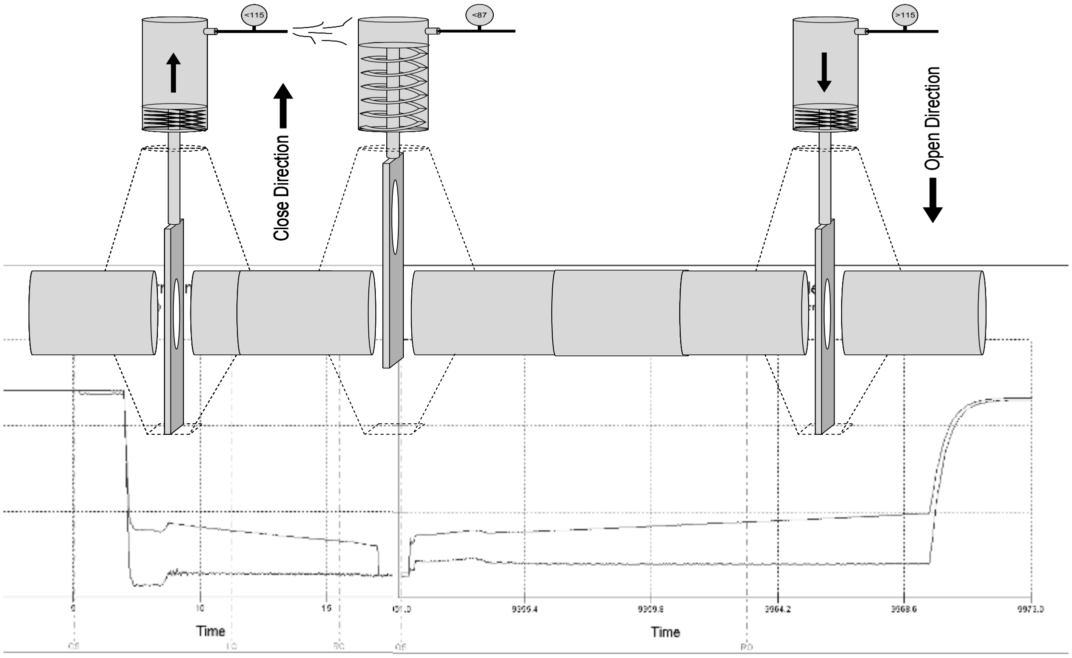


FIGURE 7
Single Acting Gate Valve Model and Example Signatures

Session 2(b): Valves II

Session Chair: Dr. Claude L. Thibault, Consultant Wyle Laboratories

OM Code Requirements for MOVs – OMN-1 and Appendix III

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* This paper was prepared by the staff of the Department of Energy Idaho National Laboratory. It may present information that does not currently represent an agreed upon Department of Energy or U.S. Nuclear Regulatory Commission staff position. The Department of Energy or U.S Nuclear Regulatory Commission has neither approved nor disapproved the technical content.

Abstract

The purpose or scope of the American Society of Mechanical Engineers (ASME) Code for Operations and Maintenance of Nuclear Power Plants (OM Code) is to establish the requirements for pre-service and in-service testing of nuclear power plant components to assess their operational readiness. For Motor-operated valves (MOVs) this includes those that perform a specific function in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, and mitigating the consequences of an accident. This paper will present a brief history of industry and regulatory activities related to MOVs and the development of Code requirements to address weaknesses in earlier versions of the OM Code. The paper will discuss the MOV requirements contained in the 2009 version of ASME OM Code, specifically Mandatory Appendix III and OMN-1, Revision 1.

Introduction

The requirements for pre-service and in-service testing of nuclear power plant components to assess their operational readiness, are found in the ASME OM Code. It identifies the components that are subject to test and Owner's responsibilities under the OM Code. The OM Code addresses test methods and intervals, defines the parameters to be measured, and provides criteria for evaluating the results. It also provides requirements for corrective actions. Its jurisdiction covers components that have met the requirements of the construction codes and commences as soon as those requirements have been met. The MOVs covered include those required to perform a specific function in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, and mitigating the consequences of an accident.

There are several approaches that can be used for component operation, testing, and maintenance. One is to simply operate the component until its performance degrades to unacceptable levels or it fails and then fix or repair the component. This run-to-failure approach has never been acceptable for safety-related components. Another method is to take a deterministic approach where components are placed in categories based upon design and function. Specific test requirements are defined for each category. Newer operations and maintenance strategies include risk-informed and performance-based testing, where tests and intervals are based on the impact to plant safety and the performance characteristics of the component.

The ASME OM Code was developed in the 1970's and early 1980's, and prior to the development of diagnostic testing. At that time, deterministic based testing and maintenance was considered to be the best available approach. This deterministic approach was implemented in the ASME OM Code, Subsection ISTC, "Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants." Stroke-time testing was the best the industry had at the time and was considered adequate for assessing MOV operational readiness. ISTC included requirements for position verification, quarterly exercising, stroke-time criteria for the quarterly testing, and leak rate testing (if required).

Industry Experience and Regulatory Actions

In the early 1980's, the nuclear industry began to develop an awareness of problems with MOVs. The United States Nuclear Regulatory Commission (NRC) issued numerous concerns and cautions, and issued a series of documents that resulted in utilities developing MOV programs.

Inspection & Enforcement Bulletin 85-03, Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings. In response to MOV events the US nuclear utilities were directed to reevaluate the control switch setting on selected safety-related MOVs. The torque switch settings were to be high enough to ensure valve operation at design-basis differential pressure conditions. This introduced the use of MOV diagnostic testing.

Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance. This Generic Letter (GL) expanded the scope of Bulletin 85-03 to all safety-related MOVs and led to utility MOV program development. These programs included:

- Review of design-basis conditions
- Development of switch setting calculations
- Use of static testing to set torque switches
- Performance of dynamic testing to demonstrate MOV operability
- Establishment of methods to maintain proper settings for the life of the plant
- Proper post-maintenance activities

Generic Letter 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves. Recommendation "d" of GL 89-10 requested that licensees prepare procedures to ensure that correct MOV switch settings are maintained throughout the life of the plant. GL 96-05 provided more complete guidance regarding periodic verification of safety-related MOVs and superseded GL 89-10 and its supplements with regard to MOV periodic verification.

A significant concern to the ASME OM committee was the fact that MOVs successfully passed the OM Code requirements, yet required additional testing, analysis, and upgrades to function at design basis. The ASME OM Code requirements for MOVs were inadequate and lagged well behind industry and regulatory activities. NRC expressed their concerns in the September 1999 Federal Register, 10CFR50, Section 2.3.2.5

> *"…since 1989, it has been recognized that the quarterly stroke-time testing requirements for MOVs in the Code are not sufficient to provide assurance of MOV operability under design-basis conditions."*

Development of OMN-1

The ASME OM Subgroup on MOVs (formerly the OM-8 Working Group on MOVs) effort to update the Code requirements for MOV testing began in 1989. The goal was to create consensus-based in-service test requirements that would assess operational readiness and eliminate the need for regulatory-based MOV programs. The new requirements would eventually replace the MOV related requirements in ISTC. The ISTC leakage rate testing would not be affected. In the early 1990's, the Subgroup on MOVs developed new test requirements and selected the ASME Code Case format for initial use. The Code Case format provided the quickest path for producing a consensus document. Code Cases are voluntary alternatives to Code requirements but they allow requirements to use and feedback obtained prior to becoming mandatory Code requirements. Code Case OMN-1, Alternative Rules for Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants, was published with the 1999 Addenda to the OM Code.

OMN-1 is performance based, where testing requirements and frequencies are determined using MOV classification (similar to ISTC), design and capabilities, operational use and environment, and maintenance programs. It provides test requirements for the design basis verification test, preservice test, inservice test, and post-maintenance test. OMN-1 encourages the use of engineering evaluations when determining the testing strategy and frequency for each MOV or for groupings of MOVs. Testing frequency is based on MOV design, capability margin, and what the Owner knows about MOV degradation rates (history). OMN-1 replaces the ISTC requirements for quarterly stroke-time testing, position verification, and provides exercising requirements in lieu of the ISTC requirements. It is also the first ASME Code document to allow risk-informed techniques.

Prior to the approval of OMN-1, utilities had to maintain dual test programs, one to meet the requirements of the ASME Code and one to meet NRC concerns (GL 89-10, GL 96-05). OMN-1 programs satisfy the concerns and requirements in both. GL 96-05 identified the OMN-1 Code Case as one approach for meeting the requirement of that

GL. Based on the 2000 modification to 10 CFR 50.55a and later in Regulatory Guide 1.192, OMN-1 was approved for use.

Code Case OMN-11 – Risk Informed Testing

As the ASME risk informed initiatives progressed in the 1990's, the Subgroup on MOVs submitted another Code Case to expand the existing risk initiative section of OMN-1. This became known as Code Case OMN-11, Risk-Informed Testing for Motor-Operated Valves. In order to apply OMN-11 the Owner must first be using OMN-1. OMN-11 allows the Owner to relax the grouping criteria found in OMN-1, Section 3.5 for Low Safety Significant Component (LSSC) MOVs. Existing groups of MOVs can have LSSC MOVs associated with them for the purpose of reducing the overall test burden.

ASME OM-2009 and OMN-1, Revision 1

While the development of Code Case OMN-1 was a significant accomplishment, it was only the first step toward updating the OM Code. The Subgroup on MOVs has continued to address industry feedback to improve OMN-1 and develop a change to the mandatory requirements in the OM Code. The goal has recently been completed in the latest edition of the OM Code. The 2009 OM Code no longer includes the stroke time and exercising requirements for MOVs in Subsection ISTC. Instead, ISTC refers MOVs to Mandatory Appendix III, Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants. The 2009 OM Code also includes Code Case OMN-1, Revision 1, Alternative Rules For Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants.

The text of Appendix III and OMN-1, Revision 1, is identical. Appendix III becomes the required IST for MOVs for users under the jurisdiction of the 2009 OM Code. OMN-1, Revision 1, allows voluntary use of Appendix III requirements for users under the jurisdiction of earlier versions of the OM Code. The scope of Appendix III/OMN-1, Revision 1, is an IST scope which differs from the scope of MOVs mandated by the NRC in GL 89-10 and GL 96-05. The scope impact has been minimized by being applicable to Active MOVs required for safe shutdown of the plant. The revision continues to stress the importance of engineering evaluations and justifications in the determination of testing methods and frequencies. Some prescriptive elements found in the earlier OMN-1, including confusing diagrams, have been removed. The use of torque versus thrust for determining margin has been clarified and Code Case OMN-11 addressing risk-based initiatives has been fully incorporated. Considerations for new testing strategies, such as Motor Control Center (MCC) diagnostic testing, have been added. Finally, quarter-turn plug and ball valves have been specifically addressed.

The 2009 OM Code was published in March 2010 and is now being reviewed by NRC for endorsement. The endorsement process is expected to take approximately 2 years.

Ongoing Efforts

Code Case OMN-1 is being implemented at numerous sites across the US. Other sites have stated a desire to implement Appendix III when it is endorsed by NRC. Table 1 provides a list of these sites and is based on our best feedback to date. The OM Subgroup on MOVs continues to address questions presented by industry and regulators. Feedback from users is appreciated and used in the effort to continuously improve Codes and Standards. Recent questions received by the Subgroup and status of these efforts include the following:

Implementation Guide. The Subgroup on MOVs has considered the need for an Implementation Guide for Appendix III and Code Case OMN-1. The Subgroup is not currently working on this guide since other industry groups are actively working to provide this. The IST Owners Group has a draft implementation guide which the Subgroup on MOVs will review and provide comments.

Scheduling Allowance (Grace Period). The ASME OM Code establishes the IST frequency for all components within the scope of the Code. The frequencies (e.g., quarterly) have always been interpreted as “nominal” frequencies and Owners have routinely applied the surveillance extension time period (grace period) contained in the plant Technical Specifications. However, instances have occurred where regulatory issues have been raised as to the applicability of the Technical Specification “Grace Period” to OM Code required IST frequencies. A Code Case and Code revision is being developed to address scheduling allowance. Current thoughts include a ≤ 25% extension for test frequencies of ≤ 2 years, with a maximum 6 month extension for test frequencies > 2 years. The allowance cannot be cumulative.

Missed Inservice Test. The ASME OM Code provides corrective actions for IST where the acceptance criteria are not satisfied. However, the Code does not consider the scenario where an Owner fails to perform an IST. The plant Technical Specifications typically contain required actions for a missed surveillance; however, instances have occurred where regulatory issues have been raised as to the applicability of the Technical Specification for a Code required IST that is not performed. A Code Case was suggested to resolve these issues and incorporate requirements when an Owner identified that a Code required IST has not been performed. The OM Committee is not pursuing this Code Case. The general opinion is that the Code provides requirements and should not provide an “out” for those who break the requirements.

Technical Inquiries. The ASME OM Committees meet regularly to conduct standards development business. This includes consideration of written requests for interpretations, Code Cases, and revisions to the code. ASME OM meetings are open to the public and we encourage feedback, questions, and suggestions for improvements to the Code. Instructions for the preparation of technical inquiries are contained in the front pages of the OM Code.

Conclusion

The ASME OM Code, Mandatory Appendix III and Code Case OMN-1, Revision 1 provide the requirements for design-basis verification, pre-service, and in-service testing of MOVs to assess their operational readiness, These requirements have evolved from industry experience and regulatory actions that have produced significant improvement in the state of the art in MOV technology and diagnostic testing. Implementation of the OM Code and Code Cases should improve the reliability of MOVs, assure their performance at design basis, and eliminate the need to regulatory-based MOV programs.

Table 1. Implementation of OMN-1 and Appendix III

Sites using or implementing OMN-1	**Sites planning to implement Appendix III**
Beaver Valley	Exelon (9 sites)
Calvert Cliffs	Southern Nuclear (6 units)
Clinton	Duke Power (3 sites, 7 units)
Comanche Peak	TVA (3 sites, 7 units)
DC Cook	
Diablo Canyon	
Ginna	
LaSalle	
Nine Mile	
Palo Verde	
Peach Bottom	
Perry	
Salem	
San Onofre	
South Texas	
Wolf Creek	

Palo Verde Implementation of ASME OM Mandatory Appendix III

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Abstract

This is paper is a complement to the overview presentation on American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code) Mandatory Appendix III, Alternative Rules for Preservice and Inservice Testing of Certain Motor-Operated Valve Assemblies in Light Water Reactor Power Plants. The paper will discuss how Palo Verde Nuclear Generation Station (Palo Verde) is implementing Mandatory Appendix III to determine the operational readiness of motor-operated valves (MOVs) and the inservice testing (IST) requirements for quarterly-stroke-time and position verification for certain MOVs.

Introduction

Arizona Public Service (APS) - Palo Verde elected to adopt the ASME OM Code Mandatory Appendix III as part of its IST Program. This election was submitted to the Nuclear Regulatory Commission (NRC) as part of the periodic 10-year IST update required by Title 10 of the Code of Federal Regulations (10 CFR) part 50.55a. Included with the IST submittal was a valve relief request which specifically adopted ASME OM Code Mandatory Appendix III. Mandatory Appendix III allows the IST program to remove stroke time testing and valve position verification for MOVs. It has been long recognized in the nuclear industry that stroke time testing does not provide assurance of valve / actuator capability. The stroke time testing essentially served to exercise the valve.

ASME Mandatory Appendix III allows the reduction in IST testing based on implementation of a more rigorous MOV diagnostic testing program. The primary concept imbedded in the Mandatory Appendix III was that credit would be taken for the MOV program developed under NRC Generic Letters (GL) 89-10 and 96-05. Although there are a number of technical requirement differences between the testing program development pursuant to NRC Generic Letters and Mandatory Appendix III, the basic concept is still valid.

Historically, IST testing has been performed under the auspices of surveillance testing in accordance with Plant Technical Specifications. IST test conducted was originally required by Technical Specifications (TS) Section 3.0. Testing is now required per TS 5.5.8 and Technical Requirements Manual (TRM) 5.0.500.8.

Based on the election of ASME OM Code Mandatory Appendix III, it is not clear if MOV diagnostic tests need to be performed as a surveillance test or simply the implementation of a required test program.

This paper presents the results of research into the requirements associated with MOV testing. The regulatory and administrative aspects of the requirements were researched.

Regulatory Requirements

The basis for regulatory requirements originated in 10 CFR 50.36 as implemented via TS.

- Review of 10 CFR 50.36:

  10 CFR 50.36 defines the requirements for Surveillance Testing and Administrative Controls. It is clear that if the NRC intended the IST program (and via Mandatory Appendix III) to be included in the surveillance test program that it would have included these test programs specifically in Section 3.0 of Improved Technical Specifications (ITS) or would have invoked surveillance requirements in Section ITS 5.5.8 and TRM 5.0.500.8. However, the NRC elected to include IST under Administrative Controls Section (5.0) of ITS.

  It should be noted that there are surveillance testing requirements contained in selected sections of ITS 5.0.

- Review of Palo Verde Technical Specifications:

  The requirements for surveillance testing originated in the plant’s TS. For the most part, surveillance requirements (SR) are contained in Sections 3.0, 3.1, 3.2, et. al of TS. The SR’s are specifically tied to the accompanying Limited Conditions of Operations (LCO’s). The definition of SR’s is not contained in TS Section 1.0, but the meaning and requirement of SR’s are clear from the context in Sections 1.0, 3.0, and 5.0 of the TS.

  Most surveillance requirements are contained in TS Section 3. However, during the transition from 1980 and 1990 vintage TS to standardize ITS, many programmatic and SR were removed from Section 3.0 of TS and moved either to Section 5.0 of TS or to TRM, e.g., radioactive effluent monitoring program, tendoning testing, etc. The surveillance requirements called out in the TS Section 5.0 and TRM need to be performed under the auspices of TS and the site surveillance test program.

The basic requirements associated with Inservice Inspections (ISI) and IST are contained in TS 5.5.8 and TRM 5.0.500.8. It should be specifically noted that no surveillance test verbiage is contained in these specific sections of TS or TRM.

Administrative Requirements

Palo Verde procedures PD-0AP01, Charter 6.0, 73DP-9ZZ14 and INPO Guideline 83-031, Rev 2 were reviewed.

- PD-0AP01
    - Charter 6.0 of PD0AP01 provides overall administrative requirements associated with testing and inspections performed at Palo Verde. It should be noted that while PD-0AP01 includes the IST program under the surveillance program, this is not a requirement of either TS or the TRM. It appears that either this was a specific election of APS/Palo Verde or it is based on historical methodology for implementing the IST program.
- 73DP-9ZZ14
    - 73DP-9ZZ14 specifically is scoped to include only surveillance testing requirements. Implementation of engineering or other test program is not included in 73DP-9ZZ14.
- INPO 86-031, Rev 2
    - INPO Guideline 85-031 specifically includes IST programs under the auspices of surveillance testing. However, 85-031 was last revised in March 1992. During that time frame, IST was included as a surveillance test per TS 3.0. This is no longer the case under ITS.

Evaluation of Requirements

It is clear that IST testing was previously required to be performed as a surveillance test. IST testing does not need to be performed as a surveillance test based solely on the verbiage contained in ITS. However, Palo Verde as elected to include the IST program as part of its surveillance test program per PD-0AP01.

There are no bases in Mandatory Appendix III, GL 96-05, ITS, TRM, INPO Guideline 85-031, PD-0AP01 or 73DP-9ZZ14 which specifically requires that the MOV program be performed as a surveillance requirement. This review includes technical, regulatory or administrative perspectives.

The only logic which lends itself to pre-suppose that the MOV program needs to be included in the surveillance program is if it is constructed to be a direct part of the IST program. This latter logic is not deemed viable since the original concept was for IST to take credit for the MOV program as opposed to incorporating the MOV program into the IST program.

Supplementary Information

The existing MOV diagnostic testing program is well established and has been functioning adequately since issuance of GL 89-10. The imposition of additional administrative requirements does not enhance the MOV program nor does it enhance nuclear safety. The only portion of the MOV program which interfaces with the IST program is the performance of periodic verification testing (PVT), i.e. inservice testing per Mandatory Appendix III. There are many MOV tests performed which are not performed as a PVT, e.g. CMWO retests. The basic requirements associated with ISI and IST are contained in TS 5.5.8 and TRM 5.0.500.8. The ISI program is currently conducted without surveillance tests even though the requirements originate from the same sections of the ITS and TRM.

Conclusion

It is clear that the method of implementing Mandatory Appendix III requirements is to utilize a surveillance test package as an administrative device to take credit for MOV diagnostic testing. It is also clear that it is not required to be performed as a surveillance test. The current program is functioning adequately.

Based on information noted above, APS/Palo Verde decided not to utilize surveillance test packages for MOV diagnostic testing. Implementation of Mandatory Appendix III can be performed without using surveillance tests. The MOV program will continue to be implemented in conformance with GL 89-10, GL 96-05 and Mandatory Appendix III while the IST program will continue to take credit for the testing performed under the existing MOV test program as implemented by site’s Routine Task program.

Code Case OMN-1: An Individual's Perspective

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Abstract

American Society of Mechanical Engineers (ASME) Code Case OMN-1 has been around for a number of years. Several nuclear power plant sites have implemented the original revision version of this Code Case, and at least one having received approval to implement the 2006 version. The requirements of Code Case OMN-1 have recently been incorporated into the 2009 Edition of the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) as Mandatory Appendix III, which means that once this edition of the OM Code has been approved by reference in the Code of Federal Regulations, all sites will be required to adopt these testing requirement/methods upon their next inservice testing (IST) interval update.

I was first introduced to OMN-1 at Wolf Creek in 2000, which was one of the first plants to implement this Code Case. I have been involved with OMN-1 at LaSalle and I recently wrote the first Relief Request used for the implementation of the 1996 version of OMN-1 for Peach Bottom Atomic Power Station.

The transition from traditionally utilized quarterly IST stroke timing of Motor Operated Valves (MOV) to essentially taking credit for the MOV Program can be a complicated undertaking. There are a number of factors that one must consider and address in order to undergo a smooth program transition. The purpose of this presentation is to provide for those Program Owners who have yet to implement OMN-1, insight into the advantages and disadvantages of adopting a risk based MOV Inservice Testing along with an experienced view of the implementation process.

Introduction

ASME Code Case OMN-1 was first published with the 1996 Addenda to the 1995 edition of the OM Code. This version of Code Case OMN-1 has been referred to as "revision 0" in the June 2003 release of Regulatory Guide 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code," where it was identified as, "Conditionally Acceptable". Since then, Code Case OMN-1 has gone through at least 3 revisions with its latest version published in the 2009 edition of the OM Code.

The 2009 edition of the OM Code, in addition to publishing the current version of Code Case OMN-1, added Mandatory Appendix III, “Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Power Plants”, essentially incorporating the rules and requirements of Code Case OMN-1 into the actual OM Code.

This means that once the NRC incorporates the 2009 edition of the OM Code into 10 CFR 50.55a(b) by reference, all future IST Programs will be required to apply these rules in lieu of the standard requirements provided in ISTC when addressing their electrically driven, active, motor operated valves. (Note, until the NRC incorporates the 2009 edition of the ASME Code into 10 CFR 50.55a(b) by reference, it is unknown if the NRC will add additional stipulations/requirements to Mandatory Appendix III).

The Revision History of ASME Code Case OMN-1

The following table attempts to explain the revision history of Code Case OMN-1.   Over the years there have been a number of changes made to this Code Case, but each re-issuance of the document has not always been denoted by an indication of revision.

Release	Publication Circumstance	ASME Denoted Revision Level	NRC Denoted Revision Level	Type of changes (not all inclusive)
1	OM 1996a	not denoted		
2	OM 1999a	not denoted	0 Note 1	No Change, only reaffirming the 1996a version
3	OM 2004	not denoted	unknown	Revised to address up to the 2000 Addenda of the ASME Code along with non-technical format/verbiage changes.
4	OM 2006a (also re-published in OM 2009 along with Rev. 1 listed below)	not denoted	Note 2	Technical changes, mainly to address the Conditional Acceptance Limits initially imposed by Regulatory Guide 1.192. Also added a statement to recognize Motor Control Center (MCC) testing.

5	OM 2009	1	unknown	Non-technical verbiage changes along with the removal of all figures which should have been removed in the 2006 edition but were not due to a publishing error.

1 – Regulatory Guide 1.192 (2003)
2 – In initial discussions with the NRC in preparation for submitting a Relief Request to use the 2006 published edition of Code Case OMN-1, we were first requested to identify this version of the Code Case as, “Revision 1”, however through the Request for Additional Information (RAI) process, we were later requested to make reference to this issuance of the Code Case as, “Code Case OMN-1 from the ASME OMb Code, 2006 Addenda”

What is Code Case OMN-1/Mandatory Appendix III

In short, the testing methodology utilized by Code Case OMN-1/Mandatory Appendix III (henceforth to be referred to as “OMN-1”) provide enhanced methods to both determine the operability of an active MOV and provide better/more accurate criteria to be used for trending the continued operability of the MOV.

In editions of the OM Code prior to 2009, an active MOV would be stroked timed in its active direction with those results compared to stroke time limits derived either directly from OM Code requirements or from the plants Design Basis Requirements. These stroke time results were also “trended” by the IST Engineer so that they may subjectively recognize a detrimental operational trend and apply corrective actions prior to the valve being unable to perform as required. Testing normally took place during plant conditions that allowed for the ease of testing, thus resulting in these MOVs being stroked during static conditions, i.e. zero flow. While these stroke time test were easily repeatable (a criteria vital to produce trendable results), the information provided by this style of testing is not as suitable for detecting component degradation as is the MOV Program where testing takes into account the dynamic operational performance of the valve (i.e. under design basis accident flow conditions).

What OMN-1 does is essentially take credit for the MOV testing currently being performed to comply with NRC Generic Letter (GL) 89-10 and GL 96-05 in lieu of the quarterly stroke time testing previously prescribed by ASME ISTC.

As with most IST, there are advantages and disadvantages with adopting new testing methods. In my opinion, the advantages far outweigh the disadvantages with the adoption of OMN-1. In the remainder of this discussion I will review, based upon my experience working with and implementing OMN-1 programs, some the advantages, disadvantages, and pitfalls that a utility may face with the adoption of an OMN-1 program.

Advantages

Reduce the Amount of Testing

Prior to the 2009 edition of the OM Code, ISTC required that active MOV be stroke timed quarterly, if not on a cold shutdown or refueling basis, based upon plant parameters. To comply with these requirements, many man hours must be spent by Operations, Engineering, Health Physics staff, in addition to a number of other support departments in preparing for and performing these test. The adoption of OMN-1, essentially takes credit for testing which is already being performed through the MOV Program. As a result, the majority of the man hours previously expended in the preparing for conduction of these quarterly testing will no longer be necessary, saving tens of thousands of dollars per year.

Reduction in Radiation Exposure

Not having to perform quarterly stroke time testing will reduce the amount of time personnel need to be in radioactive areas, thus reducing the sites collective dose.

Better Test Results

The purpose of IST is not to simply comply with regulatory requirements but to determine component operational readiness and to provide assurance that pumps and valves which perform a specific function in shutting down a reactor to the safe shutdown condition, maintain the safe shutdown condition, and mitigate the consequences of an accident, will perform as required. In order to make the most accurate determination of the ability of active MOVs to perform these functions, the most effective and efficient tools should be applied. MOV Program testing based upon GL 89-10 and GL 96-05 takes into account the valves operation under dynamic accident conditions and provides results from which the valves “margin” under these conditions can be more accurately determined than through the standard IST static stroke time testing practice. With these more accurate diagnostic tools/methods, a more efficient and effective preventative maintenance approach can be applied to the valves, resulting in a cost savings in both manpower and component availability.

Reduce Valve Wear

With the adoption of OMN-1, IST will only require that the valve be operated once per refueling cycle, for which credit can be taken for via normal plant operation, in addition to the MOV Testing frequency instead of quarterly. This reduction of valve manipulations should reduce wear not only on the valve seating surfaces but wear on the motor operator.

Disadvantages

Change to the Process

The adoption of an OMN-1 Program requires that an extensive procedure revision process be undertaken which will necessitate a review of the plants design and licensing documents along with training the plant staff on the new requirements/procedures. This conversion process will take some up front time and funding, but cost will be repaid many times over as a result of reducing the number of future MOV tests.

Up until now, nuclear plants may have put off adopting OMN-1 due to the initial funding and manpower cost, but as a result of the issuance of Mandatory Appendix III, delaying the adoption of OMN-1 will no longer be optional.

Operability Test / Post Maintenance Testing

Before OMN-1, if maintenance was performed on the valve (not the operator) of an MOV, operability might have simply been determined by the performed of an IST Stroke Time Test. If the measured time met the acceptance criteria, the valve could be rapidly declared operable. Once OMN-1 is adopted there is no longer an IST Stroke Time test which can simply be applied as the Post Maintenance Test (PMT) when work has been performed on the valve itself. (Work performed on the valve operator would necessitate as before the assignment of an MOV test for PMT). The performance of the MOV test is a more complicated process than cycling the valve with a stop watch. It involves the attachment of diagnostic equipment which captures not only the stroke time but torque/thrust generated. The full evaluation of those results could take the MOV engineer hours, if not days, to perform, depending upon the application. Waiting hours or days is normally not an acceptable option when trying to bring a plant back to power.

In my experience when an MOV test is necessary to prove operability, the MOV engineer will supply an additional set of acceptance criteria, which if passed, will provide reasonable assurance that the MOV will still meet test requirements upon a full evaluation of the data. There are a number of ways this can be implemented, but it requires some forethought and concurrence with all applicable departments prior to the implementation of OMN-1. Making sure that the necessary procedures are in place and that all departments are in concurrence with any changes to procedures and policies can be the most difficult part associated with implementing OMN-1.

An alternative to the assignment of the IST OMN-1 test as a PMT for when work has been performed on the valve (and not the operator) is to create separate, stand alone PMT instructions for each individual valve.

Reduced Valve Actuations

While reduced valve operation will reduce wear on the valve seating surfaces and valve operator, reduced valve actuation may “bring to light” MOV grease issues. Some greases are prone to separate faster over time than others where stroking the valve allows for the operator to “mix” the grease. OMN-1 states that the maximum test interval is 10 years and that each MOV shall be full cycle exercised at least once per refueling cycle, not to exceed 24 months. This exercise frequency should be sufficient to maintain the grease in a mixed state however some utilities are still identifying MOV grease issues.

What You Need to Watch Out For

Strength of your MOV Program

Peach Bottom Atomic Power Station, for whom I wrote the first Relief Request to implement the version of Code Case OMN-1 that is published in the 2006 Addenda of the Code, were within days of implementing OMN-1 when an MOV Program test discovered that a valve did not stroke due to grease issues. At that time, a decision was made to not implement OMN-1 until the root cause for the MOV issues was determined and the issues corrected. As of the time of this paper’s writing, OMN-1 has yet to be implemented at the Peach Bottom Atomic Power Station, but is expected to take place in 2012.

Let me remind us all again that your site may not have the option to postpone OMN-1 based testing methods once you are required to perform an interval update to an OM Code edition containing Mandatory Appendix III.

Coordination of your IST and MOV Programs

When implementing an OMN-1 program, one of the first steps to perform is a comparison of the valves currently being tested by the sites MOV Program and the Active MOV's being tested within the IST Program. There may be instances when your MOV 89-10/96-05 Program scope differs from your IST Active MOV scope. These differences will need to be reconciled.

Licensing Commitments

These documents need to be reviewed to see if any periodic stroke timing commitments have been made to the NRC for which credit was given to the IST Program. If found, these commitments will need to be modified or the individual stroke timing of the subject valve(s) may need to be continued to meet the commitment.

Response Time Testing

Your plant may be utilizing the quarterly stroke time values measured in their response time testing results. If so, either the Response Time Testing procedure will need to be revised to point to the MOV Testing procedure for its data or other arrangements will need to be considered.

Conclusion

Remember that the purpose of your Inservice Testing Program is not to simply comply with the regulation, but to provide reasonable assurance that the components in your plant will be able to function as required when called upon. It is your job as an IST Engineer to utilize the most “Accurate” and “Cost Effective” methods available in order to assure the readiness of your plant. The adoption of Code Case OMN-1/Mandatory Appendix III works both towards meeting the regulatory required “Accuracy” and plant owner(s) “Cost Effectiveness” requirements.

* This paper is the draft Mandatory Appendix IV of the American Society of Mechanical Engineers Code for Operation and Maintenance of Nuclear Power Plants (OM Code). This Appendix is currently in the course of preparation to be added to the OM Code at the time of this NUREG publication. The presentation of Draft Mandatory Appendix IV will be given by Fred Setzer.

Draft Mandatory Appendix IV

Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Light-Water Reactor Power Plants

(This Appendix is mandatory and contains requirements to augment the rules of Subsection ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants.)

IV-1000 Introduction

IV-1100 Applicability

This Appendix establishes the requirements for preservice and inservice testing to assess the operational readiness of active pneumatically operated valves in light water reactor (LWR) power plants in addition to the requirements of ISTC - 5130.

IV-1200 Scope

See ISTC -1200

IV-2000 Supplemental Definitions

Pneumatically operated valve (AOV) -- a valve and its associated actuator that uses air/gas as the motive force, including all sub-components required for the valve assembly to perform its intended function. For simplicity, this type of valve is referred to as an AOV throughout this document.

AOV functional margin -- the increment or percentage by which an AOV's available capability exceeds the required load to operate the AOV under design basis conditions.

Design Basis Review - A design basis review (DBR) is an engineering analysis used to verify and document the adequacy of AOV sizing, establishing conditions for verification and establishing acceptance criteria for Inservice Diagnostic Testing. Specifically, the DBR consists of both a system level and a component level review. The system review determines the AOVs design basis system conditions. The component level review establishes the AOVs required design basis loads, actuator output capability and available actuator capability margin.

Limited Design Basis Review - A limited design basis review is an engineering analysis used to verify and document the adequacy of AOV sizing and in establishing conditions for verification and establishing acceptance criteria for Inservice Diagnostic Testing. Specifically, the limited DBR consists of a component level review. The component level review establishes the AOVs required design basis loads using the best available information from existing design, testing and vendor documentation.

Inservice Functional Test - A stroke time test that exercises the AOV and verifies fail safe capability in accordance ISTC-3500.

Inservice Diagnostic Test - An Inservice Diagnostic Test consists of measurements of parameters required to assess the AOV functional margin and position verification test.

High Margin - AOV functional margin that is greater than or equal to 25 % when corrected for uncertainties.

Low Margin - AOV functional margin that is less than or equal to 25 % when corrected for uncertainties.

Position Verification Test - AOV Inservice Diagnostic Testing meets the intent of position verification testing as defined in ISTC-3700. See Section IV-3700 for risk informed insights.

IV-3000 General Testing Requirements

IV-3100 Design Basis Verification Test

A onetime test shall be conducted to verify the capability of each AOV to meet its safety-related design basis requirements. The test shall be conducted at conditions as close to design basis conditions as practicable. A design basis verification that meets the requirements of this Appendix but conducted before implementation of this Appendix may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.

(b) Where sufficient test data exists, a DBR can be performed in lieu of a design basis verification test. The basis and conclusions of the design basis review shall be documented.

(c) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an analysis shall be documented that supports applicability to the in situ conditions.

(d) Justification for testing at conditions other than design basis conditions and for grouping like AOVs shall be documented by an evaluation, alternate testing techniques, or both. Where design basis testing of the specific AOV being evaluated is impracticable, or not meaningful (provides no additional useful data); data from similar valves may be used if justified by evaluation. Sources for the data include other plant valves or test data published in industry testing programs. Where analytical techniques are used to verify design basis capability, those techniques shall be justified by an evaluation.

(e) For certain valve types (i.e., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an evaluation of operating experience may be used to verify design basis capability.

(f) The design basis verification test shall be repeated if an AOV application is changed, the AOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an evaluation, alternative testing techniques, or both.

(g) Where existing site programs and normal plant operation provide adequate demonstration of AOV capability via periodic cycling, credit can be taken for this demonstration provided that the periodic cycling conditions meet or exceed the design basis conditions. Assurance should be provided that the component and accessories are operating within allowable limits. The basis shall be documented by an evaluation.

IV-3110 Design Basis Review

A Design Basis Review (DBR) shall be performed and documented per evaluation.

IV-3200 Preservice Test

Each AOV shall be tested during the preservice test period or before implementing Inservice Testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Appendix but conducted before implementation of this Appendix may be used. Only one preservice test of each AOV is required unless, as described in Section IV-3400, the AOV has undergone maintenance that could affect its performance.

IV-3300 Inservice Test

Inservice Testing, shall commence when the AOV is required to be operable to fulfill its required function(s), as described in Section IV-1100, and shall be sufficient to assess changes in AOV functional margin consistent with Section IV-6400.

(a) A Inservice Diagnostic Test shall be performed

(b) A Inservice Functional Test shall be performed.

(c) AOVs may be grouped for inservice testing as described in Section IV-3500.

(d) Inservice tests shall be conducted such that they do not invalidate the inservice test results. If maintenance is needed between the inservice tests, see Section IV-3400. If maintenance activities are scheduled concurrent with or prior to an AOV's inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity. See Section IV-3700 for risk informed discussion. Inservice Functional Testing should be performed prior to diagnostic testing when these tests are schedule concurrently.

(e) Where existing site programs and normal plant operation provide adequate demonstration of AOV capability via periodic cycling, Inservice Diagnostic Testing is not required and credit can be taken for this demonstration provided that the periodic cycling conditions meet or exceed the design basis conditions. In these cases a component level review as part of the DBR as defined in Section IV-2000, is not required. The basis shall be documented by evaluation.

(f) Valve seat leakage testing shall be performed in accordance with ISTC-3600.

IV-3310 Inservice Test Interval

IV-3311 Diagnostic Testing

The diagnostic inservice test interval determination shall include:

(a) All AOVs with the scope of this Appendix, shall have a Inservice Diagnostic Test conducted every 2 refueling cycles, not to exceed 4 years (can be extended up to 6 months to coincide with refueling cycle) until sufficient data exists, from an applicable AOV or AOV group, to justify a longer Inservice Diagnostic Test interval.

(b) The maximum Inservice Diagnostic Test interval shall not exceed 10 years (can be extended up to 6 months to coincide with refueling cycle).

IV-3312 Functional Testing

All AOVs, within the scope of this Appendix, shall have a Inservice Functional Test performed at least once per refueling cycle, not to exceed 24 months (can be extended up to 6 months to coincide with refueling cycles). If Inservice Functional Testing of an AOV is not practical during plant operation or cold shutdown, Inservice Functional Testing shall be performed during the plant's refueling outage.

The Owner shall consider more frequent Inservice Functional Testing for AOVs in any of the following categories:

(a) AOVs with high risk significance;

(b) AOVs with severe service conditions (temperature, radiation, fluid process)

(c) AOVs with any abnormal characteristics (operational, design or maintenance conditions).

(d) AOVs with less than 10 % margin

IV-3312 Inservice Test Frequency Extension

(a) Components are required to be tested at the frequencies specified in the applicable Subsections.
(b) The test frequency specified in the applicable Subsections is a nominal time period that may be extended less than or equal to 25% of the specified time period, not to exceed 6 months and is applicable to all test frequencies.

(c) The allowable less than or equal to 25% extension is applicable to only an individual test and is not cumulative. (e.g., the 2nd occurrence of a quarterly test must be performed within 115 (i.e., 92 + 23) days of the 1st occurrence, the 3rd occurrence of a quarterly test must be performed within 207 (i.e., 92 + 92 + 23) days of the 1st occurrence, the 4th occurrence of a quarterly test must be performed within 299 (i.e., 92 + 92 + 92 + 23) days of the 1st occurrence, and so on).

IV-3400 Effect of AOV Replacement, Repair, Modification or Mainteance

When an AOV is replaced, repaired, modified or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined or the previously established inservice test values shall be confirmed before the AOV is returned to service. If the AOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required prior to and after replacement, repair, modification or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in Section IV-9000 and ISTC-3500.

IV-3500 Grouping of AOVs for Inservice Diagnostic Testing

Grouping AOVs for inservice testing is permissible. Grouping AOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping AOVs:

(a) AOVs with identical or similar actuators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of AOVs shall be validated by appropriate inservice testing of one or more representative valves.

(b) Test results shall be evaluated and justified for all AOVs in the group.

IV-3700 Risk Informed AOV Inservice Testing

Risk informed AOV inservice testing that incorporates risk insights in conjunction with performance margin to establish AOV grouping, acceptance criteria, exercising requirements and testing interval may be implemented.

IV-3710 Risk Informed Considerations

The Owner shall consider the following when incorporating risk insights in the inservice testing of AOVs:

(a) develop an acceptable risk basis for AOV risk determination,

(b) develop AOV screening criteria to determine each AOV’s contribution to risk, and

(c) finalize risk category by a documented evaluation from a plant expert panel.

IV-3720 Risk Informed Criteria

Each AOV shall be evaluated and categorized using a documented risk ranking methodology. 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.

IV-3721 HSSC AOVs

HSSC AOVs shall be tested in accordance with Section IV-3300. HSSC AOVs that can be operated during plant operation shall be inservice functionally tested quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer inservice functional test interval is small.

IV-3722 LSSC AOVs

Risk insights shall be applied to inservice testing of LSSC AOVs by the following:

(a) A limited design basis review can be performed in lieu of a design basis for review for LSSC AOVs in order to establish required design basis loads.

(b) Inservice Diagnostic Test shall be performed at least one time to assess valve AOV functional margin.

(c) Inservice Functional Test shall be performed in accordance with IV-3300.

(d) Requirements of Section IV-3400 apply for AOV replacement, repair, modification or maintenance.

(e) AOV Inservice Diagnostic Testing shall be conducted every 3 refueling cycles, not to exceed 6 years (can be extended up to 6 months to coincide with refueling cycle) until sufficient data exists, from an applicable AOV or AOV group, to justify a longer Inservice Diagnostic Test interval.

(f) Periodic inservice diagnostic testing is not required for high margin LSSC AOVs. However, position verification test is required to be performed once per refueling cycle per ISTC3700 and may be performed in conjunction with Inservice Functional Test.

IV-4000 Reserved

IV-5000 Test Methods

IV-5100 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation or other applicable procedures.

IV-5200 Inservice Diagnostic Test Conditions

Inservice Diagnostic Test conditions shall be sufficient to determine the AOV's functional margin per Section IV-6400. Test conditions shall be recorded for each test per Section IV-9000.

IV-5300 Limits and Precautions

Diagnostic Testing limits and precautions include:

(a) Manufacturer or vendor limits and precautions associated with the AOV and with the test equipment shall be considered.

(b) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(c) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the AOV by the particular testing performed.

IV-5400 Test Documents

Approved plant documents shall be established for all tests specified in this Appendix and shall provide for:

(a) methodical, repeatable, and consistent performance testing; and

(b) collection of diagnostic data required to analyze and evaluate the AOV functional margin in accordance with Section IV-6400.

IV-5500 Diagnostic Test Parameters

Sufficient diagnostic test parameters shall be selected for measurement to meet the requirements of Section IV-6000 in determining the AOV functional margin. Examples of diagnostic test parameters are: valve travel, actuator pressure and stem thrust/torque.

IV-6000 Analysis and Evaluation of Diagnostic Data

IV-6100 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each AOV within the scope of this Appendix. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the required design basis loads. Thrust, torque, or other measured parameters may be used to establish the acceptance criteria. When determining the acceptance criteria, consider the following sources of uncertainty:

(a) test measurement and equipment accuracy

(b) actuator spring preload with consideration of spring preload relaxation

(c) actuator spring displacement and force used to derive spring rate

(d) actuator supply air/gas with consideration of regulator or positioner drift

(e) effective diaphragm area (valve and actuator)

(f) analysis, evaluation, and extrapolation method

(g) grouping method.

IV-6110 Parameter Measurements

Stem force or other parameters may be used to determine AOV margins, if those parameters are consistent with Sections IV-5500 through IV-6430.

IV-6200 Analysis of Data

Data obtained from a test required by this Appendix, shall be analyzed to determine if the AOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each AOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per Section IV-6430, does not meet the acceptance criteria, the AOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

IV-6300 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each AOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating AOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable AOVs to establish appropriate time intervals for future test activities.

IV-6400 Determination of AOV Functional Margin

The Owner shall demonstrate that adequate margin exists between required design basis loads and the available actuator output capability to satisfy the acceptance criteria for AOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in AOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

IV-6410 Determination of Actuator Output Capability

IV-6411 Available Output Based on Actuator Capabilities

Available actuator output shall be determined based on the actuator’s capabilities at design basis conditions. Considerations shall include:

a) actuator effective area

b) actuator efficiency

c) other appropriate factors

IV-6500 Corrective Action

If the AOV performance is unacceptable, as established in Section IV-6200, corrective action shall be taken in accordance with Owner's corrective action requirements.

IV-6510 Record Of Corrective Action

The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent inservice tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.

IV-7000 Reserved

IV-8000 Reserved

IV-9000 Diagnostic Test Records and Reports

IV-9100 Diagnostic Test Information

Pertinent test information shall be recorded or verified for AOV testing, described in Section IV-3000. The following information shall be considered:

(a) AOV plant-specific unique identification number.

(b) Test equipment unique identification numbers and equipment calibration dates.

(c) Test method and conditions, described in Section IV-5000, including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, actuator, and piping configuration near the AOV.

(d) AOV performance test procedure and other approved plant documents containing acceptance criteria.

(e) Name of test performer and date of test.

(f) System flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.

(g) Significant observations -- any comments pertinent to the test results which otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic AOV action noted either during or preceding performance testing and any other pertinent design information which can be verified at the AOV.

IV-9200 Documentation of Analysis and Evaluation of Diagnostic Data

The documentation of acceptable AOV performance, which has been analyzed and evaluated in accordance with Section IV-6000, shall include, as a minimum:

(a) values of test data, test parameters, and test information established by Sections IV-5500 and IV-9100;

(b) summary of analysis and evaluation required per Sections IV-6200 and IV-6300;

(c) statement(s), by an individual qualified to make such a statement through the Owner's qualification requirements, confirming that the AOV is capable of performing its intended safety function; and

(d) test results and analysis shall be evaluated by qualified individuals and documented to include signature and date. Independent verification shall be by individuals qualified to verify those specific analyses and evaluations through the Owner's qualification requirements.

Technical Review of Recent Packing/Gasket Failures
(Operating Experience OE)

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Abstract

Year after year, nuclear power plants experience significant gasket and packing leaks. Although the American Society of Mechanical Engineers (ASME) code neglects this area, the failure and leakage of sealing components is imperative to nuclear power plant operation. Areas such as motor-operated valve (MOV) operability, boric acid corrosion, containment leakage, and even overall station reliability are greatly impacted by packing and gasket leakage. This paper will review the gasket and packing operating experience from the last several years and will provide understanding of the generic drivers of these issues. Actual causes, similarity between events and causes, and lessons learned will all be examined. With the current fluid sealing knowledge and availability of materials, many of these situations could be prevented, especially if this common information could be captured and incorporated into training and engineering practices. The conclusions of this paper will provide overall generic recommendations to improve fluid sealing and specific focused solutions where identified.

Introduction

This paper was prepared using data evaluated by the Fluid Leak Management User's Group (FLMUG), which facilitates improvements in all areas of fluid sealing. The nuclear industry's reporting system for collection and evaluation of data at this level is limited. The general trend over recent years for leakage from packing and gaskets has been trending down. This favorable trend recognizes the significant improvement steps which have been expended over the past years both in material improvement, training and process. However, even though the total number of these leaks is decreasing, significant station impacts from leaks continue to occur such as plant shutdowns, downpowers, and loss of safety system availability.

The steps taken by the industry are improving performance in the fluid sealing area. To ensure the continuation of this positive trend, these steps need to be solidified and engrained into the station processes and this success needs to be embraced at the remaining stations.

The belief that “all packing, gasket and pressure leaks are preventable” needs to be fostered throughout the nuclear industry. All involved parties need to maintain or sharpen their focus on minimizing leakage. The implementation of simple root cause investigations on known leaks versus the assumption that sealing material will always wear-out, age, and leak is a crucial concept to continue to foster. We cannot assume that leaks are inherent and will happen regardless of our actions, for if we do we begin to accept them as a way of life.

Information regarding known fluid sealing solutions needs to be distributed across the nuclear industry. For spiral wound gaskets, this includes the requirement for inner rings in raised face and male/female flange designs. For valve packing, this means the monitoring of adequate gland load, proper consolidation, use of improved materials, and carbon bushing for stem support. In almost all fluid sealing applications, a fundamental concept of good bolting practice must be maintained.

Although faced with challenges such as an aging work force, issues with knowledge retention, and older equipment, the nuclear industry must continue to move forward.

Identifying Issues and Trends

It is important to first identify issues and trends with gasket and packing sealing to see if the trend is increasing or decreasing to understand the impact of our current actions. Industry data is not reported directly in a useful format and must be processed before its use. Limitations exist on the information which is reported, such as only significant leaks are reported and included in the data sets. The reporting level for less significant leaks between stations will vary. If the engineer understands the limitations of the available data, however, an appropriate trend of fluid leaks can still be extracted.

The first data review focuses specifically on valves, looking at failures of either the packing or the o-rings/gaskets of a valve. The data presented in Figure 1 shows a significant declining trend for the last 4 year period. It should further be noted that partial data for 2011 shows this a continuation of this trend. Figure 1 shows the total of all reported number(s) of leaks per year.

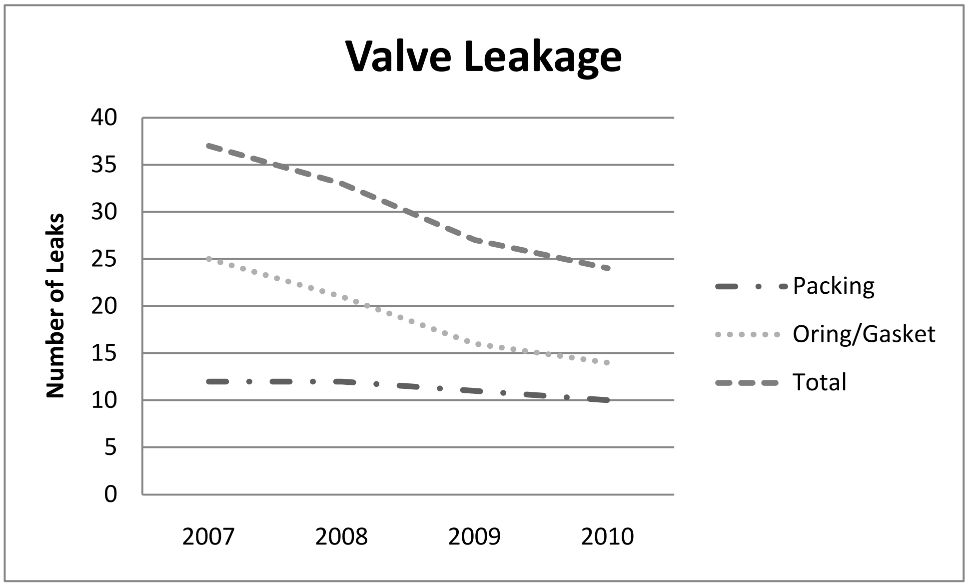


Figure 1 Failures of Valve Packing or O-ring/Gaskets

The second data review focuses specifically on “external leaks” reported on valves, pumps, heat changers and piping/fittings. Figure 2 represents the data for the last 4 years period and shows a decreasing trend. It should further be noted that partial data for 2011 shows a continuation of this trend.

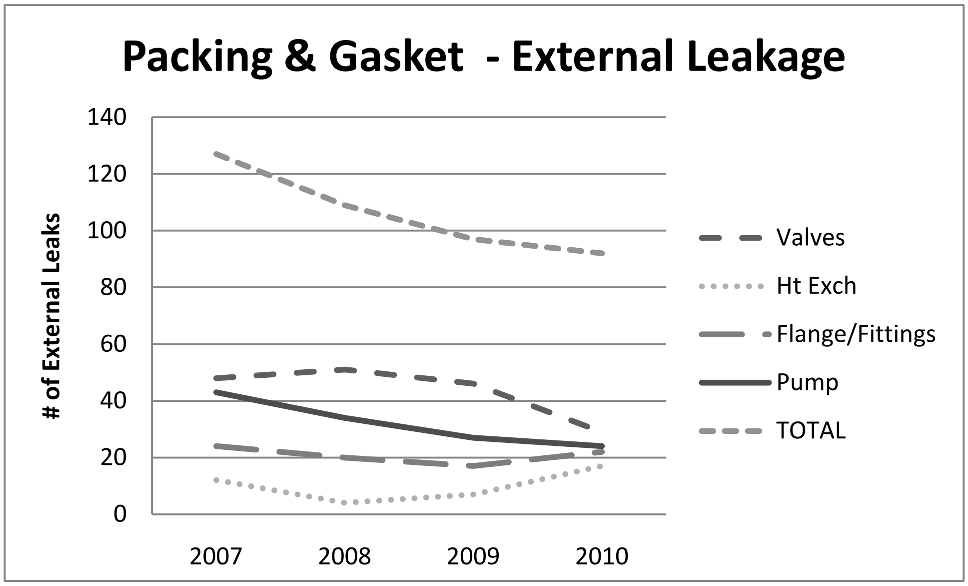


Figure 2 External Leakage by Component Type

Because of limitations on data collection and the reporting system, further detailed analysis of the data as a means to identify generic issues or trends is difficult. Regardless of these limitations, it is clear that the current trend of fluid seal leaks is decreasing. However, when leaks occur, they still have significant consequences, including plant shutdowns, large unit downpowers, impacts on safety system availability, and significant boric acid corrosion. From a review of the specific events, no significant single dominant cause was discernible. There was no single “silver bullet” solution which could be found from the data. When all of the information is taken at face value and viewed by an engineer experienced with power plant operation, it is possible to identify insights, key points, and lessons learned which can be applied to, maintain, and further this decreasing trend of fluid sealing leaks.

After careful consideration of the data available, some themes begin to surface: pre-existing conditions, age of material, missed opportunities, gaps in application of already understood technology, a culture which accepts some leakage as inherent, and prospects of simple material improvements. When considering the key factors necessary to continue decreasing seal leakage, it becomes evident that knowledge and organization are key. There is a pressing need for refined data management systems which will enable more efficient ways to investigate leaks, review history, and produce solutions to move forward. Such refined data management tools are also fundamental to knowledge retention.

Design and Material Issues

The impact of pre-existing conditions and aging of material are difficult to completely discern, as it is unrealistic and cost effective to rebuild all fluid connections periodically. Since rebuilds are impractical, there are some specific areas which engineers should be aware of and should try to incorporate into plant processes:

Gaskets can receive insufficient bolt load for the specific gasket design. In the advancement from asbestos to graphite, it was determined that graphite spiral wound gaskets require higher loads to reach design crush and new gasket constants require higher stresses to seal.

When spiral wound gaskets are installed in vertical joints, there is always the possibility of the gasket to fall out while the joint is being pulled together. Significant leaks to main turbine steam flanges have occurred from this issue. A simple adhesive can be applied to the gasket to ensure it remains in the proper position.

Flange designs have not always properly contained the gasket. Radial buckling of spiral wound gaskets, which have been upgraded to graphite or PTFE filler, continues to occur. The use of inner ring or a kamprofile gasket can address this issue. Even in a grooved flange design, a graphite filled spiral wound gaskets will extrude to the side walls when tolerances are too large, resulting in loss of gasket load.

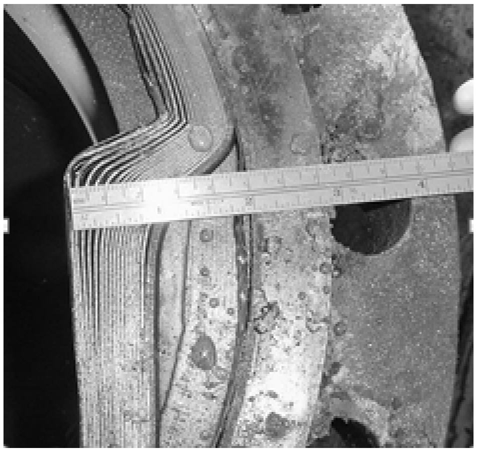


Figure 3   Radial Buckling of a Sprial Wound Gasket

With age, thermal cycles, and maintenance, flange faces are no longer square or properly aligned. This is particularly true with partition plates, heat exchangers and hydrogen cooler end plates.

Additionally, inspection of new valves should be given consideration. By disassembly and repacking of new valves, not only can all the packing dimensions be obtained, but an opportunity is provided to insure the condition of sealing surfaces and clearances prior to installation to prevent any future problems.

Packing and Gasket Maintenance

The application of proper bolting stress techniques is crucial to all fluid joints. In most situations, we apply the correct torque to achieve the desired gasket load, but we fail to follow through to insure the load actually reaches the gasket. Adequate attention may not be paid to proper lubrication (ie consistent with the temperature), the replacement of old bolting, or the use of “hardened” washers. Not using hardened washers will reduce the applied gasket stress by as much as 50%. For each gasket type and thickness, a target gasket stress should be used to achieve adequate sealing and proper gasket crush.

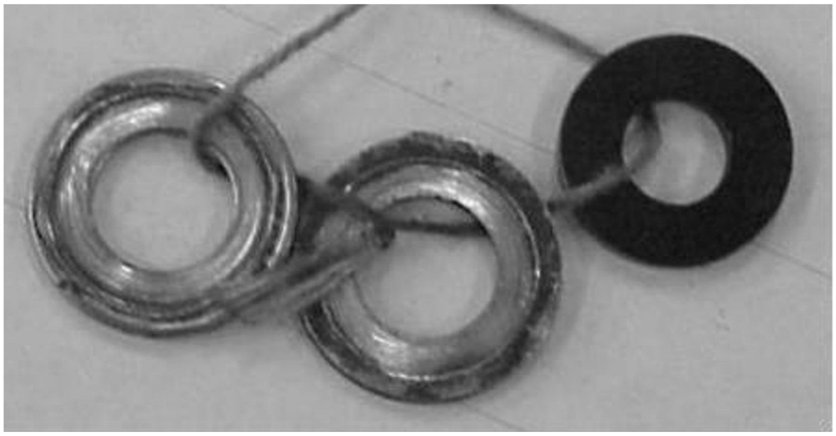


Figure 4 Comparison of typical supplied washer to hardened washer after service

The retorquing of bolted packing and gasket connections after the initial installation affords the opportunity to second check the joint. During re-torque, the engineers can discover crucial information, such as that the gasket creep was more than expected, the bolting was loose, or other related issues. For valve packing, a re-torque during the first refuel outage after a repack ensures that inservice consolidation is adequately addressed and packing stress can remain adequate for long-term, leak-free service.

Quality inert gasket materials should be selected to provide low creep and system media compatibility so in-service load is not lost and expected performance is achieved. Gasket material must be capable of withstanding the service temperature of the application with sufficient margin. Proper clearances for the gasket used must be confirmed on installation, and not just assumed.

Valve packing needs to be installed with adequate margin in order to achieve leak free service. Guaranteeing that this margin is established and maintained addresses many of the issues discussed, such as aging equipment, less than perfect stem/box finishes, slight misalignments, and manufacturer’s clearances. When valve operability stroking requirements require that packing stress be lowered, the margin to leak free service will be reduced, but compensatory actions can be taken. These valves can be live-loaded, packing loads can be periodically monitored via diagnostic equipment, or periodic packing retorque tasks can be applied.

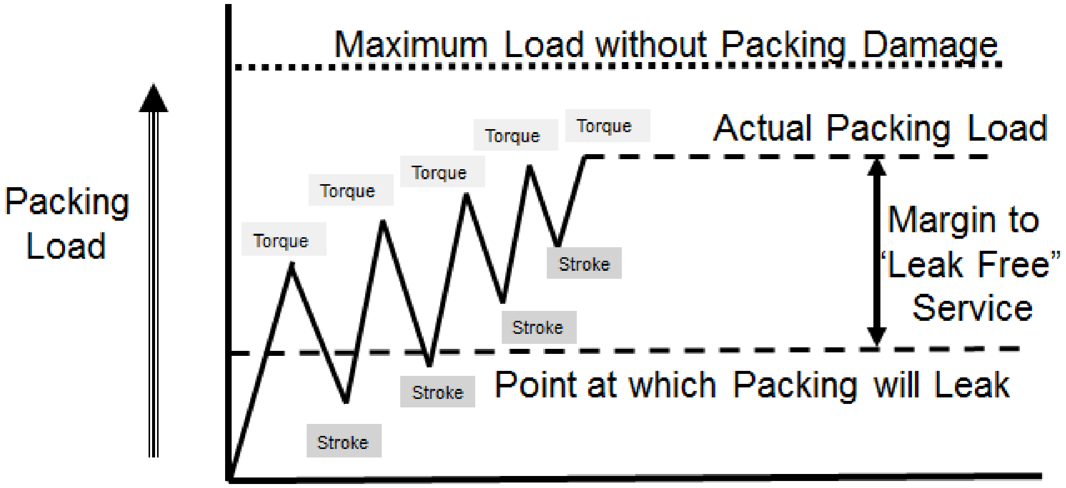


Figure 5 Concept of Packing Consolidation & Margin to Leak Free service

Achieving proper packing consolidation remains an issue, as evidenced by several events. Packing consolidation is the simple act of reforming the packing to the actual size of the stuffing box and ensuring the application of adequate packing stress. Packing consolidation is accomplished by continued stroking of the valve stem and torquing of the valve packing until no additional nut movement on the packing gland nut is achieved. Due to issues such as lack of training, concern for motor overheating, scheduling issues, or ALARA, packing consolidation is not always fully achieved.

Material Improvements

At times we focus only on the more complex issues and miss the importance and criticality of simple material improvements. Some stations processes are so rigid that the implementation of such simple material improvements are delayed or postponed.

Over the past decade, we have seen an increase in the application of graphite pressure seals versus metal. This change is a major step forward because the graphite pressure seal provides improved fluid sealing, accommodates for inherent minor damage in the sealing area, and allows for ease of valve disassembly. Several events were related to graphite pressure seals, either from bonnet misalignment or from lack of adequate containment of the graphite. Maintenance workers who have experience with working on valves with metal pressure seals need to understand that it will be more difficult to maintain bonnet alignment with graphite. The graphite pressure seal does not provide the rigid support of the metal pressure seal. The graphite is superior in its ability to flow and seal, but this same ability to flow requires extra attention to ensure that the graphite is properly contained. This containment can be accomplished by the addition of metal caps on both the top and bottom of the graphite pressure seal. Clearances between the body and bonnet must be closely maintained, and if caps are not used, these clearances become even more critical. As previously discussed in this paper, re-torquing of the graphite pressure seal is necessary after being placed in service.

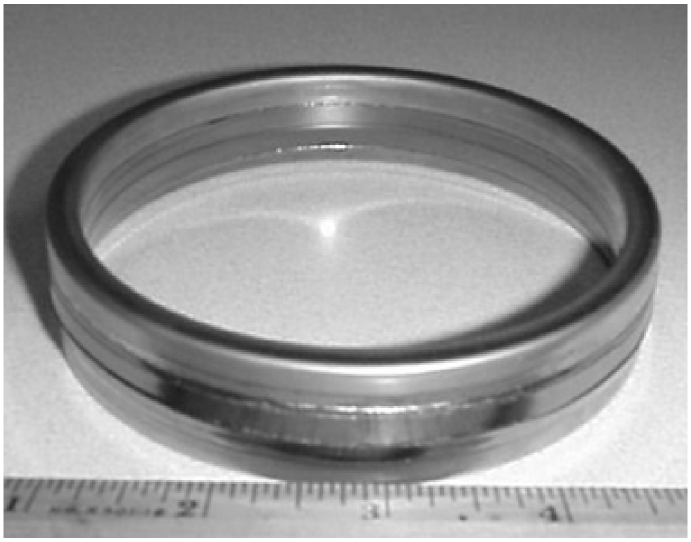


Figure 6 Typical Graphite Pressure Seal with top and bottom caps

To make certain that all of the calculated sealing stress is delivered from the torquing of the bolts to the sealing material (ie gasket, packing, pressure seal), “hardened” washers need to be installed under all bolting. Without “hardened” washers, 25-50% of the bolt load is lost, but many equipment manufacturers do not provide these washers with their equipment.

Valve packing is focused on providing a flexible seal for a moving valve stem. When added challenges arise, such as accommodating high vibration, stem misalignment, side loading from a single AOV spring, or stem loading in the horizontal position, packing leaks develop. In the past we attributed these leaks to the packing (i.e., its limited life causes it to wear out). The use of hardened carbon bushing for stem support in these situations can relieve this burden from the valve packing. With the carbon bushing handling these loads, the valve packing is capable of reliably providing long term sealing of the stem/stuffing box.

On many lower pressure joints, soft iron gaskets are originally provided by the manufacturer. The soft iron gasket does not provide a reliable seal long term and is not accommodating of the expected degradation of sealing surfaces which inevitably occurs. Graphite gasket sheet material or kamprofile gaskets provide a more reliable, robust sealing solution to these joints.

Spiral wound gaskets are the standard solution to many joint applications. Spiral wound gaskets can be purchased with “extruded” graphite. The graphite filler of the gasket simply extends (i.e., protrudes) past the metal winding. The additional graphite, though it remains captured by the gasket, provides additional sealing ability to accommodate minor surface imperfections of the metal sealing faces.

Promoting the Correct Valve Packing Attitudes

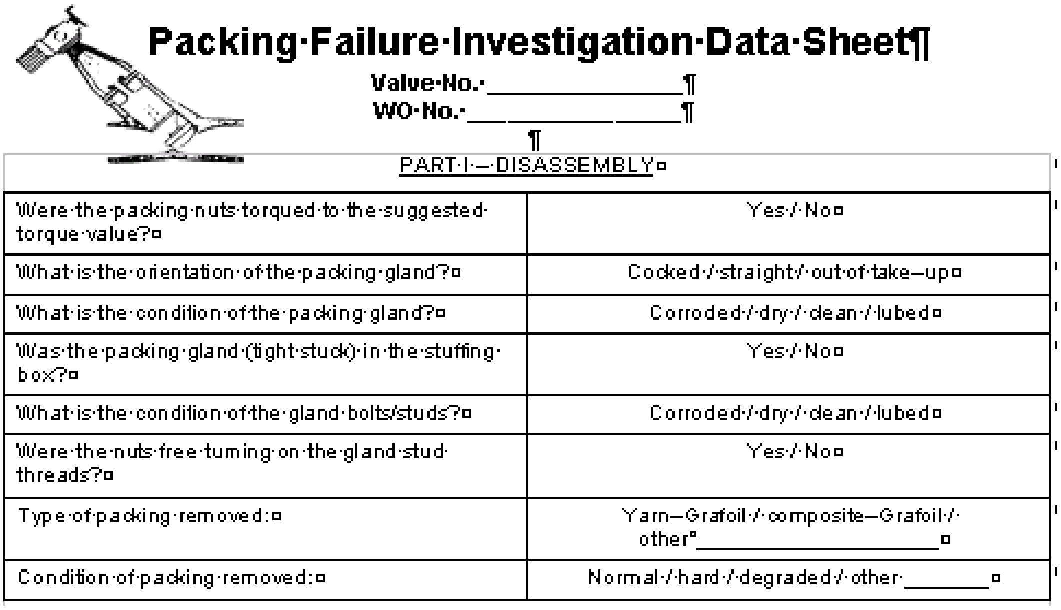
Although a number of minor leaks may exist at a station, sites do not typically attempt to determine the cause of leaks unless they have a major impact**.** A culture which believes that leaks are inevitable can easily develop. “All packing, gasket, and pressure seal leaks are preventable” must become our message. Once we believe that all leaks are preventable, it drives us to determine their causes when they occur.

Processes and procedures should incorporate simple “root cause” tools to facilitate the evaluation of leaks when they occur. The basics questions asked for any leak should be:

- Am I using the correct material for the application?
- Am I loading the packing/gasket correctly?
- Is the sealing material properly contained?
- Has it been properly consolidated (packing) or re-torqued (gaskets and pressure seals-if required)?
- Apply a simple root cause investigation to cover other areas such as dimensional clearances, available bolt load, flange design, etc…
- Review internal and external OE for similar applications
- Review work history for component and sister component data

Develop a good rapport with your manufactures and suppliers and don’t be afraid to ask contacts at other sites. There is a good chance someone has already fixed the same problem elsewhere.

An example of how this information could be incorporated into a valve packing procedure form for leak investigation is provided below:



Packing Failure Investigation Data Sheet

Valve No. ______________

WO No. ________________

PART I — DISASSEMBLY

Were the packing nuts torqued to the suggested torque value?	Yes / No
What is the orientation of the packing gland?	Cocked / straight / out of take–up
What is the condition of the packing gland?	Corroded / dry / clean / lubed
Was the packing gland (tight stuck) in the stuffing box?	Yes / No
What is the condition of the gland bolts/studs?	Corroded / dry / clean / lubed
Were the nuts free turning on the gland stud threads?	Yes / No
Type of packing removed:	Yarn—Grafoil / composite—Grafoil / other ____________________
Condition of packing removed:	Normal / hard / degraded / other _______

Figure 7 Suggestion for Packing Failure Investigation Sheet

Data Management

Many of the items discussed within this paper are neither new nor innovative, but the review of our operating experience continues to point out similar issues. An oft overlooked area in fluid sealing is that of data management.

Refined data management system needs to have the ability to track historical material changes, document actual installed situations, and capture recommended material for the next repack/disassembly. The system should provide required torque information and track leaks to allow for ease in determining similar events, potential areas for similar events, and apply generic material upgrades when identified.

When such a data management system is installed, some of the inherent issues, such as knowledge transfer, can be addressed because one knows where to go to look for answers. The experiences of the past would be readily retrievable.

A refined fluid sealing data management system *goes hand in hand with the simple analysis of leaks.* Without easily accessible data and search capabilities, these root causes are not completed due to the lack of time and resources.

Conclusion

Significant gains have occurred in packing technology and leak prevention, but we can not rest on our laurels because nuclear power plants are getting older and their experienced personnel are retiring. With proper understanding and analysis, the engineer can address aging equipment and pre-existing conditions, fill the gaps in the application of already understood technology, and promote simple material improvements. Current plant personnel must remain vigilant, utilize knowledge capture techniques, establish a simple root cause process to every fluid leak, and support knowledge transfer via organizations such as ASME and FLMUG. Valve engineers must embrace the concept that “all packing, gasket and pressure leaks are preventable.”

Figure 8 "Getting to Leak Free Operation"

Session 2(c): Valves III

Session Chair: Dr. Claude L. Thibault, Consultant Wyle Laboratories

Case Study of Valve Differential Pressure Calculation Under the Condition of Valve Degradation

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Abstract

In the nuclear electric power industry, engineers often face challenges of making decision with limited technical information. It is not uncommon that typical technical information for a certain problem, which is required for solving the problem in the method described in textbooks, is not available in the real world. This paper introduces a case study on how to solve technical problem with limited technical information in the nuclear power industry. In this case, a Pump Supply Isolation Valve has degradation (only 80% open). The differential pressure across the partially opened valve is needed for the engineering evaluation of this issue. However the value of flow coefficient (C_v) for this Pump Supply Isolation Valve was not known and the valve's equivalent length of a resistance to flow (L/D) is available. By utilizing L/D and other available technical data the valve's differential pressure is calculated and the engineering evaluation on the valve degradation was made.

Introduction

One of the challenges the nuclear power industry engineers facing is that they need to make technical decision with currently available technical information/data within limited time to meet the regulation/procedure requirements. It is not uncommon that typical technical information for a certain problem, which is required for solving the problem in the method described in textbooks, is not available in the real world. The engineers need to think about alternative way, with the utilization of available data/information, to solve the problem. This paper introduces a case study of how to use available technical information to solve problem an alternative way.

In this case, Operations observed that a Motor Operated Valve (MOV) did not fully open during the scheduled inservice test. It only opened 80% of its full stroke. This MOV is a Pump Supply Isolation Valve. To evaluate the influence of the degraded MOV to the system or the Past Operability Determination (POD), the differential pressure across the MOV is needed.

Under the worst possible scenario, the degraded MOV, or the partially opened MOV, causes the decrease of the cross sectional area of the flow path. Consequently, the differential pressure across the MOV increases. To calculate the differential pressure across a valve, its flow coefficient (C_v) is typically needed. However in this case, the C_v

of the MOV is not available. An alternative method for calculating the differential pressure across the MOV is needed. The alternative method can only use the existing data which is available from the plant technical documents or vendor technical documents.

Available Data and Calculation Assumptions

By searching the technical documents and contacting the vender, the following technical data on this MOV was collected and selected for the calculation:

- This MOV is an 8 inch flex wedge gate valve equipped with Limitorque SB-00 actuator. The MOV is limit-controlled. The MOV has been set up to open against 251 psid as required for its active safety function.
- When this MOV fully opened, the differential pressure (DP) across it is 0.145452 psid.
- L/D at full open is a maximum of 13.
- The valve disc would clear the seat at about 9% of travel from full closed based on the seat ring and the disc nominal dimensions.
- The disc would clear the flow passage at about 98% of travel.
- The L/D between the valve clearing the seat and the valve clearing the flow passage would be considered linear.
- The valve fully stroke is 7.3 inches. 80% of full stroke is 5.84 inches.

The calculation also is based on the following assumptions:

- Based on the system analysis, the flow rates through this MOV, under the condition of it fully opens (condition 1) and the condition of it 80% opens (condition 2), are the same.
- When this MOV opens to 9% of the stroke (or 0.657 inch), the differential pressure across the valve is 251 psid.
- When this MOV opens to 98% of the stroke its L/D value is 13.

The Calculation

Per Reference 1, we have the following equations:

Equation (1) the DP across valve:

$$\Delta P = \frac{\rho}{62.4}(\frac{Q}{C_v})^2 \qquad (1)$$

Equation (2) the relationship between C_v and K:

$$C_v = \frac{29.9d^2}{\sqrt{K}} \tag{2}$$

Equation (3) the relationship between K and L/D:

$$K = \left(f \frac{L}{D} \right) \tag{3}$$

Where:

ΔP : DP across valve (psid)
ρ : Fluid weight density (lb / ft^3). The value does not change under condition 1 and 2
d: internal diameter (inch)
Q: flow rate through the valve (gpm). The value does not change under condition 1 and 2
f: friction factor
C_v: Valve flow coefficient
K: resistance coefficient
L/D: equivalent length of a resistance to flow, in pipe diameters

Based on the three equations, we can have the relationship between valve DP change and valve L/D change when the valve is at different stroke positions (from condition 1, valve fully open, to condition 2, valve 80% open).

$$\frac{DP_1}{DP_2} = \frac{(L / D)_1}{(L / D)_2} \tag{4}$$

Values known when the valve fully opens: (L/D) or $(L / D)_1$ is 13 and DP or DP_1 is 0.145 psid.

Also, this MOV's valve disc would clear the seat at about 9% of travel from full closed (9% of the 7.3 inch stroke is 0.657 inch). At this position, the DP across this MOV (DP_0) is 251 psid.

The (L/D) value $(L/D)_0$ when valve travels to 9% of stroke is:

$$\boxed{(L/D)_0 = \frac{DP_0}{DP_1}(L/D)_1 = \frac{251}{0.145452} * 13 = 22433.5}$$

The valve disc would clear the flow passage at about 98% of travel. When valve travels to 7.15 inches (98% of 7.3 inches), its L/D is 13.

Based on the above two valve position data and the information that the L/D between the valve clearing the seat and the valve clearing the flow passage would be considered linear, we can have the following equation to calculate L/D from valve stroke δ (in inches).

$$(L/D) = -3453\delta + 24701.95 \qquad (5)$$

From Equation (5) we can calculate (L/D) number when EJHV8804A is at 5.84 inches open:

$$\boxed{(L/D)_2 = -3453 * 5.84 + 24701.95 = 4536.55}$$

The DP across this MOV when it fully opened is known to be:

$$DP_1 = 0.145452 \quad psid$$

From Equation 4, we can have the DP across EJHV8804A when it is at 5.84 inches open:

$$\boxed{DP_2 = \frac{(L/D)_2}{(L/D)_1} * DP_1 = \frac{4536.55}{13} * 0.145452 = 50.75 \quad psid}$$

The calculation indicates that when this MOV changed from fully open to 80% open, the DP across the valve changed from 0.145 psid to 50.75 psid. Based on the calculated DP result, the Past Operability Determination can be made accordingly.

References

1. Flow of fluids Through Valves, Fittings, and Pipe, CRANE Technical Paper No. 410

Advances in the Design and Qualification of Main Steam and Main Feedwater Isolation Valves (MSIV & MFIV) with Gas Hydraulic Actuators

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Abstract

Flowserve has supplied valves for many of the critical applications within commercial nuclear power plants since the beginning of commercial nuclear power. The supplied valves include two of the more highly critical applications: Main Steam Isolation Valves (MSIVs) and Main Feedwater Isolation Valves (MFIVs). As the requirements of these two applications have evolved, so have the applicable valve and actuator designs and their qualifications.

Main Steam Isolation Valves (MSIVs) and Main Feedwater Isolation Valves (MFIVs) perform critical functions within commercial nuclear power plants. As a result, the valve and actuator design and qualification for the MSIVs and MFIVs must be effective in demonstrating the functional capability of these valves. The MSIVs and MFIVs must also satisfy qualification requirements addressing end of life aging and radiation exposure, seismic qualifications, and Design Basis Event Accident Environmental Qualification testing in accordance with the requirements of IEEE 323, 344 and 382. ASME has prepared ASME Standard QME-1-2007 that updates the functional qualification standard for active mechanical equipment in nuclear power plants.

This paper discusses:

- The history of MSIV and MFIV applications within nuclear power plants;

- MSIV and MFIV design history;
- MSIV and MFIV qualification methodology that satisfies ASME QME-1-2007; and
- Actuator environmental qualification to IEEE 323, 344 and 382.

Introduction

Main Steam Isolation Valves (MSIV) and Main Feedwater Isolation Valves (MFIV) are critical safety equipment in nuclear plants. The sole function of the MSIV and MFIV are to isolate the steam supply system and the feedwater supply system of the steam generators in the unlikely event of a steam or feedwater pipe break. This action prevents the blowdown of the steam generator and supports the heat removal from the nuclear-fueled reactor.

Today, for Pressurized Water Reactor (PWRs) and Boiling Water Reactors (BWRs), these valves must close quickly, typically within three to five seconds, and must operate successfully under all plant conditions including normal, emergency and accident situations, even if all normal power supplies fail.

History of Application

These critical valve applications have evolved since the start of commercial nuclear power generation. Initially, MSIVs were check valves and Y-pattern globe valves in Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs), respectively. Later PWRs utilized Y-pattern globe valves to better control the closure speed of the MSIVs.

Eventually newer plant designs took advantage of the more efficient flow characteristics of gate valves in place of Y-pattern globe valves. This created the need to use gas/hydraulic actuators to actuate the gate valves due to their longer stem travel and higher closure thrust requirements.

Quickly and reliably closing MSIVs, which can stand more than 16 feet tall (6.1m) and weigh more than 20 tons (20.3 metric tons), is no easy task. It requires several hundred-thousand pounds (900 kilo newton) of force to be delivered instantaneously. Refer to Figure 1 for a picture of a typical MSIV (gate valve) with the Flowserve Edward Type A, gas/ hydraulic actuator as currently designed and manufactured.

MFIVs have only been used in PWRs, not BWRs. Initial MFIVs were motor operated gate valves.

As plant technical design criteria became more demanding and required operational times to be reduced, electric motor operators could no longer close the MFIVs within the reduced operational times and pneumatic actuators with mechanical or compressed air springs were used in their place.

Today’s MFIV configuration is essentially the same as that of the MSIV depicted in Figure 1 but with a smaller gate valve and actuator.

MSIVs and MFIVs rely on low-pressure sensors on the steam and feedwater lines to trigger the MSIV and MFIV closure signals (control signal to the type A, gas/hydraulic actuator solenoid valves). This electrical signal causes the release of hydraulic fluid in the rod end of the actuator, allowing the high-pressure stored energy of the compressed type A, gas to drive the MSIV or MFIV closed.

For more than 30 years, gate valves equipped with gas/hydraulic actuators have been the safest, most reliable and cost-effective way to close MSIVs and MFIVs without depending on an external energy source. Their small size—compared to other available designs with comparable thrust and travel properties — translates into lower installation, operation, and energy costs.

In addition, industry tests have shown gas/hydraulic actuators are capable of performing safety-related functions under harsh conditions, such as high-radiation exposure, earthquakes, and potential plant accident environmental conditions, resulting from a loss of coolant (LOCA) or a main steam line break (MSLB) accidents.

The Flowserve – Edward Gas/Hydraulic Concept

Gas/hydraulic actuators rely on high pressure to open and close the valve. The actuator cylinder rod end is pressurized to open the MSIV and depressurized to close it. The depressurization of the rod end is controlled by the hydraulic circuit to regulate the rate or speed of MSIV closure.

The cap end of the cylinder contains a high-pressure gas accumulator. On the most recent designs, this accumulator is integral with the cylinder and when filled with gaseous nitrogen, provides the stored energy to drive the MSIV closed when required. Refer to Figure 2 for a general actuator cylinder and accumulator cutaway view.

To close the valve, a quick-release hydraulic circuit discharges the fluid from the cylinder rod end to a reservoir, permitting the stored energy of the pressurized gas of the cylinder cap end to extend the actuator. To open the valve, a hydraulic power unit pumps fluid to the rod end of the cylinder to drive the MSIV open and fully pressurize the nitrogen in the cap end accumulator.

While the concept is simple, the principle has to be delivered in a way that satisfies the reliability and redundancy requirements of a nuclear power plant.

The first requirement is that stored energy must always be available. Gas stored in remotely mounted accumulators could be unavailable when needed, especially if leakage occurs in the flexible connections between the accumulators and the valve. Even if accumulators are mounted on the valve, connections between accumulators and the actuator cylinder could be vulnerable to leaks or failures.

As a result, the most efficient and reliable actuators have a built-in stored-gas volume. In this instance, gas is stored in an accumulator coupled with the cap end of the actuator cylinder. Besides eliminating potential leaks, this design eliminates pressure losses during the stroking of the valve, which ensures quick closure. Whenever the MSIV is open, the stored energy to close the MSIV is always available.

Small Size Reduces Cost, Increases Safety

In the past, some nuclear plants used large, low-pressure actuators to close the equally large valves (typically size 16 to 32). These large actuators were expensive to purchase, install and maintain. In contrast, using smaller, high-pressure stored-energy systems to actuate valves minimizes costs. The actuators have a price advantage and are more energy efficient and reliable than earlier MSIV actuators.

Actuator performance during an earthquake is paramount to ensuring plant safety. Previous actuator designs were challenged to meet stringent seismic requirements due to their large size and piping connections. The small size and integral design of modern gas/hydraulic stored-energy actuators allow for reliable performance even during a seismic event, without sacrificing the power needed to reliably close the MSIV.

Safety-Related, Active Valve Qualifications

Since the MSIVs and MFIVs must be able to function during a seismic event and / or a nuclear plant accident in order to support the safe shutdown of the nuclear reactor, they are classified as active, safety-related components. As such, the MSIVs and MFIVs must complete functional and environmental qualifications tests in accordance with ASME QME-1 and IEEE 323, 344 and 382. These standards are defined as follows:

- ASME QME-1-2007, Qualification of Active Mechanical Equipment Used in Nuclear Power Plants;
- IEEE 323-1974-1983, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations;
- IEEE 344-1987, IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations;
- IEEE 382-1996, IEEE Standard for Qualification of Safety-Related Actuators for Nuclear Power Generating Stations

Flowserve MSIV and MFIV ASME QME-1 Qualification

ASME QME-1 functional qualification testing is utilized to verify that the safety-related, active valves will function during their postulated normal and accident events. MSIV and MFIV functional qualification tests include:

- Functional tests with maximum and minimum motive force;
- Hot and cold cycle tests;
- Sealing capability tests to confirm the valve seat and stem sealing capabilities;
- Fundamental frequency determination;
- Seismic tests to confirm the valve will function during a seismic (earthquake event);
- End load tests to confirm valve function and seal with applicable pipe loads inducted on the valve body nozzles;
- Flow interruption and functional capability test

Testing was performed in accordance with the 1994 edition of the test standard. However, the test program also meets the requirements of the 2007 edition of the standard.

Valves included in the testing are listed in Table 1.

Table 1, List of Test Valves

Size	Pressure Class Rating	Actuator Size	Power Plant Service
26x24x26	900	A-290	Main Steam Isolation
4	900	A-100	Main Steam Isolation
20x16x20	900	A-260	Feedwater Isolation
8x6x8	900	A-100	Feedwater Isolation

Typical valve design conditions are listed in Table 2.

Table 2, Valve Design Conditions

Valve Size	Pressure (psig)	Temperature (^oF)
26 x 24 x 26	Saturated Steam	564
4	1390	564
20 x 16 x 20	2100	564
8 x 6 x 8	2100	564

The ultimate goal of the test program was to provide a test data base that could be used to extend the qualification to valves that were not tested.

Consequently, analytical models were developed to calculate critical parameters, including natural frequency, static deflection, and required valve closing force. The data from the test program was used to verify and validate these analytical models. This provides the basis for extending the qualification to valve which were not tested.

A closed form mathematical model was used to determine required valve closing force during the flow interruption test. The model includes the valve stem ejection load, packing friction and the internal friction load resulting from the gate sliding on the internal valve body guides.

Three-dimensional finite element models, in addition to a closed form approach, were used to calculate valve assembly natural frequencies and deflection resulting from the application of the simulated seismic load on the valve upper structure. The 3D finite element models allow a more exact representation of the weight distribution of the valve assembly.

Baseline testing was performed between each phase of the test program for each valve. During the baseline testing, main seat and valve stem packing leakage were tested and measured.

Following completion of the test program, the valves were disassembled and inspected for damage resulting from the test program.

Most Recent Gas/Hydraulic Actuator Design Advances

Due to its many plant installations and many years of installed life, the Flowserve gas/hydraulic stored-energy actuator provides a sound basis for customer operational feedback. This feedback provides the knowledge source for continuous design improvements. With this knowledge and the drive to enhance the actuator design to gain longer maintenance intervals and the use of environmentally friendly hydraulic fluids, the Flowserve gas / hydraulic actuator design was updated to include:

- Longer-life solenoid coils;
- Longer-life seals;
- Polyol-ester hydraulic fluid;
- Pressure transmitters for monitoring actuator gas/hydraulic pressures;
- Quick disconnects for actuator wiring;
- Redundant electric motor driven hydraulic pumps.

The change in soft materials (seals, solenoid coils) increases the qualified thermal lifetime (maintenance interval) of the actuator from 5 years (122°F) to 12 years (130°F). The change in hydraulic fluid reduces the disposal efforts and costs plus is much easier for maintenance personnel to work with. The addition of the pressure transmitters allows diagnostic monitoring of the actuator while in service. The quick disconnects simplify maintenance by simplifying removal of the wiring connections. The redundant hydraulic pumps improve reliability.

Flowserve Environmental Qualification of the Gas/Hydraulic Actuator

Along with the design changes that have been made to the actuator, the effects on the actuators' operation and environmental qualification were evaluated. A prototype actuator was fitted with the new seals, solenoid valves, and hydraulic fluid and functionally verified to meet all of the requirements.

However, as several of the actuator safety-related components changed, the enhanced gas / hydraulic actuator required environmental requalification to the above IEEE seismic and environmental standards. These standards require that the actuator be aged to an equivalent "end of life" condition and then demonstrate the ability to reliably perform the safety-related function.

Flowserve has qualified the actuator twice previously in accordance with the relevant IEEE test standards. However, changing the seal material, changing the hydraulic fluid, and adding the pressure transmitters and quick disconnects required that the enhanced gas / hydraulic actuator be environmentally re-qualified in accordance with the above IEEE seismic and environmental standards.

The qualification test program included the following test phases:

- Thermal aging;
- Mechanical wear aging;
- Radiation aging;
- Vibration aging;
- Multi-frequency SSE/OBE testing in accordance with IEEE-382;
- Resonance search testing (1-100 Hz);
- Single frequency SSE/OBE RIM testing (3.3 g OBE, 5.0 g SSE);
- Design Basis Even (DBE) simulation with peak transient temperature of approximately 500°F.

During DBE testing, the Actuator was actuated to "close the MSIV" at the time of the peak temperature of the DBE test. After the actuation was completed, the rupture disk on the environmental chamber burst, stopping the test. The Actuator was retracted and extended to demonstrate functionality. The rupture disk was repaired and the test resumed. After 2 weeks at 150°F, the test was completed. Following very minor maintenance to non-safety related components, the actuator was retracted and extended as a demonstration of functionality.

Conclusion

As a result of the above efforts to develop an enhanced actuator design and satisfy the functional qualification requirements in accordance with ASME QME-1 and the environmental qualification requirements in accordance with IEEE 323, 344 and 382 for the MSIV and MFIV applications, Flowserve now has the most advanced and qualified MSIV and MFIV design (valve and actuator) available to the global commercial nuclear power generation market. The MSIV and MFIV designs and qualifications support installation in current operating nuclear plants as well as the new globally available Generation 3 and 3+ nuclear power plants.

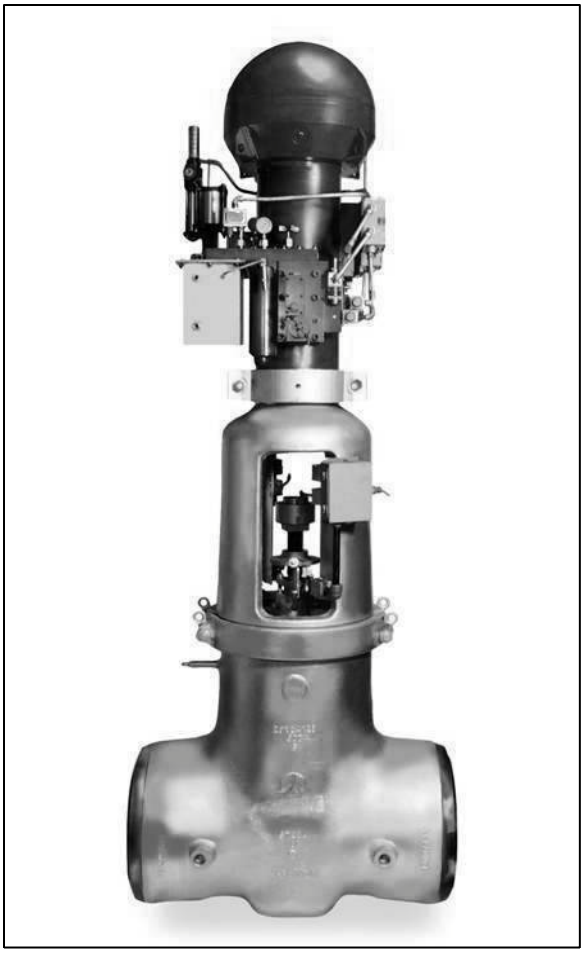

Figure 1, A Typical MSIV (Gate Valve) with a Flowserve Edward Type A, Gas / Hydraulic Actuator as Currently Designed and Manufactured Today.

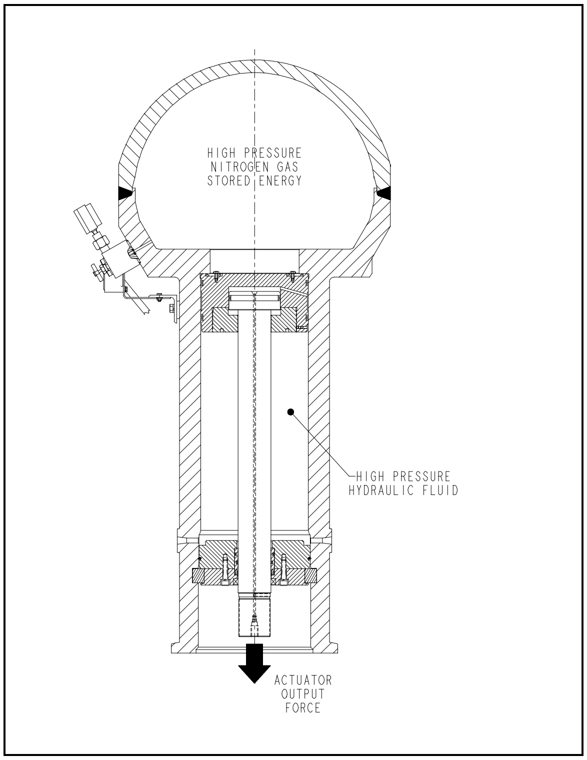

Figure 2, Cutaway View of the Flowserve Edward Type A, Gas / Hydraulic Actuator Cylinder Assembly.

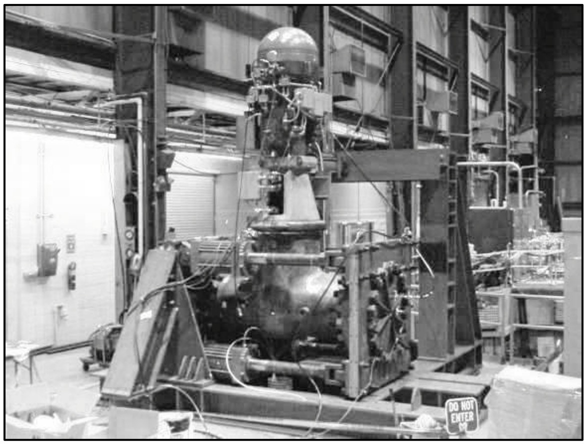

Figure 3, Flowserve MSIV (Equiwedge Gate Valve With Type A Gas / Hydraulic Actuator) Setup During the Static Seismic Tests and the Pipe End Loads Tests.

Figure 4, Flowserve Edward Type A, Gas / Hydraulic Actuator During the Dynamic Seismic Tests, Triaxial – Random Multi-Frequency Input.

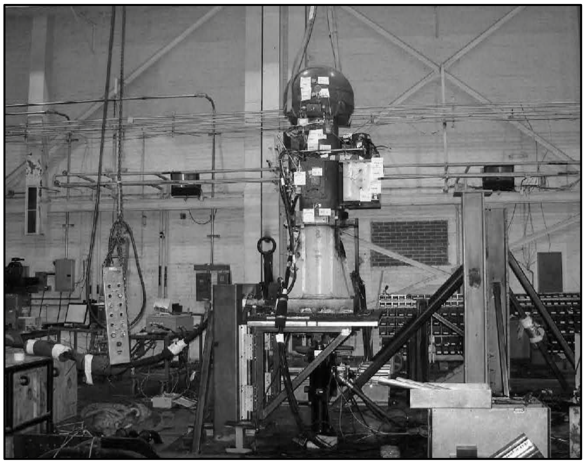

Figure 5, Flowserve Edward Type A, Gas / Hydraulic Actuator During the Dynamic Seismic Tests, Single Axis – Vertical Input.

Figure 6, Flowserve Edward Type A, Gas / Hydraulic Actuator After the Design Basis Accident (DBA) Tests.

A Practical Method to Baseline Check Valve UT

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Abstract

With the updates of the Pump and Valve Inservice Testing programs, a new requirement is being implemented to verify check valves in both the open and closed positions. Implementers of the new ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) have found out during this transition that many systems were not designed to use traditional methods for check valve close verification. This has led to the increased reliance on nonintrusive examinations as opposed to the more expensive option of disassembly and inspection.

In many of these cases, the check valves are not in a system application that lends itself to the successful implementation of the traditional acoustic method in combination with magnetic or eddy current verification. Other options in use include boroscopic inspections, radiography, or the most expensive option of disassembly and inspection. In recent years, a new method has been successfully used as an alternative. The use of Ultrasonic Testing (UT) techniques can be used to verify check valve position. This method of nonintrusive examination has been used for several years now and is established as a low cost, very convenient means of verifying check valve position.

Introduction

With the updates of the Pump and Valve Inservice Testing programs, a new requirement is being implemented to verify check valves in both the open and closed positions. Implementers of the new ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) have found out during this transition that many systems were not designed to use traditional methods for check valve close verification. This has led to the increased reliance on nonintrusive examinations as opposed to the more expensive option of disassembly and inspection.

In many of these cases, the check valves are not in a system application that lends itself to the successful implementation of the traditional acoustic method in combination with magnetic or eddy current verification. Other options in use include boroscopic inspections, radiography, or the most expensive option of disassembly and inspection. In recent years, a new method has been successfully used as an alternative. The use of Ultrasonic Testing (UT) techniques can be used to verify check valve position. This method of nonintrusive examination has been used for several years now and is established as a low cost, very convenient means of verifying check valve position.

Check Valve UT Baseline

As with any form of nonintrusive examination, getting started with the valve in a known good condition is the key to success for future measurements. This is known as establishing a baseline, or a result that sets the standard for comparison with future measurements for the purposes of verifying the component is operating acceptably. The UT baseline is best established after verifying the valve is in good condition, or after the valve has been restored to a good condition. This paper will describe a practical method to effectively establish a baseline condition for future UT measurement.

The check valve shown in Figure 1 is an 18” bonnet hung check valve manufactured by Borg Warner.

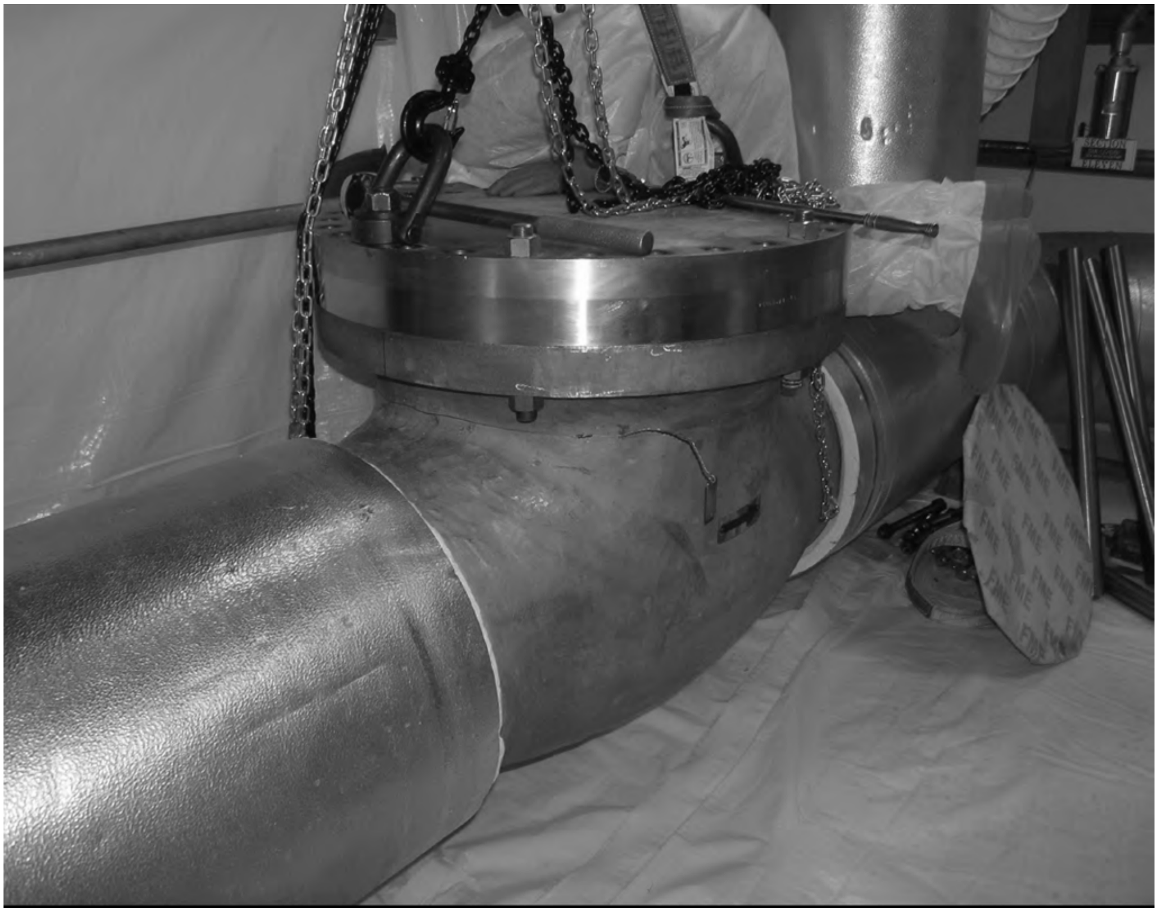


Figure 1 – 18” Borg Warner Bonnet Hung Swing Check

Some information can be obtained from the valve nameplate as shown in Figure 2. Most importantly, this can be used to confirm the right valve drawing is used for the valve of interest.

Figure 2

Information on the nameplate in Figure 2 includes the valve serial number, manufacturer’s part number, design pressure, size, weight and material of construction.

Figure 3 shows the inside of the valve body while it is being completely drained of water.

Figure 3 – Inside the Check Valve Body

Figures 4 and 5 show the bonnet hung assembly itself. Notice the nut on the stud holding the disc on the swing arm. This is the target area for the UT signal when the valve is assembled. If the nut flat is perpendicular to the valve body at the time UT is conducted, a nice strong return signal will show up on the UT meter. If it is at an angle with respect to the surface of the valve body, this return signal will not be as strong. This is normally the case, which means it is very important to know the distance range of interest for inspection when shooting through the valve's body.

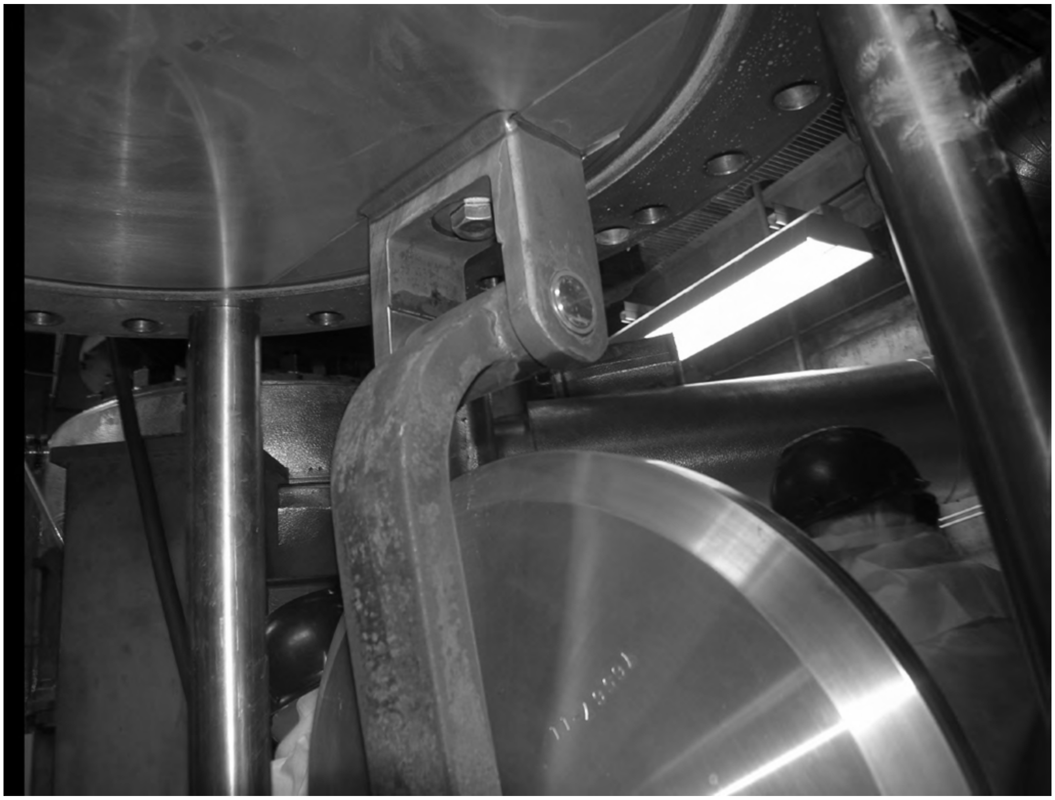


Figure 4 – Valve Bonnet Hung Assembly Upper

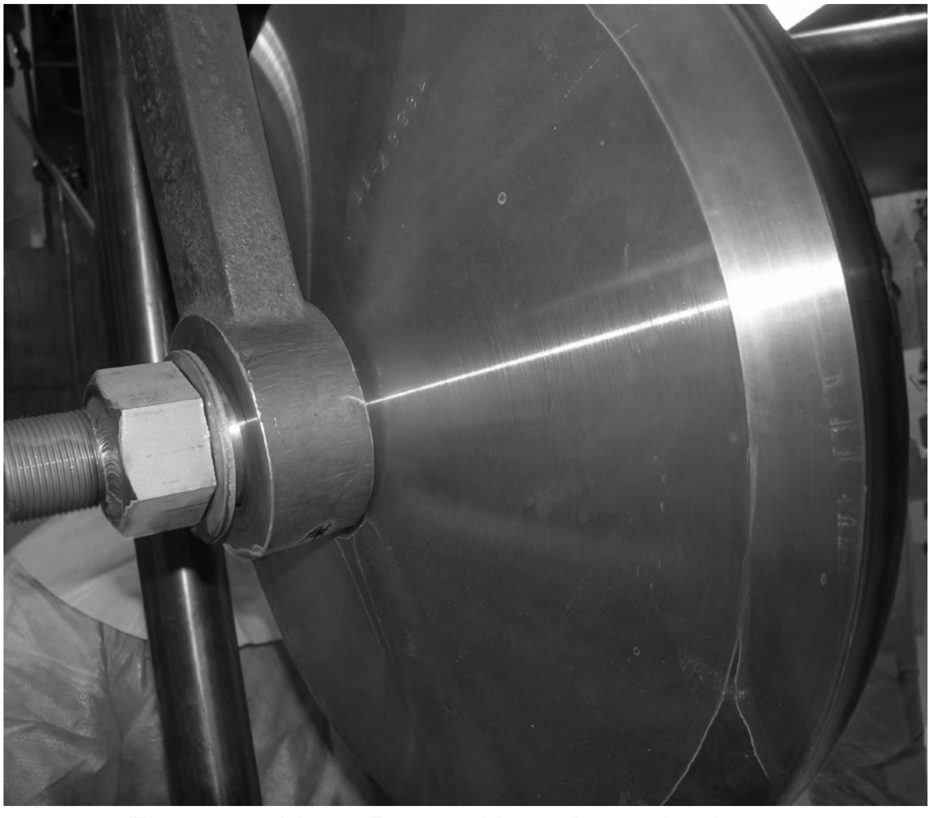


Figure 5 – Valve Bonnet Hung Assembly Lower

The physical inspection of the valve concluded that the disc and seat were in good shape, but rework was needed to optimize the distance between the disc nut and the disc arm. This can be seen in Figure 5. Operating experience with this particular type of valve has shown that this area needs to be carefully controlled within specific parameters to ensure the valve's reliability over a long period of time. After this maintenance is complete, the valve is ready to be re-assembled. The valve is now considered to be in as good or better condition than when it was originally received from the factory.

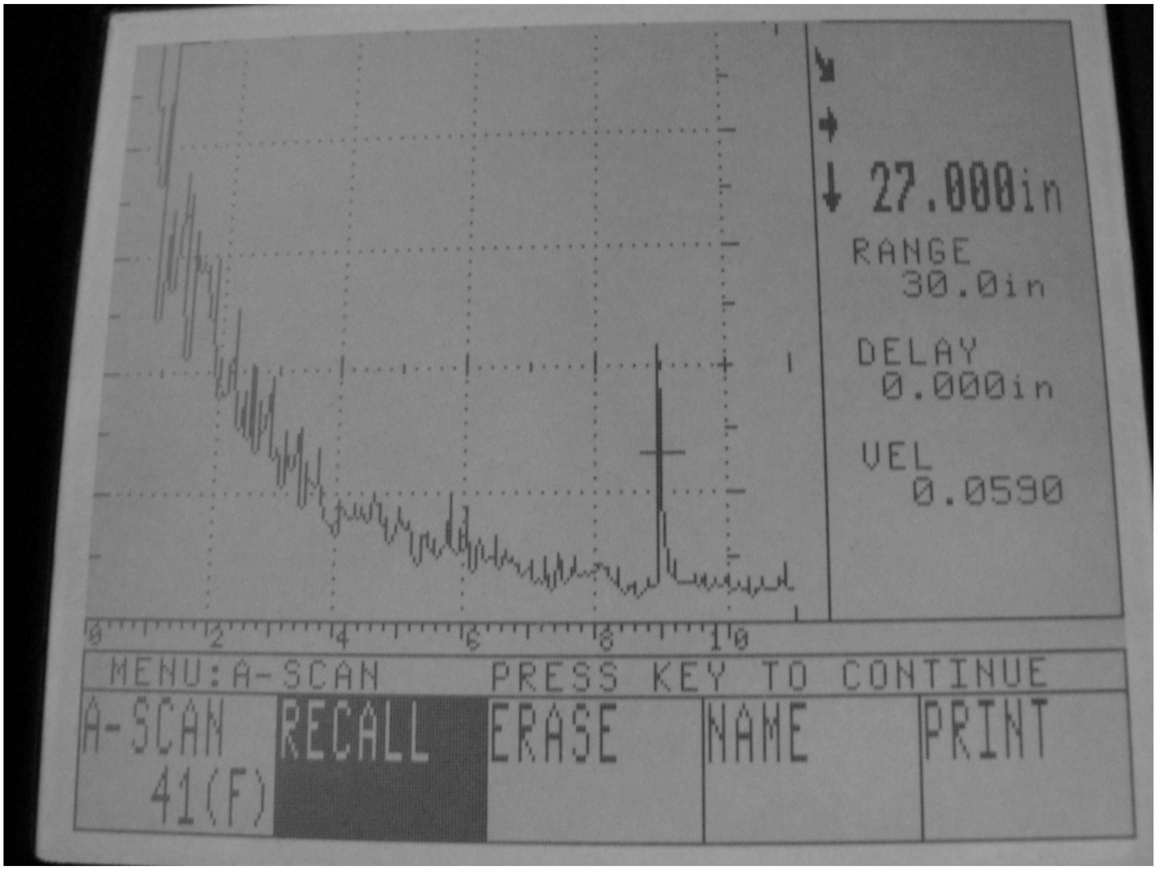
The process of physically disassembling and inspecting a check valve is the only means available to truly assess a check valve's condition. An important note – it is a process that includes disassembly to the degree necessary to measure the wear surfaces of mating parts. When this process is complete, record some dimensions in preparation for establishing the baseline measurement. Measure the bottom of the valve bonnet to the bottom of the disc nut. The measurement does not have to be exact, i.e. estimation with a tape measure using the thickness of the valve body and the distance from the valve nut to the bottom of the valve body that is perpendicular to the flow stream is sufficient. This measurement will establish a target range that should correlate approximately with the drawing provided by the manufacturer.

Another set of dimensions can also be useful - the distance from the bottom of the valve body bottom to the top of the valve at the bottom of the valve bonnet. A measurement through the valve with UT can be used to show there are no obstacles impeding the sound path, which may be used as an indication the valve is not stuck open. The geometry of the check valve with respect to the ability of the disc to get stuck under the top of the valve seat opening should be used with this method. The measurement will typically be able to determine if the check valve is in the full open position. The detection of a valve in the partial open position using UT, such as when the valve disc has dropped on the valve seat far enough to stick under the top of the valve seat opening, will depend upon where the measurement can be taken and where the edge of the bottom of the valve disc resides when the valve becomes stuck open.

When the valve has been returned to service and the system is filled and vented, a baseline reading should be obtained. Do not be disappointed if the distance from the bottom of the valve body to the top of the valve at the bottom of the valve bonnet cannot be obtained at this point. Any amount of air left in the top of the valve will impede the UT sound path. The baseline dimension is from the bottom of the valve body to the disc nut. Remember there will be some refraction through the valve metal body and again when the system fluid is encountered by the UT sound beam. The optimum measurement location will typically be slightly downstream from the area directly under the disc nut.

The baseline reading from the bottom of the valve body to the bottom of the valve nut will correlate to the physical reading taken with the valve disassembled. If your UT scope is properly calibrated between successive measurements, the same result can be used to demonstrate the valve wear surfaces, such as the hinge pins and bushings, are not degrading when the same results are obtained. Obtaining the exact same results every time is unlikely, however, and a determination will have to be made when successive measurements are trended. If the distance gets shorter in successive measurements for example, increased monitoring may be called for to confirm a trend towards failure. This will obviously be easier to detect and confirm in time for larger valves before a performance problem potentially occurs than for smaller valves.

Other methods can be used for establishing a UT baseline, but disassembly and inspection is the most superior method as the only means available to determine the check valve's physical condition. The measurements conducted during the physical inspection of the check valve concluded there was about 27" from the bottom of the valve body to the top of the valve at the bottom of the valve bonnet. A good vent was obtained when this valve was put back into service, which enabled a through valve measurement as shown in Figure 6 to demonstrate the valve disc was not stuck open impeding the sound path.



27.000in

RANGE
30.0in

DELAY
0.000in

VEL
0.0590

Figure 6 – UT Test Result From Valve Body Bottom to Bonnet

Measurement of the valve body bottom to disc nut resulted in an average distance of 12” between the bottom of the valve body and the disc nut with a difference of about ± 0.375” depending on the orientation of the disc nut as a reflective surface. Figure 7 shows the results obtained when measurement was conducted.

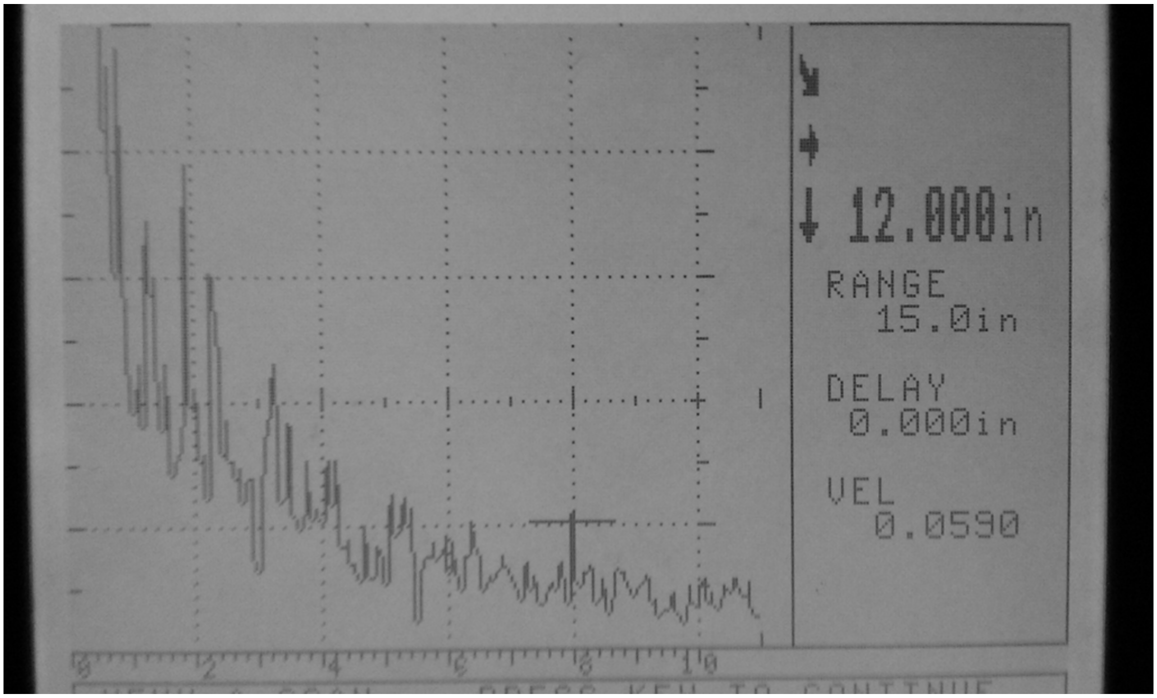


Figure 7 – Valve Body to Disc Nut UT Measurement

The combination of disassembly and inspection with UT for obtaining a baseline measurement provides for a confident measurement. The valve drawing in this case was found to be to scale with respect to the distance from the bottom of the valve body to the disc nut. This is not always the case and experience has shown it is advisable to use a physical measurement, even if it is only an external measurement to approximate the distances expected using a tape measure. Experience has also shown the centerline of valve drawings have typically been representative of the actual. This knowledge can be helpful when a baseline method other than disassembly and inspection must be utilized.

Conclusion

A UT baseline is a low cost, very convenient means of verifying check valve position. Before determining valve position, establishing a baseline that sets the standard for comparison with future measurements is a requirement for verifying the component is operating acceptably. The valve should be in a known good condition to assure an appropriate baseline and success in future measurements.

Addressing MOVs in Transition to NFPA 805

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Abstract

As of December 2010, more than 45 U.S. nuclear plants have submitted letters of intent to transition their existing Fire Protection Program to a risk-informed, performance-based program based on National Fire Protection Association Standard 805 (NFPA 805), “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants.” NFPA 805 allows the use of performance-based methods, such as fire modeling and fire risk evaluations, to demonstrate compliance with the nuclear safety performance criteria. The transition to NFPA 805 requires a methodical evaluation of safe shutdown scenarios based on fire risks. This process includes evaluations of numerous motor operated valves (MOVs) that could potentially be impacted due to fire-induced “hot-shorts” (e.g., spurious actuation, motor stall). Although the MOV “hot-short” issue is similar to that identified already in generic Nuclear Regulatory Commission (NRC) Information Notice (IN) 92-18, “Potential for Loss of Remote Shutdown Capability During a Control Room Fire,” the potential scope of MOVs impacted may be different based on fire locations and system interfaces.

As one of the lead plants, Shearon Harris has completed a significant number of evaluations of MOVs to support the transition to NFPA 805. This required defining and developing a thorough process and establishing appropriate methods and criteria for the evaluations. The process applied included a re-evaluation of the safe shutdown list to identify susceptible MOVs, applying MOV screening criteria, and performing detailed MOV evaluations for motor-stall analyses.

However, for the NFPA 805 risk evaluations, these evaluations took on a different perspective relative to the methods and criteria applied previously. In particular, the NFPA 805 evaluations for the safe shutdown equipment included reviews of systems not needed for safe shutdown but could impact required systems in ways not previously considered. The evaluations had to consider any MOVs (and other energized valves) in the non-required systems that, if spuriously operated and challenge the pressure boundary, could have an adverse impact such as flow diversion from the credited path, loss of water from supply tanks, etc. For example, while Containment Spray is not credited for Safe Shutdown, a loss of pressure boundary of certain valves would result in a loss of inventory from a tank that was credited in Safe Shutdown (i.e., the Refueling

Water Storage Tank). As a result, the evaluations had to address the pressure boundary integrity for a significant number of valves, including many non-active MOVs not already addressed in the Plant MOV Program. In many of these cases, additional analyses were required to address the pressure boundary integrity issue, including establishing analysis criteria.

The purpose of this paper is to describe the process used, highlight key methods and criteria applied, and identify important lessons learned in evaluating MOVs to support the transition to an NFPA 805 based Fire Protection Program.

Introduction

Purpose

Progress Energy's Shearon Harris Nuclear Plant (HNP) is one of the lead U.S. nuclear plants transitioning their existing Fire Protection Program to a risk-informed, performance-based program based on National Fire Protection Association Standard 805 (NFPA 805), "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." To support this transition, HNP has performed a significant number of evaluations of motor operated valves (MOVs) that required defining and developing a thorough process and establishing appropriate methods and criteria for the evaluations. The purpose of this paper is to describe the process used, highlight key methods and criteria applied, and identify important lessons learned in evaluating MOVs to support the transition to an NFPA 805 based Fire Protection Program.

Background

On June 16, 2004, the U.S. Nuclear Regulatory Commission (NRC or the Commission) revised Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "Domestic Licensing of Production and Utilization Facilities," to include Paragraph 50.48(c). Section 48, "Fire Protection," Paragraph 50.48(c), "National Fire Protection Association Standard NFPA 805," incorporates by reference NFPA 805, "Performance Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition (Reference 1), hereafter referred to as NFPA 805. This change to the NRC's fire protection regulations provides licensees with the opportunity to adopt a performance-based fire protection program (FPP) as an alternative to the existing prescriptive, deterministic fire protection regulations. Specifically, NFPA 805 allows the use of performance-based methods, such as fire modeling and fire risk evaluations, to demonstrate compliance with the nuclear safety performance criteria.

As of December 2010, more than 45 U.S. nuclear plants (see Table 1) have submitted letters of intent to transition their existing Fire Protection Program to a risk-informed, performance-based program based on NFPA 805. As one of the lead plants, HNP has implemented a transition from the existing deterministic fire protection licensing basis established in accordance with Section 9.5.1 of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: Light Water Reactor Edition" (Reference 2), to a performance-based fire protection program in accordance with 10 CFR 50.48(c) that uses risk information, in part, to demonstrate compliance with the fire protection and nuclear safety goals, objectives, and performance criteria of NFPA 805.

Before transitioning to NFPA 805, 10 CFR 50.48(c)(3)(ii) states that "the licensee shall complete its implementation of the methodology in Chapter 2 of NFPA 805 (including all required evaluations and analyses)". The evaluations and analyses process in Chapter 2 of NFPA 805 provide for the establishment of the fundamental fire protection program, identification of fire area boundaries and fire hazards, determination by analysis that the plant design satisfies the performance criteria*, identification of the structures, systems and components (SSCs) required to achieve the performance criteria*, conduct of plant change evaluations, establishment of a monitoring program, development of documentation, and configuration control.

The HNP transition to NFPA 805 required a methodical evaluation of safe shutdown scenarios based on fire risks. This process included identification and evaluations of numerous motor operated valves (MOVs) that could potentially be impacted due to fire-induced "hot-shorts". Although the MOV "hot-short" issue is similar to that identified already in generic NRC Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," the potential scope of MOVs impacted was different based on fire locations and system interfaces, especially relative to potential impact on the valve pressure boundaries. As such, for a successful transition to NFPA 805, the potential effect of the fires on the plant MOVs and the subsequent consequences (e.g., spurious actuation, motor stall) had to be addressed.

NFPA 805 Requirements and Approach for MOVs

Basic Requirements

NFPA 805 Chapter 1 defines the Nuclear Safety and Radioactive Release performance criteria that the fire protection program must meet in order to be in accordance with NFPA 805. It states that the fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. The plant must demonstrate the criteria are met in areas such as reactivity control, inventory and pressure control, and decay heat, etc. Chapter 2 of NFPA 805 identifies the following steps to be performed:

1. Selection of systems and equipment and their interrelationships necessary to achieve the nuclear safety performance criteria above
2. Selection of cables necessary to achieve the nuclear safety performance criteria in Chapter 1
3. Identification of the location of nuclear safety equipment and cables
4. Assessment of the ability to achieve the nuclear safety performance criteria given a fire in each fire area

In essence, transitioning to an NFPA 805 fire protection program required HNP to perform a re-validation of the post-fire Safe Shutdown Analysis (SSA). However, for the NFPA 805 risk evaluations, the SSA required an assessment of interconnected systems as well that were not credited for safe shutdown, but whose components could still affect the shutdown when impacted by a fire.

In particular, the NFPA 805 includes requirements for assessment of multiple spurious operations. NFPA 805 states that the circuits required for the nuclear safety functions shall be identified, and that this includes circuits that are required for operation, that could prevent the operation, or that result in the mal-operation of the equipment identified in the Nuclear Safety Capability Systems and Equipment selection. This evaluation is required to consider fire-induced failure modes such as hot shorts (external and internal), open circuits, shorts to ground, and to identify circuits that are required to support the proper operation of components required to achieve the nuclear safety performance criteria, including spurious operation and signals.

As a result, the HNP NFPA 805 evaluations for the safe shutdown equipment were different than that applied in the original safe shutdown equipment selection in that systems not needed for safe shutdown could still impact required systems. For example, spurious opening of non-active cross-tied system valves could result in diversion of flow or inadequate cooling flow. Similarly, these valves could have directed flow downstream to another valve that may or may not have been evaluated in the existing safe shutdown analysis because its mal-operation had no impact on the system. However, a breach of the pressure boundary of that downstream valve could then have an impact on the system.

Key Requirements for HNP MOVs

For the HNP MOVs, a re-evaluation of the Safe Shutdown Analysis (SSA) Safe Shutdown Equipment List (SSEL)[1] was required that included the assumption that the valves will be subjected to a “hot short” motor stall event as described by Information Notice (IN) 92-18 "Potential for Loss of Remote Shutdown Capability During a Control Room Fire" (Reference 3). However, the scope of the MOVs that had to be considered included system interface valves within all the postulated fire areas, i.e., beyond the control room fire scenario identified in IN 92-18. In addition to evaluating the electrical susceptibility of these valves to a hot-short as described in IN-92-18, the potential impact of a subsequent motor stall on the valve pressure boundary also required evaluation.

In each of these cases, the evaluations had to consider any MOVs (and other energized valves) that, if spuriously operated and break the pressure boundary, could have an adverse impact such as flow diversion from the credited path, loss of water from supply tanks, loss of pressure or net positive suction head (NPSH), etc. As such, the evaluations had to consider potential for impacts on the pressure boundary integrity of a significant number of valves, including many non-active MOVs which were not

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[1] The SSA SSEL is equivalent to the NFPA 805 Nuclear Safety Capability Systems and Equipment List.

previously addressed in the MOV Program for NRC Generic Letter (GL) 89-10 (Reference 4).

For compliance with the NFPA 805 requirements, the HNP MOV IN 92-18 analyses supporting the SSA re-evaluation had to demonstrate that either of the following functions were satisfied when the MOV was subjected to a “hot short”:

- MOV can maintain position, or
- MOV maintains pressure boundary integrity (“passive MOVs”).

For these MOV IN 92-18 “hot-short” evaluations, it was assumed that the inherent protective components (i.e. overload switches, etc) did not function properly and a motor stall event was caused. Also it was assumed that the MOV is not protected against mechanical overload.

[Note: Although not covered in this paper, other actions could also be taken to minimize fire-induced spurious actuations of the MOVs. In some cases, for example, this can be accomplished through procedural changes to de-energize the motors for those MOVs not required for normal operation or credited during accidents.]

HNP Approach to Identify Susceptible MOVs

At HNP, the specific steps applied in the re-evaluation of the SSEL to identify susceptible MOVs were as follows:

1. Performed Safe Shutdown Equipment Selection – The potential valves requiring evaluation were initially identified based on a systematic review of each system required for safe shutdown. This included consideration of the system functional and performance requirements, operational alignments, and the following specific activities:
   a. Reviewed System Flow Diagrams – The flow paths required to satisfy the safe shutdown criteria were identified.
   b. Identified Active and Boundary valves – For each required flow path, the specific valves that could be actuated and their functions were identified, including the potential impact of a fire induced spurious actuation on the flow path.

2. Re-Validated Safe Shutdown Analysis to identify success paths – Each flow path was either verified as not being impacted by the fire or any spurious valve actuations, or potential alternate flow paths were identified and evaluated. For active MOVs, this included reviews of circuitry and controls to determine mitigating features, if any.

3. Identified any Required (Manual) Action – Based on the potential alternate flow paths, reviews were performed to identify potential operational workarounds for selected MOVs, especially where the valves had a significant impact in the risk

based evaluations for satisfying the shutdown criteria but were subjected to a "hot-short" motor stall. This step included the following activities:

a. Identified any Required (Manual) Action that requires usage of Motor operated valves – This evaluation assessed the need to demonstrate the capability of a valve to continue functioning and be repositioned with manual action assuming either the valve was de-energized or the motor-operator was no longer functional.

b. Perform classical IN 92-18 evaluation to insure that the valve can be manually operated - Where needed, this evaluation was performed to demonstrate that the valve function with a manual actuation was or was not impacted by the occurrence of a "hot-short", even if the motor actuator portions became un-functional.

4. Evaluated Valves to Ensure Pressure Boundary is Intact – For each of the MOVs identified within the flow paths and at the boundaries, an evaluation of the valve capability to maintain pressure boundary integrity was performed assuming the fire induced "hot-short" resulted in a motor stall. This process included identification of other potential valves not previously required for Safe Shutdown and re-consideration of selected boundary isolations.

NOTE: The following evaluation is different than the original Safe Shutdown Equipment Selection, in that systems not needed for Safe Shutdown can still impact required systems.

a. Re-Reviewed System Flow Diagrams – Similar to step 1a above, a review was performed with a specific purpose to identify Motor Operated, or other valves that, if spuriously operated and break the pressure boundary, could have an adverse impact such as:

- Flow diversion from the credited path
- Loss of water from supply tanks
- Loss of system pressure (pump NPSH)
- Blockage of Credited Safe Shutdown Walk Paths
- Obscuration of Credited Safe Shutdown Lights.

In these cases, the review extends beyond standard safe shutdown boundary until the next isolation point was reached (i.e., closed manual valve, check valve, e.g., a non-MOV).

b. Screened Out Non-Susceptible Motor Operated Valves - From the population of valves identified in sub step 4a, several screening criteria were applied to eliminate consideration of valve designs where the pressure boundary integrity would not be challenged by a "hot-short" motor stall. This included elimination of the following design types:

- Valves with Hydromotor Actuators
- Butterfly valves
- Other quarter-turn and rotary valves where continued rotation will not impact the valve pressure boundary.

In addition, valves with the following characteristics were also determined to not require further evaluation and were removed from the scope:

- Valves in “pre-fire rackout” (not normally energized during plant operation)
- Valves in lines sizes where it can be shown that diversion loss does not affect flow for credited path (e.g., equal to or less than ¾” in size).

c. Performed stall evaluation of the MOV pressure boundary integrity – An evaluation of the MOV valve pressure boundary integrity assuming a IN 92-18 “hot-short” motor stall was performed as discussed further below.

HNP MOVs Identified for IN 92-18 Evaluation

Based on the assessment of the MOVS under the NFPA 805 program, HNP identified over 190 MOVs that are subject to a motor stall event during safe shut down. As identified above, the SSA defines the functional requirements for MOVs subjected to a motor stall as:

- the valves must maintain position (i.e., protected from a “hot-short”), or
- the valves only need to maintain pressure boundary integrity under a motor stall event.

Based on the application of the criteria above, HNP concluded that 71 valves required further evaluation with regard to demonstrating their capability to maintain pressure boundary integrity following an IN 92-18 postulated “hot-short” motor stall condition. These valves were all classified as “passive MOVs” that must maintain pressure boundary integrity but were not required to remain operable during or following a stall event.

The paragraphs below include selected examples demonstrating how of several of the MOVs were identified during the SSEL Re-evaluations process.

Example 1: For HNP, the Containment Spray System is not credited for Safe Shutdown. However, this system is connected to the Refueling Water Storage Tank (RWST) which is required for Safe Shutdown as it supplies water to other systems including to the Residual Heat Removal (RHR) and/or Charging System. If certain valves in the Containment Spray system experienced a loss of their pressure boundary, this could drain water from the RWST. A detailed review of the Containment Spray System piping and instrument diagram (P&ID) flow paths identified valves 1CT-25 and 1CT-26 as potential MOVs whose pressure boundary failure could drain the required RWST. The applicable P&ID piping section is shown in Figure 1. Consequently, these valves were selected for further evaluation to ensure they would maintain pressure boundary integrity if subjected to an IN 92-18 postulated “hot-short” motor stall event.

Example 2*:* Based on the HNP Safe Shutdown analysis, the Auxiliary Feedwater (AFW) System is credited for feedwater flow to a credited Steam Generator. Should the Pressure Boundary be breached in an area of the AFW system that is supplying another Steam Generator, the flow to the credited steam generator would be reduced, i.e. a breach of the pressure boundary will allow the water going to the credited path to be diverted to the breached path. The impact would depend on the extent of the breach. For example, if sufficient water is still directed to the credited Steam Generator, the available volume needed to cool the plant will be reduced, by leaking out of the system. However, if the leak is large enough, the needed flow to the credited Steam Generator will not be available to supply an adequate Heat Sink for the Reactor Coolant System. Six different AFW System MOVs were identified in the P&ID flow paths shown in Figure 2 whose pressure boundary failure could impact the AFW flows. These valves were also selected for further evaluation to ensure pressure boundary integrity would be maintained if subjected to a motor stall condition.

Example 3: The HNP Turbine Driven Auxiliary Feedwater (TD AFW) pump is supplied steam through a trip and throttle valve (1MS-T). Valve 1MS-T has a motor operator that could be subjected to a IN 92-18 “hot-short” motor stall. The concern with this valve is if the pressure boundary fails, the area around the TDAFW pump (i.e., in the Reactor Auxiliary Building) can become filled with steam and manual actions are not feasible. However, this area is designated as a primary walk path on that elevation and is a credited walk path for Required Actions (Manual Operator Actions). Consequently, a loss of pressure boundary of valve 1MS-T and subsequent steam leaks could block the credited walk path and operators might not be able to perform an action, or the action may be delayed. As a result, this valve was selected for further evaluation to confirm the pressure boundary integrity would be maintained if subjected to a motor stall condition.

MOV Stall Pressure Boundary Evaluations

Approach

For the 71 valves identified as “Passive MOV’s” requiring further evaluation to determine the pressure boundary integrity under stall conditions, a three step approach was applied.

STEP 1: Existing HNP documents associated with each valve were reviewed to identify valve design information. The design information was used to establish common valve groups.

STEP 2: The design information and applicable valve evaluations were reviewed to identify limiting component capacities for the motor stall events. When component capacities were not identified in existing documents, additional information was obtained from the valve vendors or supplemented by new analyses using plant specific data. The valve component capacities were used to evaluate the valve pressure boundary integrity and the potential for a non-pressure boundary component (referred to as a “mechanical fuse”) failure during a motor stall event. In particular, the HNP documents were reviewed for each valve to identify the following conditions:

- The motor stall torque and thrust load,
- The valve weakest link capacities for both the opening and closing strokes
- The pressure boundary capacity for both the opening and closing strokes, and
- The mechanical fuse limiting load for both the opening and closing strokes, if necessary

STEP 3: The capacity of the pressure boundary component relative to either the motor stall load or the mechanical fuse capacity was quantified by calculating a margin. The following margin calculations were defined relative to the valve capacity:

1. Stall Margin: The weakest pressure boundary component capacity is greater than the maximum stall load. In this case, the margin is calculated as:

$$\text{Margin} = \frac{(\text{PB Load Limit} - \text{Max Stall Load})}{\text{PB Load Limit}}$$

2. Mechanical Fuse Margin: The maximum stall load exceeds weak link and pressure boundary limiting component capacities, but the weakest pressure boundary component capacity is greater than the load at which the mechanical fuse component will fail. In this case, the margin is calculated as:

$$\text{Margin} = \frac{(\text{PB } \mathit{Load}\text{Limit} - \text{Mech Fuse Load})}{\text{PB } \mathit{Load}\text{Limit}}$$

Additionally, the potential for stem failure and subsequent ejection through the packing was evaluated for each valve.

Figure 3 shows the general evaluation logic applied.

Criteria

Overall, an MOVs' pressure boundary integrity following a motor stall event was considered to be acceptable when:

- The capacity of the pressure boundary component based on ASME Code allowable stress exceeded the maximum stall thrust of the valve, or
- The capacity of the pressure boundary component based on ASME Code allowable stress exceeded the maximum load at which a non-pressure boundary component ("mechanical fuse") failed.

The criteria defined as applicable to the HNP motor stall events included the following:

- The functional limit and torque switches are postulated to fail during a motor stall event and cannot be credited to protect valve components from overload.
- The pressure boundary component capacity is based on the allowable tensile stress limit defined as the lesser of the minimum of yield strength or 0.7 times the ultimate strength at the process temperature.
- The non-pressure boundary component capacity is based on the primary stress limits defined as the lesser of 1.2 times yield strength or 0.7 times the ultimate strength. For shear, the allowable stress is the lesser of 0.72 times yield strength or 0.42 time ultimate strength.
- For evaluation of stall conditions, ASME Appendix F can be applied for both pressure boundary and non-pressure boundary limits, allowing for an increase in the stress from those listed above.
- Motor stall events are outside of the Design Basis of the plant and therefore exclude seismic loads.

In addition, "mechanical fuse" criteria were developed and applied. For HNP, a "mechanical fuse" was defined as the failure of a non-pressure boundary valve component that will eliminate transmission of the actuator load through the valve load path. This concept is based on fact that load limiting components (mounting bolts, valve stems, etc) can provide inherent protection under motor stall conditions. In the event that the stall thrust exceeds the weakest pressure boundary component capacity, an evaluation of a mechanical fuse is considered.

Weak Link and Motor Stall Results

Based on similarities in the valves characteristics, the 71 valves were categorized into 19 distinct valve groups. This included the following breakdown by valve vendor:

- Anchor/Darling Gate Valves (14 valves in 4 groups)
- Kerotest Globe Valves (4 valves in 1 group)
- Velan Gate and Globe Valves (18 valves in 4 groups)
- Westinghouse Gate Valves (30 valves in 8 groups)

- Yarway Globe Valves (4 valves in 1 group)
- Gimpel Globe Valve (1 valve in1 group)

For each valve group, an analysis of the load path during a motor stall condition was defined for both the open and close stroke directions based on review of the valve configuration and available weak link analyses. At HNP, additional efforts and procurement activities were required to obtain complete weak link analyses for the Kerotest, Yarway, and Gimpel valves. In particular, the valves in these groups were not active safety related valves in the HNP GL 89-10 MOV program, and so weak link calculations were not originally procured or required to be prepared by HNP. For some of these, the original valve design documents had to be re-constituted by the vendor. For others, a combination of vendor provided data and plant walkdown information was required to fully evaluate the valve loading conditions and weak link capacities.

In addition, HNP also needed to procure or prepare supplemental analyses for some of the Westinghouse, Anchor Darling, and Velan valves. In some of these cases, the approach applied in the original vendor supplied weak link analysis focused on load limits in only one direction, and/or limited the scope of component capacities evaluated based on conservative and worst case load conditions. These conditions, however, did not always represent the maximum load condition for the pressure boundary components when subjected to a spurious actuation with motor stall. As an example, the original vendor weak link analyses for some flex wedge gate valves only limited the analysis of the open stroke direction to valve internal components, where the load path evaluation assumed the valve disk remains wedged in the valve seats (i.e., the original weak link evaluations focused on the connection between the stem and disk). As such, they did not evaluate the potential valve bonnet pressure boundary loads assuming the stem/disk successfully unwedged and subsequently stroked until the stem reacted against the bonnet backseats.

In general, the existing weak link analyses calculated conservative capacity limits for valve components for use in limiting the MOV controlled outputs. However, for the NFPA 805 IN 92-18 evaluations, an analysis of all possible load paths in both stroke directions was needed with an initial assumption that the non-pressure boundary components did not fail. Further, many of the existing weak link analyses included additional design basis load conditions such as seismic loads and accident temperature and pressure conditions. In these cases, the component stress limits were also defined based on the Design Basis accident temperature conditions. For the NFPA 805 motor stall evaluations, the seismic loads were excluded and in several cases, the pressures and temperatures were adjusted to reflect the normal plant operating conditions (as allowed by the HNP procedures for the IN 92-18 motor stall conditions).

Maximum possible motor stall load values used in the NFPA analyses were calculated based on existing HNP procedural methodology. In particular, the maximum motor stall loads were based on the maximum motor torques calculated using maximum voltage conditions, vendor motor torque curves, and neglecting temperature heat losses. Further, the motor torque was converted to thrust using conservative stem friction coefficients (COFs) that either bound the test data available for the valve, or was based on a site defined conservative value. In many cases, the maximum stall load that was greater than the Limitorque actuator ratings.

For several valves where the motor stall load exceeded the pressure boundary load capacity, a “mechanical fuse” evaluation was performed. Some mechanical fuse capacity calculations existed in the weak link calculations. However, these analyses determined a limiting capacity for the component based on an allowable stress typically intended to preclude plastic deformation, as opposed to determining the load at which the component will fail completely with a high degree of certainty. Therefore, these mechanical fuse capacities were adjusted to use an ultimate strength of a material to allow determination of load at which the component is likely to fail and prevent further load transmission to the pressure boundary, referred to as the mechanical fuse load.

Margin Evaluation Results

The effect of the stall event on the valve was quantified by calculating margin. For initial screening purposes, the pressure boundary integrity was considered adequate when the stall margin was greater than 10% or the mechanical fuse margin was greater than 20%. Margins lower than these threshold values were evaluated further on an individual valve basis to determine if the level of conservatism included in the evaluation is adequate. The following conservatisms were considered when determining if low margin was acceptable:

- The capacity of the pressure boundary component is based on ASME Code allowable strengths and Code acceptance criteria that include inherent conservatisms and margin. A comparison of actual material data and Code prescribed strengths is used to illustrate the conservatisms associated with the ASME Code.
- For the mechanical fuse concept, the failure capacity of the mechanical fuse is calculated using the highest reported ultimate material strength identified in open literature. This failure point is compared to the pressure boundary component capacity based on ASME Code allowable strength. Therefore, when the mechanical fuse failure capacity is less than the pressure boundary capacity, it is reasonable to conclude that the mechanical fuse component will fail before the pressure boundary component. Note that the larger margin of 20% is bounding when reported standard deviations in tensile properties are considered for the mechanical fuse capacity.

The HNP evaluations of the 71 Passive MOVs subjected to motor stall determined that all the valves had positive margin, and therefore, did not require modifications. Of these, 13 valves had margin based on use of the mechanical fuse concept. The results included the following:

- 56 valves had acceptable pressure boundary stress margin for maximum stall thrust in both valve stroke directions (i.e., in excess of the initial screening criteria).
- Eleven (11) valves had low margin for maximum stall thrust based on pressure boundary capacity.
- Four (4) valves had low margin for mechanical fuse failure based on capscrew shear failure.

The valves with the low margins were evaluated further to confirm sufficient conservatism existed in the pressure boundary capacity analysis and the ASME Code requirements applied. In a couple cases, the analysis concluded that although the valve may experience bonnet leakage under the stall conditions, it was not considered a compromise of the pressure boundary (i.e., ASME Code Section III Appendix F limits applied as allowed by HNP procedures).

The evaluations also addressed the potential for stem failure and full extraction from the valve (i.e., beyond the packing). These evaluations determined that full stem extraction would not occur with any of the 71 valves.

Summary and Lessons Learned

To support the NFPA 805 transition, the SSA re-evaluation approach was developed and applied by HNP as presented in this paper. This approach identified 71 “passive” MOVs at HNP that required pressure boundary evaluations to demonstrate integrity when subjected to IN 92-18 “hot-short” motor stall conditions. HNP also developed a pressure boundary analysis approach and criteria and applied it to the 71 passive MOVs. The results of the pressure boundary analyses confirmed that there is positive margin between the limiting pressure boundary based on the allowable stress limits and either the maximum stall thrust or the capacity at which some other non-pressure boundary component in the load path will fail (referred to as a “mechanical fuse”). The latter case was only considered when the maximum stall thrust exceeded the capacity of the weakest pressure boundary component. Although some valves had lower margins than desired (i.e., below the initial screening limits), the available margins were determined to be acceptable based on inherent conservatism in the pressure boundary capacities and the applicable ASME Code requirements.

Based on the lead effort at HNP in transitioning to NFPA 805, important lessons have been presented regarding the process for identifying MOVs potentially susceptible to “hot-shorts” per IN 92-18, and for evaluating the MOV pressure boundaries when subjected to the motor stall. The key lessons are:

- The NFPA 805 transition requires a different evaluation approach in selecting the system boundaries and equipment for evaluation to support the SSA. The main difference is the need to consider the potential impact of an IN 92-18 type “hot-short” motor stall on the pressure boundary of non-credited MOVs at the system interfaces/boundaries.
- The transition may require detailed evaluation of some MOVs that previously were not required for SSA. Some of these valves have limited design basis information available to do a complete IN 92-18 motor stall analysis of the pressure boundary integrity. Accordingly, new analyses may be required to address pressure boundary integrity.
- Some of the existing weak link calculations prepared for MOVs in the GL 89-10 MOV Program do not cover the analysis load path components and conditions required to fully assess the pressure boundary integrity for the IN 92-18 motor stall analysis. As a result, interactions with the valve vendor may be required to obtain the necessary information or analyses.
- In some cases, the valve vendors may need to reconstitute the design basis information, or plant walkdowns may be required to obtain necessary valve information to complete the IN 92-18 motor stall evaluation.
- The “mechanical fuse” capacity calculation requires re-defining the limiting capacity for the component based on determining the load at which the component will fail completely with a high degree of certainty that it will prevent further load transmission.

References

1. National Fire Protection Association (NFPA) Standard 805, "Performance Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition.
2. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: Light Water Reactor Edition."
3. NRC Information Notice (IN) 92-18 "Potential for Loss of Remote Shutdown Capability During a Control Room Fire."
4. NRC Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance."

Annex A

Tables and Figures

Table 1: Plants with letters of intent to adopt NFPA 805

Plant Name	Date submitted	Reactor type	Owner/ Operator
Arkansas Nuclear 1/2	11/2/2005	PWR	Entergy Nuclear
Beaver Valley 1/2	12/22/2005	PWR	First Energy Co.
Browns Ferry 1/2/3	3/4/2009	BWR	Tennesse Valley Authority
Brunswick 1/2	6/10/2005	BWR	Progress Energy
Callaway	12/2/2005	PWR	Ameren UE
Calvert Cliffs 1/2	4/17/2006	PWR	Constellation Energy
Catawba 1/2	2/28/2005	PWR	Duke Energy
Cooper	12/22/2005	BWR	Nebraska Public Power District
Crystal River 3	6/10/2005	PWR	Progress Energy
Davis Besse 1	12/22/2005	PWR	First Energy Co.
D. C. Cook 1/2	12/28/2005	PWR	Indiana/Michigan Power
Diablo Canyon 1/2	12/29/2005	PWR	Pacific Gas & Electric
Duane Arnold	11/30/2005	BWR	Florida Power & Light
Fort Calhoun	6/9/2008	PWR	Omaha Public Power District
Ginna	12/19/2005	PWR	Constellation Energy
Kewaunee	7/21/2008	PWR	Dominion Generation
McGuire 1/2	2/28/2005	PWR	Duke Energy
Nine Mile Point 1/2	4/17/2006	BWR	Constellation Energy
Oconee 1/2/3 (Note 1)	2/28/2005	PWR	Duke Energy
Palisades	11/30/2005	PWR	Entergy Nuclear
Point Beach 1/2	11/30/2005	PWR	Florida Power & Light
Prairie Island 1/2	11/30/2005	PWR	Nuclear Management Co.
Robinson 2	6/10/2005	PWR	Progress Energy
Saint Lucie 1/2	12/22/2005	PWR	Florida Power & Light
San Onofre 2/3	3/28/2008	PWR	PSE&G Nuclear
Shearon Harris 1 (Note 1)	6/10/2005	PWR	Progress Energy
Summer	10/19/2006	PWR	South Carolina Electric & Gas
Turkey Point 3/4	11/15/2005	PWR	Florida Power & Light
Waterford 3	12/21/2005	PWR	Entergy Nuclear

Note 1: Shearon Harris and Oconee implementing transition as lead/pilot plants.

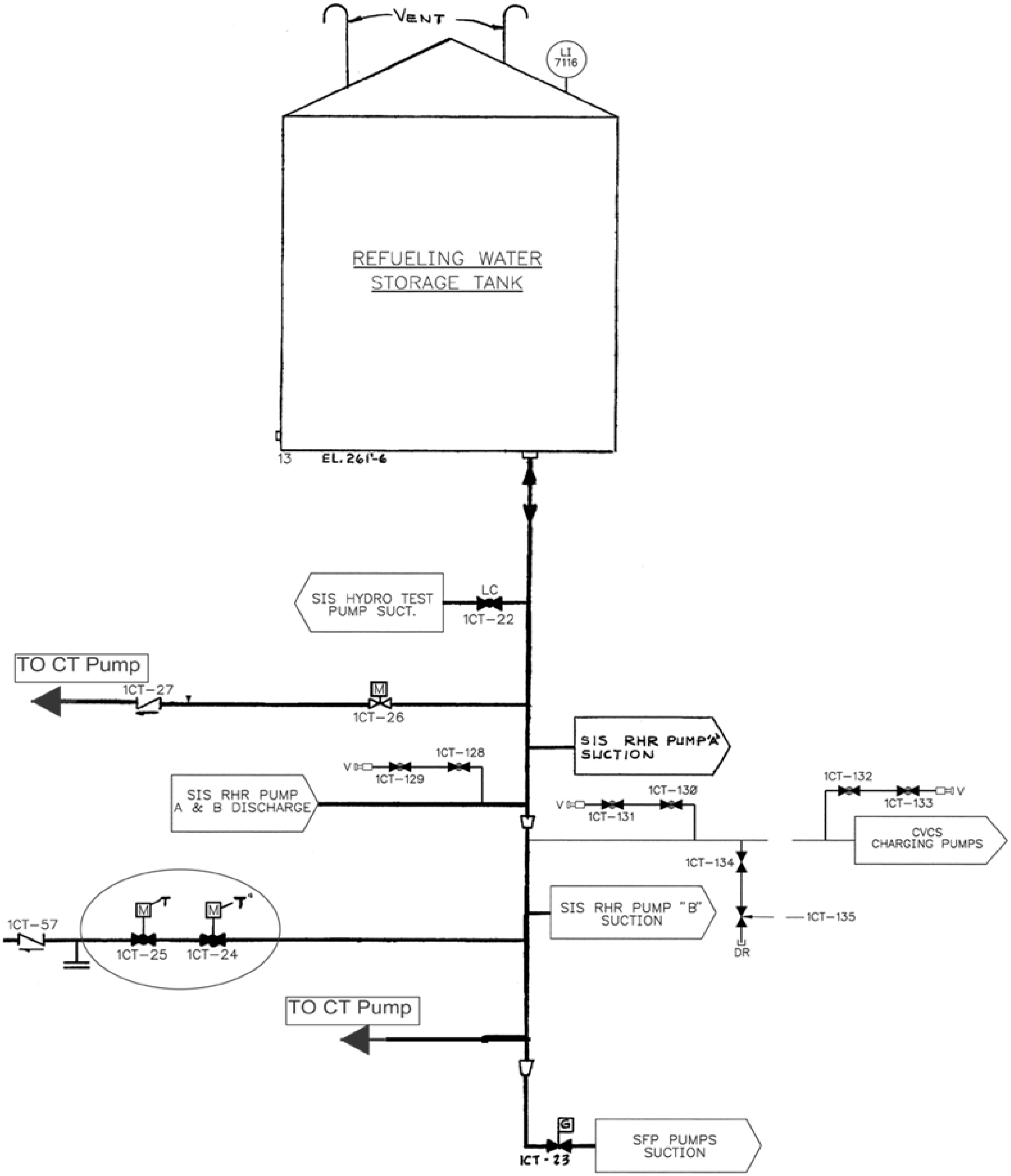

Figure 1 - Containment Spray Valves 1CT-25 and 1-CT26 Selected for IN 92-18 Evaluation

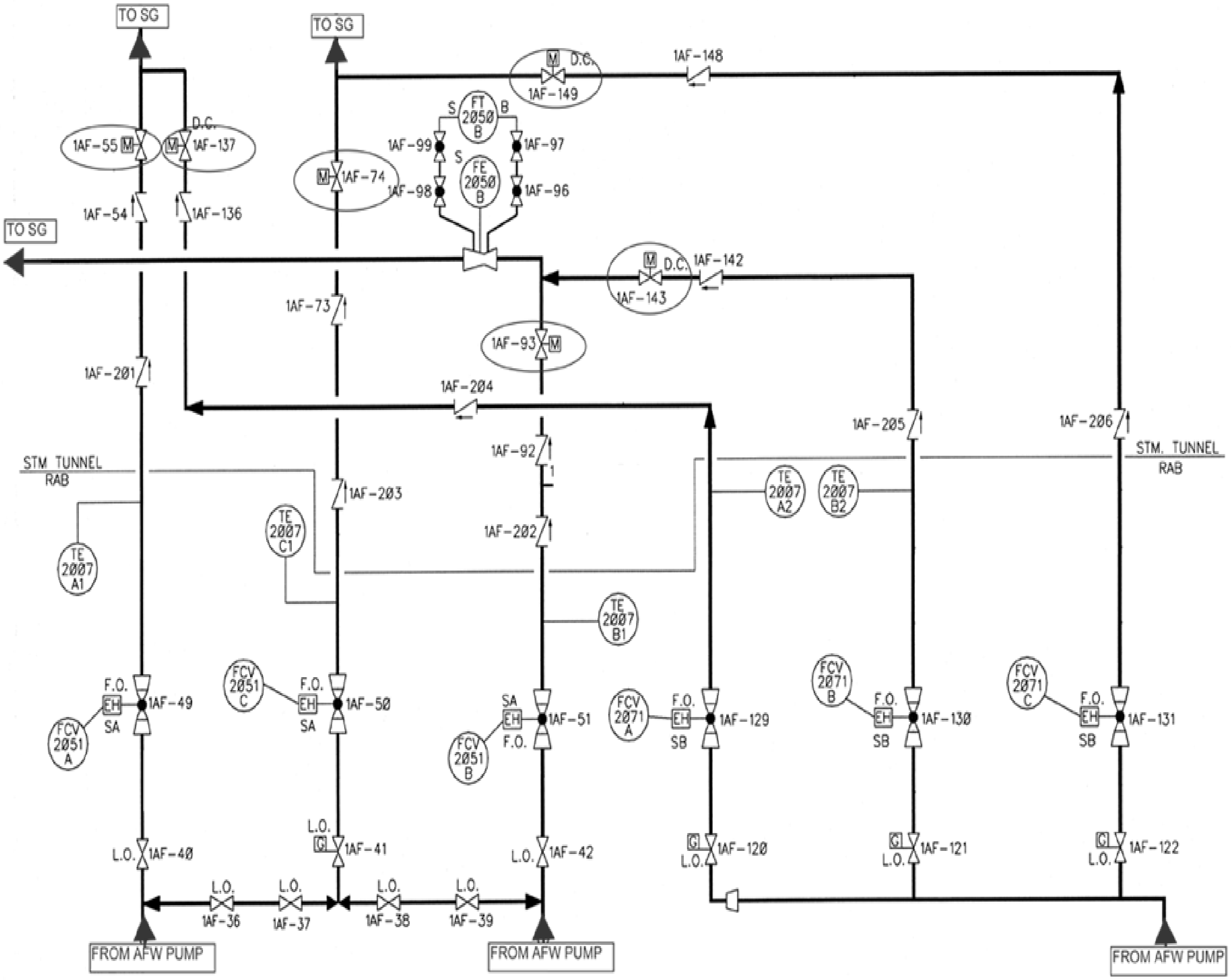

Figure 2 - AFW System MOVs Selected for IN 92-18 Evaluation

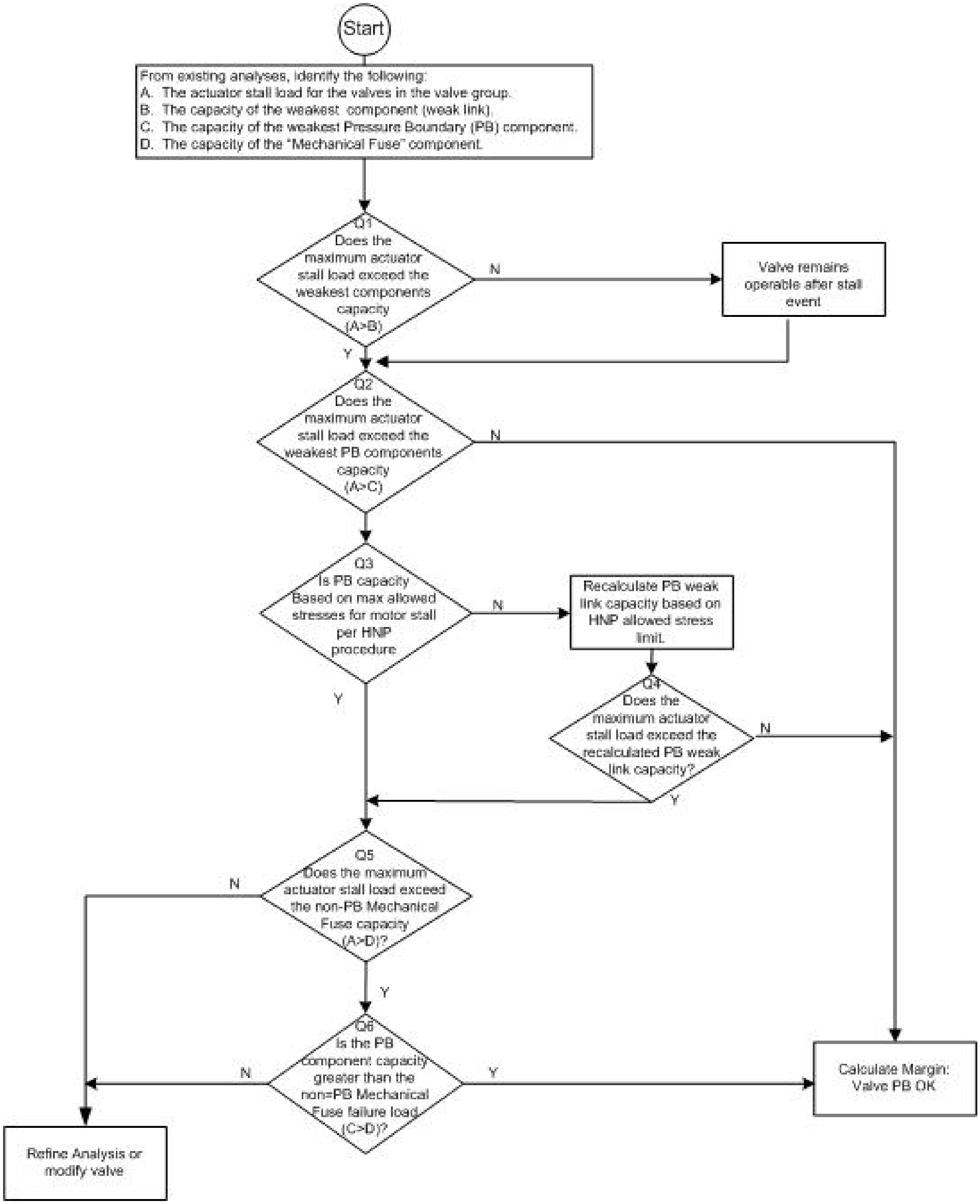

Figure 3 – MOV Motor Stall Event Evaluation Logic

Session 3: New Reactors

Session Chair: Michael Norato, U.S. NRC

New Reactors OM Code Pump and Valve Testing Overview

Thomas Ruggiero, PE
Exelon Energy Corporation
Ron Lippy
True North Consulting

Abstract

This abstract describes and discusses a path forward with regard to preparation of an American Society of Mechanical Engineers (ASME) Code for Operations and Maintenance of Nuclear Power Plants (OM Code) applicable for new reactor plants. There have been discussions within the industry regarding the expansion of the commercial nuclear power fleet and the ongoing work in new reactor plant design and construction. As a result of these discussions, the ASME is evaluating the OM Code for completeness, clarity, compatibility, and correctness with regards to the testing of new reactor systems and components. Since 2005, the ASME OM Code Committee has been evaluating the necessity of revising the OM Code to ensure that adequate guidance is provided for the development of testing scope, requirements, methods, and acceptance criteria for pumps, valves, and dynamic restraints (snubbers) to ensure that the "operational readiness" of these components is adequately provided.

The ASME OM Code considered the lessons learned from operating experience at current and past operating nuclear power plants and from research conducted by the nuclear industry and regulatory authority to provide for effective Inservice Testing (IST) programs to be developed and implemented at new nuclear power plants. These lessons learned include the following:

1. Design and qualification of pumps, valves, and dynamic restraints to allow IST activities (including sufficient flow testing) to assess the operational readiness of those components, and the development of ASME QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants,” to incorporate lessons learned in the qualification of mechanical equipment for nuclear power plants.

2. Insights obtained from the operational performance and testing of Motor-Operated Valves (MOVs) that indicate the need for improved activities, such as importance of adequate design and qualification, sufficient flow during testing to assess valve performance, etc.

3. Application of MOV lessons learned to other Power-Operated Valves (POVs).

4. Provisions for bi-directional testing of all safety-related check valves.

5. Implementation of pre-service and comprehensive pump testing (PST and CPT) provisions without the need for Code relief.

6. Consideration of potential adverse flow effects on plant components from flow-induced vibration resulting from hydrodynamic loads and acoustic resonance.

In addition to lessons learned from nuclear power plant operating experience and research programs, the ASME OM Code Committee addressed new reactor issues in its provisions for IST programs. These new reactor issues included the following:

1. Development of IST program descriptions by Combined Operating License (COL) applicants in accordance with Title 10 of the Code of Federal Regulations (10 CFR) Part 52 with implementation of Design Certification provisions for design, qualification, and IST activities.

2. Coordination of PST and Inspections, Tests Analysis, and Acceptance Criteria (ITAAC) tests so that testing is performed once for both purposes.

3. Design, qualification, IST, and inspection activities for squib valves that are much larger and represent more significant engineering challenges for new reactors than for currently operating plants.

4. Design of plant systems and development of IST programs to minimize the need for relief from the ASME OM Code requirements.

5. Design, qualification, PST, and IST activities of non-safety related components within the scope of Regulatory Treatment of Non-Safety Systems (RTNSS) that perform important to-safety functions.

6. Development and implementation of risk-informed IST programs, including 10 CFR 50.69 programs, for new reactors.

7. Consideration of appropriate Code and standards modifications for design, qualification, PST, and IST activities in response to application of software-based digital technology in mechanical components (e.g., pumps and valves).

Introduction

This white paper describes and discusses a path forward for the preparation of an ASME OM Code applicable for new reactor plants. Advanced reactor designs are not currently included in this effort.

As a result of discussions within the nuclear industry on the expansion of the commercial nuclear power fleet and ongoing work in new reactor plant design and construction, the ASME is evaluating the OM Code for completeness, clarity, compatibility and correctness for the testing of new reactor systems and components. Since 2005, the ASME OM Code Committee has been evaluating the necessity of revising the OM Code to ensure that adequate guidance is provided for the development of testing scope, requirements, methods, and acceptance criteria for pumps, valves and dynamic restraints (snubbers) to ensure that the "operational readiness" of these components is adequately provided.

Lessons learned from nuclear power plant operating experience and research

The ASME OM Code considered the operational experiences from current and past operating nuclear power plants and research conducted by the nuclear industry and regulatory authority to develop effective IST programs for new nuclear power plants. These lessons learned include the following:

1. Design and qualification of pumps, valves, and dynamic restraints to allow IST activities (including sufficient flow testing) to assess the operational readiness of those components, and development of ASME QME-1-2007 to incorporate lessons learned in the qualification of mechanical equipment for nuclear power plants.

2. Insights obtained from the operational performance and testing of MOVs that indicate the need for improved activities, such as importance of adequate design and qualification, sufficient flow during testing to assess valve performance, consideration of performance parameters (including valve disc and stem friction coefficients, reduced voltage, elevated temperature, and load sensitive behavior), use of adequate diagnostic instrumentation to allow proper evaluation and setup, improved maintenance and personnel training, monitoring of potential motor magnesium rotor degradation, and justification for motor control center testing.

3. Application of MOV lessons learned to other POVs.

4. Provisions for bi-directional testing of all safety-related check valves.

5. Implementation of PST and CPT provisions without the need for Code relief.

6. Consideration of potential adverse flow effects on plant components from flow-induced vibration resulting from hydrodynamic loads and acoustic resonance

New Reactor Issues

In addition to lessons learned from nuclear power plant operating experience and research programs, the ASME OM Code Committee addressed new reactor issues in its provisions for IST programs. These new reactor issues included the following:

1. Development of IST program descriptions by combined operating license (COL) applicants in accordance with 10 CFR Part 52 with implementation of design certification provisions for design, qualification, and IST activities.

2. Coordination of PST and Inspections, Tests Analysis and Acceptance Criteria (ITAAC) tests so that testing is performed once for both purposes. For example, how do PST requirements fit into the new Part 52 ITAAC closure and maintenance process? Under the new Part 52 process, an applicant is required to meet OM Code requirements after the 52.103(g) finding is made although it would be preferable to complete the PST requirements earlier.

3. Design, qualification, IST, and inspection activities for squib valves that are much larger and represent more significant engineering challenges for new reactors than for currently operating plants.

4. Design of plant systems and development of IST programs to minimize the need for relief from the ASME OM Code requirements.

5. Design, qualification, PST, and IST activities of non-safety related components within the scope of Regulatory Treatment of Non-Safety Systems (RTNSS) that perform important to-safety functions.

6. Development and implementation of risk-informed IST programs, including 10 CFR 50.69 programs, for new reactors.

7. Consideration of appropriate Code and standards modifications for design, qualification, PST, and IST activities in response to application of software-based digital technology in mechanical components (e.g., pumps and valves).

Deliverables

The OM Code Standards Committee determined that two deliverables are needed for new nuclear plants, a Design Guide and a New Reactor OM Code (NROMC).

The Design Guide will provide guidance for implementing the NROMC and performing preoperational and startup testing and periodic IST throughout the new plant life.

The NROMC will update/supplement/replace the existing OM Code so that both the new plant designers and the regulators have a more clear vision of IST requirements for new reactors.

The NROMC has been developed to remove the code provisions specifically for components that were not provided with provisions to permit IST from the OM Code. The NROMC requires that all components within IST scope must have provisions to permit full IST with no exceptions.

The method of producing the NROMC has been discussed with the following options considered:

1. Develop and issue a new OM Code, removing the provisions specifically for components that were not provided with provisions to permit IST from the current OM Code. This would be the most straightforward method; however, it would involve the maintenance of two separate Codes and might require extensive ongoing Code committee efforts.

   The use of a Code Case would allow the new reactors to incorporate "alternatives" to the Code.

2. Develop a mandatory appendix. This may be the quickest method to develop Code requirements specific to new reactors. The use of a Mandatory Appendix may be acceptable, but would involve significant duplication of the existing Code sections and subsections.

3. Create a new division within the OM Code similar to the existing divisions of several of the ASME Boiler and Pressure Vessel Code Sections. As in recommendation #1 above, this would also involve the maintenance of two somewhat identical or similar Codes.

4. The fourth option is to revise OM Code Subsection ISTA to include the general requirements for both new and existing reactors and to create new Subsections, as necessary, to identify specific testing requirements for new reactors. For example, Subsections ISTF, ISTG, ISTH and ISTI might be created to identify

pump, valve, snubber and risk-informed testing requirements for the new reactors in lieu of Subsections ISTB, ISTC, ISTD and ISTE. This method would require minimal change to the existing Code, and does not require that a separate Code, Appendix or division be maintained. This is the option that is recommended by the Task Group.

Overview of the Changes in the Code for New Plants

Definitions

Pre – 2000 Plant: A nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

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

Changes to Subsection ISTA

Defined Preservice Test Period

The test plan for the preservice test period shall comply with the latest edition and addenda of this Section that has been adopted by the regulatory authority 36 months prior to the docket date of the Unit's construction permit, or the edition and addenda of the OM Code referenced in the Unit's COL, as applicable. Alternately, the test plan for the preservice test period shall comply with subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions and addenda may be used, provided all related requirements are met.

Initial Inservice Test Interval

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

Changes to Subsection ISTB

ISTB is now applicable solely to Pre – 2000 Plants

Changes to Subsection ISTC

ISTC 5223 Series Valves in pairs is applicable to pre-2000 or earlier plants

Changes to Subsection ISTE

Table ISTE-5120-1 LSSC Pump Testing Pump groups are applicable to pre-2000 plants only

New Subsection ISTF for post-2000 Plants

No Pump Groupings
All Pumps must have full flow test loops, including instrumentation and valves that can be throttled

Conclusion

This ASME New Build Effort was viewed to be within the current OM Code Scope as listed in ISTA. Option 4 is the preferred option with a Design Guide to assist in the implementation.

The location of these products will be determined at a future date, but a structure similar to the current documents is desired, e.g. duplication of requirements will be eliminated to the extent practical.

1. The Project Team will prepare the Design Guide to address the additional design provisions that are needed to help convert New Plant Design Control Documents (DCDs) into detailed design documents.
2. The Project Team will update the OM Code to address operating experience and new reactor issues, and also will have a Code Cleanup effort to remove the “as practical issues” from the code.
3. RTNSS [Regulatory Treatment of Non-Safety Systems] issues will be addressed after these first documents are completed.

Comparison of Existing 2009 Edition of OM Code to New Reactor Code

AS PUBLISHED	AS PROPOSED
PREFACE	**PREFACE**
Division 1: Section IST — Light-Water Reactor Nuclear Power Plants Subsection ISTA General Requirements Subsection ISTB Inservice Testing of Pumps Subsection ISTC Inservice Testing of Valves Subsection ISTD Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) Subsection ISTE Risk-Informed Inservice Testing of Components	**Division 1: Section IST — Light-Water Reactor Nuclear Power Plants** Subsection ISTA General Requirements Subsection ISTB Inservice Testing of Pumps – *Pre-2000 Plants*[1] Subsection ISTC Inservice Testing of Valves Subsection ISTD Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) Subsection ISTE Risk-Informed Inservice Testing of Components *Subsection ISTF Inservice Testing of Pumps – Post – 2000 Plants*[2] [1] *Pre – 2000 Plant: A nuclear power plant that was issued its' construction permit by the applicable regulatory authority prior to January 1, 2000.* [2] *Post – 2000 Plant: A nuclear power plant that was issued (or will be issued) its' construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.*
Subsection ISTA	**Subsection ISTA**
ISTA-1500 Owner's Responsibilities The responsibilities of the Owner of the nuclear power plant shall include the following: *(a)* determination of the appropriate Code Class for each component of the plant, identification of the system boundaries for each class of components subject to test or examination, and the components exempt from testing or examination requirements *(b)* design and arrangement of system components to include allowance for adequate access and clearances for conduct of the tests and examinations *(c)* preparation of plans and schedules	**ISTA-1500 Owner's Responsibilities** The responsibilities of the Owner of the nuclear power plant shall include the following: *(a)* determination of the appropriate Code Class for each component of the plant, identification of the system boundaries for each class of components subject to test or examination, and the components exempt from testing or examination requirements *(b)* design and arrangement of system components to include allowance for adequate access and clearances for conduct of the tests and examinations. *Refer to Nonmandatory Appendix M of this Division for guidance.* *(c)* preparation of plans and schedules
ISTA-3200 Administrative Requirements *(a)* IST Plans shall be filed with the regulatory authorities having jurisdiction at the plant site. *(b)* The selection of components included in the test plan is subject to review by the regulatory authorities having jurisdiction at the plant site. *(c)* Application of the requirements of this Section shall be governed by group classification criteria of the regulatory authority having jurisdiction at the plant site. *(d)* The use of any Code Case is subject to acceptance by the regulatory authorities having jurisdiction at the plant site.	**ISTA-3200 Administrative Requirements** *(a)* IST Plans shall be filed with the regulatory authorities having jurisdiction at the plant site. *(b)* The selection of components included in the test plan is subject to review by the regulatory authorities having jurisdiction at the plant site. *(c)* Application of the requirements of this Section shall be governed by group classification criteria of the regulatory authority having jurisdiction at the plant site. *(d)* The use of any Code Case is subject to acceptance by the regulatory authorities having jurisdiction at the plant site.

(e) Revisions to a previously approved Code Case may be substituted for that Code Case with the acceptance of the regulatory authorities having jurisdiction at the plant site. *(f)* Tests and examinations shall meet the requirements of the edition and addenda of this Section specified in the following paragraphs: *(1) Preservice Test Period.* The test plan for the preservice test period shall comply with the edition and addenda of this Section that has been adopted by the regulatory authority 36 mo prior to the docket date of the unit's construction permit, or subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions and addenda may be used, provided all related requirements are met. *(2) Initial Inservice Test Interval.* The test plan for the initial Inservice test interval shall comply with the edition and addenda of the Section that have been adopted by the regulatory authority 12 mo prior to the issuance of the operating license, or subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions or addenda may be used, provided all related requirements are met.	*(e)* Revisions to a previously approved Code Case may be substituted for that Code Case with the acceptance of the regulatory authorities having jurisdiction at the plant site. *(f)* Tests and examinations shall meet the requirements of the edition and addenda of this Section specified in the following paragraphs: *(1) Preservice Test Period – The test plan for the preservice test period shall comply with the latest edition and addenda of this Section that has been adopted by the regulatory authority 36 months prior to the docket date of the Unit's construction permit, or the edition and addenda of the OM Code referenced in the Unit's Combined License, as applicable. Alternately, the test plan for the preservice test period shall comply with subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions and addenda may be used, provided all related requirements are met.* *(2) Initial Inservice Test Interval – The test plan for the initial Inservice test interval shall comply with the latest edition and addenda of the Section that have been adopted by the regulatory authority 12 months prior to the issuance of the operating license, or 12 months before the date scheduled for initial loading of fuel under a Combined License, applicable. Alternately, the test plan for the initial Inservice test interval shall comply with subsequent editions and addenda that have been adopted by the regulatory authority. Specific portions of such subsequent editions and addenda may be used, provided all related requirements are met.*
Subsection ISTB	**Subsection ISTB**
Subsection ISTB **Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants**	**Subsection ISTB** **Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants – *Pre – 2000 Plants*[1]** *[1] Pre – 2000 Plant: A nuclear power plant that was issued its' construction permit by the applicable regulatory prior to January 1, 2000.*
Subsection ISTC	**Subsection ISTC**
ISTC-5223 Series Valves in Pairs. If two check valves are in a series configuration without provisions to verify individual reverse flow closure (e.g., keepfill pressurization valves) and the plant safety analysis assumes closure of either valve (but not both), the valve pair may be operationally tested closed as a unit. If the plant safety analysis assumes that a specific valve or both valves of the pair close to perform the safety function(s), the required valve(s) shall be tested to demonstrate individual valve closure.	**ISTC-5223 Series Valves in Pairs.**[10] If two check valves are in a series configuration without provisions to verify individual reverse flow closure (e.g., keepfill pressurization valves) and the plant safety analysis assumes closure of either valve (but not both), the valve pair may be operationally tested closed as a unit. If the plant safety analysis assumes that a specific valve or both valves of the pair close to perform the safety function(s), the required valve(s) shall be tested to demonstrate individual valve closure. *[10] ISTC – 5223 only applicable to Pre – 2000 Plants whose construction permit was issued January 1, 2000 or earlier.*

<table>
<tr><th>Subsection ISTE</th><th>Subsection ISTE</th></tr>
<tr><td>ISTE-5110 High Safety Significant Pump Testing.
Group A and Group B pumps categorized as HSSCs shall meet all requirements of Subsections ISTA and ISTB.</td><td>ISTE-5110 High Safety Significant Pump Testing.
<i>Pumps</i> categorized as HSSCs shall meet all requirements of Subsections ISTA and <i>ISTB or ISTF</i>.</td></tr>
<tr><td>Subsection ISTE
Table ISTE-5120-1 LSSC Pump Testing</td><td>Subsection ISTE
Table ISTE-5120-1 LSSC Pump Testing</td></tr>
<tr><td>
<table>
<tr><th>Pump Group</th><th>Group A Test</th><th>Group B Test</th><th>Comprehensive Test</th></tr>
<tr><td>Group A (routinely or continuously operated pumps)</td><td>6 mo [Note (1)]</td><td>Not required</td><td>Not required</td></tr>
<tr><td>Group B (standby pumps)</td><td>2 Yr</td><td>6 mo [Note (1)]</td><td>Not required</td></tr>
</table>
NOTE:
(1) To meet vendor recommendations, pump operation may be required more frequently than the specified test frequency.
</td><td>
<table>
<tr><th>Pump Group</th><th>Group A Test</th><th>Group B Test</th><th>Comprehensive Test</th></tr>
<tr><td>Group A (routinely or continuously operated pumps)</td><td>6 mo [Note (1)]</td><td>Not required</td><td>Not required</td></tr>
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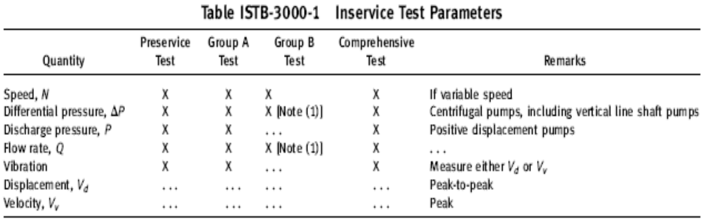
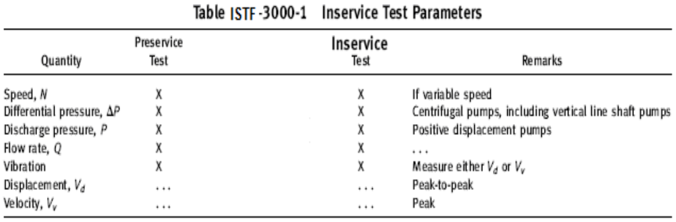
</table>
NOTE:
(1) To meet vendor recommendations, pump operation may be required more frequently than the specified test frequency.
<i>(2) This column also applies if using ISTF.</i>
</td></tr>
<tr><td>ISTE-5120 Low Safety Significant Pump Testing
<i>(a)</i> Group A and Group B pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTB, except that the testing requirements identified in this paragraph and in Table ISTE 5120-1 may be substituted for those in para. ISTB-3400 (Table ISTB-3400-1).
<i>(b)</i> All Group A and Group B LSSC pumps shall receive an initial Group A test conducted within ±20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.
<i>(c)</i> Thereafter, all Group A and Group B LSSC pumps shall be Group A tested within ±20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.</td><td><i>ISTE-5120 Low Safety Significant Pump Testing</i>

<i>ISTE-5121 Low Safety Significant Pump Testing – Pre – 2000 Plants</i>[1]
<i>(a) Group A and Group B pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTB, except that the testing requirements identified in this paragraph and in Table ISTE 5121-1 may be substituted for those in para. ISTB-3400 (Table ISTB-3400-1)</i>
<i>(b) All Group A and Group B LSSC pumps shall receive an initial Group A test conducted within +/-20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.</i>
<i>(c) Thereafter, all Group A and Group B LSSC pumps shall be Group A tested within +/-20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.</i>

<i>ISTE-5122 Low Safety Significant Pump Testing – Post – 2000 Plants</i>[2]
<i>(a) Pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTF, except that the testing requirements identified in this paragraph and in Table ISTE 5120-1 may be substituted for those in para. ISTF-3400.</i>
<i>(b) All LSSC pumps shall receive an initial test conducted within +/-20% of pump design flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.</i>
<i>(c) Thereafter, LSSC pumps shall be tested every 6 months in accordance with ISTF and within +/-20% of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.</i>

[1] <i>Pre – 2000 Plant: A nuclear power plant that was issued its'</i></td></tr>
</table>

	construction permit by the applicable regulatory authority prior to January 1, 2000. *[2]Post – 2000 Plant: A nuclear power plant that was issued (or will be issued) its' construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.*
ISTE-5130 Maximum Test Interval.	**ISTE-5130 Maximum Test Interval – *Pre – 2000 Plant***
Subsection ISTF	**Subsection ISTF**
Subsection ISTB **Inservice Testing of Pumps in Light-Water Reactor Nuclear** **Power Plants**	**Subsection *ISTF*** **Inservice Testing of Pumps in Light-Water Reactor Nuclear** **Power Plants– *Post – 2000 Plants*[1]** *[1]Post – 2000 Plant: A nuclear power plant that was issued (or will be issued) its' construction permit, or combined license for construction and operation, by the applicable regulatory on or following January 1, 2000.*
ISTB-1000 INTRODUCTION **ISTB-1100 Applicability** The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.	***ISTF*-1000 INTRODUCTION** ***ISTF*-1100 Applicability** The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.
ISTB-1200 Exclusions	***ISTF*-1200 Exclusions**
ISTB-1300 Pump Categories All pumps within the scope of paras. ISTA-1100 and ISTB-1100 shall be categorized as either a Group A or Group B pump.	***ISTF -1300 Owner's Responsibility*** *In addition to the requirements of para. ISTA-1500, it is the Owner's responsibility to* *(a) include in both the pumps and plant design all necessary valving, instrumentation, test loops, required fluid inventory, or other provisions that are required to fully comply with the requirements of this Subsection. Testing capability shall be possible irrespective of plant mode.* *(b) identify each pump to be tested in accordance with the rules of this Subsection.*
ISTB-2000 SUPPLEMENTAL DEFINITIONS The following are provided to ensure a uniform understanding of selected terms used in this Subsection. *Group A pumps:* pumps that are operated continuously or routinely during normal operation, cold shutdown, or refueling operations. *Group B pumps:* pumps in standby systems that are not operated routinely except for testing. *vertical line shaft pump:* a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.	***ISTF*-2000 SUPPLEMENTAL DEFINITIONS** The following *is* provided to ensure a uniform understanding of selected terms used in this Subsection. *vertical line shaft pump:* a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.
ISTB-3000 GENERAL TESTING REQUIREMENTS The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action. The parameters to be measured during preservice and Inservice	***ISTF*-3000 GENERAL TESTING REQUIREMENTS** The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action. The parameters to be measured during preservice and

<table>
<tr><td>testing are specified in Table ISTB-3000-1.</td><td>Inservice testing are specified in Table *ISTF*-3000-1.</td></tr>
<tr><td>
Table ISTB-3000-1 Inservice Test Parameters
<table>
<tr><th>Quantity</th><th>Preservice Test</th><th>Group A Test</th><th>Group B Test</th><th>Comprehensive Test</th><th>Remarks</th></tr>
<tr><td>Speed, N</td><td>X</td><td>X</td><td>X</td><td>X</td><td>If variable speed</td></tr>
<tr><td>Differential pressure, ΔP</td><td>X</td><td>X</td><td>X [Note (1)]</td><td>X</td><td>Centrifugal pumps, including vertical line shaft pumps</td></tr>
<tr><td>Discharge pressure, P</td><td>X</td><td>X</td><td>. . .</td><td>X</td><td>Positive displacement pumps</td></tr>
<tr><td>Flow rate, Q</td><td>X</td><td>X</td><td>X [Note (1)]</td><td>X</td><td>. . .</td></tr>
<tr><td>Vibration</td><td>X</td><td>X</td><td>. . .</td><td>X</td><td>Measure either V_d or V_v</td></tr>
<tr><td>Displacement, V_d</td><td>. . .</td><td>. . .</td><td>. . .</td><td>. . .</td><td>Peak-to-peak</td></tr>
<tr><td>Velocity, V_v</td><td>. . .</td><td>. . .</td><td>. . .</td><td>. . .</td><td>Peak</td></tr>
</table>
NOTE:
(1) For positive displacement pumps, flow rate shall be measured or determined, for all other pumps, differential pressure or flow rate shall be measured or determined.</td><td>
Table ISTF -3000-1 Inservice Test Parameters
<table>
<tr><th>Quantity</th><th>Preservice Test</th><th>Inservice Test</th><th>Remarks</th></tr>
<tr><td>Speed, N</td><td>X</td><td>X</td><td>If variable speed</td></tr>
<tr><td>Differential pressure, ΔP</td><td>X</td><td>X</td><td>Centrifugal pumps, including vertical line shaft pumps</td></tr>
<tr><td>Discharge pressure, P</td><td>X</td><td>X</td><td>Positive displacement pumps</td></tr>
<tr><td>Flow rate, Q</td><td>X</td><td>X</td><td>. . .</td></tr>
<tr><td>Vibration</td><td>X</td><td>X</td><td>Measure either V_d or V_v</td></tr>
<tr><td>Displacement, V_d</td><td>. . .</td><td>. . .</td><td>Peak-to-peak</td></tr>
<tr><td>Velocity, V_v</td><td>. . .</td><td>. . .</td><td>Peak</td></tr>
</table>
Note deleted.</td></tr>
<tr><td>**ISTB-3100 Preservice Testing**
During the preservice test period or before implementing Inservice testing, an initial set of reference values shall be established for each pump. These tests shall be conducted under conditions as near as practicable to those expected during subsequent Inservice testing. Except as specified in para. ISTB-3310, only one preservice test is required for each pump. A set of reference values shall be established in accordance with para.
ISTB-3300 for each pump required to be tested by this Subsection. Preservice testing shall be performed in accordance with the requirements of the following paragraphs:
(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTB-5110
(b) vertical line shaft centrifugal pump tests in accordance with para. ISTB-5210
(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTB-5310
(d) reciprocating positive displacement pump tests in accordance with para. ISTB-5310</td><td>***ISTF*-3100 Preservice Testing**
During the preservice test period or before implementing Inservice testing, an initial set of reference values shall be established for each pump. These tests shall be conducted under conditions as near as practicable to those expected during subsequent Inservice testing. Except as specified in para. *ISTF*-3310, only one preservice test is required for each pump. A set of reference values shall be established in accordance with para.
ISTF-3300 for each pump required to be tested by this Subsection. Preservice testing shall be performed in accordance with the requirements of the following paragraphs:
(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. *ISTF*-5110
(b) vertical line shaft centrifugal pump tests in accordance with para. *ISTF*-5210
(c) positive displacement pump (except reciprocating) tests in accordance with para. *ISTF*-5310
(d) reciprocating positive displacement pump tests in accordance with para. *ISTF*-5310</td></tr>
<tr><td>**ISTB-3200 Inservice Testing**
Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see para. ISTB-1100). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:
(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. ISTB-5120
(b) vertical line shaft centrifugal pump tests in accordance with para. ISTB-5220
(c) positive displacement pump (except reciprocating) tests in accordance with para. ISTB-5320
(d) reciprocating positive displacement pump tests in accordance with para. ISTB-5320</td><td>***ISTF*-3200 Inservice Testing**
Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see para. *ISTF*-1100). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:
(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with para. *ISTF*-5120
(b) vertical line shaft centrifugal pump tests in accordance with para. *ISTF*-5220
(c) positive displacement pump (except reciprocating) tests in accordance with para. *ISTF*-5320
(d) reciprocating positive displacement pump tests in accordance with para. *ISTF*-5320</td></tr>
<tr><td>**ISTB-3300 Reference Values**
Reference values shall be obtained as follows:
(a) Initial reference values shall be determined from the results of testing meeting the requirements of para.
ISTB-3100, Preservice Testing, or from the results of the first Inservice test.
(b) New or additional reference values shall be established as required by para. ISTB-3310 or ISTB-3320, or subpara. ISTB-6200(c).</td><td>***ISTF*-3300 Reference Values**
Reference values shall be obtained as follows:
(a) Initial reference values shall be determined from the results of testing meeting the requirements of para.
ISTF-3100, Preservice Testing, or from the results of the first Inservice test.
(b) New or additional reference values shall be established as required by para. *ISTF*-3310 or *ISTF*-3320, or subpara. *ISTF*-6200(c).</td></tr>
</table>

(c) Reference values shall be established only when the pump is known to be operating acceptably. *(d)* Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests. *(e)* Reference values shall be established in a region(s) of relatively stable pump flow. *(1)* Reference values shall be established within ±20% of pump design flow rate for the comprehensive test. *(2)* Reference values shall be established within ±20% of pump design flow for the Group A and Group B tests, if practicable. If not practicable, the reference point flow rate shall be established at the highest practical flow rate. *(f)* All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with para. ISTB-3310 or ISTB-3320, or subpara. ISTB-6200(c). *(g)* Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with para. ISTB-6400.	*(c)* Reference values shall be established only when the pump is known to be operating acceptably. *(d)* Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests. *(e)* Reference values shall be established in a region(s) of relatively stable pump flow. *(1)* Reference values shall be established within ±20% of pump design flow rate for the *Inservice* test. *(2)* Reference values shall be established within ±20% of pump design flow. *(f)* All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with para. *ISTF*-3310 or *ISTF*-3320, or subpara. *ISTF*-6200(c). *(g)* Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with para. *ISTF*-6400.
ISTB-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values. When a reference value or set of values may have been affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with para. ISTB-3300, or the previous value reconfirmed by a comprehensive or Group A test run before declaring the pump operable. The Owner shall determine whether the requirements of para. ISTB-3100, to reestablish reference values, apply. Deviations between the previous and new set of reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see section ISTB-9000).	***ISTF*-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values.** When a reference value or set of values may have been affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with para. *ISTF*-3300, or the previous value reconfirmed by *an Inservice* test run before declaring the pump operable. The Owner shall determine whether the requirements of para. *ISTF*-3100, to reestablish reference values, apply. Deviations between the previous and new set of reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see section *ISTF*-9000).
ISTB-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable, for some reason other than stated in para. ISTB-3310, to establish an additional set of reference values, a Group A or comprehensive test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is acceptable per para. ISTB-6200, an additional set of reference values may be established as follows: *(a)* For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in para. ISTB-5110 or ISTB-5210, as applicable. Vibration acceptance criteria shall be established by a Group A or comprehensive test at the new reference point. If vibration data was taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable. *(b)* For positive displacement pumps, the additional set of reference values shall be established per para. ISTB-5310. A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see section ISTB-9000). The requirements of para. ISTB-3300 apply.	***ISTF*-3320 Establishment of Additional Set of Reference Values.** If it is necessary or desirable, for some reason other than stated in para. *ISTF*-3310, to establish an additional set of reference values, a Group A or comprehensive test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is acceptable per para. *ISTF*-6200, an additional set of reference values may be established as follows: *(a)* For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in para. *ISTF*-5110 or *ISTF*-5210, as applicable. Vibration acceptance criteria shall be established by *an Inservice* test at the new reference point. If vibration data was taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable. *(b)* For positive displacement pumps, the additional set of reference values shall be established per para. *ISTF*-5310. A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see section *ISTF*-9000). The requirements of para. *ISTF*-3300 apply.

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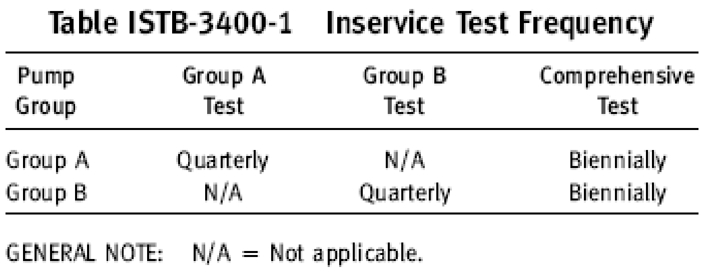

Table ISTB-3400-1 Inservice Test Frequency

<table>
<tr><th>Pump Group</th><th>Group A Test</th><th>Group B Test</th><th>Comprehensive Test</th></tr>
<tr><td>Group A</td><td>Quarterly</td><td>N/A</td><td>Biennially</td></tr>
<tr><td>Group B</td><td>N/A</td><td>Quarterly</td><td>Biennially</td></tr>
</table>

GENERAL NOTE: N/A = Not applicable.
</td>
<td><i>Table deleted.</i></td>
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<tr>
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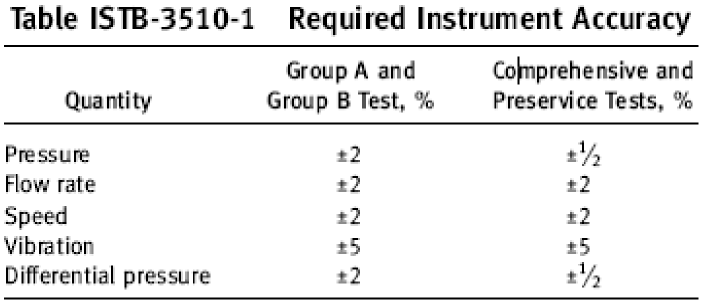


Table ISTB-3510-1 Required Instrument Accuracy

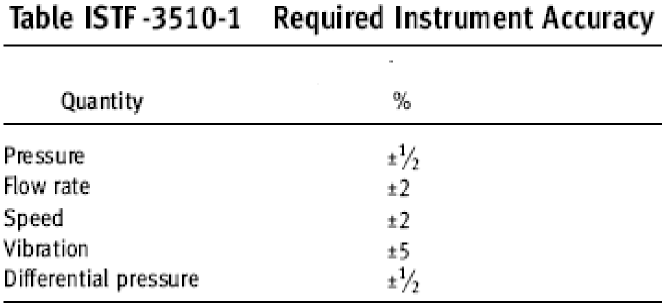
<table>
<tr><th>Quantity</th><th>Group A and Group B Test, %</th><th>Comprehensive and Preservice Tests, %</th></tr>
<tr><td>Pressure</td><td>±2</td><td>$\pm\frac{1}{2}$</td></tr>
<tr><td>Flow rate</td><td>±2</td><td>±2</td></tr>
<tr><td>Speed</td><td>±2</td><td>±2</td></tr>
<tr><td>Vibration</td><td>±5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


Table ISTF -3510-1 Required Instrument Accuracy

<table>
<tr><th>Quantity</th><th>%</th></tr>
<tr><td>Pressure</td><td>$\pm\frac{1}{2}$</td></tr>
<tr><td>Flow rate</td><td>±2</td></tr>
<tr><td>Speed</td><td>±2</td></tr>
<tr><td>Vibration</td><td>±5</td></tr>
<tr><td>Differential pressure</td><td>$\pm\frac{1}{2}$</td></tr>
</table>
</td>
</tr>
<tr>
<td>ISTB-3400 Frequency of Inservice Tests
An Inservice test shall be run on each pump as specified in Table ISTB-3400-1.</td>
<td><i>ISTF</i>-3400 Frequency of Inservice Tests
An Inservice test shall be run on each pump <i>quarterly.</i></td>
</tr>
<tr>
<td>ISTB-3410 Pumps in Regular Use. Group A pumps that are operated more frequently than every 3 mo need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 mo at the reference conditions, and the quantities specified were determined, recorded, and analyzed per section ISTB-6000.</td>
<td><i>ISTF</i>-3410 Pumps in Regular Use. <i>Pumps</i> that are operated more frequently than every 3 mo need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 <i>months</i> at the reference conditions, and the quantities specified were determined, recorded, and analyzed per section <i>ISTF</i>-6000.</td>
</tr>
<tr>
<td>ISTB-3420 Pumps in Systems Out of Service. For a pump in a system declared inoperable or not required to be operable, the test schedule need not be followed.
Within 3 months before the system is placed in an operable status, the pump shall be tested and the test schedule followed in accordance with the requirements of this Subsection. Pumps that can only be tested during plant operation shall be tested within 1 week following plant startup.</td>
<td><i>ISTF</i>-3420 Pumps in Systems Out of Service. For a pump in a system declared inoperable or not required to be operable, the test schedule need not be followed.
Within 3 months before the system is placed in an operable status, the pump shall be tested and the test schedule followed in accordance with the requirements of this Subsection.</td>
</tr>
<tr>
<td>ISTB-3430 Pumps Lacking Required Fluid Inventory.</td>
<td><i>Section deleted.</i></td>
</tr>
<tr>
<td>ISTB-3500 Data Collection</td>
<td><i>ISTF</i>-3500 Data Collection</td>
</tr>
<tr>
<td>ISTB-3510 General
<i>(a) Accuracy.</i> Instrument accuracy shall be within the limits of Table ISTB-3510-1. If a parameter is determined by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of Table ISTB-3510-1 (e.g., flow rate determination shall be accurate to within ±2% of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.</td>
<td><i>ISTF</i>-3510 General
<i>(a) Accuracy.</i> Instrument accuracy shall be within the limits of Table <i>ISTF</i>-3510-1. If a parameter is determined by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of Table <i>ISTF</i> -3510-1 (e.g., flow rate determination shall be accurate to within ±2% of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.</td>
</tr>
</table>

(b) Range *(1)* The full-scale range of each analog instrument shall be not greater than three times the reference value. *(2)* Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument. *(3)* Vibration instruments are excluded from the range requirements of subparas. ISTB-3510(b)(1) and ISTB-3510(b)(2). *(c) Instrument Location.* The sensor location shall be established by the Owner, documented in the plant records (see section ISTB-9000), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be either permanently mounted, or provision shall be made to duplicate their position during each test. *(d) Fluctuations.* Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines. *(e) Frequency Response Range.* The frequency response range of the vibration measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.	*(b) Range* *(1)* The full-scale range of each analog instrument shall be not greater than three times the reference value. *(2)* Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument. *(3)* Vibration instruments are excluded from the range requirements of subparas. *ISTF* -3510(b)(1) and *ISTF* -3510(b)(2). *(c) Instrument Location.* The sensor location shall be established by the Owner, documented in the plant records (see section *ISTF* -9000), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be either permanently mounted, or provision shall be made to duplicate their position during each test. *(d) Fluctuations.* Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines. *(e) Frequency Response Range.* The frequency response range of the vibration measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.
ISTB-3520 Pressure	***ISTF*-3520 Pressure**
ISTB-3530 Rotational Speed. Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of para. ISTB-3510.	***ISTF*-3530 Rotational Speed.** Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of para. *ISTF*-3510.
ISTB-3540 Vibration	***ISTF*-3540 Vibration**
ISTB-3550 Flow Rate. When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. External recirculated flow is not required to be measured if it is not practical to isolate, has a fixed resistance, and has been evaluated by the Owner to not have a substantial effect on the results of the test.	***ISTF*-3550 Flow Rate.** When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. *External recirculated flow is required to be measured if such flow is present during the design function of the pump*.
ISTB-4000 TO BE PROVIDED AT A LATER DATE	***ISTF*-4000 TO BE PROVIDED AT A LATER DATE**
ISTB-5000 SPECIFIC TESTING REQUIREMENTS This Subsection defines requirements for Group A, Group B, and comprehensive tests. When a Group A test is required, a comprehensive test may be substituted. When a Group B test is required, a Group A or comprehensive test may be substituted. A preservice test may be substituted for any Inservice test.	***ISTF*-5000 SPECIFIC TESTING REQUIREMENTS** *A preservice test may be substituted for any Inservice test.*
ISTB-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps) *(a) Duration of Tests* *(1)* For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded. *(2)* For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by	***ISTF*-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps)** *(a) Duration of Tests* *(1)* For the *Inservice test*, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table *ISTF*-3000-1 shall be made and recorded. *(b) Bypass Loops* *(1)* A bypass test loop may be used for *an Inservice* test,

Table ISTB-3000-1 shall be made and recorded. *(b) Bypass Loops* *(1)* A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300. *(2)* A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.	provided the flow rate through the loop meets the requirements as specified in para. *ISTF* -3300.
ISTB-5110 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1. *(a)* In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of Inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied. *(b)* Vibration measurements are only required to be taken at the reference point(s).	***ISTF*-5110 Preservice Testing.** The parameters to be measured are specified in Table *ISTF*-3000-1. (*a*)Flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of Inservice tests. *(b)* Vibration measurements are only required to be taken at the reference point(s).
ISTB-5120 Inservice Testing	***ISTF*-5120 Inservice Testing**
ISTB-5121 Group A Test Procedure. ISTB-5122 Group B Test Procedure.	***These Sections deleted.***
ISTB-5123 Comprehensive Test Procedure Comprehensive tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* For centrifugal and vertical line shaft pumps, the resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value. *(c)* Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values. *(d)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. *(e)* All deviations from the reference values shall be compared with the ranges of Table ISTB-5121-1 and corrective action taken as specified in para. ISTB-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5121-1. For example, if vibration exceeds either 6*Vr* or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.	*Inservice* tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table *ISTF*-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* For centrifugal and vertical line shaft pumps, the resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value. *(c)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. *(d)* All deviations from the reference values shall be compared with the ranges of Table *ISTF*-5121-1 and corrective action taken as specified in para. *ISTF* -6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table I*STF* -5121-1. For example, if vibration exceeds either 6*Vr* or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

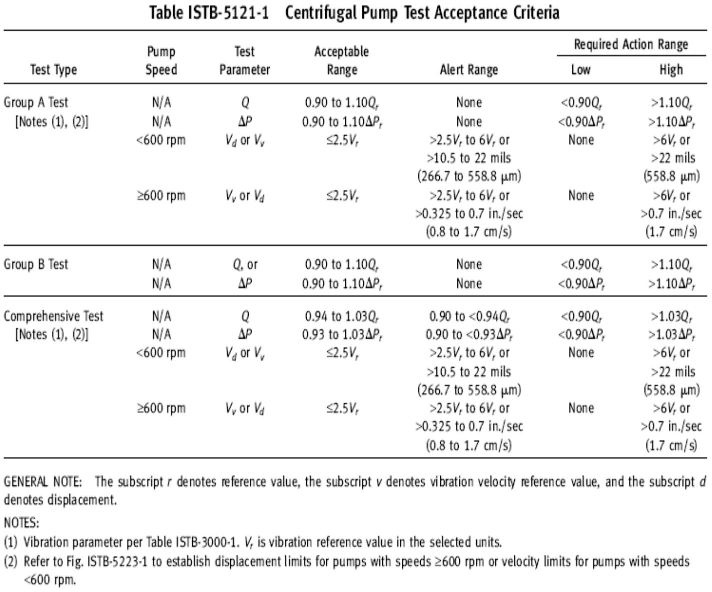


Table ISTB-5121-1 Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range Low	Required Action Range High
Group A Test [Notes (1), (2)]	N/A	Q	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	0.90 to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q, or	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	0.90 to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.94 to $1.03Q_r$	0.90 to $<0.94Q_r$	$<0.90Q_r$	$>1.03Q_r$
	N/A	ΔP	0.93 to $1.03\Delta P_r$	0.90 to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.03\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

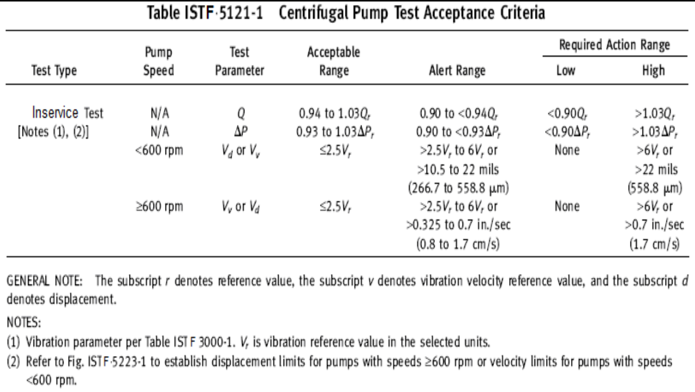


Table ISTF·5121-1 Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range Low	Required Action Range High
Inservice Test [Notes (1), (2)]	N/A	Q	0.94 to $1.03Q_r$	0.90 to $<0.94Q_r$	$<0.90Q_r$	$>1.03Q_r$
	N/A	ΔP	0.93 to $1.03\Delta P_r$	0.90 to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.03\Delta P_r$
	<600 rpm	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 μm)	None	$>6V_r$ or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

ISTB-5200 Vertical Line Shaft Centrifugal Pumps *(a) Duration of Tests* *(1)* For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded. *(2)* For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by Table ISTB-3000-1 shall be made and recorded. *(b) Bypass Loops* *(1)* A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300. *(2)* A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.	***ISTF*-5200 Vertical Line Shaft Centrifugal Pumps** *(a) Duration of Tests* *For* the *Inservice* test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTF-3000-1 shall be made and recorded. *(b) Bypass Loops* A bypass test loop may be used for *an Inservice* test, provided the flow rate through the loop meets the requirements as specified in para. ISTF-3300.
ISTB-5210 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1. *(a)* In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of Inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied. *(b)* Vibration measurements are only required to be taken at the reference point(s).	***ISTF*-5210 Preservice Testing.** The parameters to be measured are specified in Table *ISTF*-3000-1. *(a) Flow* rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of Inservice tests. *(b)* Vibration measurements are only required to be taken at the reference point(s).
ISTB-5220 Inservice Testing	***ISTF*-5220 Inservice Testing**
ISTB-5221 Group A Test Procedure. ISTB-5222 Group B Test Procedure.	***These Sections deleted.***

ISTB-5223 Comprehensive Test Procedure. Comprehensive tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* The resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value. *(c)* Where system resistance cannot be varied, flow rate and pressure shall be determined and compared to their respective reference values. *(d)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See Fig. ISTB-5223-1.) *(e)* All deviations from the reference values shall be compared with the ranges of Table ISTB-5221-1 and corrective action taken as specified in para. ISTB-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5221-1. For example, if vibration exceeds either 6*Vr* or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.	*Tests* shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table *ISTF*-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* The resistance of the system shall be varied until the flow rate equals the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure equals the reference point and the flow rate determined and compared to the reference flow rate value. *(c)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See Fig. *ISTF*-5223-1.) *(d)* All deviations from the reference values shall be compared with the ranges of Table *ISTF*-5221-1 and corrective action taken as specified in para. ISTB-6200. The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table *ISTF* -5221-1. For example, if vibration exceeds either 6*Vr* or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

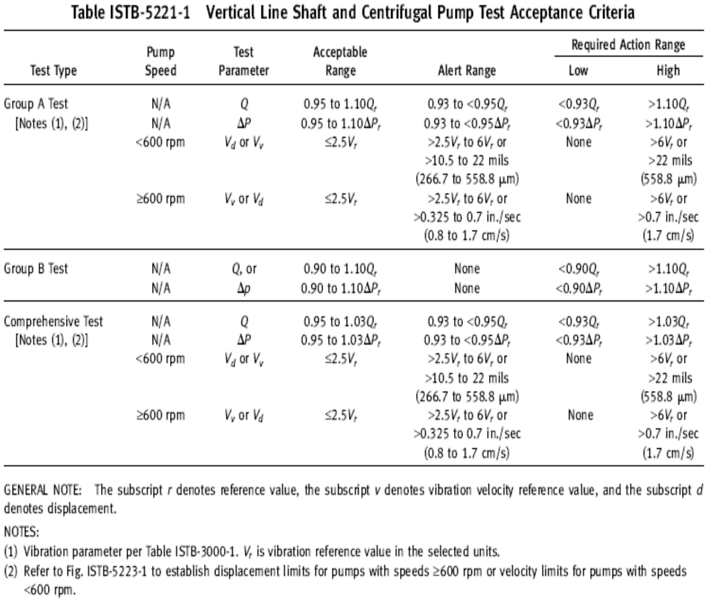


Table ISTB-5221-1 Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria

					Required Action Range	
Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Low	High
Group A Test [Notes (1), (2)]	N/A	Q	0.95 to 1.10Q_r	0.93 to <0.95Q_r	<0.93Q_r	>1.10Q_r
	N/A	ΔP	0.95 to 1.10ΔP_r	0.93 to <0.95ΔP_r	<0.93ΔP_r	>1.10ΔP_r
	<600 rpm	V_d or V_v	≤2.5V_r	>2.5V_r to 6V_r or >10.5 to 22 mils (266.7 to 558.8 μm)	None	>6V_r or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	≤2.5V_r	>2.5V_r to 6V_r or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	>6V_r or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q_r or	0.90 to 1.10Q_r	None	<0.90Q_r	>1.10Q_r
	N/A	Δp	0.90 to 1.10ΔP_r	None	<0.90ΔP_r	>1.10ΔP_r
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.95 to 1.03Q_r	0.93 to <0.95Q_r	<0.93Q_r	>1.03Q_r
	N/A	ΔP	0.95 to 1.03ΔP_r	0.93 to <0.95ΔP_r	<0.93ΔP_r	>1.03ΔP_r
	<600 rpm	V_d or V_v	≤2.5V_r	>2.5V_r to 6V_r or >10.5 to 22 mils (266.7 to 558.8 μm)	None	>6V_r or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	≤2.5V_r	>2.5V_r to 6V_r or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	>6V_r or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

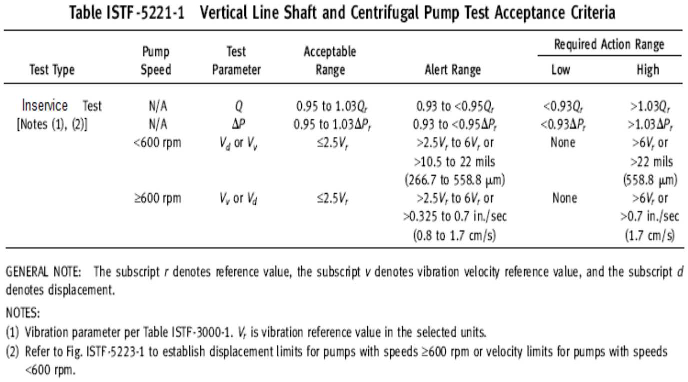


Table ISTF-5221-1 Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria

					Required Action Range	
Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Low	High
Inservice Test [Notes (1), (2)]	N/A	Q	0.95 to 1.03Q_r	0.93 to <0.95Q_r	<0.93Q_r	>1.03Q_r
	N/A	ΔP	0.95 to 1.03ΔP_r	0.93 to <0.95ΔP_r	<0.93ΔP_r	>1.03ΔP_r
	<600 rpm	V_d or V_v	≤2.5V_r	>2.5V_r to 6V_r or >10.5 to 22 mils (266.7 to 558.8 μm)	None	>6V_r or >22 mils (558.8 μm)
	≥600 rpm	V_v or V_d	≤2.5V_r	>2.5V_r to 6V_r or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	>6V_r or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

ISTB-5300 Positive Displacement Pumps *(a) Duration of Tests* *(1)* For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement	***ISTF*-5300 Positive Displacement Pumps** *(a) Duration of Tests* For the *Inservice* test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of

or determination of each of the quantities required by Table ISTB-3000-1 shall be made and recorded. *(2)* For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by Table ISTB-3000-1 shall be made and recorded. *(b) Bypass Loops.* A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in para. ISTB-3300. A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.	each of the quantities required by Table *ISTF*-3000-1 shall be made and recorded. *(b) Bypass Loops.* A bypass test loop may be used for *an Inservice* test, provided the flow rate through the loop meets the requirements as specified in para. *ISTF*-3300.
ISTB-5310 Preservice Testing. The parameters to be measured are specified in Table ISTB-3000-1. *(a)* For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in Table ISTB-3000-1. *(b)* Vibration measurements are only required to be taken at the reference point(s).	***ISTF*-5310 Preservice Testing.** The parameters to be measured are specified in Table *ISTF*-3000-1. *(a)* For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in Table *ISTF*-3000-1. *(b)* Vibration measurements are only required to be taken at the reference point(s).
ISTB-5320 Inservice Testing	***ISTF*-5320 Inservice Testing**
ISTB-5321 Group A Test Procedure. ISTB-5322 Group B Test Procedure.	***These Sections deleted.***
ISTB-5323 Comprehensive Test Procedure. Comprehensive tests shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* The resistance of the system shall be varied until the discharge pressure equals the reference point. The flow rate shall then be determined and compared to its reference value. *(c)* Where system resistance cannot be varied, flow rate and pressure shall be determined and compared to their respective reference values. *(d)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. *(e)* All deviations from the reference values shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in para. ISTB-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTB-5321-1. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5321-2. For example, if vibration exceeds either 6V_r or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.	*Tests* shall be conducted with the pump operating at a specified reference point. The test parameters shown in Table *ISTF*-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows: *(a)* The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point (±1%) for variable speed drives. *(b)* The resistance of the system shall be varied until the discharge pressure equals the reference point. The flow rate shall then be determined and compared to its reference value. *(c)* Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be broad band (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. *(d)* All deviations from the reference values shall be compared with the ranges of Table *ISTF* -5321-1 or Table *ISTF* -5321-2, as applicable, and corrective action taken as specified in para. *ISTF* -6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table *ISTF* -5321-1. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table *ISTF* -5321-2. For example, if vibration exceeds either 6V_r or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

Fig. ISTB-5223-1 Vibration Limits

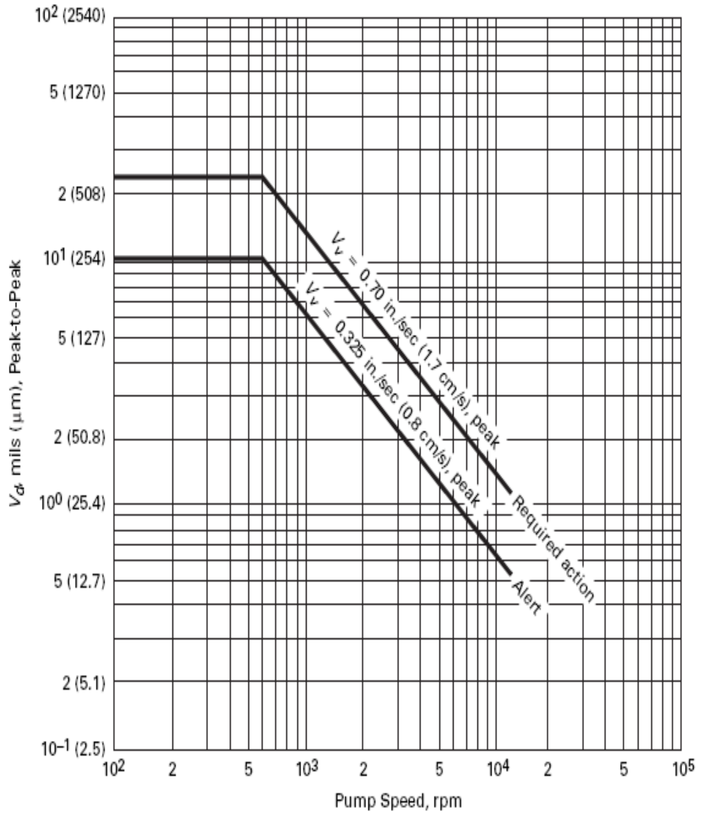


Table ISTB-5321-1 Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test [Notes (1), (2)]	N/A	Q	0.95 to $1.10Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	P	0.93 to $1.10P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.10P_r$
	<600 rpm	V_d or V_v	$\le 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 µm)	None	$>6V_r$ or >22 mils (558.8 µm)
	≥600 rpm	V_v or V_d	$<2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)
Group B Test	N/A	Q	0.90 to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
Comprehensive Test [Notes (1), (2)]	N/A	Q	0.95 to $1.03Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.03Q_r$
	N/A	P	0.93 to $1.03P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.03P_r$
	<600 rpm	V_d or V_v	$\le 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 µm)	None	$>6V_r$ or >22 mils (558.8 µm)
	≥600 rpm	V_v or V_d	$\le 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

Fig. ISTF-5223-1 Vibration Limits

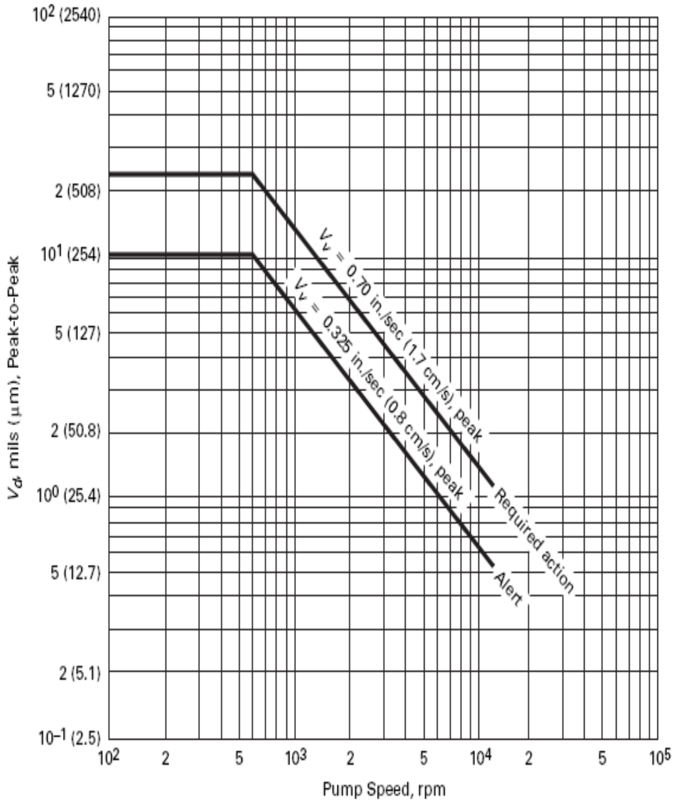


Table ISTF-5321-1 Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice Test [Notes (1), (2)]	N/A	Q	0.95 to $1.03Q_r$	0.93 to $<0.95Q_r$	$<0.93Q_r$	$>1.03Q_r$
	N/A	P	0.93 to $1.03P_r$	0.90 to $<0.93P_r$	$<0.90P_r$	$>1.03P_r$
	<600 rpm	V_d or V_v	$\le 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 to 22 mils (266.7 to 558.8 µm)	None	$>6V_r$ or >22 mils (558.8 µm)
	≥600 rpm	V_v or V_d	$\le 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 to 0.7 in./sec (0.8 to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (1.7 cm/s)

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

NOTES:

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

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

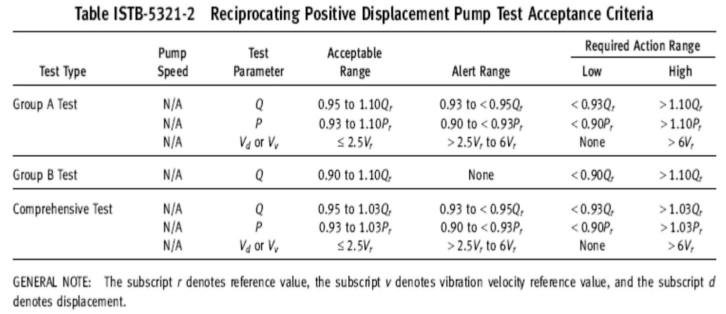
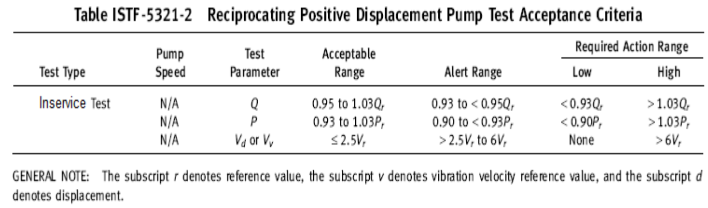
	
ISTB-6000 MONITORING, ANALYSIS, AND EVALUATION	***ISTF*-6000 MONITORING, ANALYSIS, AND EVALUATION**
ISTB-6100 Trending Test parameters shown in Table ISTB-3000-1, except for fixed values, shall be trended.	***ISTF*-6100 Trending** Test parameters shown in Table *ISTF*-3000-1, except for fixed values, shall be trended.
ISTB-6200 Corrective Action *(a) Alert Range.* If the measured test parameter values fall within the alert range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the frequency of testing specified in para. ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected. *(b) Action Range.* If the measured test parameter values fall within the required action range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed and new reference values are established in accordance with subpara. ISTB-6200(c). *(c) New Reference Values.* In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, and the pump's continued use at the changed values is supported by an analysis, a new set of reference values may be established. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The results of this analysis shall be documented in the record of tests (see section ISTB-9000).	***ISTF*-6200 Corrective Action** *(a) Alert Range.* If the measured test parameter values fall within the alert range of Table *ISTF*-5121-1, Table *ISTF*-5221-1, Table *ISTF*-5321-1, or Table *ISTF*-5321-2, as applicable, the frequency of testing specified in para. ISTF-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected. *(b) Action Range.* If the measured test parameter values fall within the required action range of Table *ISTF*-5121-1, Table *ISTF*-5221-1, Table *ISTF*-5321-1, or Table *ISTF*-5321-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed and new reference values are established in accordance with subpara. *ISTF*-6200(c). *(c) New Reference Values.* In cases where the pump's test parameters are within either the alert or required action ranges of Table *ISTF*-5121-1, Table *ISTF*-5221-1, Table *ISTF*-5321-1, or Table *ISTF*-5321-2, as applicable, and the pump's continued use at the changed values is supported by an analysis, a new set of reference values may be established. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The results of this analysis shall be documented in the record of tests (see section *ISTF*-9000).
ISTB-6300 Systematic Error When a test shows measured parameter values that fall outside of the acceptable range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.	***ISTF*-6300 Systematic Error** When a test shows measured parameter values that fall outside of the acceptable range of Table *ISTF*-5121-1, Table *ISTF*-5221-1, Table *ISTF*-5321-1, or Table ISTF-5321-2, as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.
ISTB-6400 Analysis of Related Conditions If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed1 and documented in the record of tests (see section ISTB-9000).	***ISTF*-6400 Analysis of Related Conditions** If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed1 and documented in the record of tests (see section ISTF-9000).

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

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A Test	N/A	Q	0.95 to $1.10Q_r$	0.93 to $< 0.95Q_r$	$< 0.93Q_r$	$> 1.10Q_r$
	N/A	P	0.93 to $1.10P_r$	0.90 to $< 0.93P_r$	$< 0.90P_r$	$> 1.10P_r$
	N/A	V_d or V_v	$\leq 2.5V_r$	$> 2.5V_r$ to $6V_r$	None	$> 6V_r$
Group B Test	N/A	Q	0.90 to $1.10Q_r$	None	$< 0.90Q_r$	$> 1.10Q_r$
Comprehensive Test	N/A	Q	0.95 to $1.03Q_r$	0.93 to $< 0.95Q_r$	$< 0.93Q_r$	$> 1.03Q_r$
	N/A	P	0.93 to $1.03P_r$	0.90 to $< 0.93P_r$	$< 0.90P_r$	$> 1.03P_r$
	N/A	V_d or V_v	$\leq 2.5V_r$	$> 2.5V_r$ to $6V_r$	None	$> 6V_r$

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

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

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice Test	N/A	Q	0.95 to $1.03Q_r$	0.93 to $< 0.95Q_r$	$< 0.93Q_r$	$> 1.03Q_r$
	N/A	P	0.93 to $1.03P_r$	0.90 to $< 0.93P_r$	$< 0.90P_r$	$> 1.03P_r$
	N/A	V_d or V_v	$\leq 2.5V_r$	$> 2.5V_r$ to $6V_r$	None	$> 6V_r$

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

ISTB-7000 TO BE PROVIDED AT A LATER DATE	***ISTF*-7000 *Reserved***
ISTB-8000 TO BE PROVIDED AT A LATER DATE	**ISTF-8000 *Reserved***
ISTB-9000 RECORDS AND REPORTS	***ISTF*-9000 RECORDS AND REPORTS**
ISTB-9100 Pump Records The Owner shall maintain a record that shall include the following for each pump covered by this Subsection: *(a)* the manufacturer and the manufacturer's model and serial or other identification number *(b)* a copy or summary of the manufacturer's acceptance test report if available *(c)* a copy of the pump manufacturer's operating limits	***ISTF*-9100 Pump Records** The Owner shall maintain a record that shall include the following for each pump covered by this Subsection: *(a)* the manufacturer and the manufacturer's model and serial or other identification number *(b)* a copy or summary of the manufacturer's acceptance test report if available *(c)* a copy of the pump manufacturer's operating limits
ISTB-9200 Test Plans In addition to the requirements of paras. ISTA-3110 and ISTA-3160, the test plans and procedures shall include the following: *(a)* category of each pump *(b)* the hydraulic circuit to be used *(c)* the location and type of measurement for the required test parameters *(d)* the method of determining test parameter values that are not directly measured by instrumentation	***ISTF*-9200 Test Plans** In addition to the requirements of paras. *ISTF*-3110 and *ISTF*-3160, the test plans and procedures shall include the following: *(a) type* of each pump *(b)* the hydraulic circuit to be used *(c)* the location and type of measurement for the required test parameters *(d)* the method of determining test parameter values that are not directly measured by instrumentation
ISTB-9300 Record of Tests See para. ISTA-9230.	***ISTF*-9300 Record of Tests** See para. ISTA-9230.
ISTB-9400 Record of Corrective Action See para. ISTA-9240.	***ISTF*-9400 Record of Corrective Action** See para. ISTA-9240.

Inservice Testing Program Improvements for New Reactors

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

Abstract

The nuclear industry is preparing for the licensing and construction of new nuclear power plants in the United States. The U.S. Nuclear Regulatory Commission (NRC) reviews information provided by applicants related to inservice testing (IST) programs for Design Certifications and Combined Licenses (COLs) under Part 52, “Licenses, Certifications, and Approvals for Nuclear Power Plants,” in Title 10 of the Code of Federal Regulations (10 CFR Part 52). The NRC discusses the development of IST programs for new reactors in Commission papers (including SECY 90-016, 93-087, and 95-132, and their Staff Requirements Memoranda), and Regulatory Guide 1.206 (June 2007), “Combined License Applications for Nuclear Power Plants (LWR Edition).” The American Society of Mechanical Engineers (ASME) has a program underway to develop improved IST provisions for new reactors in the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code). As part of its review of COL applications, the NRC staff is evaluating the descriptions of IST programs provided by COL applicants in their Final Safety Analysis Reports, including the incorporation by reference of information provided by reactor vendors in support of the NRC review of applicable certified designs. In its review, the NRC staff evaluates compliance of the IST program description with the ASME OM Code as incorporated by reference in the NRC regulations. The staff also evaluates the IST program description for consideration of Commission policy on IST programs for new reactors; and lessons learned from nuclear power plant operating experience, NRC and industry valve testing programs, and design of new nuclear power plant systems and components. This paper discusses the NRC staff review of IST program descriptions for new reactors; and improvements in IST surveillance activities for new reactors based on industry operating experience, testing programs, and new reactor system and component design.

Introduction

The nuclear industry is preparing for the licensing and construction of new nuclear power plants in the United States. The U.S. Nuclear Regulatory Commission (NRC) reviews information provided by applicants related to inservice testing (IST) programs for Design Certifications and Combined Licenses (COLs) under Part 52, “Licenses, Certifications, and Approvals for Nuclear Power Plants,” in Title 10 of the Code of Federal Regulations (10 CFR Part 52). The NRC discusses the development of IST programs for new reactors in several Commission papers and a regulatory guide. The American Society of Mechanical Engineers (ASME) has a program underway to develop improved IST provisions for new reactors in the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code). As part of its review of COL applications, the NRC staff is evaluating the descriptions of IST programs provided by COL applicants in their Final Safety Analysis Reports (FSARs), including the incorporation by reference of information provided by reactor vendors in support of the NRC review of applicable certified designs.

NRC Regulations

The NRC regulations in 10 CFR Part 52 provide a process for licensing of new nuclear power plants in the United States as an alternative to the process described in 10 CFR Part 50 “Domestic Licensing of Production and Utilization Facilities.” Part 52 specifies rules for (1) Early Site Permits (ESPs), (2) Standard Design Certifications, (3) COLs, (4) Standard Design Approvals, and (5) Manufacturing Licenses. It is anticipated that most applicants for the construction and licensing of new nuclear power plants will follow the process established in 10 CFR Part 52.

The NRC regulations in 10 CFR 52.79(a)(11) require a COL applicant to provide in its safety analysis report, at a level sufficient to enable the NRC to reach a final conclusion on all safety matters that must be resolved before COL issuance, a description of the programs and their implementation necessary to ensure that the systems and components meet the requirements of the ASME Boiler & Pressure Vessel Code (BPV Code) and the ASME OM Code in accordance with 10 CFR 50.55a. The NRC regulations in 10 CFR 52.79(a)(41) require that COL applications include an evaluation of the standard plant design against the revision of the NRC NUREG-0800 Standard Review Plan (SRP) in effect 6 months before the docket date of the application. In addition, the NRC regulations in 10 CFR 52.79(a)(37) require that COL applications include information necessary to demonstrate how operating experience insights have been incorporated into the plant design.

The NRC regulations in 10 CFR 50.55a(f)(4)(i) state that inservice tests to verify operational readiness of pumps and valves, whose function is required for safety, conducted during the initial 120-month interval must comply with the requirements in the latest edition and addenda of the ASME OM Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date scheduled for initial fuel loading under a COL issued per 10 CFR Part 52 or the optional ASME Code cases listed in NRC Regulatory Guide (RG) 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code,” subject to the limitations and modifications listed in Section 50.55a.

Commission Guidance for New Reactor Designs

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

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

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

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

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

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

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

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

In SECY-93-087, the NRC staff recommended that the Commission approve the position that the recommended IST requirements for evolutionary plants also be imposed for passive ALWR plants. The staff noted that additional IST requirements may be necessary for certain pumps and valves in passive plant designs. This necessity was said to arise because passive safety systems rely heavily on the proper operation of certain equipment (such as check valves and depressurization valves) to mitigate the effects of accidents and to shut down the reactor. Depressurization valves are operated by pyrotechnic (squib) actuators in some new plant designs. In its SRM dated July 21, 1993, the Commission did not object to the staff's position, but noted that the staff planned to provide more detail in a future paper.

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

In SECY-95-132, the NRC staff provided a revision to the staff recommendations in SECY-94-084 based on the Commission's direction in the SRM dated June 30, 1994. With respect to IST activities for passive plant designs, the staff stated in SECY-95-132 that the "unique passive plant design relies significantly on passive safety systems, but also depends on non-safety systems (which are traditionally safety-related systems in current light water reactors) to prevent challenges to passive systems. Therefore, the reliable performance of individual components is a significant factor in enhancing the safety of passive plant designs." The staff recommended that the following provisions be applied to passive ALWR plants to provide assurance of proper component performance:

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

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

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

4. The passive system designs should incorporate provisions to test safety-related power-operated valves (POVs) under design-basis differential pressure and flow. Similarly, to

the extent practicable, the design of nonsafety-related piping systems with functions that have been identified as important by the RTNSS process should incorporate provisions to test POVs in the system to assure that the valves meet their intended functions under design-basis conditions.

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

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

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

IST Operational Program Description

In SECY-02-0067, “Inspections, Tests, Analyses, and Acceptance Criteria for Operational Programs (Programmatic ITAAC),” the NRC staff recommended that COL applications for nuclear power plants submitted in accordance with the requirements of 10 CFR Part 52 contain ITAAC for operational programs required by regulations, such as training and emergency planning, to the extent that such ITAAC are necessary and sufficient to support the finding that the facility has been constructed and will be operated in conformity with the license, the provisions of the Atomic Energy Act, and the Commission’s rules and regulations. In an SRM dated September 11, 2002, the Commission determined that a COL applicant is not required to have ITAAC for an operational program for a nuclear power plant licensed under 10 CFR Part 52 with the exception of emergency planning. The Commission stated that ITAAC for an operational program should not be necessary if the program and its implementation are fully described in a COL application and found to be acceptable by the NRC staff at the COL stage. The Commission noted that the burden is on the applicant to provide the necessary and sufficient programmatic information for approval of the COL without ITAAC.

In SECY-04-0032, “Programmatic Information Needed for Approval of a Combined License Without Inspections, Tests, Analyses, and Acceptance Criteria,” the NRC staff provided recommendations to the Commission regarding the level of programmatic information needed for approval of a COL without ITAAC for operational programs. In an SRM dated May 14, 2004, the Commission stated that “fully described” for an operational program should be understood to mean that the program is clearly and sufficiently described in terms for scope and level of detail to allow a reasonable assurance finding of acceptability. The Commission noted that required operational programs should always be described at a functional level and an increasing level of detail where implementation choices could materially and negatively affect the program effectiveness and acceptability.

The NRC staff discussed the Commission’s position on operational programs in SECY-05-197, “Review of Operational Programs in a Combined License Application and General Emergency Planning Inspections, Tests, Analyses, and Acceptance Criteria [ITAAC].” In particular, COL applicants should fully describe the IST and MOV testing operational programs to avoid the need for ITAAC for the implementation of those programs. In SECY-05-0197, the NRC staff defines operational programs for new nuclear power plants as programs that are required by regulation, are reviewed by NRC staff for acceptability with the results documented in the safety evaluation report, and will be verified for implementation by NRC inspectors. The description of the program would contain the information necessary for the staff to make a reasonable assurance finding on the acceptability of the operational program in the review of a COL application. The staff proposed license conditions to provide certainty as to when the operational programs are scheduled to be implemented.

With the requirement in 10 CFR 50.55a(f)(4)(i) that the IST program comply with the Code edition and addenda incorporated by reference in the NRC regulations 12 months before fuel load, a COL applicant may describe the IST and MOV testing operational programs based on the ASME Code edition and addenda applicable at the time of submittal of the COL application. The COL applicant could then provide milestones for development and implementation of the final operational programs. The milestones should allow sufficient time for NRC inspections to review development and implementation of operational programs prior to relying on equipment to perform their safety functions.

Regulatory Guide 1.206

Regulatory Guide 1.206, “Combined License Applications for Nuclear Power Plants (LWR Edition),” provides guidance for COL applicants to use in preparing applications to construct and operate their proposed nuclear power plants. As noted in the Supplementary Information provided in the *Federal Register* notice for the revision to 10 CFR Part 52 (72 FR 49352, 49387), the NRC does not require applicants to evaluate their facility against RG 1.206. However, RG 1.206 can provide useful guidance to COL applicants in preparing their applications and that use of this guidance will facilitate the NRC’s review. Therefore, the staff considers the information in RG 1.206 for operational programs to be addressed in COL applications to be one method of fully describing those operational programs consistent with Commission guidance.

In Section C.I.3.9.6, “Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints,” of RG 1.206, the NRC staff provides guidance for submittal of COL application information on functional design, qualification, and IST programs for pumps, valves, and dynamic restraints in plants not referencing a certified design. In Section C.III.3.9.6 of the same title in RG 1.206, the staff provides guidance for a COL applicant referencing a certified design. The guidance is intended to minimize requests for additional information, streamline the review process, and reduce inspection activity.

In Section C.IV.4, “Operational Programs,” of RG 1.206, the NRC staff summarizes the Commission guidance provided in the SECY papers and SRM for the description of operational programs by COL applicants. In Section C.IV.9, “Regulatory Treatment of Nonsafety Systems,” of RG 1.206, the staff summarizes the Commission guidance provided in the SECY papers and SRM on the treatment of RTNSS equipment in new reactors.

<u>IST Lessons Learned for New Reactors</u>

Lessons learned from operating experience at operating nuclear power plants and from research conducted by the nuclear industry and regulatory authority related to IST programs should be applied to new reactors. These IST lessons learned include:

7. Design and qualification of pumps, valves, and dynamic restraints should allow IST activities (including sufficient flow testing) to assess the operational readiness of those components, and to implement ASME Standard QME-1-2007, “Qualification of Active Mechanical Equipment used in Nuclear Power Plants,” that incorporates lessons learned for the qualification of mechanical equipment for nuclear power plants.

8. Lessons learned from performance and testing of MOVs indicate the need for improved activities, such as importance of adequate design and qualification, sufficient flow during testing to assess valve performance, consideration of performance parameters (including valve disc and stem friction coefficients, reduced voltage, elevated temperature, and load sensitive behavior), use of adequate diagnostic instrumentation to allow proper evaluation and setup, unique direct current motor characteristics, improved maintenance and personnel training, monitoring of potential motor magnesium rotor degradation, and justification for motor control center testing.

9. MOV lessons learned should be applied in the design, qualification, and testing of other POVs. The NRC staff discusses the application of MOV lessons learned to other POVs in Regulatory Issue Summary (RIS) 2000-03, “Resolution of Generic Safety Issue 158, Performance of Safety-Related Power-Operated

Valves Under Design-Basis Conditions," and Information Notice 96-48, "Motor-Operated Valve Performance Issues."

10. Provisions for bi-directional testing should be implemented for all safety-related check valves. Nuclear power plant operating experience has revealed that testing check valves in only the flow direction can result in significant degradation (such as a missing valve disc) not being identified by the test.

11. Comprehensive pump testing (CPT) provisions should be implemented for new reactors. Pump testing at operating nuclear power plants revealed that current plant designs may not provide an effective means to test safety-related pumps with sufficient flow to identify potential degradation in pump performance.

12. Potential adverse flow effects on plant components from flow-induced vibration resulting from hydrodynamic loads and acoustic resonance should be considered in design, qualification, and startup testing of new reactors. Nuclear power plant operating experience has revealed that hydrodynamic loads and acoustic resonance can damage plant components (including valve actuators) that may not be revealed until the component is incapable of performing its design function.

IST Improvement Areas

Based on the IST lessons learned from operating reactors and the design of new reactors, there are several areas of potential improvement for IST programs for new reactors. For example, these IST improvement areas include:

8. Development of effective functional qualification of IST components: The NRC staff accepted ASME Standard QME-1-2007 for the functional qualification of active mechanical equipment in Revision 3 to RG 1.100, "Seismic Qualification of Electric and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," with specific provisions. Design Certification applicants are addressing functional qualification of IST components through applications of ASME QME-1-2007 as accepted in RG 1.100 (Revision 3) and other similar methods.

9. Performance of full flow testing of pumps: New reactors are being designed to allow for sufficient flow testing of pumps to assess their operational readiness in response to Commission guidance for new reactors.

10. Demonstration of MOV design-basis capability and periodic verification: Design Certification and COL applicants are addressing MOV design-basis capability through application of ASME Standard QME-1-2007 as accepted in RG 1.100 (Revision 3). COL applicants are addressing periodic verification of MOV design-basis capability to comply with 10 CFR 50.55a(3)(b)(ii) through application of ASME OM Code Case OMN-1 (as accepted in RG 1.192) and the Joint Owners

Group (JOG) Program on MOV Periodic Verification (as accepted in an NRC safety evaluation report dated September 2006 and its supplement dated September 2008).

11. Application of MOV lessons learned to other POVs: COL applicants are applying MOV lessons learned to other POVs by the specification of the attributes for successful implementation of POV programs provided in RIS 2000-03 in their COL FSARs.

12. Performance of bi-directional testing of check valves: New reactors are being designed to allow bi-directional testing of check valves in their IST programs in response to Commission guidance for new reactors.

13. Design, qualification, IST and inspection activities for pyrotechnic-actuated (squib) valves: Design and qualification activities are underway for the AP1000 squib valves that are much larger and represent more significant engineering challenges than the squib valves used at current operating plants. Lessons learned from those activities can be applied in developing IST surveillance activities to periodically assess the operational readiness of squib valves in new reactors.

14. Design of plant systems and development of IST programs to minimize the need for relief from the ASME OM Code requirements: Design Certification applicants are designing new reactors to minimize the need for relief from the ASME OM Code requirements, such as including full flow test lines for safety-related pumps.

15. Surveillance of potential adverse flow effects from flow-induced vibration caused by hydrodynamic loads and acoustic resonance: Design Certification applicants are addressing potential adverse flow effects from hydrodynamic loads and acoustic resonance during the design process with verification through startup surveillance programs. COL applicants will address potential adverse effects from flow-induced vibration during the preoperational testing programs described in the Design Certification and COL supporting documentation.

16. Design, qualification, preservice testing (PST), and IST activities of RTNSS components that perform important to-safety functions: New reactors may use nonsafety-related components that perform risk-significant functions.

17. Development and implementation of risk-informed IST programs, including 10 CFR 50.69 programs, for new reactors: COL applicants may apply risk insights in the development and implementation of their IST programs. The ASME has developed initial guidance for the treatment of low-risk safety-related components in OM Part 29.

18. Consideration of design, qualification, PST, and IST activities for software-based digital technology in mechanical components: Component suppliers have indicated an interest in applying digital technology in mechanical components.

ASME Activities

ASME has activities underway to improve the IST programs to be implemented at new reactors. Some of these activities include:

ASME Code Case OMN-1, “Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light Water Reactor Power Plants,” and Code Case OMN-11, “Risk-Informed Testing for Motor-Operated Valves,” specify an approach of periodic MOV exercising and diagnostic testing as an alternative to the quarterly stroke-time testing provisions in the ASME OM Code editions prior to 2009. The NRC staff accepted the use of Code Cases OMN-1 and OMN-11 with conditions in RG 1.192. The MOV program described in Code Cases OMN-1 and OMN-11 can be used to help satisfy the requirement in 10 CFR 50.55a(b)(3)(ii) to establish a program to demonstrate the design-basis capability of safety-related MOVs on a periodic basis. ASME has incorporated Code Cases OMN-1 and OMN-11 into the 2009 Edition of the ASME OM Code as Appendix III.

ASME has prepared a White Paper on its activities to improve the IST provisions for new reactors in the ASME OM Code. As part of this effort, ASME is preparing new sections in the OM Code to specify IST provisions for new reactors. The first phase of this effort will address full flow pump testing for new reactors and specific clarification issues. The second phase will address additional lessons learned and new reactor issues. When the effort is complete, the NRC staff will consider the ASME OM Code for new reactors for incorporation by reference in 10 CFR 50.55a.

ASME is preparing a non-mandatory appendix to the ASME OM Code to provide guidance for system and component design to support IST activities for new reactors. For example, ASME is considering recommendations for accessibility to perform IST activities in the design of new reactors. The proposed non-mandatory appendix also addresses recommendations for individual components such as MOVs and other POVs. ASME is evaluating the proposed non-mandatory appendix through its ballot process.

NRC Staff Activities

The NRC staff is reviewing IST program descriptions in COL applications and referenced Design Certification provisions to determine whether the descriptions satisfy the NRC regulations in 10 CFR Part 52 for issuance of a COL for new reactors. The NRC staff conducts audits of IST program documentation including valve design and procurement specifications as part of the review of COL applications. The NRC staff is preparing inspection procedures for ITAAC completion and IST program development and implementation.

The NRC staff is updating NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants,” to provide improved guidance for development and implementation of IST programs. The staff plans to incorporate lessons learned from operating experience at current nuclear power plants in the updated NUREG. This information will also be useful in the development of IST programs at new nuclear power plants.

The NRC staff will continue to participate in ASME activities to update the OM Code for new reactors. The staff will evaluate the new OM Code editions and addenda for incorporation by reference in 10 CFR 50.55a with any appropriate limitations and modifications. The staff is currently working on an update to 10 CFR 50.55a that will consider for incorporation by reference the latest ASME Code edition and addenda, including sections related to new reactors.

Conclusion

The nuclear industry is preparing for the licensing and construction of new nuclear power plants in the United States. ASME has a program underway to develop improved IST provisions for new reactors in the ASME OM Code. As part of its review of COL applications, the NRC staff is evaluating the descriptions of IST programs provided by COL applicants in their FSARs, including the incorporation by reference of applicable Design Certification information. In its review, the NRC staff evaluates compliance of the IST program description with the ASME OM Code as incorporated by reference in the NRC regulations. The staff will evaluate the ASME OM Code editions and addenda that include IST provisions for new reactors for incorporation by reference in 10 CFR 50.55a with any appropriate limitations and modifications.

Design and Baseline Testing of Motor Operated Valves for Generation 3+ Nuclear Power Generating Plants

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Abstract

Flowserve is currently supplying motor operated valves (MOVs) to Generation 3+ nuclear power plants. These valves have been custom designed to meet the design and qualification criteria for ASME Section III, Class 1 nuclear service. To support plant operations, these valve designs benefit from the lessons learned from US NRC Generic Letter (GL) 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance”, the subsequent MOV testing programs, the Joint Owners Group (JOG) MOV Periodic Verification Program and ASME QME-1 functional qualifications.

As a result, some new MOV designs are larger and heavier than typical valves of corresponding size and pressure class supplied to existing nuclear power plants.

During the valve functional testing portion of valve manufacturer’s testing, each MOV assembly is instrumented to record stem thrust, torque and position, motor operator voltage and current draw, and limit switch and torque switch function. The data are digitally recorded for further review and acceptance. The baseline data will allow the end user to confirm proper MOV installation and setup. The baseline data can also be

compared to future test data to evaluate potential performance degradation during the nuclear power plant operation.

This paper discusses:

- MOV design parameters and design features
- the production testing to establish and record MOV baseline functional data and
- ASME QME-1-2007 qualification of these MOVs

Introduction

The issuance of the NRC's GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," has resulted in substantial changes in the design, manufacture, and testing of nuclear valves for suppliers, utilities, and their agents worldwide. As the qualification requirements have been refined, the eventual requirements placed much emphasis on verification by testing and design validation that safety-related MOVs are capable of performing their safety-related functions during all postulated plant conditions, throughout the plant life.

Prior to the issuance of GL 89-10, ASME had developed ASME B16.41, "Functional Qualification of Power Operated, Safety-Related Valves." This standard was the first standard released to address testing and validation requirements for the power operated, safety-related valves under normal and accident conditions. Subsequently, ASME developed ASME QME-1-2007 to supersede ASME B16.41. B16.41 based functional adequacy on stroke time measurements, an approach that was ultimately considered unsatisfactory. The QME-1-2007 standard uses a much more detailed approach towards determination of functional adequacy and the extension of qualification to valves not tested under design-basis conditions.

As a result of the test methods and data collection methods developed during the Electric Power Research Institute (EPRI) and utilities' GL 89-10 valve testing programs, many updates have been incorporated into ASME QME-1-2007. The NRC has accepted ASME QME-1-2007 with specific provisions in Revision 3 to Regulatory Guide 1.100, "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants." Today, the testing and validation results of ASME QME-1-2007 provide additional assurance of valve functional capabilities when required within the operation of the commercial nuclear power plant.

Along with the above, many of the recent valve design specifications for the Generation 3+ commercial nuclear power plants require baseline testing and baseline data collection of safety-related, power operated valves (POVs) prior to shipment to the new power generation plants. These testing and data collections require the addition of instrumentation to the valve during testing to measure the operator and valve performance characteristics. Additionally, digital recording equipment is utilized to record the data and allow its initial review and later comparisons to equivalent data collected during plant installation and operation.

US NRC Generic Letter 89-10 Influence on Valve Design

GL 89-10 requested that nuclear power plant licensees verify the design-basis capability of their safety-related MOVs through design-basis testing where practicable. The NRC issued GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," to address the long-term testing of MOVs to maintain their design-basis capability. The NRC subsequently incorporated a requirement in 10 CFR 50.55a for the periodic verification of MOV design-basis capability to supplement the ASME *Code for Operation and Maintenance at Nuclear Power Plants* (OM Code). Prior to this, valve testing focused on stroke-time testing under static (no load) conditions per the ASME Boiler and Pressure Vessel Code and the ASME OM Code.

As a result, high quantities of valve testing and analysis have been performed. Along with this, valve performance enhancements and predictability also followed. In order to assure the capability of safety-related MOVs (and other POVs) throughout the life of the power plant, valve degradation must be better understood and controlled. Design enhancements must be validated with testing that takes into account the aging parameters such as interaction, corrosion and wear of the sliding surfaces in valves; seats, stems, disc guides, etc. If these surfaces and their clearances and edges are not design properly or become significantly marred over time, the capability of the valve might become unpredictable.

Valve designs have been enhanced and verified to address these concerns. These are the designs that are being supplied to the next generation commercial nuclear power plants, Generation 3 and 3+.

Design Features to Support Nuclear Island Applications

The Flowserve-Anchor/Darling flex wedge gate valve and Flowserve-Edward T-Pattern Globe valve designs have been enhanced for the ASME Section III, class 1, nuclear island applications to assure continued predictability and capability. These enhancements include:

- Flex wedge gate and globe valves with hardfaced disc guide surfaces (see Figures 2, 3, 4 and 5)
- Controlled hardfaced disc guide slot and body guide clearances to control disc tilt of flex wedge gate valve disc (see Figure 2)
- Chamfers on leading edges on the seating and disc guiding surfaces of the disc and body seats
- Body/bonnet flanges and gasket seals designed with an option for in-service seal weld capabilities
- Valve “structures” designed to handle the applicable seismic parameters including the “hard-rock formations” of some new nuclear power plant locations
- Flowserve-Limitorque motor actuators sized conservatively using a valve seating coefficient of friction from the JOG MOV Periodic Verification Test Program data

MOV Design Process

To start, basic dimensions of the valves were used from previous designs such as seat and stem diameters. Using this basic information, along with specific closing pressure requirements and the JOG recommended friction factors, a required torque and thrust to fully seat each valve was developed.

Actuator Control: The electrical control to close each valve was developed based on each valve application. Once the gate contacts the seat, if there was sufficient pressure in the line to aid in sealing the valve, the control for this assembly would be position seated (the electric motor would shut off at a certain stem location). However, if the specific application for the valve assembly does not have sufficient line pressure to aid in the sealing of the valve, the assembly would need to rely on a calculated amount of torque from the actuator to completely seal the valve (the electric motor would shut off at a certain torque).

Margin of Uncertainties: The disadvantage of the torque controlled system is the uncertainty of the rate of loading that must be added to the required thrust to seat the valve. Where a stem friction coefficient based on design-basis conditions (rather than static loading conditions) is applied in the MOV sizing calculations, the rate of loading for a position controlled system is zero since the actuator will shut off at the same point in its travel considering the repeatability of the switch – whereas the rate of loading for a torque switch control (based on EPRI testing) is 5.6% bias and 26.4% random. A torque switch’s repeatability for this application is an additional 10% while a position switch control repeatability is significantly lower at 1%. This amounts to (including 10% test equipment accuracy for either control system) a required margin of uncertainty when sizing the actuator of an additional 35.5% for torque control and 14% for position controlled.

Seismic Considerations: Once the actuators were sized appropriately, the enhanced features listed above were implemented into the designs. In addition to these features, each assembly was designed to simultaneously withstand biaxial seismic accelerations of 6 g's horizontally plus 7 g's vertically with at least a 10% margin. These seismic considerations have an effect on many parts of the valve assembly including flange thicknesses, body neck thickness, bolt sizes and circle diameter, gasket and lipseal diameter, yoke thickness, and actuator bolting.

Many of the designs are of a higher pressure class and designing for these high seismic loads creates a heavier more robust design than the previous lipseal designs.

Materials: The traceability and chemical composition of the raw materials used are also a major aspect in the design process. Most of the parts on the valve are treated as a safety related item in order to maintain traceability of the product. This includes anything from raw material origin to the way in which the part was handled within the Flowserve facility. Many of the designs are stainless steel body and bonnets; however, any exposed carbon steel parts (such as the yoke and actuator) are coated with a sealant to resist corrosion. Packing or gasket materials are mainly made of graphite materials with controlled contents of certain elements, such as leachable chloride, fluoride, and sulfur.

Additional Features: Furthermore, a unique element to the design is a small undercut in the stem located between the packing chamber and actuator. This undercut serves two purposes. The first is to provide a location for the mounting of a position indication arm. This arm can be used for local visual position indication, or mounted with a magnet for the safety related proximity switches for remote valve position indication. The second purpose for this undercut is to provide a breaking point in the event of an actuator malfunction. In the event of a catastrophic electrical failure and the actuator motor stalls (indefinite maximum amount of torque output), the stem will break prior to any other piece outside of the packing chamber. Because of the location of the breaking point, valve pressure boundary integrity will be maintained since the pressure boundary will not be violated, nor will this create any projectiles leaving the valve assembly.

The remote position indication is a new design from previous generation's nuclear facilities. The previous designs typically used a lever operated limit switch while these new designs for the Generation 3+ facilities use a magnetically operated Topworx GO switch. The advantage to this new design is that it is a completely sealed 303 stainless steel switch and target magnet housing with no seals or gaskets to replace over its qualified life (60 years). The sensing range can vary, depending on the magnet type, from within a 0.250" gap to a 0.100" gap between the magnet and switch. Also, since there are no arms or levers that are required to move, there is no force required to activate the switch.

Valve Manufacturer Testing Requirements

Typical valve production testing requirements as required by ASME Section III, ASME B16.34 and MSS-SP-61 for gate valves include:

- Hydrostatic shell and disc tests
- Packing tests
- Main seat and backseat leakage

Design specifications and manufacturer standards also require valve functional tests to verify operational times and proper valve travel under the manufacturer's test system conditions.

The valve design specifications for Generation 3+ nuclear power stations take the functional testing requirements further. They require the valve stems be instrumented with a strain gauge (see Figure 6, Teledyne Test Services Quick Stem Sensor (QSS)) which measures strain in the stem during the functional testing. Flowserve uses a 16 channel diagnostic computer to measure and record this strain which can then be converted to thrust and torque as a function of time. At a frequency of 1000 Hz, the computer records the data in addition to:

- Voltage (AC or DC)
- Current
- Torque switch indication
- Actuator control limit switch indication
- Stem position (using a string potentiometer)
- Actuator spring pack displacement (using a Linear Variable Differential Transmitter (LVDT))

Using this recorded information, additional parameters can be calculated such as motor power, packing thrust/torque, maximum running current, stem thread coefficient, and countless other data points of interest. Once both pressurized and non-pressurized testing for each individual valve is complete, a report is compiled which contains a wealth of baseline data for use in a Generation 3+ nuclear power station.

The baseline data can be used throughout the 60+ year lifespan of the valve for comparison to the results of subsequent plant testing evaluating the attributes of the valve, such as degradation of the wear components. With the ability to understand and document these changes to the valve functions, valve capability can be evaluated, and maintenance during plant shut-downs can be better planned.

Refer to Figures 7 and 8 for a typical test setup of functional testing to measure and record functional test performance data at Flowserve-Raleigh.

Flowserve ASME QME-1-2007 Qualification of MOVs

ASME QME-1-2007 functional qualification testing is utilized to verify that the safety-related, active valves will function during their normal operation and postulated accident events. MOV functional qualification tests include:

- Fundamental frequency determination
- Sealing tests to confirm the valve seat and stem sealing capabilities
- Seismic tests to confirm the valve will function during a seismic event (static deflection method, see Figure 9)
- Piping End load tests to confirm valve function and seal with applicable pipe loads applied to the valve body nozzles
- Flow interruption and functional capability test

In addition to the tests listed above, both pre- and post- test dimensional and visual inspections of the wear surfaces will be documented. This information is vitally important to show the aging effect of the performed tests.

The test valves chosen from the designs in Table 1 are intended to envelope all sizes and pressure class ranges. Even where a specific valve design is not tested under design-basis conditions, the program will be developed to adequately assure that the valve is qualified through analysis combined with reduced qualification testing requirements since all the designs within a group are geometrically similar.

Currently within the MOV assemblies, there are a total of 14 unique designs in the qualification program – six of these are intended to be design-basis test qualified valves per ASME QME-1-2007. These designs are divided into two geometrically similar Groups, A & B, which consist of Flowserve-Anchor/Darling Flexwedge valves and Flowserve-Edward Globe valves respectively. The design-basis test qualified valves are indicated in Table 1.

The test data will be used to validate and verify the analytical models used to design the valve assemblies. The intent is that the data used for the validation and verification will apply to as wide a range of valve sizes as possible, within the requirements for extrapolation of valve qualification provided in the QME-1-2007 standard. This is one reason the smallest and largest valves were chosen. The verified and validated analytical models are then used to qualify other valves using the provisions in QME-1-2007. Since Group A contains a large quantity of valve assemblies, an intermediate size valve (Size 6 Class 150) was also chosen to be tested to show correlation over a larger group of valves.

The three Flowserve-Edward Globe valves are all design-basis test valves, so interpolation of test results for these valves is not required.

Table 1: QME-1 Qualification Program

GROUP A	Size 3 Class 150 Flexwedge manual gate
	Size 3 Class 1500 Flexwedge MOV
	Size 4 Class 150 Flexwedge manual gate
	Size 4 Class 1500 Flexwedge MOV
	Size 6 Class 150 Flexwedge MOV
	Size 6 Class 900 Flexwedge MOV
	Size 6 Class 1500 Flexwedge MOV
	Size 8 Class 150 Flexwedge MOV
	Size 8 Class 1500 Flexwedge MOV
	Size 10 Class 1500 Flexwedge MOV
	Size 14 Class 1500 Flexwedge MOV
GROU PB	**Size 3 Class 1500 Globe MOV**
	Size 4 Class 1500 Globe MOV
	Size 8 Class 1500 Globe MOV

**** Indicates test valve**

As of this writing, Flowserve had developed the test plan and procedures for the ASME QME-1-2007 qualification and was in the initial stages of testing. The symposium presentation will provide updates to the Flowserve ASME QME-1-2007 test program.

Conclusion

As a result of the above design enhancement, valve functional tests and functional qualifications in accordance with ASME QME-1-2007, the MOVs supplied for the nuclear island application of the Generation 3 and 3+ commercial nuclear power plants are much better positioned to provide predictable, initial and long-term, validated functional reliability than previously supplied MOVs.

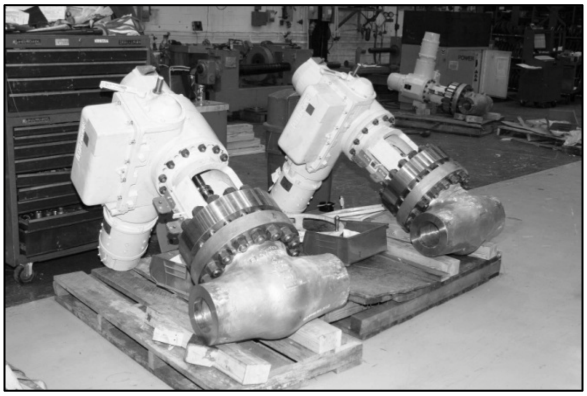

Figure 1: Typical Motor Operated Flex Wedge Gate Valve Ready for Shipment to a Generation 3+ Nuclear Power Generation Plant.

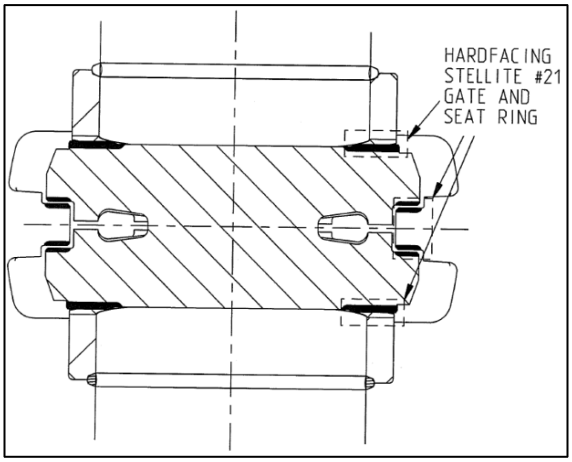

Figure 2: Flex Wedge Guide Top View with Hardfacing

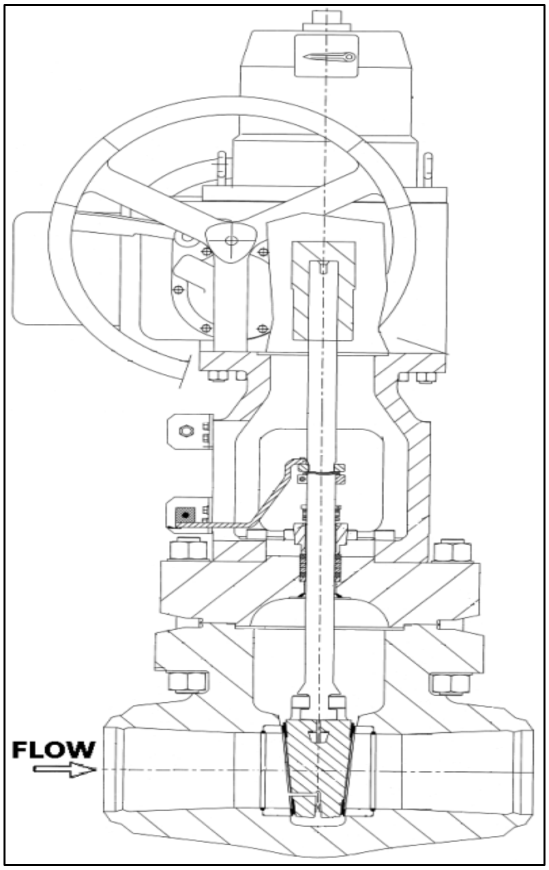

Figure 3: Typical Motor Actuated, Flex Wedge Gate Valve Drawing

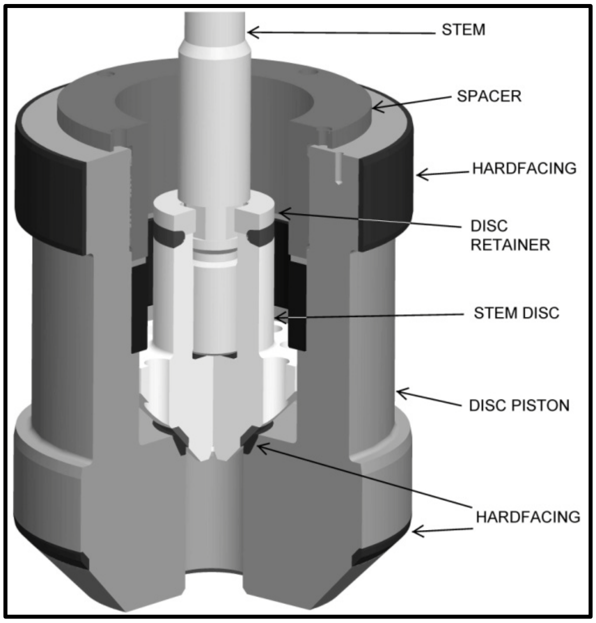

Figure 4: Globe Valve Plug Hardfacing

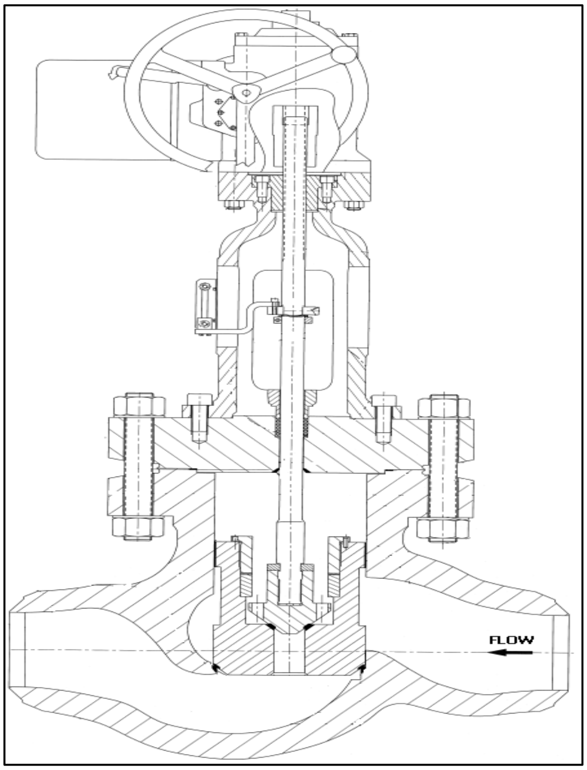

Figure 5: Flowserve-Edward Typical Balanced Plug Globe Valve

Figure 6: View of Instrumented Stem with Position Indication Arm

Figure 7: Picture of Production Functional Testing of an MOV with Full Instrumentation and Test Data Collection.

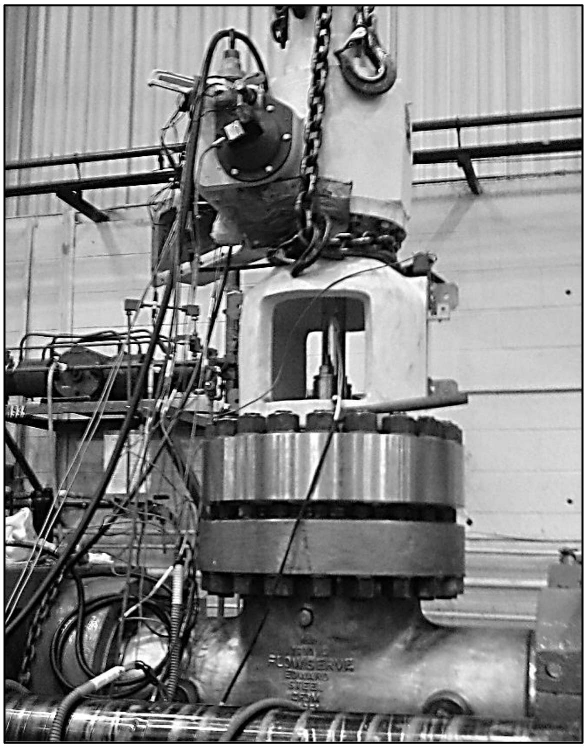

Figure 8: Additional Picture of Production Functional Testing of MOV

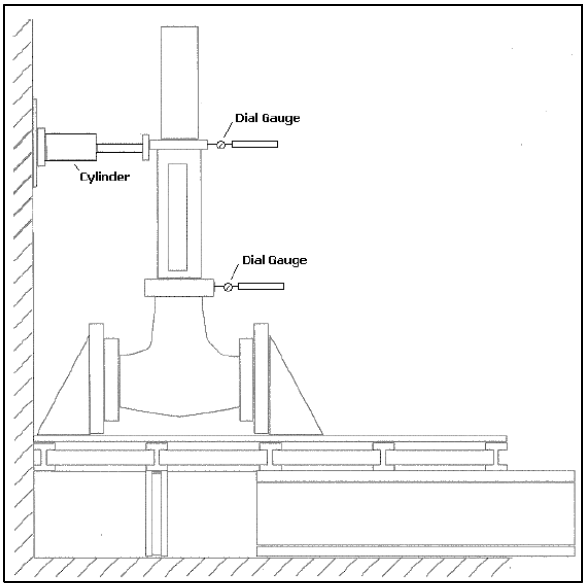

Figure 9: Static Deflection Seismic Qualification Setup

Nuclear Standards for Small Modular Reactors

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Abstract

Nuclear Standards have been in place for nuclear reactors for almost 40 years. Standards Development Organizations (SDOs), including American Nuclear Society (ANS), American Society of Mechanical Engineers (ASME), and Institute of Electrical and Electronic Engineers (IEEE), work closely together and coordinate over international boundaries to ensure current applicability and completeness of nuclear standards. For the last five years, IEEE has been collaborating with International Electrotechnical Commission (IEC) to harmonize the standards that apply to qualification of safety related equipment. This harmonization process recognizes that nuclear power plants will be deployed both nationally and internationally and ensures that the standards for equipment qualification are universally accepted. The large reactor vendors have been key players in the harmonization process to ensure their respective designs can be used worldwide. Recently, momentum has increased for Small Modular Reactors (SMRs) and the process for equipment qualification will need to be incorporated into their designs. This paper discusses some of the standards that will likely apply to SMRs and a few of the challenges for the standards organizations and reactor suppliers.

Introduction

ANS, ASME, and IEEE, along with other SDOs have been crucial in establishing the consensus approach for safety standards used in the construction and operation of nuclear power plants. These consensus standards have been in effect for almost 40 years and the nuclear power industry and nuclear fuel facilities regularly utilize these standards during operations. Many of these standards have been endorsed by regulators worldwide as applicable to nuclear power plants and nuclear fuel facilities. Traditional nuclear suppliers and their regulators are very familiar with these standards and regularly participate on the standards committees. A new type of nuclear power plant, the SMR, is receiving a lot of attention and has created new opportunities and challenges for the nuclear industry. In most cases, industry articles focus on the attributes of SMRs, few articles discuss the standards that will likely apply to SMRs, and even fewer articles discuss the challenges for the standards organizations and reactor suppliers. This paper adds to the discussion of standards and challenges for SMRs.

Industry Acceptance of SMRs

Significant design aspects of a nuclear plant are independent of the type of reactor. For example, the mechanical, structural, electrical, and Instrumentation and Control (I&C) characteristics of all Nuclear Power Plants (NPPs) are similar, as are the treatment of quality assurance, environmental qualification, seismic qualification, mechanical design and qualification, and the site hazards designs. The most challenging regulatory issues for a new reactor design tend to center on core and reactor coolant design, materials applications, system configuration, accident analysis, and containment.

The recent earthquake and tsunami in Japan demonstrated the need for NPPs to not only survive an earthquake, but to remain safe after a subsequent tsunami. These events suggest that the efforts of the standards development organizations are crucial to the use of nuclear power because safety standards provide confidence of the performance of safety systems and safety equipment. Safety standards consider conditions, natural events, performance requirements, acceptance methods, and acceptance criteria and ensure safety for the public and workers. The earthquake, tsunami, and following accidents illustrate an interdependency among structural, electrical, mechanical, instrumentation and control features, and human interface to ensure operation of safety systems that needs to be considered for light water reactors (LWRs) and SMRs. Standards will need to evaluate the flooding potential following an earthquake and re-evaluate the hydrogen explosion scenario since preliminary indications signal that hydrogen explosions occurred at Fukushima. Additionally, other gases and their explosive and deleterious consequences will have to be addressed at SMRs through standards.

The current fleet of light water NPP designs differs from SMRs in important ways. SMRs generally incorporate innovative approaches to achieve simplicity, improved operational performance, and enhanced safety. Gas-cooled and liquid metal–cooled reactors represent an even greater departure from current designs and consequently greater challenges to the application of current regulatory guidance and the consensus standards to which they are designed and comply. Light water NPP requirements provide assurance of safety system quality, capability, reliability, and redundancy commensurate with the safety characteristics of current designs. Since SMR designs incorporate passive safety features, enhanced safety margins, slower accident response, and improved severe accident performance in comparison to non-SMR designs, opportunities to simplify and streamline the regulatory process and requirements should be considered.

Some aspects of non-LWR SMR designs could present hazards that need additional review to ensure compliance with regulatory requirements. An example of a hazard is sodium fires postulated at liquid metal–cooled plants. Theoretically, some non-LWR designs are postulated to be unsusceptible to Loss of Coolant Accidents (LOCA) and might not require an emergency core cooling system (ECCS).

In 2010, the nuclear community discussed opportunities for SMRs and regulatory aspects (Reference 1). A general theme presented was that SMRs were different from existing licensed large NPPs and their inherent safety features would result in a less difficult licensing process with the applicable regulator.

The general theme from the community was that the SMR community should provide a consensus approach.

Since much of the design of a nuclear plant is independent of the type of reactor, the mechanical, structural, electrical, and I&C characteristics of all NPPs are similar, and the treatment of quality assurance, environmental qualification, and design for site hazards are addressed in industry standards, the existing consensus approach is applicable to SMRs.

It is widely anticipated that the SMR designs will have a much lower calculated probability of core damage and radioactive release than current-generation plants. Smaller core inventory, simpler design with fewer systems, and the inclusion of advanced design features such as passive safety systems contribute to this anticipation. Attached to these advanced features are requirements from standards as to their construction and performance. For instance, in order for some passive features to perform as designed, instrumentation, controls, valves, and actuators will need to perform safety functions under adverse conditions. The ASME and IEEE qualification standards thus are applicable to these features; therefore, it is apparent that ASME and IEEE qualification committees will have to ensure that the standards adequately test and evaluate passive safety system performance and properly qualify the equipment for the expected environments.

External events

SMRs are being proposed for remote locations generally not chosen for large nuclear reactors, such as the proposed Galena Nuclear Power Plant to be constructed in the

Yukon River village of Galena in the U.S. state of Alaska. These remote sites introduce the possibility that certain external events may be the dominant accident initiators and would have to be addressed through standards and regulations. Additionally, earthquake risk, less reliance on offsite power, and additional external events might be higher at remote sites.

Additional external events that would be of particular concern for SMRs include the following:

- Flood: Some SMR designs have the reactor located underground, and groundwater intrusion or flooding of the buildings would be a design and qualification consideration.
- External fire: For sites near wooded areas, an off-site forest fire could challenge plant operation and features such as dampers and internal circulation might be necessary.
- Extreme cold: For sites with very cold temperatures, such as -60°F, and very high temperatures, such as + 115 °F, extreme temperatures represent unique challenges to equipment and would have to be accounted for in the design and qualification.
- Extreme snow and/or ice: Extreme snow and/or ice conditions could limit access to the plant and would necessitate additional human factors considerations.
- Volcanic ash conditions: Volcanic ash effects on equipment, dampers, and limited access to the plant would have human factors, design and qualification impacts.

The design of some SMRs could accommodate these challenges due to their ability to provide core cooling with natural circulation in the absence of off-site power or operator intervention. The affected standards might require modifications to account for these newly anticipated occurrences. Fortunately, passive safety features have been designed into advanced LWRs, such as Westinghouse’s AP1000 and General Electric Hitachi’s ESBWR and the applicable ACI, ANS, ASME, and IEEE standards already consider risk, performance, and qualification for passive features. The active mechanical and electrical safety equipment necessary to initiate the passive safety features are also covered by the consensus standards, such as ASME QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants,” and IEEE 323, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

Coordination and Concerns

The SDOs are working together with the Nuclear Energy Standards Coordinating Council to ensure that SMRs are adequately considered in the standards. Additional work is needed due to confusion in the licensing process. An example of this confusion was a recent announcement of discussions on the use of topical reports in lieu of consensus standards to protect proprietary features of SMRs. This proposal is a potential concern. The standards committees take pride and passion in ensuring a consensus approach to safety. A large effort was made in the last two decades to ensure that the standards apply to LWRs and SMRs with international consensus. The standards development process is purposely not instantaneous, which allows for careful and widespread consideration among the world's experts before a conclusion is reached. The consensus timeline results in several standards generated and approved within 2 to 3 years, and processes are in place for swiftly addressing clarifications. The misconception that topical reports can be used instead of consensus standards needs to be swiftly, visibly, and strongly corrected by the SDOs. The use of topical reports is to provide proprietary documents and discussion on how proprietary features meet the consensus standards and the applicable regulations. Topical reports are common in large LWRs, but topical reports for SMRs should not to be used as an alternate to consensus standards.

A process for the design of SMRs must not be allowed outside of the consensus standards approach. It is up to each SDO to monitor this situation and correct this misconception when noted. The SDOs also need to coordinate through the liaison committee process whenever issues such as this come up.

Conclusion

SDOs are ready for SMRs, but as noted, the consideration of recent events, such as the March 2011 earthquake and tsunami in Japan and the additional severity of natural hazards, demonstrates that standards work is not complete. SDOs, and specifically ANS, ASME, and IEEE, need to continue the active liaison process in which members of each committee and subcommittee regularly attend and present the status and details of standards activities. As SMR safety features and performance requirements evolve, the SDOs need to evolve with them to ensure their safety. The ANS, ASME, and IEEE standards that address safety equipment performance, qualification, and natural hazard mitigation need to be applied to SMRs. It is our collective safety interest to ensure safety structures, systems and components perform properly during plant operation and in response to plant events.

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1. Interim Report of the American Nuclear Society President's Special Committee on Small and Medium Sized reactor (SMR) Generic Licensing Issues, July 2010

Session 4: Pumps

Session Chair: Robert Kershaw, Arizona Public Service Company

Comprehensive Pump Inservice Testing (IST) Issues - Seeking Resolution of Two Long Standing Regulatory Concerns

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Sub-Group ISTB Member and CPT Issues Project Team Member

Abstract

The purpose of this paper is to document the various historical issues associated with two long standing pump inservice testing regulatory concerns. The first issue is the definition and the testing of the “pump design flow rate” as used in the comprehensive pump testing (CPT) requirements. The term “pump design flow rate” was not clearly defined in the American Society of Mechanical Engineers (ASME) Operations & Maintenance (OM) Code for Operation and Maintenance of Nuclear Power Plants and Nuclear Regulatory Commission (NRC) expressed their concerns that pump design basis accident capability was not explicitly being addressed by the current CPT requirements. The second issue discussed is that the NRC questioned the bases for the upper hydraulic acceptance criteria limits and how are the limits related to instrumentation issues versus the test technique. The Sub-Group ISTB investigated the bases for the 1.03% and OM code changes are currently being developed to address these issues.

Introduction

The American Society of Mechanical Engineers (ASME) Operations & Maintenance (OM) Code for Operation and Maintenance of Nuclear Power Plants, ASME OM CODE-1996 Addenda, and later editions and addenda have incorporated comprehensive pump testing (CPT) requirements. One of the requirements of the CPT is to establish reference values within +/- 20% of the *pump design flow rate.* However these editions and subsequent addenda have not defined “pump design flow rate”. The ASME OM Committee, and in particular the Sub-Group ISTB who is responsible for the requirements of Subsection ISTB, Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants, have received numerous questions regarding the definition and intended use of this term in the IST Code.

The second issue discussed in this paper is that the NRC questioned the bases for the upper hydraulic acceptance criteria limits and how are the limits related to instrumentation issues versus the test technique. The current upper hydraulic acceptance criterion is 1.03%. Flow measurements performed at operating nuclear power plants often do not achieve this accuracy during routine CPT when the pump is not suffering from degradation. Additionally, instrumentation issues with pump testing in the field include using 2% Full Scale loop accuracy instrument loops for pressure. Because the OM Code also limits the full scale range of the pressure device to three times the reference value, it is possible to have almost 6% uncertainty for the test reading for pressure without consideration for the flow uncertainty. The Sub-Group ISTB is currently developing OM Code changes to alleviate the instrument accuracy issues faced by operating plants.

This paper will refer to the various key reference materials as attachments – but the actual attachments are not included due to needing to limit the document length for publication. (Please contact the authors for copies of the references if interested.)

Unresolved issues

The 1996 CPT change addressed the testing of pumps using minimum flow lines which have limited ability in detecting pump degradation. The 1996 CPT change was meant to test each pump at a point at which degradation was more readily detectable.

During several ASME OM meetings, the Nuclear Regulatory Commission (NRC) expressed their concerns that pump design basis accident capability was not explicitly being addressed by the current CPT requirements. As a result of several stalled code changes, a special joint ASME OM/NRC June 2007 meeting was scheduled, and from a detailed review of all the issues, a conceptual agreement was reached. ASME agreed to initiate ISTB Code actions to address the conceptual agreement.

ASME was essentially of the opinion that the 1996 Comprehensive Pump Test Code change had resolved the original NRC concerns that dealt with the transition from ASME Section XI IWP to the 1988 OM Part 6 requirements. Attachment 1 describes, thru a review of three papers presented at the First NRC/ASME Pump & Valve Symposium, August, 1989, the ASME OM Code Committee pump testing philosophy that existed in the 1990 timeframe. Many comments received during the OM Part 6 final approval process indicated that further changes to the IST pump testing requirements would be needed. The resolution of these final ballot comments integrated with the OM Part 6 pump testing concepts, lead to the development of the Comprehensive Pump Test. The CPT was approved and published in the 1996 Addenda to the 1995 Edition of the OM Code.

There were the normal questions associated with any major code addition as the CPT was initially implemented by the Owners starting in the 2000 timeframe. The Sub-Group ISTB tried on several occasions to clarify the application and the use of the CPT “design flow” for not only the regulators but for the users of the code.

The Subgroup ISTB had proposed changes to the ASME OM Code Subsection ISTB, 2004 Edition through the 2006 addenda, and provided the basis for why the changes were being made. The changes attempted to resolve the regulatory issue of what exactly is the design flow rate? These changes were not successful and it became apparent that ASME and the NRC were at a philosophical impasse.

In April, 2007, ASME requested a special meeting with the NRC to discuss pump testing issues. This meeting was separate from the regularly scheduled ASME OM Code meetings and was solely focused on the CPT and the code pump testing philosophy. The goal of the meeting was to allow each organization time to explain their perspectives associated with the Comprehensive Pump Testing issues. From this candid discussion, ASME OM Code members hoped to then seek a path to ultimately resolve the long standing pump testing issues. Key representatives from the ASME Committee including Committee officers, Sub-Group ISTB members, and NRC interested parties were asked to attend this meeting.

Attachment 2 contains a copy of the ASME Request for a Special Meeting in a letter dated April 23, 2007.

The meeting was held at the NRC offices in White Flint, Maryland on June 4, 2007. Attachment 3 contains the NRC Presentation used to describe their issues with the current ISTB requirements. Attachment 4 contains the ASME OM presentation materials for this meeting. There was open discussion during both presentations. Both the NRC and ASME presentations were filed on the ASME OM Committee Webpage under Committee File Sharing.

With regard to the Comprehensive Pump test, the discussions identified there were three long standing issues (the first two of which are discussed in this paper), that ASME OM needed to be address:

1. Design Flow – What is exactly meant by design flow? Is it accident analysis? Is it Best Efficiency Point or BEP? Who defines design flow? Is the slope of the pump curve a consideration? Does NRC Information Notice (IN) 97-90, “Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests,”– being above the minimum address the issue?
2. Instrumentation issues – For plants who can run their quarterly tests at “Design Flow”, why do they still need to use better instrumentation? Why do high alerts happen? Why are there separate criteria for the Comprehensive Pump Test versus the Group A?
3. What is the purpose of the Group B test? “Go or a NoGo” test to validate a start demand – no degradation? Only one parameter monitored – Flow or differential pressure (DP), not both? No degradation other than it started and got into the hydraulic box? No vibration needed?

Conceptual Agreement

As a result of this joint meeting, the ASME OM members in attendance now had a clear understanding of the regulatory issues and the basis of their concerns. As this material was reviewed and further discussed as the ASME OM Committee Meetings in June 2007, a conceptual agreement was developed for use by the ISTB CPT Project Team. Attachment 5 contains a copy of the Conceptual Agreement that was filed on the ASME OM Committee Webpage under Committee File Sharing.

Major portions of this agreement are contained in this paper.

First Issue – Design Flow

The CPT flow needed to be in a relative stable hydraulic region due to the application of the vibration acceptance criteria as a major indicator of pump health. Testing at points of the accident analysis did not necessarily present hydraulically stable regions. One of the NRC‘s concerns was to have a Technical Specification (TS) Program requiring certain Emergency Core Cooling System (ECCS) and Emergency Feedwater (EFW) pumps to be tested at a specific flow rate i.e., at design accident conditions. This concern was identified as being largely associated with the TS Change (processed approximately in the 2000 time period). The change deleted testing requirements at design accident flow rate conditions by replacing those requirements with references to testing in accordance with TS 4.0.5 or the IST Program. The NRC wanted certain pumps to be periodically tested at their design accident conditions and they wanted this testing to be in a TS Program.

These old TS requirements, for some plants, did not generally require testing at "design accident" conditions. Instead of having the specific hydraulic parameters for each pump listed in the TS, the TS change simply referenced the IST program. This TS change did not realize that IST did not necessarily require specific flow rates to be achieved other than the range as specified by the CPT (e.g., 80 to 120% of the design flow rate). Some pumps had a specific post maintenance surveillance requirement, like EFW pumps that would demonstrate their safety function. The 1996 CPT code change would require a five point head curve validation for pumps that were overhauled due to maintenance issues, yet there would be no periodic test if maintenance was not done.

The 1996 Comprehensive Pump test was an improvement over the old TS recirculation tests as CPT was conducted at a more representative flow rate, depending on how the owner defined "design flow rate". Vibration acceptance criteria also was used in a more prominent role than it had been during the ASME Section XI, IWP testing.

For some IST pumps, like pressurized water reactor (PWR) ECCS pumps, the design accident flow rate hydraulic parameters may be very close to run out conditions. The “design” flow used in 1996 CPT was not explicitly defined. The CPT also applied vibration criteria where the old TS IST type tests simply had the hydraulic parameters listed. This vibration check was specifically required during the CPT to compliment the hydraulic assessment of the pump health. The establishment of the CPT test point involves having a hydraulically stable region, such as the Best Efficiency Point (BEP), as the reference value for both the hydraulic and vibration assessments. The BEP may be at a much lower flow rate than the design accident condition. The hydraulic stability conditions at run out are not always conducive to the application of the ISTB vibration criteria (0.325 inches per second (ips) for ALERT and 0.7 ips for REQUIRED ACTION) without having specifically having these requirements imposed on the pump manufacturer during the original pump procurement process.

It was realized that there are also some pumps that have a design accident condition flow rate that is much less than BEP. ASME OM was also concerned that the two requirements, the CPT and the design accident condition flow test, could conflict with each other, meaning that we would be applying test criteria to a pump that was not designed for that condition.

OM Action

ASME OM agreed that a potential additional test point (DP and Flow only) to address the design accident flow conditions could be added to the ISTB requirements. The NRC indicated that this request would be to recreate the original TS surveillance requirements. Essential attributes for this new requirement were:

- FREQUENCY: Two year timeframe like the CPT, and most likely done at the same time as the CPT if that was convenient for the Owner. It should be the Owner’s decision on how to schedule the new testing activity.
- HYDRAULIC ONLY : No vibration is required to be taken as the pumps, based on the site specific safety analysis, may not be in a region that is hydraulically stable. As such the application of the vibration criteria is not appropriate. ITSB members wanted to minimize the time in this configuration, so not taking vibration data helps reduce the overall test duration.
- PREVIOUS TEST BASIS: The original TS requirements did not include explicit vibration requirements.
- APPLICABILITY: Generally the applicability is for those certain pumps that were listed in the plant TS. For example, PWR ECCS pumps, and other pumps like EFW or Containment Building Spray pumps that had design accident flow and DP (or maybe discharge pressure) values listed in the plant’s TS.

Resolution of the Design Flow Rate - Pump Periodic Verification Test Code Change

The Sub-Group ISTB is resolving the first of the NRC’s long standing issue by *defining* a comprehensive pump test flow rate and by the addition of a *new* pump periodic verification test.

The following information is contained in the White Paper for the OM Code change. During one of the many ballots, the white paper was presented as a non-mandatory appendix to the OM Code in an attempt to capture the information and make it readily available to the end users. It was ultimately removed as part of the OM Code change as several OM Committee felt that including the white paper as a non-mandatory appendix would be the exception. Since the white paper contains some of the basis for the code change, it is included as Attachment 6.

To many ASME OM Committee members the pump periodic verification test (PPVT) was not an IST test. To highlight that the new pump periodic verification test satisfies a different purpose and to separate it from applying other IST requirements, the PPVT was added as a separate Mandatory Appendix in the OM Code.

Discussion of Proposed Code Change

Attachment 7 contains the 2011 PPVT proposed code changes.

The change will be to 1) eliminate the “pump design flow” wording, and 2) to replace it with the “comprehensive pump test flow rate” and 3) add in a PPVT for those certain applicable pumps that have design basis accident flow rates specified in their TS or Updated Safety Analysis Report. The PPVT is not expected to be required for all of the pumps in the IST Program.

The *comprehensive pump test flow rate* is defined as the flow rate established by the Owner that is effective for detecting mechanical and hydraulic degradation during subsequent testing. The best efficiency point, system flow rates, and any other plant specific flow rates shall be considered. Under the definition, the owner will be given some flexibility in establishing this value by being able to consider pump best efficiency point as defined by the pump manufacturer, system flow rate requirements, and any other plant specific flow rate requirements. With this allowed flexibility, it is possible that the comprehensive pump test flow rate will not encompass the highest required accident flow rate (if applicable) as is defined in the owner’s safety analysis (e.g. TS and/or Updated Safety Analysis Report). If, in this case, there is a design basis accident flow rate in the owner’s safety analysis not bounded by the comprehensive pump test or Group A test, then the owner will be required to perform a *pump periodic verification test*. The pump periodic verification test details are located in a separate stand alone appendix, Division 1, Mandatory Appendix V, to denote that this is a separate test not traditionally considered an IST activity. As indicated above, if required, the Owner may elect to combine this pump periodic verification test with the comprehensive pump test activity or perform it separately.

The reason for having the pump periodic verification test has been derived from the previous TS requirements and the Criterion XI requirement to demonstrate that safety related pumps are capable of meeting their design bases accident conditions - flow rate and the associated DP (discharge pressure for positive displacement pumps).

The frequency requirement for the pump periodic verification test will be once every 2 years. This will allow the test to be performed during a refueling outage, if necessary, and is consistent with the comprehensive pump test frequency. Instrumentation for flow and/or DP will be consistent with the comprehensive pump test since this verification could be performed while the gauges are installed, or the instrument inaccuracies shall be accounted for in either in the analysis, itself, or in the acceptance criteria of the test.

The intent of the pump periodic verification test is not to require the owner to develop new design basis accident flow and DP (discharge pressure for positive displacement pumps) requirements for those pumps in which this does not apply. For example, if design basis accident flow rates are not specified in the Owner's TS, Updated Safety Analysis Report, or other design basis documentation for specific IST pumps, then those pumps would not have to be considered for a pump periodic verification test.

Similarly, certain IST pumps that have design basis accident flow rates in the Owner's credited safety analysis, but the maximum required flow and associated DP (discharge pressure for positive displacement pumps) are encompassed within a Group A or Comprehensive pump test, then a separate pump periodic verification test would not be required. The owner would document that the comprehensive test satisfies both tests in the IST Program Plan. The Owner is responsible for capturing the basis for the comprehensive pump test flow rate and the pump periodic verification test flow rate and associated pressure within the owner’s pump records [ISTB-9100(d) and by Division 1, Mandatory Appendix V].

Criterion XI

Criterion XI of Appendix B to 10CFR50, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, requires that each safety-related pump achieves its minimum design-required performance.

Appendix B establishes quality assurance requirements for the design, manufacture, construction, and operation of those structures, systems, and components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of those structures, systems, and components; these activities include designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying.

XI. Test Control

A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program shall include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests during nuclear power plant or fuel reprocessing plant operation, of structures, systems, and components. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Test results shall be documented and evaluated to assure that test requirements have been satisfied.

Richardson Letter

Attachment 8 contains a copy of the Richardson Letter.

In the early 1990’s, the NRC requested that ASME OM Committee revise the pump testing requirements to ensure the ability of certain pumps to perform their intended “hydraulic and mechanical” safety function(s). The NRC indicated that the then current pump and valve tests did not: a) include each component that has a hydraulic or mechanical safety function; b) accomplish verification of each safety function of such a component; or c) require that such verification be accomplished at the design basis conditions. The NRC indicated that an amendment to 50.55a might be initiated to …….ii) require verification of each safety function……; iii) require such verification be accomplished at the design basis conditions or where such verification is not possible a test, at less than the design basis conditions, combined with an analysis may be substituted …

ASME OM Response to the Richardson Letter

Attachment 9 contains a copy of the ASME response to the Richardson Letter.

ASME OM Committee indicated that new requirements were being prepared that would be more related to the design basis for the pump. ASME OM Committee indicated that the opinions on what is required to fulfill the request vary widely. The options vary from radical redefinition of current pump and valve testing to continuation of the present evolutionary changes that are being planned and implemented as part of our revision process. Those ASME OM members who met directly with the staff believe that they too have difficulty in appreciating all of the implications of the suggested changes.

Pumps – ASME OM Committee indicated that a major effort was underway (*at that time it had been underway for 2 years*) to add new requirements for pump testing that would be more related to the design basis testing for the pumps. The comprehensive pump test revisions were then undergoing ballot at the OM Committee. ASME OM Committee believed that this effort would be a significant improvement for testing of some pumps, and in line with the requested suggestions. Testing was based on degradation with respect to the baseline head curve and vibration.

ASME OM Committee also indicated that…..there is increased recognition that it is difficult to establish relatively simple go-no-go acceptance criteria for pumps and valves. Changes to add requirements for analysis of the measured parameters in the acceptance criteria to ensure that the acceptance criteria are more consistent with the design basis conditions are being developed. ASME OM Committee recognizes that the evaluation and analysis of data and the results of tests is a very necessary part of the program. These requirements are being added as necessary to ensure adequate engineering is applied to the determination of the acceptability of the results of individual inservice tests.

W Standard Technical Specifications

"Periodic surveillance monitoring of Emergency Core Cooling Systems (ECCS) pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pumps baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis."

Pumps in a nuclear power plant system may have a variety of requirements or features such as making a specific flow rate, operating over a range of flow for various functions, making a total developed head, a start time requirement to achieve rated flow, motor current usage restrictions, and a multitude of system requirements.

The purpose of ISTB is not to validate all of these above features but to test the pump to detect degradation. Initial program attributes that shaped the IST pump tests were:

1. Surveillance frequency (i.e., the need for frequent tests at either monthly and then later quarterly intervals);
2. Hydraulic performance with either discharge pressures or DP actually specified in plant TS;
3. Available hydraulic flow paths to conduct the on line at power surveillance activities; and,
4. Mechanical performance (vibration) taken as a secondary performance measure.

Information Notice 97-90

In December 1997, the NRC noted that some licensees had concentrated on IST requirements without explicitly ensuring that their pump performance met the specific plant safety analysis. The absence of an explicit tie to plant safety analysis could allow pumps to degrade over time more than values specified in their analysis. The NRC indicated that the ASME Code "does not require that pumps be tested at the design-basis conditions".

Information Notice 07-05

The NRC indicated that Service Water pump shaft failures events demonstrate that IST alone might not be sufficient to ensure pumps meet their accident acceptance criteria. Operating experience also shows that pump shaft failures and coupling failures can result in sudden total loss of flow before standard performance monitoring techniques alert plant staff to the impending failure. Other techniques such as inspection and refurbishment or more sophisticated vibration analysis techniques may be capable of identifying the onset of degradation.

Second Issue – Limits and Instrumentation

The NRC questioned the bases for the upper hydraulic acceptance criteria limits and how are the limits related to instrumentation issues versus the test technique.

Where did the 1.03% come from?

The 1.03% is believed to be from an API standard *test stand* limit where the vendor had control of the test flow rate (instrument tap locations, weigh tank, or highly accurate flow device) and could minimize its error contribution. Field flow measurements, especially on the older plants, cannot match the vendor test facility standards. Test technique issues such as waiting an appropriate time for the system to stabilize before making further adjustments can also impact high flow readings.

Instrumentation issues with pump testing in the field include using 2% Full Scale loop accuracy instrument loops for pressure (flow accuracy requirements were not changed during the Comprehensive Pump Test). The Code also limits the full scale range of the pressure device to three times the reference value. Thus, it is possible to have almost 6% uncertainty for the test reading for pressure alone without consideration for the flow uncertainty.

Example 1: Test reference 34 psig, Full Scale 100 psig, 2% Full Scale is 2 psig or 2/34 psig is about 6% (5.88%) of reading.

Example 2: USNRC Information Notice 97-90 approach to look at why we can exceed 1.03%

- Reference flow at 10,000 gallons per minute (gpm) with 64.525 pounds per square inch differential (psid). (on the pump curve)
- +/- Tolerance on flow for Operations is +/- 100 GPM. (gage scale)
- Flow uncertainty is 240 gpm, so when OPS is at 9900 gpm, they could also really be at 9760 gpm.
- At 9760 gpm, DP uncertainty for Comprehensive Pump test is about 0.3 FT X 0.445 or about 0.134 psid.
- The CPT Minimum DP is therefore 64.659 psid.
- The Group A minimum DP is 6 FT or 6 FT X .445 or about 2.67 psid.
- The Group A minimum DP is therefore 67.195 psid. This is 1.04% of the reference pressure.

If we assume that the reference was taken at the high end of the uncertainty and was really 2.67 psid lower, or 64.525 – 2.67 = 61.855 psid. It is possible then that the Group A minimum DP of 67.195/61.855 is 1.086%. All accuracy's are within the OM Code allowable values.

Even if we use the 0.5% pressure gages (CPT), we are still subject to the slope of the curve and the flow uncertainty errors and these combined can easily exceed 1.03%.

OM Action

The Sub-Group ISTB investigated the bases for the 1.03% and considered adding some requirements to the analysis section so that Owners understand the reasons for the exceeding the 1.03%. Another potential is to increase the Group A acceptance criteria for those plants who can test at the CPT flow rate.

Resolution of the Instrumentation Issue - Relaxation of CPT High Required Action

The Sub-Group ISTB is resolving the second of the NRC's long standing issues by providing a relaxation of the high required action range for the Comprehensive Pump Test Hydraulic Parameters (1.03 to 1.06).

This code change will address the instrumentation issues previously proposed under record #05-1134, ballot 08-1449. It was independently voted on (e.g., separated from the Design Flow issue) under a new record to allow more focus on the particular topic.

Instrument Code Change:

1. Revise the CPT high required action acceptance criteria from 1.03 times the reference to 1.06 times the reference.
2. This, in turn, results in the same revision to the upper acceptable range.

Background:

Owners are having difficulties with the implementation of the current CPT required action range high limit of only 3% above the established reference value for the measured hydraulic value of either DP or Flow. Owners have or will be faced with declaring pumps inoperable for reasons that do not represent a pump degradation issue. Revising the code to allow a high required action limit of 6% above the reference value is a more realistic value that should allow any true potential degradation issues to be captured and should alleviate unnecessarily declaring pumps inoperable.

This issue was also discussed at the ASME/NRC special meeting on June 4th, 2007. The NRC questioned the basis for the upper required action limits. At the June OM code meeting, the NRC was receptive to a compromise between the 1.03 value and the 1.10 value for the comprehensive pump test upper required action limit. The basis for this change is discussed below.

Basis for Change:

There are several factors that may quickly cut into the existing 3% upper limit. Each factor is discussed below.

1. Instrument inaccuracies of measured hydraulic value:

   a. Case A: Set Flow, Measure DP: If flow is set and DP (or pressure) is measured, up to 1.5% of the current 3% band may be eliminated based on the code allowed pressure instrument inaccuracies, alone. Currently, ISTB-3510(a) and table ISTB-3510-1 require analog pressure instrumentation for the CPT to meet +/-0.5% of full scale. Based on ISTB-3510(b)(1), the full scale range of each analog instrument shall not be greater than three times the reference value. Therefore, the existing code allows the measured DP (or pressure) reference value to have instrument inaccuracies of up to +/-1.5% of the reference value. A similar discussion is addressed within NUREG 1482, Revision 1, section 5.5.1.

   b. Case B: Set DP, measure Flow: If DP is set and Flow is measured, up to 6%, or over twice of the current 3% band may be reached based on the code allowed flow instrument inaccuracies, alone. Currently, ISTB-3510(a) and table ISTB-3510-1 require analog flow instrumentation for the CPT to meet +/-2.0% of full scale. Based on ISTB-3510(b)(1), the full scale range of each analog instrument shall not be greater than three times the reference value. Therefore, the existing code allows the measured Flow reference value to have instrument inaccuracies of up to +/-6% of the reference value. A similar discussion is addressed within NUREG 1482, Revision 1, section 5.5.1.

2. Instrument inaccuracies of set value and its affect on measured value:

   a. Case A: Set Flow, Measure DP: If flow is being set, for the same reasons as were discussed under item #1, the reference set flow value may have instrument inaccuracies of up to +/-6%. This allowed amount of inaccuracy for the set flow value for a comprehensive pump test that is performed at a point well out on the sloped portion of the pump curve would have a significant impact on the measured DP value. The impact would vary from pump to pump, but this factor alone may jeopardize or exceed the current upper +/-3% criteria that would be applied to the measured DP value.

   b. Case B: Set DP, Measure Flow: If DP is being set, for the same reasons as were discussed under item #1, the reference set DP value may have instrument inaccuracies of up to +/-1.5%. This allowed amount of inaccuracy for the set DP value for a comprehensive pump test that is performed at a point well out on the sloped portion of the pump curve would have an impact on the measured flow value. The impact would vary from pump to pump, but this factor alone may jeopardize the current upper +/-3% criteria that would be applied to the measured Flow value.

3. Instrument inaccuracies and allowed tolerance for Speed:
   For those pumps with variable speed drives, table ISTB-3510-1 and subsection ISTB-3510 requires the instrument accuracy for speed to meet +/-2% of full scale for analog instruments or over the calibrated range if it is a digital instrument. Additionally, the CPT (and Group A and B pump tests) allows speed to be adjusted to the reference point with an allowed tolerance of +/-1% around the reference point. Therefore, a total variation of up to +/-3% of the reference speed is possible for variable speed drive pumps. Variations from the reference point would actually shift the entire pump curve up or down. A shift downward would impact the current upper 3% required action limit for the measured hydraulic value of flow or DP, whichever is applicable.

4. Human Factors involved with setting and measuring flow, DP, and speed:
   As is discussed in NUREG 1482, Revision 1, section 5.3, certain designs do not allow for the licensee to set the flow [or potentially DP or speed] at an exact value because of limitations in the instruments and controls for maintaining steady flow [or potentially DP or speed]. If the owner takes the approach to obtain a steady value at approximately the set value for the parameter being measured, there most likely will be some minor variations in what is read from test to test and from individual to individual. The same would be true if a plant has taken the approach to justify various degrees of tolerance around the set value being measured. Therefore, the human factors involved with these issues may also reduce the margin to the +3% upper limit that is currently in the OM Code for the measured flow or DP, whichever is applicable.

5. Readability of Gauges based on the smallest gauge increment:
   The OM Code does not address the affects that the readability of test gauges may have on the value being measured. Gauges should only be read to ½ of the smallest increment. Following this basic rule may at least have a minor impact on the 3% upper limit.

6. Misc. Factors:
   The Code does not explicitly require the licensee to consider physical attributes (such as orifice plate tolerances), tap locations, environmental effects (such as temperature, radiation or humidity), vibration effects (such as seismic) or process effects (such as temperature). All of these factors may impact the accuracy of the measured flow or DP.

Comprehensive Pump Test Operating Experience

Industry Experience associated with the implementation of the upper 1.03 required action limit for the comprehensive pump test was gathered through the IST Owner's group (ISTOG) mass email system. Two questions were asked concerning the implementation of the comprehensive pump testing. The results support the conclusions previously reached that the upper limit of 1.03 is too limiting and should be revised. The following is a summary of the information obtained. The plant names have been withheld to maintain the focus on the information provided and not who it was provided from.

1. **Do you have any pumps in which the 1.03 upper required action limit has been exceeded? If so, what was the cause and how did you resolve the condition?**

   <u>Summary of responses</u>:

   <u>Plant A</u>: We had a test failure due to exceeding the 3% flow upper limit. No definitive cause could be determined and I was forced to re-baseline at the higher flow rate. The pump was declared inoperable when it was clearly capable of performing its specified function. Plant resources were unnecessarily expended by bringing in personnel in the middle of the night to establish an action plan, etc.

   <u>Plant B</u>: We have had 2 occasions where the quarterly test [using same instrumentation as the comprehensive pump test] exceeded 1.03 and have written corrective actions to investigate. In the first case further investigation revealed an improper lineup and I declared the test invalid and performed another test with acceptable results. The second event is an instrument readability issue with the 0.5% accuracy gauge. Nothing was wrong with the pumps in either case.

   <u>Plant C</u>: We have had one pump failure in which we slightly exceeded the 1.03 upper acceptance criteria, which was conservatively being applied to the quarterly Group A test, since the test setup was identical to the comprehensive pump test. The test was reviewed and compared to historical test data. It was determined that the data point obtained was within the normal data scatter. Therefore, the pump was unnecessarily declared inoperable. One corrective action was to utilize the 1.10 criteria for the quarterly test and 1.03 criteria for the comprehensive pump test.

2. **Do you have any pumps in which you anticipate possibly exceeding the 1.03 upper required action limit? If so, what is the anticipated reason for exceeding the 1.03 upper required action limit?**

   <u>Summary of responses</u>:

   <u>Plant D:</u> Approximately 70% of the Group A tests at this plant are mirror images of the associated CPT (same test gage, reference flow rate or DP). A quick look at previous test data reveals 18 instances (6 DP, 12 flow rate) where flow or pressure/DP exceeded the 3% upper acceptance limit since 2002, but was well within the test allowable 10% limit. Subsequent test results returned to within the allowable CPT values.

   <u>Plant E:</u> At this plant, we are concerned about river water supply pumps due to normal data scatter.

   <u>Plant F:</u> Some potential failures because data scatter is larger than the 1.03 will tolerate. All of our tests are now using the 0.5% pressure gauges as a standard, so it is not related to instrument inaccuracies. OM Code testing is not performed in a laboratory controlled and instrumented environment so the ability to get consistent data within +3% will be challenging in some cases. We go from a 20% window to a 13% window.

Plant G: We don't have any OE yet, but I can see it coming with our SW pumps and dye flow testing. We meet the +10% fine, but we have not always been within +3%.

Plant H: We are currently in the process of updating to the 2001 Edition through 2003 addenda, so we have not realized any failures yet. I fully expect there will be failures [referenced many of the same reasons presented in this white paper].

Plant I: We are struggling with the CPT of all the ECCS pumps as there is very high probability of the pumps being declared inoperable due to exceeding the 103% upper limit. It is very difficult to explain to the management that the pumps which show no sign of degradation for years of testing and trending have to be declared inoperable due to exceeding their performance by 3% during CPT.

Plant J: We are upgrading to the 2001 (2003 Addenda), so the 103% criteria hasn't affected our testing yet. However, after reviewing past test data, there are several pumps which we anticipate will exceed the 103% criteria periodically. We do not believe this is indicative of pump degradation, but rather to the scatter in the data.

Plant K: We have established or are working on establishing new reference values for most of our comprehensive pump testing due to the installation of higher accuracy gauges even though all other aspects of the test in relation to the quarterly test is the same. The second time the test is run may be almost 4 years into the interval. Based on past historical data, the potential exists for several of our comprehensive pump tests to begin to fail at that time due to the upper 1.03 limit. Due to all the uncertainties, it is not expected that the higher accuracy pressure instruments will make that much difference in the readings obtained every quarter. This has been validated in several instances with the establishment of new comprehensive pump test reference values and comparing them to the quarterly reference values. Also, in some cases, our quarterly pressure gauge accuracies are not far from the 0.5% accuracy required for the 2-YR tests, further supporting this information.

Conclusions for Limits and Instrumentation

Based on what has been presented, the current allowed inaccuracies associated with obtaining the Comprehensive pump test hydraulic data may very easily result in the measured value to exceed the existing Code allowed upper required action limit of 3%. In fact, evidence has been shown that even the proposed upper 6% limit could potentially be in jeopardy of being exceeded. However, when compiling all the affects of the individual inputs discussed above, most pumps will typically be able to meet the newly proposed 6% upper limit. The most likely reason for this is that not all of the inputs discussed, above, will impact the measured value to the largest extent possible and each input would not act upon the measured value in the same direction (i.e. all push the measured value upward or downward). Therefore, the proposed 6% upper limit will be a much better indication of potential degradation of the pump (or increased affect of an input) in the upward direction rather than the current 3% upper limit. This new limit should also alleviate owners from unnecessarily declaring pumps inoperable and entering unplanned LCOs.

Acknowledgements

Special thanks to Jack McHale, NRC Representative and ASME OM Standards Committee Member who helped arrange the June 2007 Special Meeting on Pump Inservice Testing Issues.

The final resolution of these pump testing issues is directly related to the substantial support provided by Thomas Ruggiero, Sub-Group ISTB Chair, Wavel Justice, Sub-Group ISTB Secretary, Dennis Swann, Sub-Committee OM Code Chair and Sub-Group ISTB Member, and R. Scott Hartley and David Kanuch, both Sub-Group ISTB Members. Also the remaining SG ISTB membership needs to be recognized for their technical review and integration of the recent ISTB Code changes. This support spanned over many years as the issues were refined and as code deliverables were identified.

Materials used for this paper were from the ballot white papers prepared by the original ISTB Task Group of Tom Robinson, Dave Kanuch, and Scott Hartley.

Attachments *(contact the authors for copies of #2 - #9)*

1. 1990 ASME OM Working Group Pump IST Historical Perspective (included)
2. April 23, 2007 Letter from ASME to the NRC for a Special Meeting to discuss pump testing issues.
3. NRC Presentation Materials, June 4, 2007 Meeting with ASME.
4. ASME OM Presentation Materials, June 4, 2007 Meeting with NRC.
5. ASME OM Conceptual Agreement, date June 19, 2007 outlining OM Actions to resolve three long standing pump testing issues.
6. Pump Periodic Pump Testing White Paper
7. Proposed Code Change Pump Periodic Verification Test
8. James E. Richardson, Director Division of Engineering Technology, Office of Nuclear Reactor Regulation, Letter 9/9/1991 to Forrest T. Rhodes, Chair ASME Operations & Maintenance Committee.
9. Forrest T. Rhodes, Chair ASME Operations & Maintenance Committee. Response to James E. Richardson, Director Division of Engineering Technology, Office of Nuclear Reactor Regulation, Letter 9/6/1992.

Attachment 1

1990 ASME OM Working Group Pump IST Historical Perspective

Using published articles and Letters of Correspondence between ASME and the Nuclear Regulatory Commission (NRC), a historical perspective on pump testing can be determined. These three papers were from key individuals heavily involved in the ASME OM Code Committee work, in pump testing, and in pump failure investigations.

These papers reflect the prevalent ASME OM thought process at that time. The main elements of these three papers are summarized below in the following eight perspectives and in the more detailed capsule summary sections for each paper.

- Vibration was being treated as the prime indicator of pump health more so than it was during ASME Section XI testing.
- More stringent hydraulic acceptance criteria were being required for positive displacement and vertical line shaft pumps as vibration was judged to be less effective in detecting issues with these pumps.
- Although manufactured to exacting tolerances, no two pumps are ever exactly the same; therefore, small performance variations should be expected.
- At the design or BEP flow rate, the fluid motion is comparable with the physical contours of the hydraulic passages and is therefore well behaved.
- The industry should not rely solely on low-flow testing for operational readiness determinations.
- Based on many of the comments received during the final OM Part 6 Code balloting process, the OM working group on pump and valve testing began actively considering further improvements to these standards.
- Even when operating at these points, performance of the same pump can vary from test to test. Performing in the hydraulically stable regions should provide less data scatter, and will generally simplify the data interpretation process.
- Pumps should be tested when they are operating at hydraulically stable areas, such as the best efficiency point. This is a key consideration as we are also applying the vibration acceptance criteria to the hydraulics. Having test results suitable for trending was an important part of this change.

1. ASME/NRC Symposium on Inservice Testing of Pumps & Valves, August 1989, Washington, DC.

1. Article by John Zudans, Introduction to ASME/ANSI OMa-1989a Part 6 – “Inservice Testing of Pumps in Light-Water Reactor Power Plants” and Technical Differences between Part 6 and ASME Section XI, Subsection IWP.[1]

John Zudans, at that time, was the Vice Chair on the Working Group on Pump & Valves. He had also previously served as Chair of this working group. He is currently the Chair of the OM Committee.

This article was the introduction article for the new IST pump requirements. The then new OM pump and valve standards (Part 6 and Part 10) had just been published as the 1988 addendum to the OM-1987 Operation and Maintenance Document.

The purpose of the article was to highlight differences between the new and the old IST pump requirements. The article also highlighted some changes in a future change section.

In the future change section, the following statement was made:

"The OM working group on pump and valve testing is actively considering further improvements to these standards. The areas for improvement have been recommended by industry as well as regulatory bodies. Task groups and action plans have been established for the higher priority issues and results should be forthcoming. Some of the pump issues being considered include; improvements in mini-flow acceptance criteria, hydraulic acceptance criteria, trending, and analysis time limits- 96 hour criteria."

To highlight the differences, Attachment 1 in this article contained a three column comparison between the new and the old IST requirements. One column contained the IWP paragraph requirement, the second column contained the corresponding OM Part 6 requirement, and the third column provided the change and the basis for the change.

On Attachment 1, page 8 of 18, the change and basis section contained the following:

"Early in the development of this Standard, it was recognized there were many problems with detecting change in pump performances based on hydraulic parameters. Additionally, there were concerns raised about causing undue wear because of excessive testing. This is of particular concern for those pumps tested on a mini flow line. As a result, a change in emphasis was made towards using vibration as the primary indicator of pump degradation. Vibration testing is more indicative of pump mechanical condition that hydraulic testing. It is expected there will be fewer pumps requiring increased testing or corrective action based on erroneous test results. A careful investigation showed that all pumps could not be treated the same. Thus Table 6100-1 differentiates between three types of pumps; positive displacement, vertical line shaft, and centrifugal pumps."

"While vibration is to be relied upon more heavily, it is also recognized that positive displacement and vertical line shaft pump degradation could go undetected with typical instrumentation being used in most plants. Therefore, more stringent hydraulic acceptance criteria are still used for these pumps."

"For all other centrifugal pumps, the hydraulic acceptance criteria have been relaxed. The extent of the change is to allow the equipment to be run in a "window" hydraulically and to then evaluate pump condition more closely with vibration. The purpose of the window is twofold. First, it ensures the pump is performing its primary function that is, pumping liquid. Second, that it is operated in a specified narrow band where the vibration data will be comparable."

2. Article by James J. Healy, Enhance Pump Reliability through Improved Inservice Testing"

   Mr. Healy, at that time, was the Pump Specialist for Stone & Webster Engineering Corporation.

   As part of the introduction, an important point is made with regard to the traditional IST methodology. "ANSI/ASME OM-6 has taken the place of Subsection IWP, and has changed a number of test ranges and shifted the focus of testing for centrifugal pumps from hydraulic criteria to an emphasis on changes in mechanical criteria, such as vibration levels. EPRI has undertaken a study to assess the effectiveness of existing testing programs to accurately monitor and predict performance changes before either pump performance degrades of an actual failure occurs. Anticipated changes in inservice testing techniques are directed towards enhancing the validity of test data, ensuring its repeatability, and avoiding deterioration of the pump assembly. There is a new-found interest in the test programs of all types that has occurred, in part because of an increase in reported pump degradation and pump failure." He concluded that inservice testing of pumps, which has long been a basis of assuring operability, has apparently produced an opposite effect; namely, the appearance of a reduction in reliability.

   Two of the four pump characteristics are mentioned here:

   1. Pumps are hydraulically designed to operate over a wide range of flows but perform best at, or near, their best efficiency point of flow.
   2. Performance of "identical pumps" varies from pump to pump, even when they are built at the same time. Performance of the same pump can vary from test to test. Although manufactured to exacting tolerances, no two pumps are ever exactly the same; therefore, small performance variations should be expected.

   One of the recommendations made to enhance pump reliability, was the selection of an optimal point where the pump should be tested it characteristic curve. The proper selection of this optimal point would result in improved test results. Often existing system configurations dictates that safety pumps be tested at or below the minimum continuous recirculation flows specified by the pump manufacturer.

Testing flows at or near a minimum flow point specified by the manufacturer may be convenient but usually result in an undefined point. Testing at flows below 25% of the best efficiency point can result in IST results that are inconsistent and may or may not indicate that the pump has degraded.

Furthermore, the author indicates that experience has shown that both new and worn pump characteristic curves share the same shutoff head if the impellers (s) diameter(s) and speed remain the same. IF IST is done at low flows, the ability to differentiate between the new and worn conditions approaches a level below instrument accuracy.

3. Article by William L. Greenstreet, Low-Flow Operation and Testing of Pumps in Nuclear Plants. Dr. Greenstreet worked for Oak Ridge National Labs, Oak Ridge TN and this paper was based on research done for the NRC.

   The article discusses the need to test pumps at the best efficiency point, or BEP. The author states that pumps are designed for best performance at a specific combination of capacity, head, and speed that is the BEP. At the design or BEP flow rate, the fluid motion is comparable with the physical contours of the hydraulic passages and is therefore well behaved. Hydraulic instability is a term used to describe unsteady flow phenomena that become progressively more pronounced as a pump is operated farther away from BEP. The hydraulic instability is manifested by flow recirculation in both the suction and discharge regions of an impeller stage when operating below the design flow.

   As part of his conclusion, he indicated that “Head and flow data are not reliable indicators for health because head vs. capacity curves, in many instances, exhibit very little change at low flows (especially as shut-off is approached) because of degradation. He states that.” hydraulic instability can complicate the data interpretation process.” He recommended on not placing reliance on low-flow testing for operational readiness determinations.

2. ASME/NRC Symposium on Inservice Testing of Pumps & Valves, July 1994, Washington, DC.

This paper describes the thought process that existed at that time. The main elements of these three papers are summarized below in the more detailed capsule summary section but the following five perspectives can be noted:

- Vibration was still being used as the prime indicator of pump health with the major difference being that pumps now had a flow requirement that was closer to the design conditions.
- The higher pressure instrument requirements helps to obtain more accurate reference values and minimize measurement uncertainties during testing.
- The critical performance analysis for pumps was to be done when the pumps are operating at hydraulically stable areas, such as the best efficiency point.

- The change in the Group B testing addressed the previous concerns that industry should not rely solely on low-flow testing for operational readiness determinations.
- The OM working group on pump and valve testing finally felt that they had adequately addressed all of the NRC concerns with regard to pump testing.

1. Article by R. Scott Hartley, Description of Comprehensive Pump Test Change to ASME OM Code, Subsection ISTB.

Scott Hartley has been a long time member of the ASME OM Code Committee, and is currently a member of the Standards Committee and the Sub Group ISTB.

The article provide this background: “The USNRC was considering adopting Part 6 in the regulations in 1988 and requested a meeting with the OM Committee. The OM Working Group on Pumps & Valves (WGPV) met with the USNRC in March 1989. The meeting was held to discuss concerns related to the newly approved pump and valve testing standards, OM-6 and OM-10, respectively. The OM-6 pump testing standard increased the upper action limit for hydraulic test parameters from 103% (ASME, 1986) to 110%. The reasoning for the increase was that hydraulic performance was not expected to improve (Zudans, 1990). However, the higher limit could allow significant instrument drift. The USNRC also had raised concerns about the potential for damage during low flow testing of pumps in IST programs (USNRC, 1988). The USNRC agreed to accept OM-6 as written, if the ASME WGPV would consider improvements to the pump testing requirements.”

“Following the discussions, the OM-6 Task Group on NRC Issues, a task group under WGPV, began work to develop a better, more comprehensive test for assessing pump condition.”

“The OM-6 pump test standard was issued in October 1990 as OM Code-1990, Subsection ISTB (ASME, 1990). The comprehensive pump test change was written against the 1990 Subsection ISTB.”

From the Development of the Comprehensive Test section the following items are highlighted:

1. Pumps were categorized into two categories, Group A, and Group B. Group A pumps are defined as pumps that operate continuously ore routinely during normal operation, cold shutdown, or refueling outages. Group B pumps are defined as pumps in standby systems that are not operating routinely except for testing.
2. Pumps that operated more frequently, such as service water or component cooling water pumps, are likely to degrade at higher rates than pumps that are only operated occasionally, such as standby liquid control pumps.
3. Four test were identified – preservice, comprehensive, Group A and Group B. Pumps in dry sumps were exempted from the quarterly tests, with all pumps receiving the 2 year test.

4. The preservice test would use high precision pressure instruments and establish accurate reference values at points of operation that would allow a precise assessment of pump performance, or operational readiness. For a centrifugal pump in variable resistance systems, the test requires differential pressure and flow rate to be taken at five points of operation, from pump minimum to near design flow rates, to establish a baseline pump curve.
5. The comprehensive test was developed to help ensure a better evaluation of pump performance characteristics at a reduced frequency. The test is performed at a single reference value, or near (within 20%), the pump's design flow rate for centrifugal pumps. This area of the curve is considered to be most representative of the pump's hydraulic characteristics (Greenstreet, 1990).
6. The difference between the Group A test and the ISTB-1990 test is that the test should be performed at as high a flow rate (or discharge pressure for positive displacement pumps) as practical. ISTB-1990 did not address the flow rate or pressure at which pumps tests were to be preformed.
7. The Group B test, for standby pumps, was intended to be a quick, simple, largely qualitative test. The test would roll the pump to keep the bearings from taking a set and to lubricate and exercise the moving parts. It was not intended to be used to determine hydraulic performance capabilities or to detect minor imbalances through vibration measurements. The critical performance analysis for Group B pumps were to be done with the less frequent comprehensive pump test. The Group B test can allow detection of gross mechanical or hydraulic failures of electrical or control systems.

Allowable Variance from Reference Value for IST Test Flow

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Abstract

The American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code) requires during subsequent inservice testing (IST), after the establishment of reference values, that the flow rate or differential pressure be set to the exact reference value. The OM Code does not acknowledge the possibility that there may be limitations in the ability of plant personnel and equipment to meet this requirement. This issue is discussed in NUREG-1482, Revision 1, Section 5.3, “Allowable Variance from Reference Points and Fixed-Resistance Systems.” Close reading of this guidance reveals that the Nuclear Regulatory Commission (NRC) would find it acceptable for plants to apply a variance limit of ± 2%, but this 2% must include inaccuracy of the flow measurement device. The industry recently discovered that many plants were misinterpreting the NUREG-1482 guidance and using procedural flow range limits of up to ± 2% without the consideration of flow accuracy. This presentation will share lessons learned from recent experience in obtaining approved relief for this issue. A primary basis for regulatory approval of this relief was the proven ability to accurately trend pump performance using data normalization techniques to overcome the data scatter problem. Examples of actual pump degradation data and normalization will be provided.

Introduction

IST of pumps has been accomplished in a successful manner for decades. The intent of the activity is to detect degrading conditions as early as possible, allowing for sufficient time to implement corrective actions before loss of the pump’s safety function. IST Program Owners establish testing procedures which are intended to produce repeatable conditions and measurement methods, allowing them to directly compare new test data to component history.

Repeatable pump testing requires operations personnel to establish and adjust system conditions to the pump reference value. Typically, this involves throttling on a valve or valves until the reference value measurement matches the desired value. Many systems do not have throttling control sufficient to achieve a specific repeatable reference value. This paper describes the methodologies employed by IST Program Managers in order to meet the intent of the testing in those situations.

NUREG-1482 Guidance

NUREG-1482, Revision 1, correctly identified that many plant systems did not have the throttling control to precisely adjust to reference values test to test. ASME OM Code does not address this issue. The NUREG-1482, Rev. 1, guidance allowed for ± 2% variance in reference value, however, the exact wording in NUREG-1482, Rev. 1, required that this 2% value must be inclusive of instrument accuracy. For most IST pumps, the reference parameter is flow and the variable parameter is differential pressure (DP). The accuracy of flow indication required by the Code is 2%. Given the discussion in NUREG-1482, Rev. 1, if the flow measurement accuracy is 2%, there is no remaining variance allowance. IST Engineers are left with the same guidance as the OM Code, which is to adjust the flow to exactly the reference value.

Plant Testing Example

The Residual Heat Removal Service Water system (RHRSW) at Fermi Power Plant, Unit 2, has identical divisions, each containing two identical vertical line shaft two-stage centrifugal pumps. These pumps can each deliver flow values in the range of 3000 – 7000 gallons per minute (gpm) at a discharge pressure between 30 – 60 pounds per square inch (psi). Each pump discharges through a 16 inch pipe before joining to a 24 inch header. The RHRSW flowpath travels approximately 900 feet horizontally and approximately 40 feet vertically into the reactor building and through the RHR heat exchangers. On the outlet of the heat exchanger is a motor-operated throttle valve (MOV). This is a globe valve with an SMB-3 Limitorque operator. The gearing of the MOV is relatively slow to allow for better throttling characteristics, however the valve has a safety function to close in order to isolate the residual heat removal system (RHR) from RHRSW and prevent any leakage of primary fluid outside of secondary containment. This closure function warrants a speed of isolation which limits how slow the MOV stroke time can be. During test operations with a single pump running, the Operations crew attempts to adjust flow using this MOV to the 5400 gpm reference value. Individual, rapid operations of the pushbutton typically yield flow changes of between 60-80 gpm. If the test procedure required them to establish exactly 5400 gpm, it could take several hours or longer to achieve that condition. Multiple motor starts on the MOV are limited to ensure motor temperatures stay within reasonable levels and require cooldown periods. Manual throttling of the test MOV is not feasible due to their location in High Radiation Areas.

It is simply unreasonable to expect the operations staff to perform testing on a quarterly basis in such a manner. An acceptable range for test flow in this scenario is 5400 gpm ± 100 gpm. This equates to a 1.85% variance. Flow is measured with temporary digital equipment with a best accuracy possible of 0.8%. Combination of these two factors, even using square root sum of the squares (SRSS), yields a total variance of greater than 2%.

Fermi has 10 safety-related service water pumps located in our RHR / emergency diesel generator complex. All of these pumps are deep-draft vertical line shaft pumps from the same vendor and were initially placed in service in 1984. Analysis of historic test data in 2000 showed that all of the pumps had experienced some degree of hydraulic degradation. Pump replacement activities were initiated and the sequence / prioritization was based on the IST trend data. Because of the degree of scatter in the data, a normalization method was established to allow for accurate short term trending.

The first pump replacement occurred in 2004 and involved the pump with the lowest remaining margin and most aggressive degradation trend. Pumps were replaced as scheduled in the years following, with the last pump replacement in early 2011. No pump ever reached the required action threshold. Some pumps did operate in Alert range for periods of time with increased frequency testing. IST trend information was used throughout this time to drive the scheduling and selection of the pump replacements.

Case for Change

The concern about limiting reference value variance is due to the degree of data scatter. The concern about data scatter is the impact on the ability to detect an increasingly degraded condition.

The example described above is an actual situation where the reference flow variance did produce some degree of data scatter AND the pumps were in fact degrading over time. The example proves that analytical methods exist to reduce the data scatter and that trending can be performed quite successfully despite the higher reference flow variance.

The Inservice Testing Owners Group and ASME OM Code Committees have been working to adopt improved guidance on this subject. It is a simple fact that IST testing of most pumps cannot be performed such that an exact reference value is achieved in every test. The OM Code language needs to include some allowance for variability about the reference values.

Recent discussions have promoted the idea of using a -1% / +2% band for the setting of reference values. This would be independent of any discussion of instrument accuracy (which is already covered explicitly in ASME OM Code Section ISTB). This amounts to a total 3% band in which to set flow or pressure, with the desire that effort be made to be as close to the actual reference value as possible. This 3% band will accommodate almost all situations of throttling and control capability. Any isolated situations where repeatable testing within the 3% variance is not possible would likely require special relief from the regulatory authority. The limitation of -1% provides additional conservatism since the typical scatter would be in the "conservative" direction for the variable parameter. IST Engineers should employ data normalization (or equivalent) techniques to reduce the data scatter. This will ensure the ability to detect and monitor degradation.

Acknowledgments

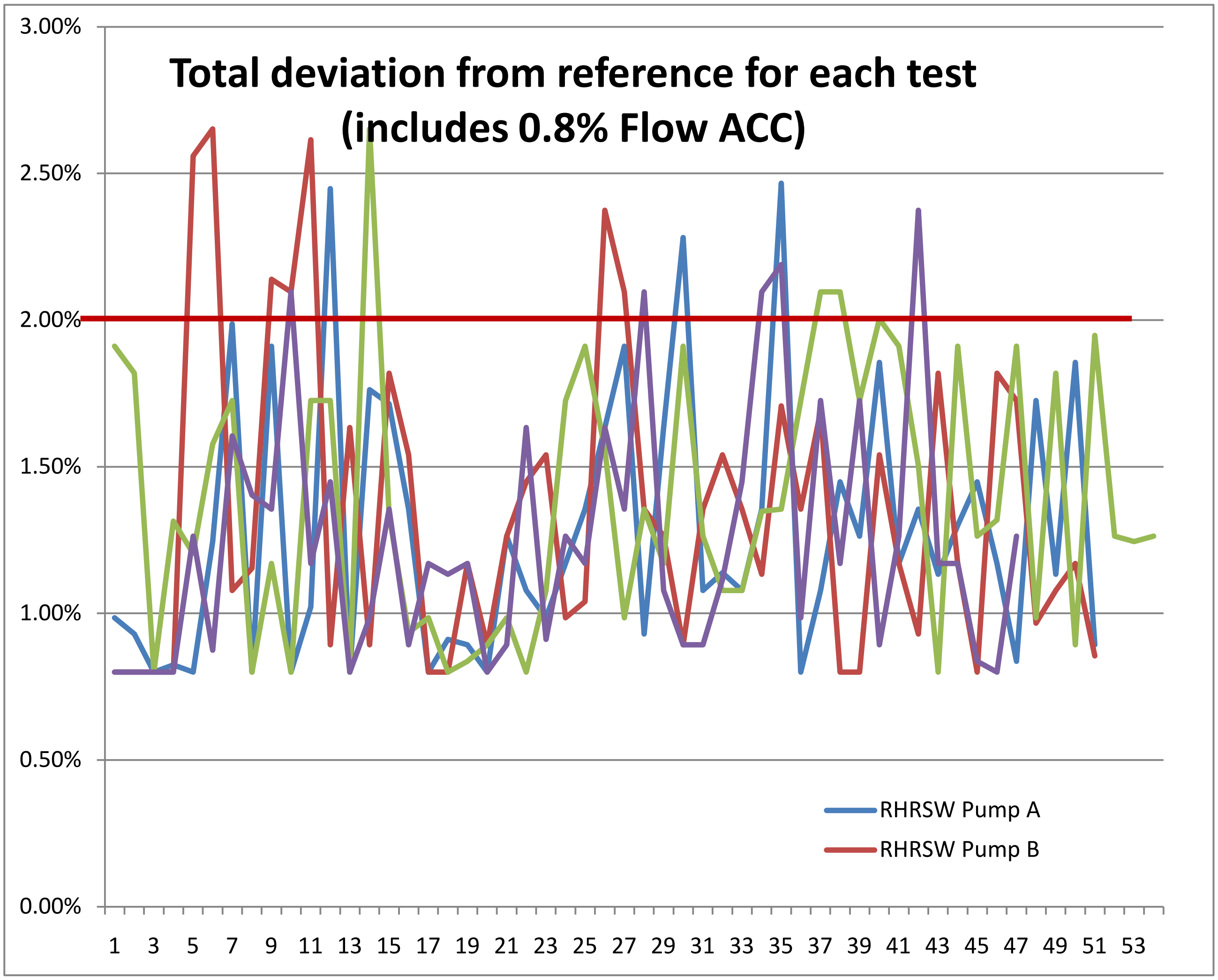
B. Leimkuehler - System Engineering Lead Fermi 2

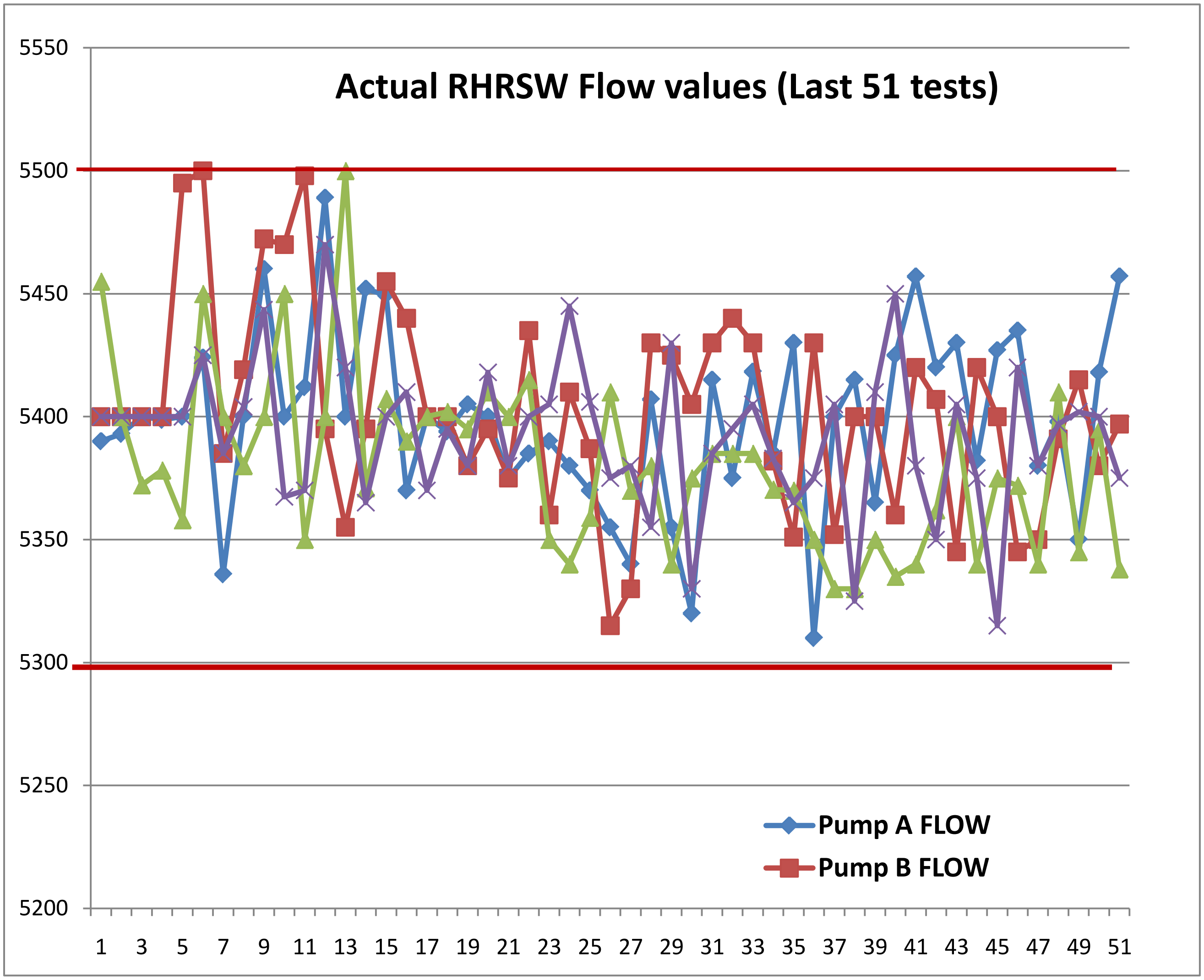
References

2004 edition ASME OM Code Section ISTB

NUREG-1482 Revision 1

ANNEX B
RHRSW TREND DATA




Actual RHRSW Flow values (Last 51 tests)
5550
5500
5450
5400
5350
5300
5250
5200
1
3
5
7
9
11
13
15
17
19
21
23
25
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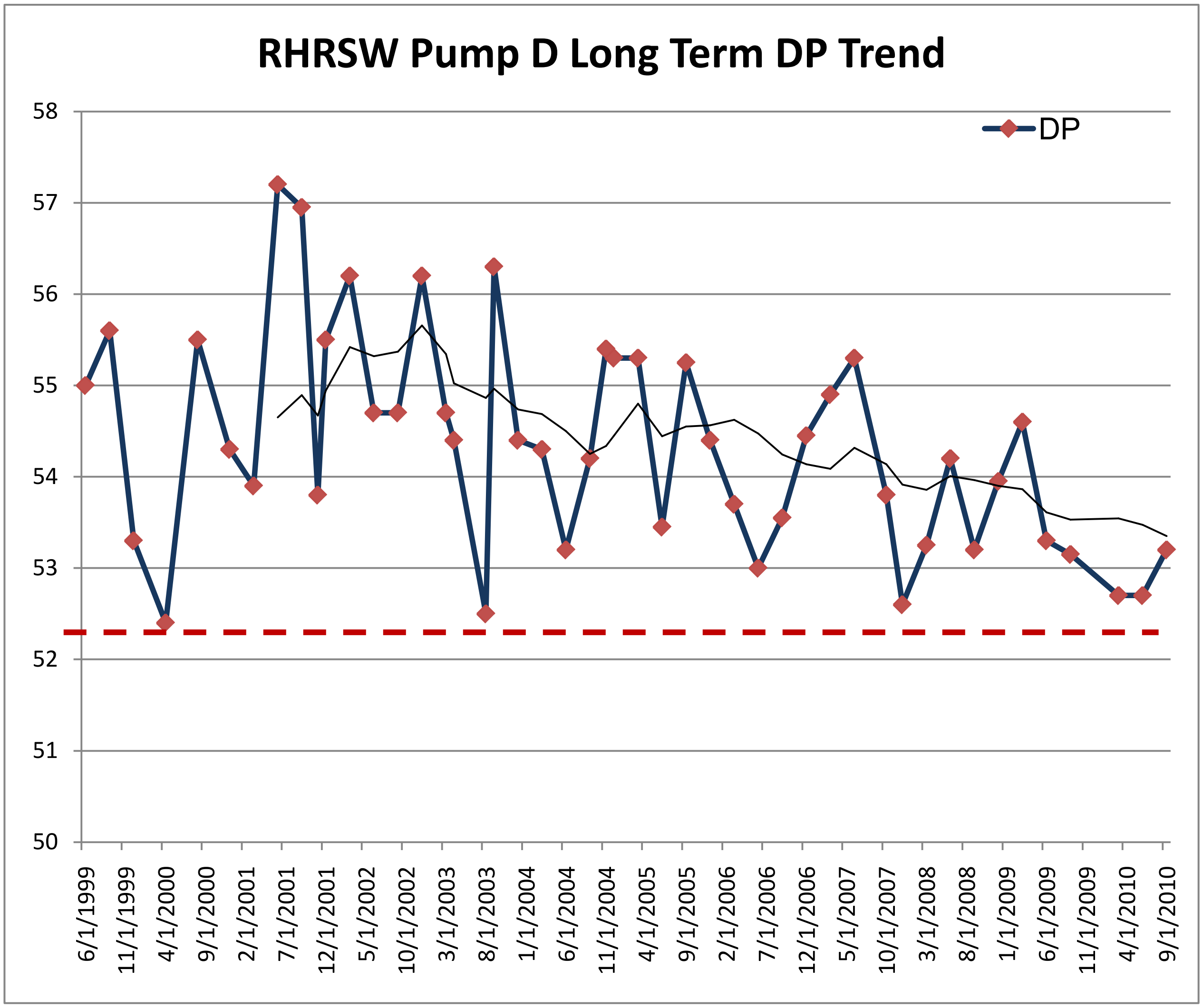
31
33
35
37
39
41
43
45
47
49
51
Pump A FLOW
Pump B FLOW


RHRSW Pump D Long Term DP Trend
DP
58
57
56
55
54
53
52
51
50
6/1/1999
11/1/1999
4/1/2000
9/1/2000
2/1/2001
7/1/2001
12/1/2001
5/1/2002
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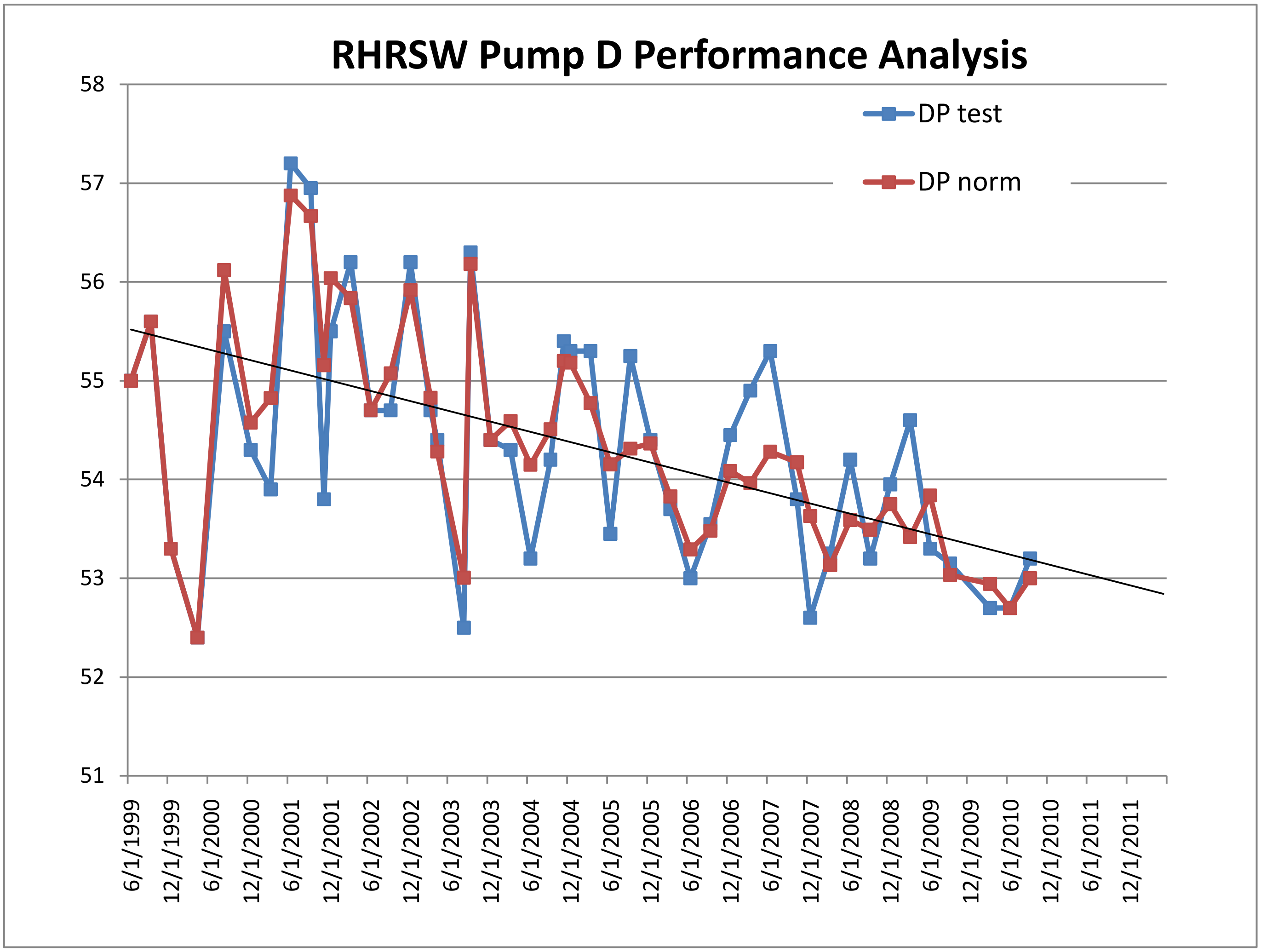
RHRSW Pump D Performance Analysis
DP test
DP norm
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12/1/1999
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12/1/2000
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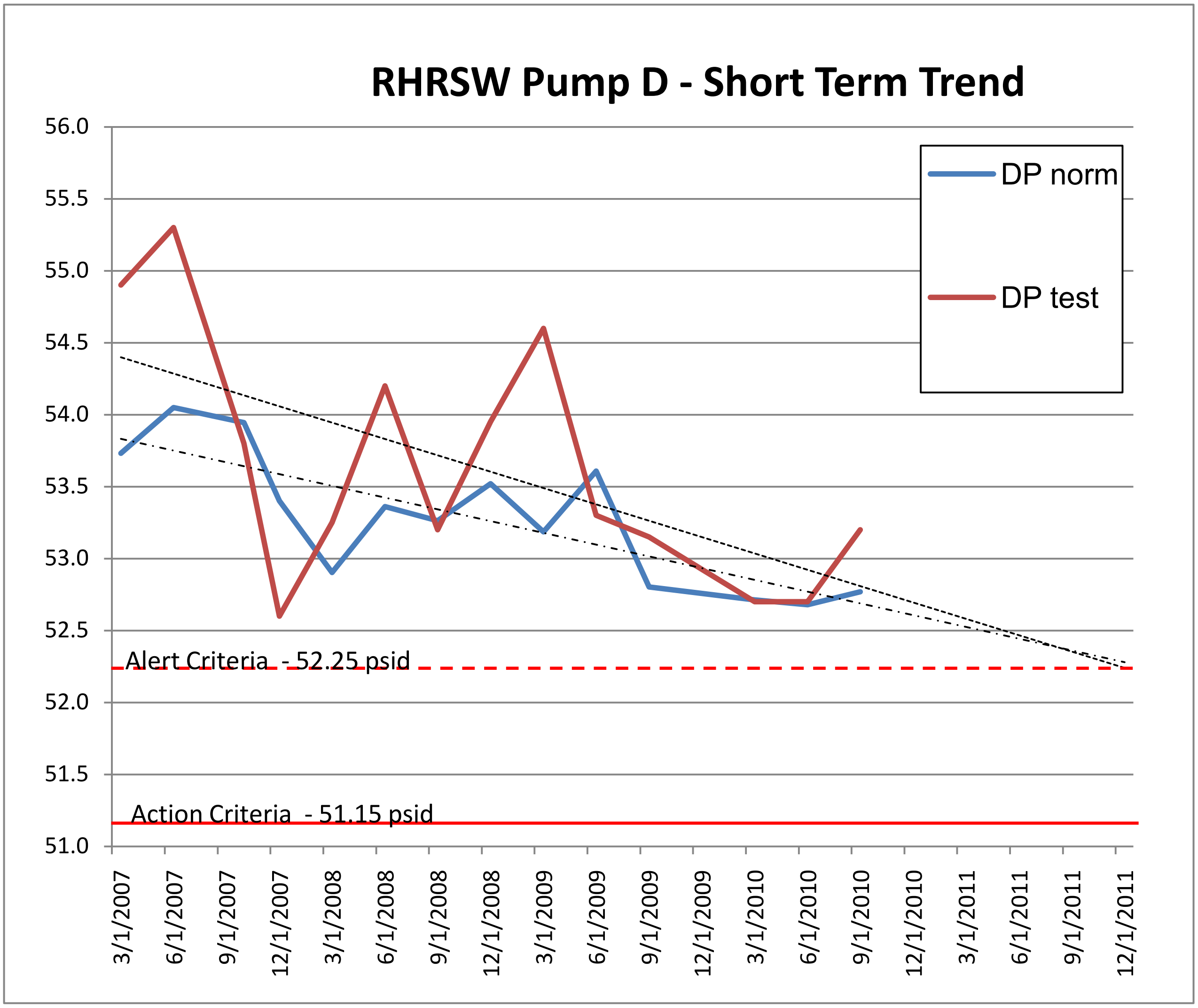
RHRSW Pump D - Short Term Trend
DP norm
DP test
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53.5
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51.0
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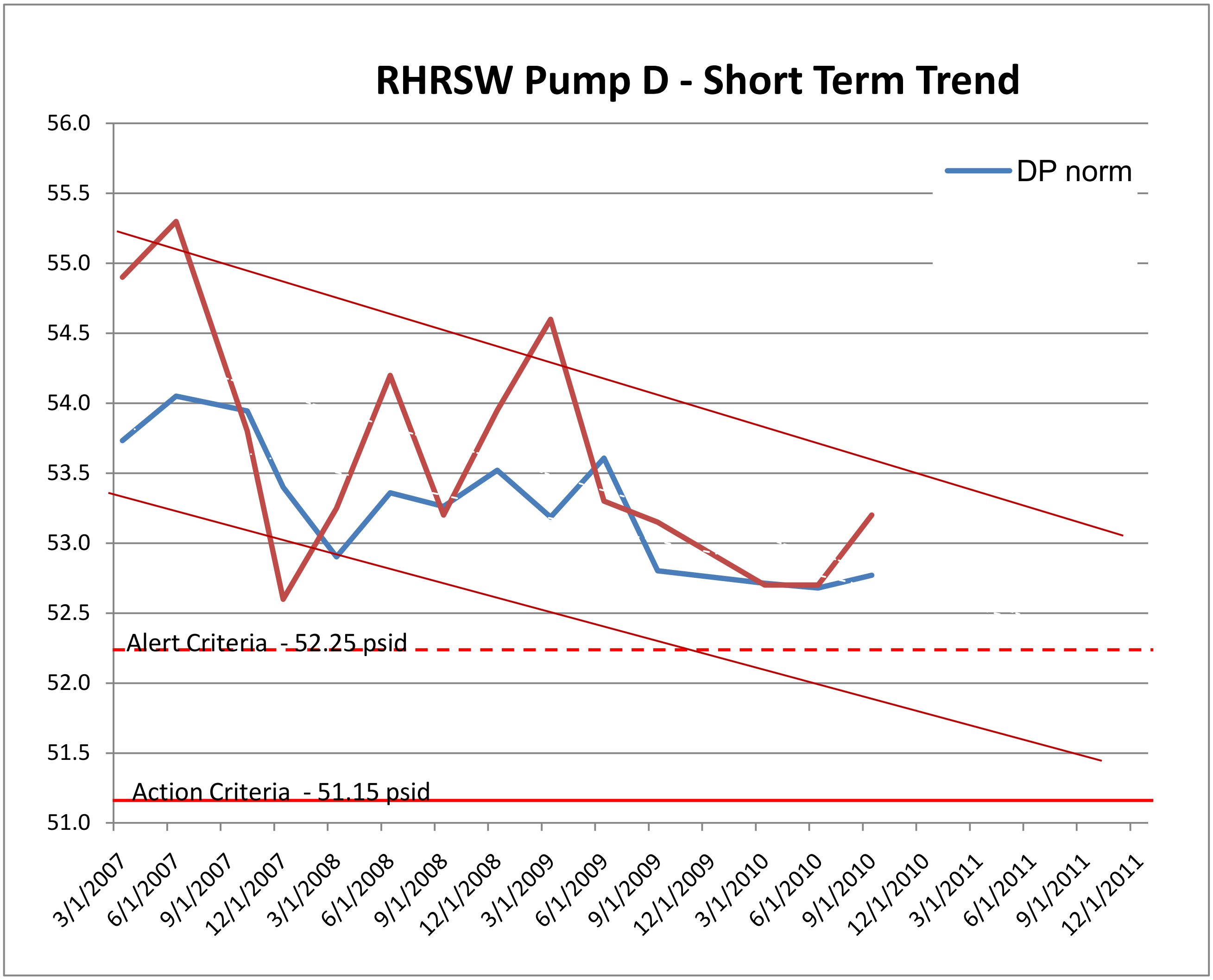
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DP norm
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Alert Criteria - 52.25 psid
Action Criteria - 51.15 psid
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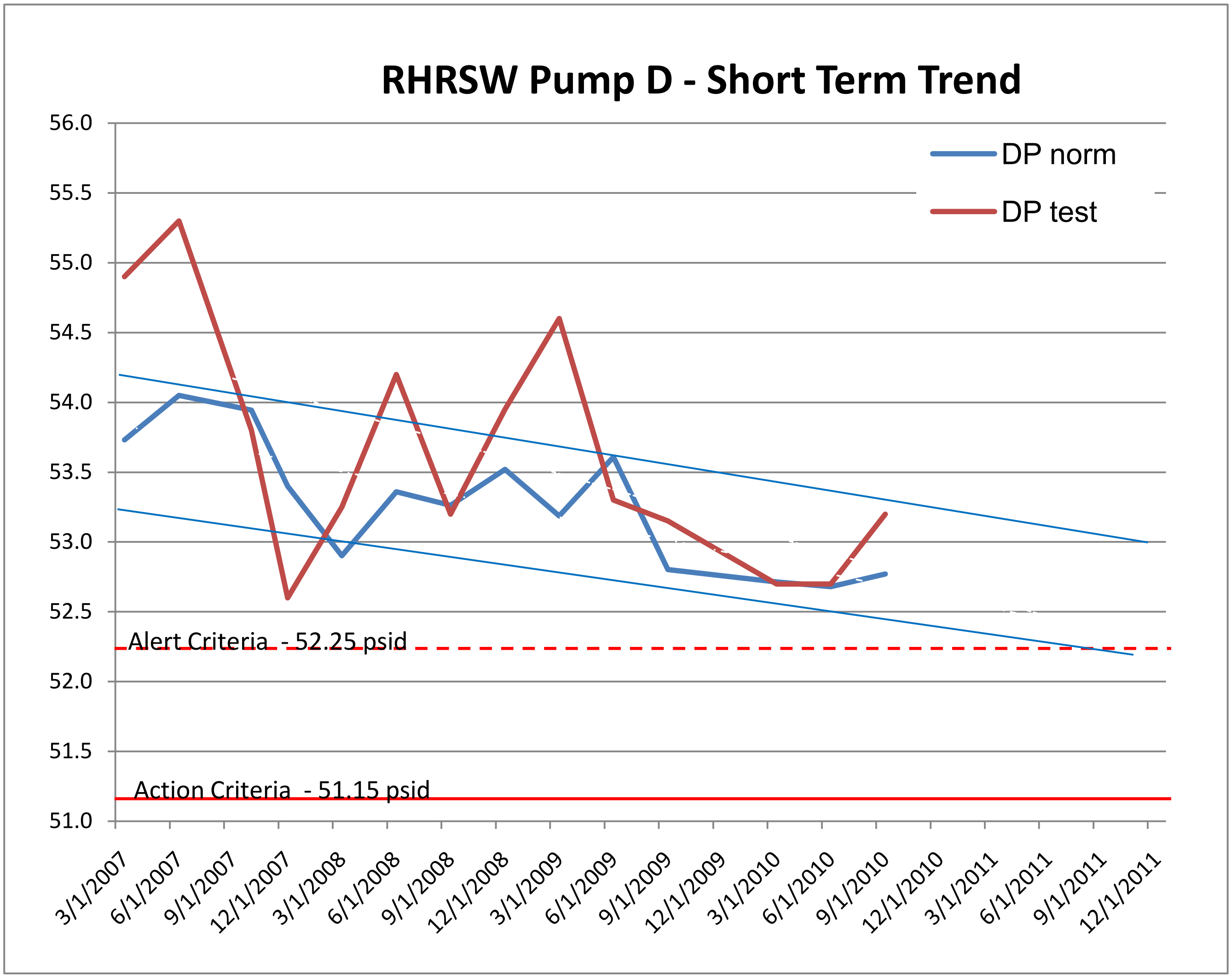
RHRSW Pump D - Short Term Trend
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52.0
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51.0
DP norm
DP test
Alert Criteria - 52.25 psid
Action Criteria - 51.15 psid
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6/1/2007
9/1/2007
12/1/2007
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9/1/2011
12/1/2011

High Pressure Safety Injection Pump Mechanical Seal Leakage Cause Analysis

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Arizona Public Service Company

Abstract

In February 2010, the PVNGS Unit 2 “B” Train High Pressure Safety Injection (HPSI) Pump was found to have a high leak rate from the pump’s outboard mechanical seal during a functional test following a bearing oil change. The initial leakage, a pencil size stream, decreased during an hour of operation to approximately 250 milliliter per hour (ml/hr). Initial observations, made during seal trouble shooting and replacement, indicated abnormal wear on the carbon stationary seal ring. Failure cause analysis found that the seal carrier springs that hold the rotating tungsten ring against the stationary carbon ring had been over stressed by maintenance and engineering personnel during pre-installation manipulation. PVNGS had experienced several HPSI seal leakage problems over the 2 previous years that led station personnel to measure the spring force of spare seal parts in an attempt to install the ‘strongest’ seal available in the spare part inventory when replacing HPSI mechanical seals. While measuring the spring force, the carrier springs were collapsed to solid which over stressed the springs and resulted in a loss of 30-40% of the spring force. The weakened springs resulted in excessive seal leakage during pump starts. The carbon ring degradation, caused by seal flushing water flowing across the carbon seal face during pump starts while the seal faces slowly reseated, contributed to the seal leak rate. It was found that the seal manufacturer provided seals designed to operate 24 hours a day for extended periods of time – not for a pump used in standby and required to operate for much shorter durations. New seal design with stronger springs for the operational expectations for these standby pumps are being developed by the seal vendor for the PVNGS application.

Introduction

In February 2010, while the Unit 2 PVNGS “B” Train of the Safety Injection (SI) System was in a 72 hour Limiting Condition of Operation (LCO) for planned maintenance, operations personnel observed that the 2B High Pressure Safety Injection (HPSI) Pump was leaking excessively from the pump's outboard mechanical shaft seal during a functional run following an oil change. The leakage challenged the pump design expectation and impacted the plant's Technical Specification for leakage from Primary Coolant Sources Outside Containment which has a maximum limit of 1500 ml/hr for all Emergency Core Cooling System (ECCS) piping outside of containment.

The 2B HPSI Pump high seal leakage was corrected by replacing the seal. The 2B HPSI Pump was returned to service before the end of the 72 hour LCO time period. A failure cause analysis was performed to determine causes and take corrective action to minimize recurrence.

Equipment Description

The PVNGS HPSI Pumps are Ingersol-Rand, Model 4X11CA-8, 1000 horsepower, horizontal, high pressure pumps with a design discharge pressure of 2050 pounds per square inch gauge (psig). Pump output flow at 1000 psig is approximately 1040 gallons per minute (gpm). These pumps are hydraulically balanced to minimize thrust forces by injecting high pressure discharge to the low pressure end bearing housing. The inboard bearing is a journal bearing. The outboard bearing is a combination journal and thrust bearing. It is an 8 stage pump with a 4 inch discharge. They are basically 1930 vintage boiler feed pumps manufactured to nuclear grade requirements.

Event Narrative

On February 17, 2010, the 2B HPSI Pump, exhibited high leakage from the outboard pump mechanical shaft seal when the pump was started for a functional run following an oil change. When the pump was started at 1600 hours, operations personnel noticed a pencil size steady stream of water flowing from the outboard pump seal. After 15 minutes of run time, at 1615, seal leakage had decreased and was determined to be 500 ml/hr. The leak rate continued to decrease and was determined to be 250 ml/hr at 1640. The pump was shutdown at 1656, and seal leakage decreased to 1 drop per 20 seconds at 1700 (based on 10-15 drops per ml, this equates to ~14 ml/hr).

Immediately prior to this pump run, under static conditions, the seal had been leaking at the rate of 1 drop per 7-8 seconds (~40 ml/hr).

The design specification (not a Technical Specification) for HPSI Pump seal leakage indicates that these seals should leak less than 50 ml/hr. The LCO, Primary Coolant Sources Outside Containment, establishes a limit of 1500 ml/hr for all ECCS piping outside of containment, which is in contact with recirculation sump inventory during loss of coolant (LOCA) conditions.

The 50 ml/hr was a design value for normal leakage during operational conditions developed by the plant's designer. Significantly more leakage is necessary before the pump would become inoperable (unable to deliver the credited safety related flow). A plant calculation for HPSI System performance includes a Surveillance Requirement Basis that assumes a net flow loss of 20 gpm. The leak rate experienced is far less than this amount. In addition, the leak rate would need to exceed the capacity of the Engineered Safety Features (ESF) room floor drains (and sump/sump pump) which is on the order of several hundred gpm. Therefore, the 2B HPSI Pump leak would have been a small contributor to the system requirements of 1500 ml/hr and as such would not impact the Title 10 of the Code of Federal Regulations (10 CFR) Part 100 off-site dose.

HPSI Pump 2B was isolated and drained for seal replacement. During the seal disassembly and inspection of parts the following observations were made:

- Spring preload appeared satisfactory (gap measurement)
- Shaft play was satisfactory (~0.015", within the acceptable range 0 - 0.030")
- Rotating face (tungsten) was satisfactory (disassembly caused a small chip)
- Stationary face (carbon) had non-uniform coloration – 90 degrees counter clockwise from the locating pin
- Carrier looked good
- Lip was satisfactory (not a repeat of 3R14 issue)
- O-rings were satisfactory

This particular seal was installed in the 2B HPSI Pump during a refueling outage in November 2009. It was installed as part of an effort to replace the old non-Q class seals with new Q class parts.

Inspections of the leaking seal parts found a discolored area on the stationary (carbon) seal surface. Under optical flat/monochromatic light, the seal area in question had only approximately 30% of contact area. This lack of flatness is measured in fractions of a mil. The rotating (tungsten) seal surface was found in good condition. New thrust bearings and a new mechanical seal were installed. Seal performance was satisfactory during retest. See diagram in the analysis section for internal seal details.

Inspections, following this 2010 seal replacement, have identified that the new outboard seal on the 2B HPSI Pump had again begun to develop a very slow leak under static conditions – as evidenced by the formation of boron on the bottom of the seal. The leakage had not developed to the point of developing drops falling from the seal housing.

Pictures taken during the seal trouble shooting and replacement:

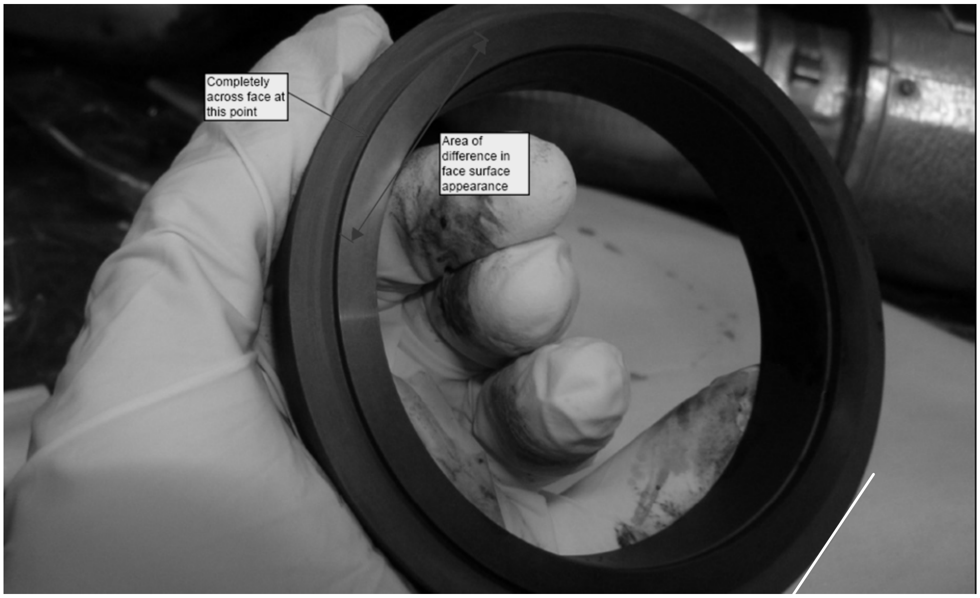
Seal flushing line

HPSI mechanical seal – Boron indicates leaking seal

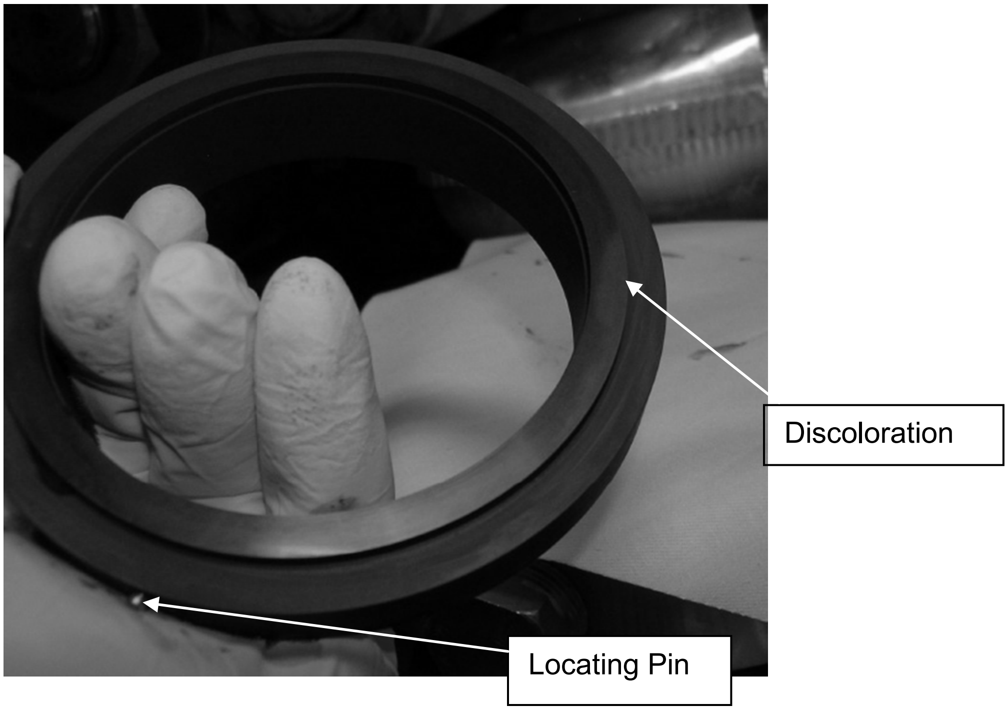
Leaking seal – note Boron


Seal carrier springs (TYP)

HPSI mechanical seal being disassembled

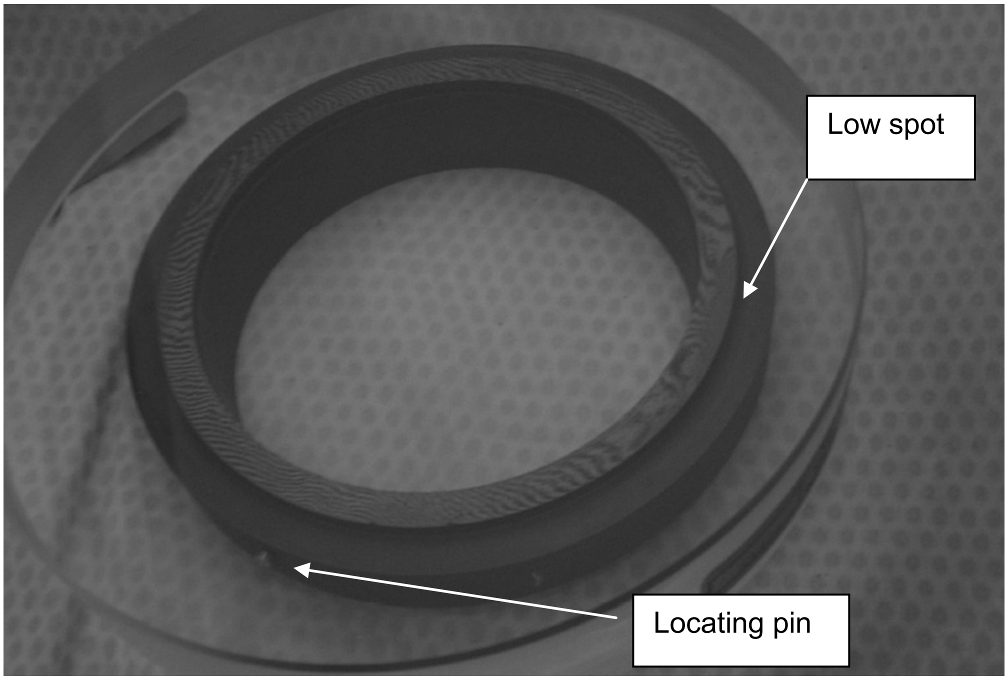


Stationary ring – Carbon – note discoloration

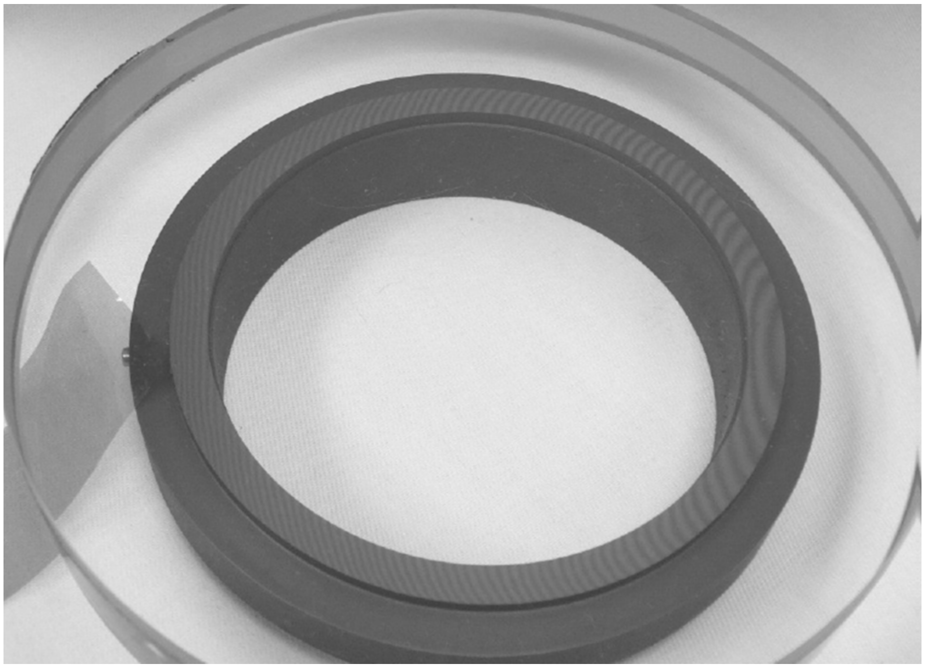


Stationary Ring – Carbon - details

The flatness of both the stationary and rotating seal rings was measured using an optical flat plus a monochromatic light. The light rings/pattern is an indication or measurement of surface flatness.



Leaking carbon seal showing lack of flatness as indicated by the wavy lines and low spot at area of discoloration



New carbon seal showing what flat looks like

A Maintenance Rule Functional Failure (MRFF) evaluation was performed. HPSI pump mechanical seal leakage of 250 ml/hr (most conservative assumption even though the leak rate was decreasing at the time the pump was secured) is much less than the 20 gpm limit discussed in Safety Injection (SI) System calculation. This calculation indicates that up to 20 gallons per minute of system leakage can be diverted from the HPSI pump and it will still continue to operate and provide normal performance. Therefore, the U2 B HPSI pump's capacity (flow and pressure) would not have been affected by the 250 ml/hr leakage from its outboard mechanical seal. Therefore, the Reactor Heat Removal (HR), Reactivity Control (RXC) and Inventory and Pressure Control (IPC) MR Key Safety Functions (KSFs) would have been fully protected and met.

With respect to the Indirect Radiation Release (IRR) MR KSF, the 250 ml/hr leakage would NOT have exceeded the Technical Specification leakage limit for ECCS Leakage Outside of Containment of 1500 ml/hr. This leakage limit is established to ensure that ECCS Leakage Outside of Containment, during the Safety Injection System recirculation mode of operation following a Loss Of Coolant Accident, does not result in dose rates to the public in excess of the 10 CFR 100 limits. For PVNGS Unit 2, the approximate ECCS Leakage Outside of Containment at the time of this event was 35 ml/hr. An additional 250 ml/hr leakage would have resulted in a total of 285 ml/hr, which is still considerably less than the 1500 ml/hr limit. Therefore, the IRR MR KSF would have been fully protected and met.

Therefore there was no MRFF or MR impact for this seal leakage event. Similarly, there was no significant impact to nuclear safety resulting from this seal leakage event.

Industry and plant Operating Experience were reviewed for similar events. Numerous previous events were identified that involved leaking HPSI seals – reasons for previous leakage were attributed to use of wrong lubricant during assembly, foreign material and poor workmanship during installation. In each case the corrective actions involved installation of new seals. Seal problems appeared to be handled as a component issue and not as an issue related to nuclear power.

Analysis

A Fault Tree and an Equipment Failure Modes and Causal Factors Chart were used in the analysis of this event and are included at the end of this paper.

The following are the facts and observations gathered by the cause investigation team:

- PVNGS handles the seals very carefully and installs them with great care (observation made by pump vendor representative).
- Foreign material contamination was not observed and is not considered an issue for this leakage event.
- PVNGS maintenance personnel have noted that the seal kit carrier springs do not seem as strong in the Q class parts as they were in the previously used Non-Q class parts.
- PVNGS personnel have measured spring rates and installed those kits with the strongest springs by measuring the spring forces versus compression of the carrier surfaces.
- The seal vendor measures the spring force by compressing the carrier to ¼ inch spacing and records the spring force at that position (50-72 pounds force [lbf]).
- The seal vendor has informed PVNGS that if the carrier springs are compressed to solid height, the springs are degraded and will only retain ~70% of their original spring force.
    - PVNGS has measured spring force of spares considered for installation and found 40-47 lbf at 1/4 inch spacing that would have been 57-67 lbf force (according to the vendor) before being compressed to solid height.
        - Degraded seal removed from 2B HPSI measured 42.5 lbf
        - Spare seal S/N …02 measured 47.7 lbf
        - Spare seal S/N …03 measured 46.9 lbf
        - Spare seal S/N …06 measured 39.9 lbf
    - PVNGS regularly compresses the carriers to solid height to ensure the guides move freely and to obtain a spring force curve – which the vendor has now indicated could have damaged the springs.
    - This indicates that PVNGS practices, according to the vendor, could have degraded the springs.
- Static leakage is controlled solely by spring force.
    - The new Q class parts have been observed to regularly leak under static conditions in the drops per minute range – even before the practice of measuring spring force was started.
    - Upon pump startup, although the HPSI pump is balanced, the pump shaft moves slightly towards the motor which tends to decrease the force that the outboard seal rotating face is pressing against the stationary face.
    - At pump startup, a spray of leakage has been noted in the outboard seal followed by a steady leak rate that slowly decreases over time – usually decreasing back to zero leakage.
    - When the pump is running, the seal cavity is slowly pressurized by pump pressure and the sealing is aided by the hydraulic forces. This pressure build up occurs slowly due to the torturous path the pressure takes along the pump shaft in the bearing/seal area.
    - Since changing to Q class seals, PVNGS has implemented a 10 hour HPSI run for post maintenance to get the mechanical seals to seat and seal as expected.

    - Greater than normal leak static leak rates have been observed on the three PVNGS HPSI pumps that have had the new Q class seals installed. 2B outboard seal is the only seal that has developed a gross leak upon pump start that has not decreased to near zero after pump was running. This leakage developed after the pump was run for a total of ~44 hours of operation since installing this seal.
- During the disassembly of the leaking seal the carbon seal face was found to be discolored and not completely flat when measured with an optical flat.
    - The low spot was the area of discoloration.
    - This area is 90 degrees counter clockwise from the seal locating pin which corresponds to the flushing water inlet.
    - It is believed, by the vendor, that the flushing water flow impacted the carbon sealing face during the time the tungsten face was not firmly seated on the carbon – causing a slight erosion of the sealing face. This is considered to be collateral damage of weak springs.
    - This loss of flatness of the carbon seat is the most likely cause of the sustained high leak rate experienced on this seal and over time the tungsten rotating seal would have reseated better and better – effectively decreasing the leak rate.
- HPSI operation was monitored as normal for pressure, vibration, shaft movement/alignment, balancing drum operation, flushing flow, etc.

Maintenance History

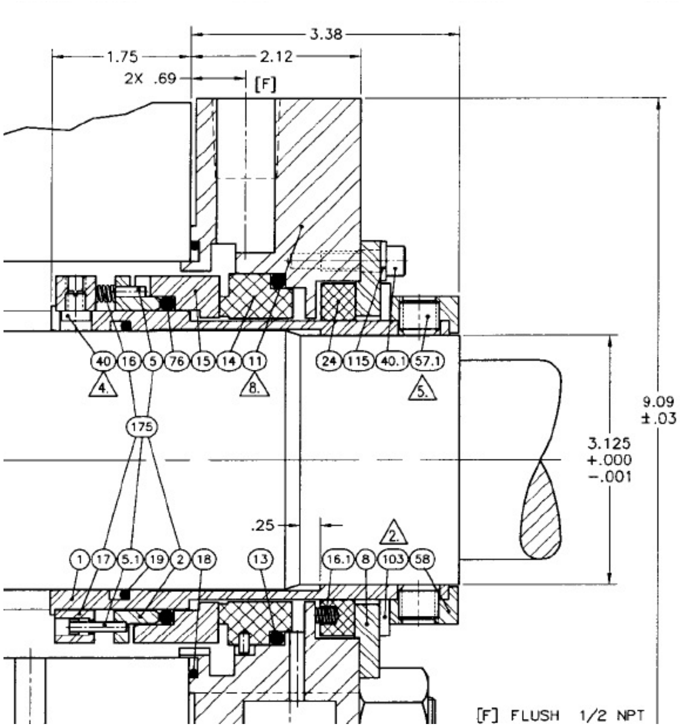
During the PVNGS Unit 3 refueling outage in April 2009, the “3A” and “3B” HPSI pump seals were replaced as part of planned maintenance with a pump vendor representative supervising the pump work. Replacement of the “3B” pump seal required multiple evolutions prior to successful pump performance. Following the first replacement, excessive leakage was observed during initial pump filling activities. A decision was made to replace this seal, based on the leakage likely being due to installation issues. A small piece of a carbon-like material was found in the area of the stationary seal o-ring seating area. The second seal replacement again resulted in excessive leakage which was determined to be a result of an installation error which caused a rolled gland lip. After the third replacement a successful post-maintenance testing was completed with minimal seal leakage that went to zero after about 10 minutes of run time. There were no indications, at that time, of a defective seal face.

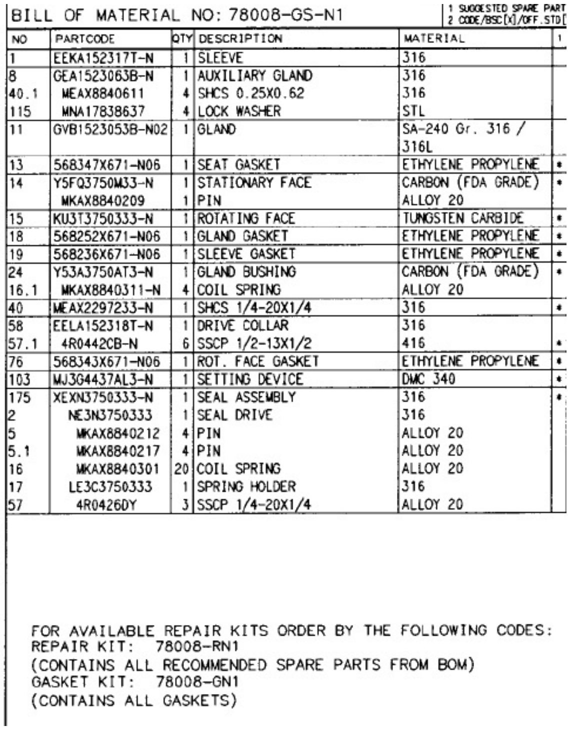
During PVNGS Unit 2 refueling outage in October 2009, the “2B” HPSI pump seals were replaced as part of planned maintenance. The post maintenance testing (PMT) revealed seal leakage from both seals – initially 3-4 drops per minute (~18.5 ml/hr) but continued pump operation resulted in zero mechanical seal leakage. Including the PMT and Surveillance Testing, this pump was run 43.9 hours before the pump was started on 2/17/2010 and experienced the pencil stream high leak rate.

The new, Q class parts were leaking - both under static and dynamic conditions compared to no active leakage with the older non-Q class seals that were replaced in all three of these pumps. The new Q class seals, in contrast to the older non-Q class seals, often exhibit a spray of leakage when the pump is started or when system valve alignments are changed. The new Q class seals sometimes have leaked large amounts (200-500 ml/hr) upon startup but over several minutes to hours have settled in and the leak rate has decreased to drops per minute. This is now understood to probably be as much a function of the development of hydraulic forces in the seal as it is for the seal surfaces to seat. The static leakage and leakage upon pump start is caused by weakened spring in the seal package not needing time for the seal surfaces to wear in.

The degraded 2B HPSI Pump seal was leaking, under static conditions at the rate of 1 drop every 7-8 seconds (~37 ml/hr), prior to starting the pump when the gross leakage was experienced before the seal was replaced in February 2010. The new seal, just installed in the 2B HPSI pump in February 2010, leaked minimally at first but leakage stopped after 10 minutes of run time. The vendor representative (a pump specialist, not a seal specialist) was present and involved in its installation. He made comments to the effect that the PVNGS Mechanics handled the seal very carefully and exhibited great skill and care in the way they installed the seal - that it could have not be installed better. During walk downs and inspections in March 2010, boron deposits were observed be forming on the bottom of the 2B HPSI seal indicating that it is weeping under static conditions. The leak rate had not developed to the point of forming droplets at that time. This is not a condition PVNGS was used to seeing while operating with the non-Q class seal assemblies in the past or on pumps that have not had their seals replaced with Q class parts.

To deal with these leaking seals - the pump vendor representative stated to properly break in the seal faces, the pump should be run for 3-4 hours of normal pump pressures and temperatures (i.e. no starts and stops). The way PVNGS starts and stops the pump could potentially be impacting the seal break-in. So a 10 hour PMT run time was instituted.





BILL OF MATERIAL NO: 78008-GS-N1

1 SUGGESTED SPARE PART
2 CODE/BSC[X]/OFF.STD[

NO	PARTCODE	QTY	DESCRIPTION	MATERIAL	1
1	EEKA152317T-N	1	SLEEVE	316	
8	GEA1523063B-N	1	AUXILIARY GLAND	316	
40.1	MEAX8840611	4	SHCS 0.25X0.62	316	
115	MNA17838637	4	LOCK WASHER	STL	
11	GVB1523053B-N02	1	GLAND	SA-240 Gr. 316 / 316L	
13	568347X671-N06	1	SEAT GASKET	ETHYLENE PROPYLENE	•
14	Y5FQ3750M33-N	1	STATIONARY FACE	CARBON (FDA GRADE)	•
	MKAX8840209	1	PIN	ALLOY 20	
15	KU3T3750333-N	1	ROTATING FACE	TUNGSTEN CARBIDE	•
18	568252X671-N06	1	GLAND GASKET	ETHYLENE PROPYLENE	•
19	568236X671-N06	1	SLEEVE GASKET	ETHYLENE PROPYLENE	•
24	Y53A3750AT3-N	1	GLAND BUSHING	CARBON (FDA GRADE)	•
16.1	MKAX8840311-N	4	COIL SPRING	ALLOY 20	
40	MEAX2297233-N	1	SHCS 1/4-20X1/4	316	•
58	EELA152318T-N	1	DRIVE COLLAR	316	
57.1	4R0442CB-N	6	SSCP 1/2-13X1/2	416	•
76	568343X671-N06	1	ROT. FACE GASKET	ETHYLENE PROPYLENE	•
103	MJ3G4437AL3-N	1	SETTING DEVICE	DMC 340	•
175	XEXN3750333-N	1	SEAL ASSEMBLY	316	•
2	NE3N3750333	1	SEAL DRIVE	316	
5	MKAX8840212	4	PIN	ALLOY 20	
5.1	MKAX8840217	4	PIN	ALLOY 20	
16	MKAX8840301	20	COIL SPRING	ALLOY 20	
17	LE3C3750333	1	SPRING HOLDER	316	
57	4R0426DY	3	SSCP 1/4-20X1/4	ALLOY 20	

FOR AVAILABLE REPAIR KITS ORDER BY THE FOLLOWING CODES:
REPAIR KIT: 78008-RN1
(CONTAINS ALL RECOMMENDED SPARE PARTS FROM BOM)
GASKET KIT: 78008-GN1
(CONTAINS ALL GASKETS)

Vendor seal Diagram

Summary of Investigation Analysis

The cause of the 2B HPSI seal leak was weak/degraded springs in the Q class parts. If the springs supplied in these new Q parts are compressed beyond 1/4 inch gap, the seal vendor has indicated they have then been compressed too far. If the carrier is compressed completely to 'solid height', the spring force will only return to about 70% of its rated amount when the carrier is released. The seal vendor was able to duplicate our spring force findings on the 3 spare parts in their inventory (mid 40 lbf range at 1/4 inch versus the design 50-72 lbf) by compressing the carrier of a new spare part completely and then re-measuring the spring force at 1/4 inch spacing.

PVNGS had developed the practice of compressing the carriers all the way to solid to measure spring rates to choose the best carrier during the installation part choice effort, as well as exercising the carrier to ensure the guide pins move smoothly and are not bound up.

The spring force provides sealing during static periods and during pump startup. During pump runs, hydraulic forces, pushing against the rotating element, provide the sealing force. The hydraulic forces take time to build up and reseat the sealing surfaces if spring force is insufficient to keep the seal tight during pump start.

During the period of startup, if the seal is not tightly sealing, the carbon stationary seal is exposed to flushing water flow. There is an area on the degraded carbon seal removed from the 2B HPSI Pump that was discolored and not completely flat when measured using an optical flat. This was not well understood and further analysis by an off-site Laboratory was performed. This location aligns with the flushing water line. There were micro mils of 'erosion' caused to the carbon sealing surface while the seating faces were not touching tightly during pump start and period of running waiting for the seal to reseat - sometimes hours long. Since the carbon seal is stationary, the flushing water flow strikes the same area of the seal face until the seal reseats. The ‘erosion’ appears to have contributed to the sustained leak flow experienced in this event. The ‘erosion’ is considered to be a contributing cause resulting from the effects of the weakened springs.

When the pump is not running or just after being started, it is the seal carrier springs that provide the sealing force pressing the rotating seal (tungsten) against the stationary seal (carbon). If the springs are not strong enough, the seal will develop slow leaks or weeping under static conditions (i.e. the pump not running). Also on pump start, there will be a spray of water out of the seal followed by a leak rate that will decrease over time. This is what has been observed with the Q class HPSI Pump seals installed to date. These seals were installed in the 3A, 3B HPSI Pumps April 2009 and in the 2B HPSI Pump October 2009. The 2B pump developed a larger than usual leak rate upon the pump start in February 2010. The leak rate began as a pencil stream and decreased to 500 ml/hr in 15 minutes. The leak rate continued to decrease and was measured as 250 ml/hr 25 minutes later. This is indicative of weak springs allowing a large leak rate at pump start and the leak rate decreasing as the hydraulic forces build up in the seal area which combine with run time to reseat the rotating seal on the stationary seal face.

Our experience with HPSI Pumps has been the longer they run the less they leak. The seals need time to reseat themselves and the components need time to heat up and come to stable equilibrium for these seals to work optimally.

Seal vendor representatives, present for the seal installation of the 1B Low Pressure SI (LPSI) pump seal (similar seal construction) informed PVNGS personnel that they build their seals for pumps that are in use most of the time, not used in standby and only operated for short periods of time. The seal vendor representative suggested the need for stronger springs to maintain no leakage during standby periods and infrequent pump starts. The seal faces would wear slightly faster during pump operation but that wear would not impact our pump mission times.

Conclusion

The new Q Class mechanical seals currently installed in the 3A, 3B, and 2B HPSI Pumps may have been degraded by the way PVNGS maintenance and engineering personnel have manipulated these seals and therefore are susceptible to leakage during static conditions (i.e. pump not running) and during pump start. If leakage occurs during pump start, it is expected to decrease rapidly after the pump is running and should decrease to minimal or no leakage. If static leakage occurs, it is expected to slowly increase until the pump is run long enough to completely reseat the sealing faces. This time is not necessarily constant or precisely quantifiable (depends on the particular pump and seal), but it is expected to be a reasonably short time (order of hours), after which seal leakage should have decreased to a negligible rate relative to the system limits of 1500 ml/hr.

Obviously, if more measureable leakage were to persist over a longer time, the system limits of 1500 ml/hr would ultimately govern this leakage. However, at this time, there is no evidence that leakage would increase during pump operation over the mission time of the pump and therefore reasonable assurance that the 1500 ml/hr total ECCS piping leakage limit would continue to be met.

Corrective actions

Have seal vendor representatives support for any future seal replacements until corrective actions are in place to preclude seal degradation during installation by PVNGS personnel.

Add information to the HPSI Pump rework procedure, with instructions to not compress the seal carrier closer than 1/4 inch spacing with a caution about spring damage and check for seal flatness. Make similar changes to LPSI and Containment Spray procedures also.

Evaluate whether the HPSI pump should be run continuously for 3-4 hours upon initial startup following a seal change to properly break in the new seal(s). Make appropriate changes to the HPSI Pump rework procedure. This would be considered a lessons-learned enhancement action.

Return the 3 degraded HPSI spare seal kits to the vendor to be refurbished.

PVNGS Engineering - work with the seal vendor to obtain springs that still provide design force after being compressed tight - return all spare parts for refurbishment if springs are changed.

Determine needed changes to ECCS pump maintenance training courses.

Direct Cause

HPSI 2B seal leakage was caused by weakened springs that allowed the seal faces to not be tightly compressed which resulted in a large leak rate.

Apparent Cause

A lack of vendor information allowed PVNGS personnel to fully compress the HPSI Pump seal carrier springs which resulted in weakening these springs.

Supporting Facts

- Vendor information, in their shop drawings, not provided to PVNGS, cautions against compressing the new Q class HPSI seal carrier springs beyond their ‘working height’ and no cautions were provided about potential seal damage if the springs are compressed.
- Static leakage is controlled by seal spring force acting on the seal surfaces.
- Initial pump start causes a spray of leakage that is not immediately stopped by spring force – indicating weak springs.
- PVNGS spring rate testing methodology versus vendor methodology (seals S/N 02, 03, & 06 are now degraded and need to be refurbished).
- PVNGS compressing the carrier to ensure guide pins moved smoothly.
- Spring force measurements performed by PVNGS and vendor verified this degradation mechanism.
- Leak rate decreases over time as the pump is being run indicating sealing surfaces were wearing in and reseating as the seal was being pressurized by pump flow.

Contributing Cause

A lack of surface flatness or sealing surface degradation occurred in the carbon seal face which was exposed to flushing water flow when the seal faces were not tightly compressed.

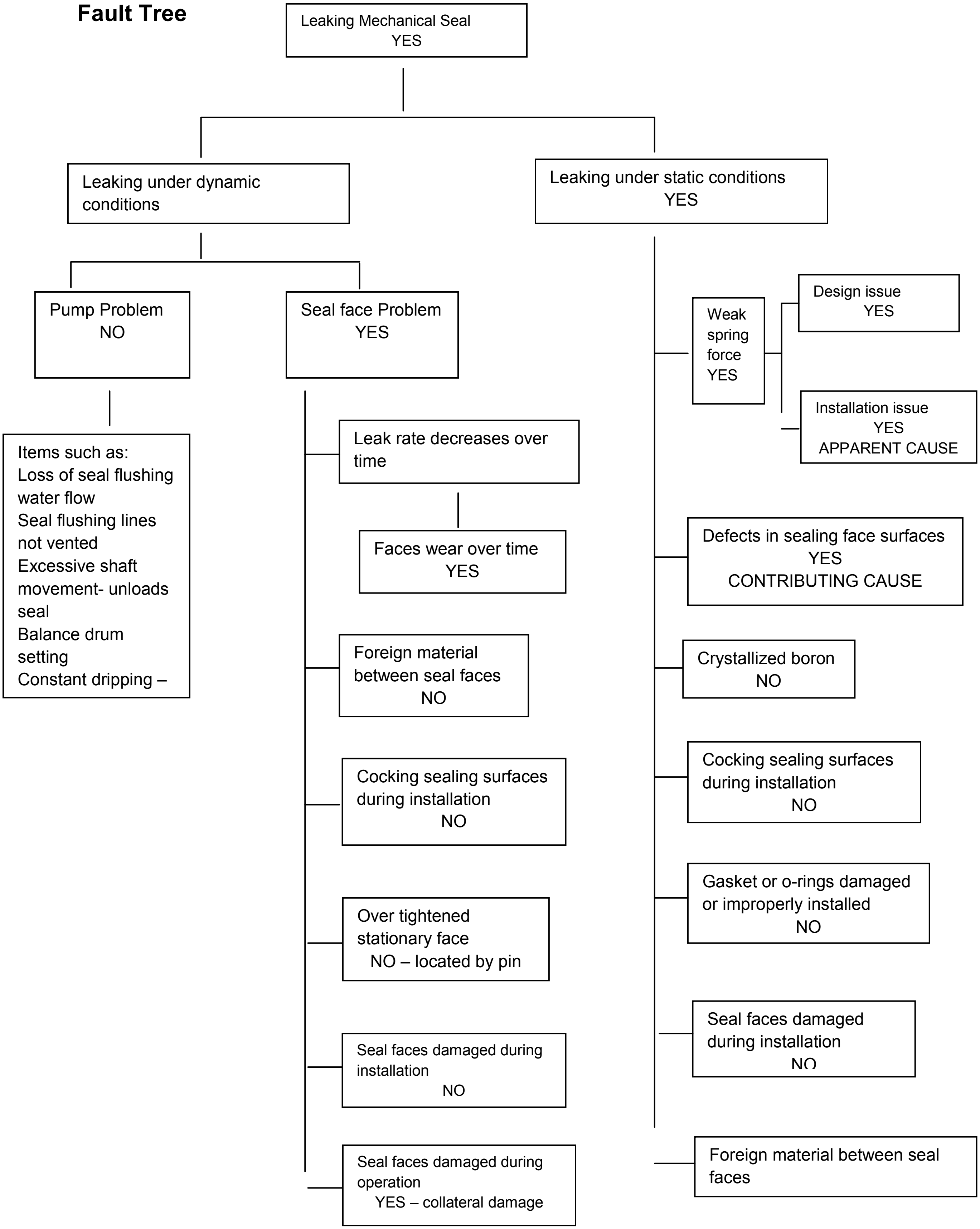
Supporting Facts

- Flatness test using light table/light bands.
- Discoloration.
- Possible material issue since the discoloration, area that is not flat, aligns with the flushing water flow.

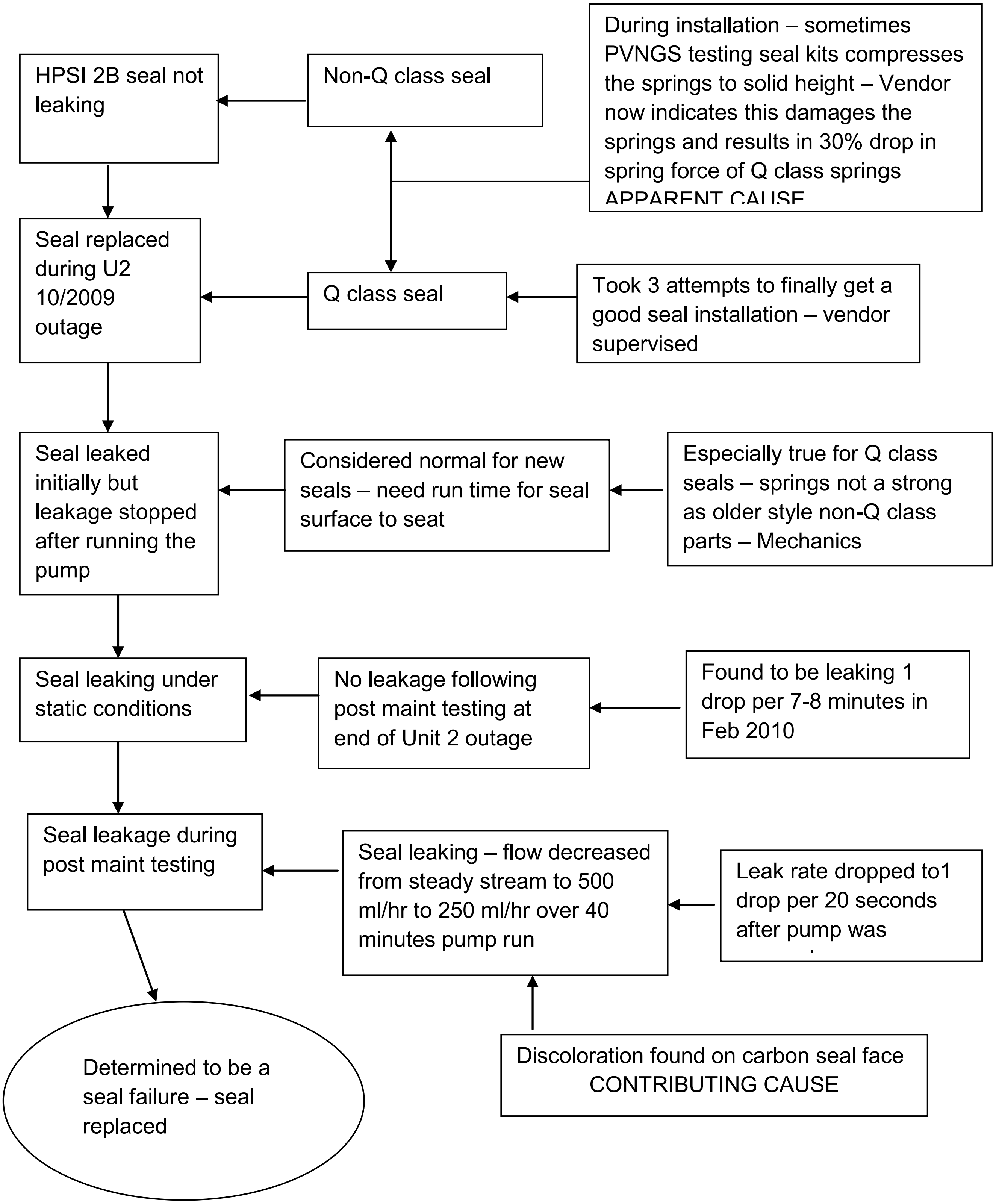
Other Issue

PVNGS should work with Flowserve to obtain springs that still provide design force after being compressed tight.

Fault Tree


Leaking Mechanical Seal
YES
Leaking under dynamic conditions
Leaking under static conditions
YES
Pump Problem
NO
Seal face Problem
YES
Items such as:
Loss of seal flushing water flow
Seal flushing lines not vented
Excessive shaft movement- unloads seal
Balance drum setting
Constant dripping –
Leak rate decreases over time
Faces wear over time
YES
Foreign material between seal faces
NO
Cocking sealing surfaces during installation
NO
Over tightened stationary face
NO – located by pin
Seal faces damaged during installation
NO
Seal faces damaged during operation
YES – collateral damage
Weak spring force
YES
Design issue
YES
Installation issue
YES
APPARENT CAUSE
Defects in sealing face surfaces
YES
CONTRIBUTING CAUSE
Crystallized boron
NO
Cocking sealing surfaces during installation
NO
Gasket or o-rings damaged or improperly installed
NO
Seal faces damaged during installation
NO
Foreign material between seal faces

EQUIPMENT FAILURE MODES and CAUSAL FACTORS CHART



Session 5: Regulatory Interactive

Session Chair: Anthony C. McMurtray, U.S. NRC

Interface Between IST Program and Design Engineering

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Abstract

Several issues arose in recent years that demonstrate the need for a structured process for interface between the Design Engineering group and the Inservice Testing (IST) Programs at each power reactor site. A few examples are:

- Valve stroke time limits - design issues such as the effect of Emergency Diesel Generator (EDG) frequency and Limit Switch settings on Motor Operated Valve (MOV) stroke times and whether IST criteria is reconciled with those impacts.

- The effect of actual fluid temperature on indicated pump flow readings due to fluid density impact on flow element output.

- The impacts of design calculation factors such as EDG frequency, suction strainer clogging, etc. on IST pump performance limits.

This presentation will examine these and other examples in detail to illustrate the need for design engineering to quantify and communicate the appropriate design limits. IST engineers need access to this information when they are determining procedural criteria for pumps and valves so the acceptance criteria can be truncated as necessary.

Introduction

Individual power plants undergo periodic Nuclear Regulatory Commission (NRC) inspections, including Component Design Basis Inspections (CDBI). These inspections often involve highly technical issues, including IST and criteria involved with specific components. Inspectors often question the IST Program Managers about test methodology and the basis for acceptance criteria. When acceptance criteria is based on design limits, which are more limiting than Code-based criteria, the IST personnel need to be able to engage design engineering personnel in the discussion.

Recent CDBI Issues

EDG Low Frequency

There have been several instances in the past 6 years where inspectors were intent on verifying that surveillance test criteria for alternating current (AC) powered pumps was truncated appropriately for EDG low frequency conditions. Most plants have EDG speed and emergency bus frequency controls with limits of +/- 2% or ± 1.2 hz. It is understood that pumping performance of an AC powered pump will be diminished with a reduced input power frequency and for pumps with relatively low operating margins this 2% impact can be significant. In some cases, the IST criteria was adjusted in the conservative direction to account for the 2% underfrequency condition. The impacts of such conditions need to be embedded into plant design calculations, not parsed one-by-one into IST criteria.

Emergency bus frequency can have a slight effect on AC powered valves as well. Stroke times of these valves would increase. IST engineers may be prompted to adjust their acceptance criteria by the 2% value as a response to inspector concerns. Again, these factors need to be evaluated within design calculations.

MOV Limit Switch Settings

Another recent issue involved the setting of limit switches in MOVs. MOVs are typically stroke timed from the control room using the open / close indications. The limit switches that actuate the remote indications are set at points of valve travel. For example, the limit switch that extinguishes the valve open light at the end of a closing stroke may be set at a point approximately 3-5% away from valve hard seat contact. That setting is appropriate because the same limit switch rotor may also operate the contact which provides for electrical bypass of the open torque switch contact.

The limit switch which operates the close light may be set at the point of opening valve travel well away from the backseat position. The same rotor may operate the limit switch that turns off the motor in the opening direction. Many valves with relatively high stroke speeds would suffer higher than desired inertial seating forces in the open direction if the motor cutoff point is too close to the backseat point. The recorded stroke times are based on these limit switch settings, not actual valve position. For valves with small operating margins between actual stroke times and design requirements, this variation between true and indicated valve position may be a concern.

Design calculations have to reconcile many different design factors and assumptions. Design engineers must consider many different accident scenarios and operating conditions. The hydraulic calculation for the Fermi 2 Core Spray system (Design Calculation 0230 Vol. I) is 399 pages long. Some key aspects of this calculation are:

1) Provides the minimum head / differential pressure limits to satisfy the Technical Specifications.

2) States the minimum accuracy requirements for flow and pressure indications during acceptance testing.
3) Considers the effects of EDG frequency, system frictional losses, suction strainer clogging, flow orifice plate degradation, 8 different operating modes, 3 to 4 specific cases in each mode, system source water temperatures and other factors.

This design calculation is very complex and the incorporation of all the design factors requires very careful analysis. If IST engineers are employing simple truncations to criteria without close cooperation with their design engineering staff, it is likely that margins would be reduced unnecessarily.

When questions involving non-Code impacts on pump and valve criterion come up during CDBI inspections, the IST Engineer needs to ensure that design engineers become involved. Engineering managers may need to become involved to ensure that issues are evaluated in a comprehensive multi-disciplined approach. NRC inspectors need to be sensitive to these issues as well. If the question they ask is "Why doesn't this IST criteria account for EDG underfrequency?" it may influence the IST and Licensing personnel to "fix that problem" without engaging the design personnel.

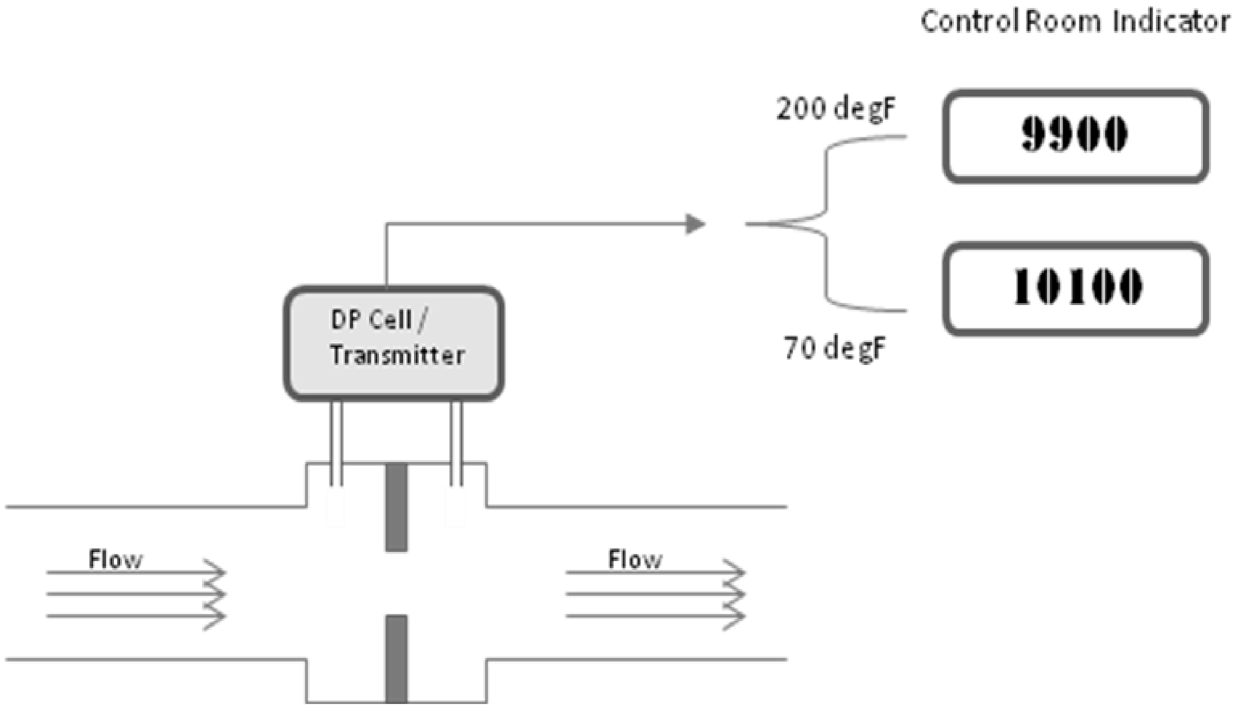
Emergency Core Cooling Systems (ECCS) Pump Flow Indication Errors Due to Temperature Bias

In July 2009 Operational Experience (OE) 29428 was issued. The following is one paragraph from that OE:

> On June 25, 2009 NRC CDBI inspectors questioned the Inservice Testing Engineer on how various uncertainties, including the pump flow element accuracy, were considered in the RHR *[Residual Heat Removal]* pump, ASME OM Code Comprehensive Pump test acceptance criteria. The basis for the question was to ensure design requirements were properly considered during testing as identified in NRC Information Notice IN 97-90, “Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests.” During the response to this question and related follow up questions review of the vendor supplied orifice data sheet appeared to indicate that the orifice full scale differential pressure was 316.15 inches of water at a flow rate of 3000 gpm and a flow temperature of 350 degrees F. RHR pump testing is routinely performed at flow temperatures of 80 to 95 degrees F. Testing with a fluid temperature considerably less than the assumed fluid temperature for the transmitter calibration would result in the indicated flow being higher, approximately 5%, than the actual flow.

This OE was reviewed and it was determined that Fermi likely contains the same vulnerability. The RHR pump flow indication uses an inline flow orifice as its source. Flow passing through this orifice creates a pressure drop which is measured by a differential pressure (DP) transmitter. As the fluid temperature varies, the density varies proportionally. The fluid density affects the amount of pressure drop across the orifice and thus influences the indicated value. The instrumentation and control (I&C) calibration for the flow loop inserts a known DP at the transmitter and verifies correct reading in the control room. The calibration tables correlate the flow and DP readings at the assumed accident temperature. According to I&C design engineering personnel, the overriding design philosophy is that the instrumentation in the control room be accurate under accident conditions. If accuracy could be affected by system conditions, it is better that any manual corrections required be done when the plant is in a normal steady-state condition. An accident scenario or event, with all of the extraordinary demands on the operating crew, is not the time to have to perform manual calculations for critical parameter accuracy. See Figure 1 below:

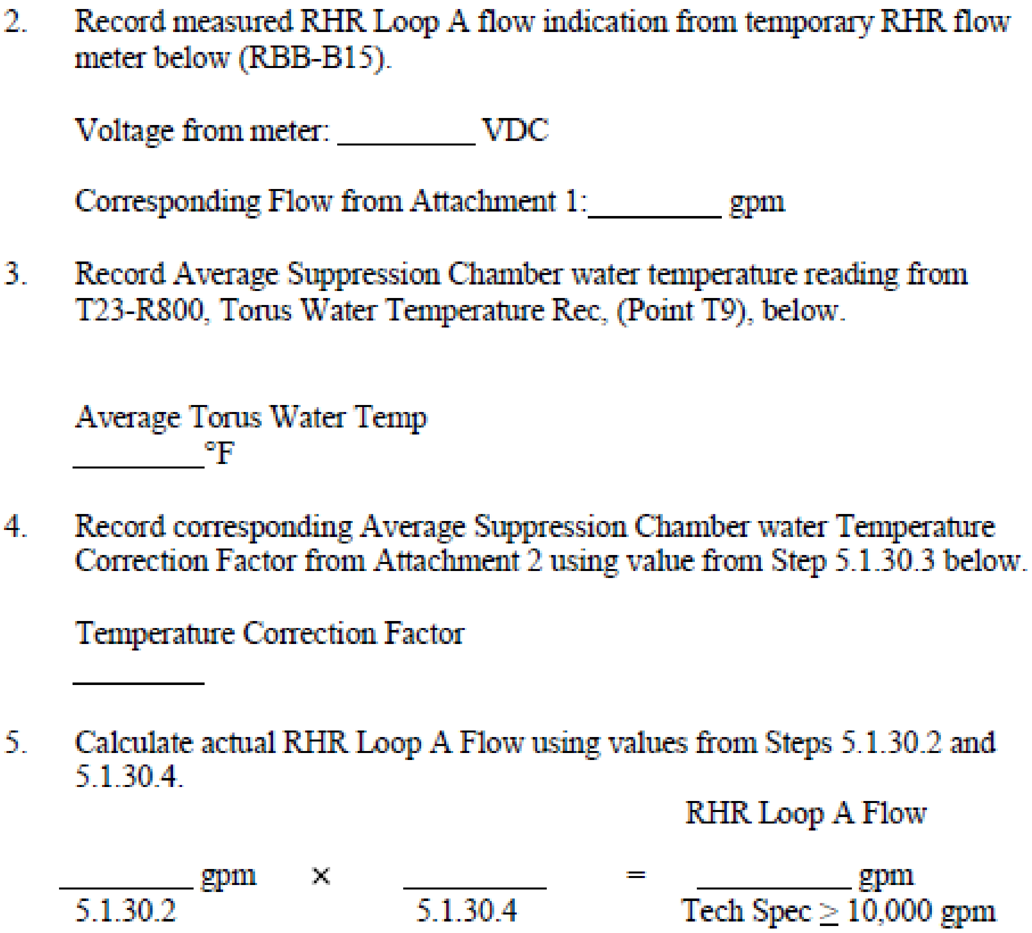
FIGURE 1



The flow orifice design calculations are circa 1983-1984 documents and are likely without revision since that period. These design calculations state that the calibrated indications will be accurate at the design temperature and if inservice testing is performed at a fluid temperature other than the design value, a correction factor must be applied. These calculations provide a graph displaying the temperature correction factor versus temperature to aid the IST engineers. Initial system acceptance testing in the early 1980's was completed using the appropriate temperature corrections;

however, the initial surveillance procedures created for RHR and other pump systems did not include any temperature correction for flow.

Fermi corrective action document (CARD) 09-26745 was initiated in early September 2009 based on this concern and assigned to Design Engineering - I&C. Unfortunately, that CARD investigation was less than adequate and the CARD was dispositioned and closed in late October with no action taken. That CARD disposition was challenged with the help of the Nuclear Quality Assurance group. A series of meetings were held in November 2009 to more thoroughly evaluate the impact of the OE on Fermi plant systems. It was determined that Fermi contained a similar problem with flow measurement accuracy for the RHR pumps. Additionally, this adverse issue applied to all divisions of all Fermi ECCS systems, but the RHR impact was the most significant because of the higher flow values involved. Investigation identified that flow readings in the Main Control Room (MCR) are calibrated for true accuracy when the fluid temperature (RHR suction) is 200 deg F. At normal system temperatures of 70° - 75° F, the MCR flow indication will indicate approximately 200 GPM HIGHER than actual flow. Quarterly testing verifies Technical Specification (TS) surveillance requirement (SR) that RHR can deliver ≥ 10,000 GPM. **Applying the density correction to past surveillance results showed that the majority of the testing had corrected flow values < 10,000 GPM**. A Level 2 (high safety significance) CARD 09-28815 was initiated as a result, requiring immediate operability reviews of all ECCS systems. The RHR surveillance procedures were revised immediately and testing was performed within days to confirm RHR operability. Further extent of condition analysis was able to support initial operability determinations on the other affected systems. Procedure revisions for all the other affected systems have been made. Below is an excerpt from our current RHR system surveillance procedure which illustrates the change that was made to account for the density correction to flow.



2. Record measured RHR Loop A flow indication from temporary RHR flow meter below (RBB-B15).

   Voltage from meter: ________ VDC

   Corresponding Flow from Attachment 1:________ gpm

3. Record Average Suppression Chamber water temperature reading from T23-R800, Torus Water Temperature Rec, (Point T9), below.

   Average Torus Water Temp
   ________°F

4. Record corresponding Average Suppression Chamber water Temperature Correction Factor from Attachment 2 using value from Step 5.1.30.3 below.

   Temperature Correction Factor
   ____

5. Calculate actual RHR Loop A Flow using values from Steps 5.1.30.2 and 5.1.30.4.

				RHR Loop A Flow
________ gpm	×	________	=	________ gpm
5.1.30.2		5.1.30.4		Tech Spec ≥ 10,000 gpm

This is an example of the need for close cooperation between "in plant" engineers such as IST and System Engineers and the design engineering staff.

One example of a "structured process" for interface between design engineering and IST at Fermi was a one-time reconciliation of all IST pump testing conditions and acceptance criteria against design calculations performed in 2006. That effort produced an engineering evaluation to document the effort and did discover a few necessary corrections to both design calculations and IST procedures. In one instance, it was discovered that a design calculation included an assumption of no more than 5% lifetime pump degradation. The IST criteria had been set based on typical ASME OM Code 10% allowance. The IST criteria for that pump was adjusted to match the 5% assumption in the design document.

Following that one-time effort, a process change was made that required design engineering review and concurrence for any changes to pump testing methods or criteria. These in-line reviews by the design engineering personnel ensure fidelity to the 2006 base evaluation.

The purpose of inservice testing is to detect and trend component degradation. It is commonly believed that there should be deliberate separation between IST and TS operability testing. One philosophical view I have heard is that TS surveillance testing proves that a component or system is operable at this moment and that it has remained operable since the last test. The IST test then establishes confidence that the system or component will remain operable until the next test. In real world application, there is often a single test which is meant to satisfy both the TS SR and the IST. This "double duty" style of testing is what creates the need for close cooperation between IST engineers and design engineers.

Conclusion

This process at Fermi has made the design engineers more aware of the ASME OM Code requirements for testing and criteria, which has helped to ensure that subsequent revisions to design calculations did not invoke more restrictive limitations unless absolutely necessary. The IST and system engineers have likewise become much more familiar with the hydraulic design calculations and especially how all the various design factors are embedded. This process has strengthened our compliance with 10 CFR 50.55a as well as 10 CFR 50 Appendix B.

Acknowledgments

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References

OE 29428

Inservice Testing Is About Operability

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Abstract

Title 10 of the *Code of Federal* Regulations (10 CFR) 50.55a(f) requires that nuclear power plants perform inservice testing (IST) of American Society of Mechanical Engineers (ASME) Section III Class 1, 2, and 3 components (pumps and valves) in accordance with the ASME *Code for Operation and Maintenance of Nuclear Power* Plants (OM Code) to determine component degradation. In addition to the CFR, the requirement for testing using the ASME OM Code had historically been found within many licensee technical specifications (TSs). This requirement has subsequently been removed from many TSs and now resides in the licensee Technical Requirements Manual (TRM). In addition to the testing required by the ASME OM Code, licensees are required to test safety-related structures, systems, and components (SSCs) to verify operability and ensure TS surveillances, and in some cases design requirements, are met. Licensees have established test programs to meet the requirements of the ASME OM Code, as required by 10 CFR 50.55a, and quarterly TS surveillance requirements, as required by their license. Because different component performance criteria are required to confirm compliance with the ASME OM Code, TS surveillances, and design requirements, test results are sometimes not properly evaluated to ensure the results meet all the requirements of the license and ensure the system can perform its design function. This paper will compare the various parameters measured during IST and TS testing, and show how those parameters are used in design calculation assumptions as they relate to the ability of safety-related pumps to respond to a design basis accident or event. Additionally, the paper will discuss violations of Nuclear Regulatory Commission (NRC) requirements resulting from incorrect pump testing acceptance criteria and improper evaluation of pump test results.

Introduction

To ensure that pumps are capable of responding to design basis events and accidents, licensees are required to comply with Title 10 of the Code of Federal Regulations (10 CFR), including 10 CFR 50.55a, “Codes and Standards,” and implement programs that meet the quality assurance requirements of 10 CFR 50 Appendix B, Criterion III, “Design Control”; Criterion V, “Procedures”; and Criterion XI, “Test Control.” Additionally, licensees’ TSs include specific requirements for performance of periodic surveillance testing of safety-related pumps. The purpose of these programs, in combination, is to verify the operability of the pumps and to provide reasonable assurance that the pumps will be able to adequately respond to design basis events and accidents.

There are five terms defined below that are used to describe the operating condition of the safety related systems. These terms are used to describe component readiness and need to be understood and addressed when evaluating pump testing results.

> Fully Qualified: An SSC is fully qualified when it conforms to all aspects of its licensing basis, including all applicable codes and standards, design criteria, safety analyses assumptions and specifications, and licensing commitments.
>
> Degraded Condition: A degraded condition is one in which the qualification of an SSC or its functional capability is reduced. Examples of degraded conditions are failures, malfunctions, deficiencies, deviations, and defective material and equipment. Examples of conditions that can reduce the capability of a system are aging, erosion, corrosion, improper operation, and maintenance (Reference 1).
>
> Nonconforming Condition: A nonconforming condition is a condition of an SSC that involves a failure to meet the current licensing basis (CLB) or a situation in which quality has been reduced because of factors such as improper design, testing, construction, or modification so that an SSC fails to conform to one or more applicable codes or standards (Reference 1).
>
> Operability: A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety functions, and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s). (Reference 2)

> Inoperable: A system, subsystem, train, component, or device is Inoperable when it is not capable of performing its specified safety functions.

To inform licensees of the NRC's expectations for 10 CFR compliance, the NRC has published various generic communications. Specifically, the NRC has created several generic communications to assist the licensee in determining how to determine the operating condition of an SSC. The NRC's guidance for inservice testing was provided in Generic Letter (GL) 89-04(Reference 3) and NUREG -1482, Rev. 1, (Reference 4). These two NRC generic communications provide guidance on how to develop and implement an acceptable IST program.

As part of the guidance for implementation of an IST program, NUREG-1482, Rev. 1 also established expectations in order to conclude that a pump is fully qualified. NUREG-1482, Rev. 1, Section 2.1, "Compliance Considerations," states "This testing is intended to assess the operational readiness of the stated component," and Section 5.6, "Operability Limits of Pumps," describes how operability limits must always meet, or be consistent with, licensing based assumptions in the safety analysis for a plant. Section 5.6 also references an additional NRC GL 91-18 (Reference 5) (replaced by Regulatory Issue Summary (RIS) 2005-20 (Reference 6)). With regard to pump testing, GL 91-18 is referenced to provide guidance on how to assess operability of a system when pump testing determines a pump is degraded or not fully qualified.

Subsequent to the issuance of the generic communications listed above, the NRC, through the inspection program, continued to identify deficiencies with licensees' testing programs. To inform all licensees of these deficiencies, the NRC issued Information Notice (IN) 97-90 (Reference 7). The purpose of the IN was to inform licensees that "although licensees have established IST acceptance criteria that meet the requirements specified in the ASME OM Code, the criteria at some plants allowed safety-related pumps to degrade below the performance assumed in the accident analysis." The discussion in the IN focused on the requirement for licensees to address the operational readiness aspect of these pumps when reviewing test results.

Since the issuance of the IN, NRC inspection teams have continued to find non-conservative acceptance criteria in testing programs. The establishment of pump testing requirements and review of pump testing results should not only verify ASME OM Code compliance, but verify that design basis functions have been maintained, including TS requirements. This paper discusses, in general terms, NRC inspection findings related to identified deficiencies between the various testing programs and associated requirements that could lead to, or has lead to, incorrectly assessing operability of safety-related pumps. Additionally, some of the inspection findings identified by NRC inspection teams over the last five years are listed in the attachment to this paper.

ASME OM Code Limits

The ASME OM Code provides testing guidelines and acceptance ranges for pump testing. The alert and required action ranges are defined by the ASME OM Code. When the pump testing is performed in accordance with the requirements of the ASME OM Code and the results are maintained within the limits of the acceptable range, the component can be considered in conformance with the ASME OM Code testing requirements. If the limits are exceeded, the ASME OM Code requires actions by the user to address the degradation. The NRC has also provided guidance on requirements for assessing the degraded condition as it relates to operability of pumps that enter alert and required action ranges. As previously discussed, RIS 2005-20 provides guidance for assessing the operability of equipment that is found to be degraded or non-conforming. Additionally, Position 8 of Attachment 1 to GL 89-04 (Reference 3) notes that if performance data fall within the required action range, regardless of whether the limit is equal to the TS limit or more restrictive, the pump or valve must be declared inoperable immediately and the limiting condition of operation (LCO) must be declared not met and the applicable conditions must be entered. The failure to meet the acceptance levels in the ASME OM Code is considered a degraded and nonconforming condition.

The 9900 Technical Guidance (Reference 6) clarifies the basis for this position by discussing the underlying assumptions as the basis for operability. Reference 6 states, in part, that the SSCs that TS require to be operable are designed and operated, as described in the CLB [current licensing basis], with design margins and engineering margins of safety to ensure, among other things, that some loss of quality does not result in immediate failure to meet a specified function. The CLB includes commitments to specific codes and standards, design criteria, and some regulations that also dictate margins. Therefore, the underlying assumption that there is margin for degradation of a pump is no longer valid when the pump enters the ASME OM Code action range absent any understanding of the causes of the degradation.

Therefore, the NRC has defined that the required action range for a component is also bounded by any design and engineering margins. When a pump parameter required for a pump by the TSs falls within the required action limit, it should be considered degraded and non-conforming and consequently, licensees must enter the TS Action Statement and evaluate the cause of the degradation. A variety of actions exist to address a nonconforming condition of pump performance being within this required action range. For example, when the required action range is more limiting than its corresponding TSs, the corrective action need not be limited to replacement or repair; it could involve an analysis to demonstrate that the specific performance degradation does not impair operability and that the pump will still fulfill its safety function. The analysis should address the capability of the pump to deliver the required flow for the required mission time. This may allow justification for establishing a new required action range as allowed by the ASME OM Code.

Design Flow and Pressure

TS or design basis testing performed on pumps should demonstrate that they can meet the design requirements. NRC inspections have determined that, for a variety of reasons, ASME OM Code acceptance limits do not always bound the design basis flow and pressure requirements for the system. This is acceptable, but licensees should not be using the ASME OM Code acceptance limits for a TS or design basis test. The IST program engineer, system engineer, and design engineer should all understand and concur with the testing methodology so that the operability of the system can be properly evaluated. Various program requirements are incorporated into test programs and procedures employed by licensees to determine operability, TS surveillance compliance, and ASME OM Code compliance. Unfortunately, these requirements come from different sources and the test results that are evaluated may not be measuring the same flow or pressure attribute.

In order to evaluate the operability of a pump, test results should show, to the maximum extent practical, that the pump will be capable of responding to design basis accidents and events. This should be done through TS or design basis parameter testing. As a minimum, the test results should ensure, either directly or in concert with design calculations, that the minimum acceptable pump performance will provide flow credited in the worst case accident or licensing basis event. The Updated Final Safety Analysis Report defines the design basis accidents and what equipment is credited to respond to events. Typically, the assumed Core Operating Limit Report (COLR) flow rate determines the minimum actual flow requirement for a pump; however, there are other licensing basis events (Fire or Station Blackout) that may determine the most limiting flow rate for a pump. It should be noted that although the analysis methodology used for the COLR has conservatism built into it, the NRC considers the COLR flow rates as the minimum requirements and credit for additional conservatisms within the COLR cannot be used for additional margin. Because the COLR flow rates do not account for inaccuracies, such as measurement error, other analysis must include these inaccuracies to determine the minimum acceptable test flow.

Licensees' TSs also contain minimum flow requirements within the TS surveillance requirements and these flow rates are typically greater than those established in the COLR. The TS minimum flow rates are part of the plant's license and must be met to maintain system operability. The difference between these two flow rates is a result of conservatism accounting for some measurement error within the TS surveillance acceptance limits.

The NRC Inspection Manual, Part 9900 (Reference 1), Technical Guidance, Section 3.0, “Acceptable Measurement Tolerances for Technical Specification Limits,” states:

> “The TS limits are established with allowance for measurement tolerances already incorporated. The limits take into consideration measurement uncertainties as necessary to assure safe plant operation. The stated limit presupposes that the licensees have tolerances consistent with normal industry standards (e.g., ASTM, IEEE, ACI, etc.).”

In general, IST instrumentation inaccuracies are within the limits of the TS surveillance requirements. Therefore, IST test results can be readily compared to TS surveillance requirements to determine if the surveillance was met, as long as the test is measuring the same attribute.

The calculations to determine the design pressure requirements for a pump are typically developed by the licensee. The calculations determine the minimum pump discharge pressure required to meet the assumed flow conditions stated in the COLR. An additional calculation may be needed to determine the discharge pressure required to meet TS surveillance requirements. This pressure is based on the verbiage used in the TS surveillance and these calculations include the worst case design pressures at the pump suction using minimum tank or heat sink level and suction piping head losses at design flows. The calculations should also assume the highest backpressure that would occur at the discharge point of the system. For pumps that discharge into the primary system or steam generators, this should include the safety relief valve pressure plus drifting tolerances. Other variables that should be included in the calculations when determining the minimum acceptable levels for the IST tests are variations in suction sources, maximum assumed vessel pressure, piping and component friction factors, and pressure gauge accuracy.

The ASME OM Code has criteria to establish the flow and differential pressure test point(s) for pumps. The reference flow and/or differential pressure are based, in part, on the design flow rate and discharge pressure requirements of a pump, but the acceptance criteria are based on a percentage increase or decrease in pump performance. There is a potential concern with the developed acceptance criteria because the allowed degradation of a pump in the ASME OM Code, as defined by the “Alert Range” and “Required Action Range,” could result in COLR or design bases pump performance assumptions not being met. Additionally, for centrifugal pumps, the IST test pressure acceptance limits are stated as differential pressure across the pump, while required pressure to ensure adequate flow to the vessel is based on pump discharge pressure limits. Finally, unlike required flow rates, which can be found in licensing basis documents, discharge pressure requirements are determined through design calculations and must include conservative evaluations in the calculation.

Speed Control

The ability to control and adjust the speed of the driver can become critical in determining the flow and pressure limits for a pump. The testing of turbine driven pumps that discharge into the primary system or steam generators is typically not performed and is not required to be performed, at design pressures and flow rates. To ensure that the design bases of the pump can be achieved, the developed test criteria for the quarterly and biennial testing results must be compared to a design calculation to determine pump operability. Typically, pump affinity laws are used to extrapolate the results to verify the ability of a pump to reach the required flow and pressure. For these pumps, it is important to understand the design calculation assumptions and system capabilities to assure that the testing program acceptance criteria are bounding.

One key assumption in the design calculation is the speed of the turbine. NRC inspections have identified that, due to the design or setup of the control circuit of the flow/speed control circuit, licensees' calculations sometimes assume an unachievable increase in the turbine/pump speed. Typically, reactor core isolation cooling (RCIC) and high pressure cooling injection (HPCI) controllers are designed to achieve a preset flow. If the flow is below the setpoint, the controller sends a signal to open the throttle valve until the preset flow is achieved. This will increase pump discharge pressure as the speed of the turbine increases, resulting in additional flow until the design flow is met. However, the controller signal is limited in range and an internal speed control loop is calibrated to not allow speed to increase above a design speed reference. This has resulted in controllers not being able to open the steam admission valve far enough to meet the design flow and pressure requirements because the required speed, perhaps due to pump degradation, was above the maximum output signal of the controller. In this case, the pump IST and TS surveillance tests were met, but the pump, although capable of meeting the design requirements, would not have provided the required flow because it would have been limited by the controller output. This can occur because the existing TSs often only require pump flow rates at normal reactor pressure and not the worst case backpressures as afforded by safety relief valve setpoints.

Because auxiliary feedwater (AFW) turbine system controllers are designed to maintain turbine speed, they are not susceptible to the RCIC and HPCI control issues referenced above, but control of the speed during the testing is important to maintain design assumptions. Typically, these tests are performed by setting the speed manually. Licensees have created operability questions when the speed used in the test is higher than that assumed in the design calculations. Additionally, the AFW quarterly testing is typically performed using minimum flow lines, resulting in flow rates that are much lower than design flow rates. Therefore the results are not readily comparable to design requirements in order to assess pump operability without reviewing pump differential pressure parameters. Understanding the assumptions used to extrapolate pump curves and making adjustments using affinity laws can lead to errors in the evaluation of pump performance. Speed controller errors and measurement errors must also be accounted for in either the design calculation or the test procedure. It is critical to understand the assumptions in the design calculations in order to set the speed range of the test. For ASME OM Code testing, the speed is one of the reference values used for variable speed drives. If the acceptance criterion for speed is higher than the speed assumed in the design calculation or the speed set per the operating procedures, then the pump could be operating outside of its design limits. In this case, the higher speed could result in acceptable IST head and flow results, but these results would not be achieved during a design basis event.

When testing pumps with electric driven motors, speed is assumed to be consistent from test to test and is, therefore, not recorded as part of IST testing. This assumption is appropriate since the offsite grid provides a very consistent 60 Hertz (Hz) to the motors. The NRC has raised questions as to the validity of the motor speed assumption for design calculations because the system shall be operable whether it is supplied from the offsite grid or the onsite emergency diesel generators (EDGs). TS surveillances for EDG regulators generally have a ± 1.2 Hz allowed frequency variation when being tested, which calls into question what speed the motor should be assumed to be operating at during a design basis accident or event. Additionally, NRC inspections have found that some licensees set their EDGs at a frequency other than 60 Hz. Licensees should address the basis for the speed they are using in their design calculations as it relates to electric driven motors.

System Flow Balances

For cooling water systems, licensees have taken two approaches to addressing system operability. Some licensees have developed system models to determine flow to each component. Typically, a licensee will determine the flow and pressure, through actual measurement, at some points in the system to validate the model. Another approach is to perform a system flow balance, which is typically performed during refueling outages. For this method, each component flow must be verified above some predetermined flow rate to establish system operability.

In both approaches, the quarterly IST pump test may be critical to assuring system operability. If the system flow balance method is used, then the licensee has established system operability based on the current pump curve for the pump used in the test. If degradation of the pump is identified, then the basis for operability of the system could be called into question. Licensees should know what flow rate margins exist for components in the system and what level of pump degradation or increase in system dynamic head loss would call into question the previously performed flow balance. Measurement of pump degradation based on ASME OM Code limits may not be indicative of TS system operability.

For the modeling method, the curve used to establish the validity of the model and the curve used to ensure system operability should not be the same curve. The degraded curve, assuming a maximum system head loss, should be used in the model to show bounding pump and system performance. These limits should be evaluated to determine if the ASME OM Code action ranges or the model requirements are the most limiting. The more conservative curve should be used as the acceptance limit in the testing procedures.

Conclusion

Testing of pumps in accordance with the limits established by the ASME OM Code may not be adequate to ensure operability of SSCs. The limiting acceptable conditions for a pump must be understood in order to properly evaluate if the pump is operable and fully qualified. The NRC has found that licensees have incorrectly used IST test procedures limits, established in accordance with the requirements of the ASME OM Code, in order to show compliance with TS surveillance requirements and to demonstrate operability of systems. Although the use of these test procedures may be appropriate for demonstrating operability of safety-related SSCs, they should only be used when the licensee understands the limits of the testing, the assumptions of the associated design calculations, and the way the test procedure is actually performed, including measuring flow, differential pressure, and equipment speed. The implementing pump test procedures should have acceptance limits, which may be different or more limiting than ASME OM Code requirements, which can provide reasonable assurance that the SSCs will be able to respond to the licensee’s design basis accidents and events. These values are often found in TSs or the licensees’ design basis or licensing documents.

References

1. NRC Inspection Manual, Part 9900, Technical Guidance, “Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety.”

2. NUREGs 1430-1434, Standard Technical Specifications- Babcock and Wilcox Plants, Westinghouse Plants, Combustion Engineering Plants, General Electric Plants (BWR/4) and General Electric Plants (BWR/6)

3. Generic Letter 89-04, “Guidance on Developing Acceptable Inservice Testing Programs,” April 3, 1989

4. NUREG-1482, Revision 1, “Guidelines for Inservice Testing at Nuclear Power Plants,” Washington, DC, January 2005

5. NRC Generic Letter 91-18, “Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability,” November 7, 1991

6. Regulatory Issue Summary 2005-20, “Revision to NRC Inspection Manual Part 9900 Technical Guidance, ‘Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions. Adverse to Quality or Safety,’” Revision 1, Washington, DC, April 1, 2008

7. Information Notice 97-90, “Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests,” December 30, 1997

Violations Identified

The following is a list of testing related findings identified by NRC CDBI teams from 2006 to 2011. Inspection reports can be accessed via:

http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/listofrpts_body.html

IST Limits Below Accident Analysis

05000461/2007008 Inappropriate SX Pump Test Acceptance Criteria

Green. The team identified an NCV of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” having very low safety significance, in that, the shutdown service water (SX) pump tests conducted did not appropriately demonstrate that the SX pumps met design basis accident requirements. Specifically, the pump test acceptance criteria allowed the pump performance to degrade below the performance assumed by the design analysis. Once identified, the licensee completed an evaluation. Follow-up retesting demonstrated the pumps’ capacity to perform required safety functions.

05000456/2010007, Non-Conservative Acceptance Criteria for CS Pump Performance Testing

The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” having very low safety significance for the licensee’s failure to ensure adequate acceptance limits were incorporated into test procedures. Specifically, the licensee failed to consider instrument loop uncertainties when determining the alert and required action values used in the IST procedure for testing of the containment spray (CS) pumps. Consequently, the acceptance criteria for both the upper and lower limits on total developed head (TDH) were non-conservative. Specifically, the failure to consider instrument uncertainties in the development of IST acceptance criteria resulted in the creation of acceptance criteria values that did not ensure that the CS pump could meet its intended safety function. As a result, the licensee subsequently entered the issue into their corrective action program, performed an operability evaluation and concluded equipment were operable. Additional corrective actions were assigned to investigate and correct the cause of the apparent degradation of the 2B CS pump.

05000302/2007006 Violation of 10 CFR 50, Appendix B, Criterion XI for Failure to Account for Instrument Uncertainty During EFP-2 Testing

The inspectors identified a finding of very low safety significance involving a violation of 10 CFR 50, Appendix B, Criterion XI, “Test Control,” for failure to implement a test program which accounted for the effects of instrument uncertainty on surveillance testing of Emergency Feedwater Pump (EFP)-2 in accordance with the approved In-service Testing (IST) program.

<u>05000321/366/2009006 Failure to Correctly Establish Acceptance Criteria for the Standby Diesel Service Water Pump Section</u>

The team identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XI, “Test Control,” for failure to correctly establish acceptance criteria for the Standby Diesel Service Water (SDSW) System. The licensee performed a past operability determination and initiated a Condition Report to revise the acceptance criteria.

Modeling and Design Basis Calculations

<u>05000424/425/2008002 Capability of Auxiliary Feedwater System to Meet Design and Licensing Requirements</u>

The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control,” for failure to include the cumulative effects of the replacement of the 1A motor driven auxiliary feedwater (AFW) pump rotating element, accuracy of AFW system resistance values, safety relief valve setpoint tolerances, and turbine driven AFW pump speed settings on evaluation of the performance of the AFW system.

<u>05000382/2006008 Failure to Translate Design Basis Information into Specifications and Procedures</u>

The team identified a finding of very low safety significance for a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” for the failure to translate all design basis information into specifications and procedures were not adequate to assure that instrument uncertainties were correctly accounted for in the development of Technical Specification values or in the surveillance test acceptance criteria.

<u>5000498/499/2007007 Failure to Incorporate Instrument Uncertainties into Surveillance Requirements for Technical Specification Limiting Condition for Operation 3.5.2</u>

The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criteria III, "Design Control," of very low safety significance for the failure to adequately translate design basis information into specifications and procedures. Specifically, measurement instrument uncertainties were not included in the determination of minimum allowed high head safety injection pump and low head safety injection pump developed head values used during periodic technical specification surveillance testing.

05000286/2007006 Non-Conservative Calculation for TDAFW Pump Discharge Pressure Used for Surveillance Testing

The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," in that the licensee had not verified the adequacy of design for the turbine driven auxiliary feedwater (TDAFW) pump. Specifically, the pump hydraulic analysis was non-conservative, but was used to verify adequacy of surveillance test acceptance criteria for pump minimum discharge pressure. The licensee subsequently verified that the pump remained operable and entered the finding into their corrective action program to revise the system analysis.

05000369/370/2008002 Nuclear Service Water (RN) System Flow Analysis Deficiencies

The inspectors identified a NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control,” for failure to establish measures to verify the design capability of the RN pumps. Specifically, the licensee did not perform system hydraulic analyses or use other means to demonstrate that RN pumps 1A and 1B could perform their safety function under the most limiting design basis conditions.

0500305/2007006 Non-Conservative Assumption Used in Service Water Flow Model Calculation

The inspectors identified a finding having very low significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control.” Specifically, the licensee failed to appropriately account for service water strainer plugging in the service water system flow model. Upon discovery, the licensee placed this issue into their corrective action program and planned to formally revise the service water system flow model to reflect plugging of both strainers in a train.

EDG Frequency

05000369/370/2006007 Effect of EDG Under-Frequency not Included in ECCS Pump Test Acceptance Criteria

The team identified a non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” The licensee did not account for emergency diesel generator under frequency in test acceptance criterion for ASME Section XI testing of the high head safety injection (NV) pumps 1A and 1B. The licensee entered this issue into the corrective action program and performed an operability assessment which determined that the pumps were operable.

Speed Control

05000277/278/2006009 Non-Conservative HPCI and RCIC Pumps Test Acceptance Criteria

The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR 50, Appendix B, Criterion XI, Test Control. The team determined that the licensee had failed to ensure that the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) pump hydraulic performance test procedures had acceptance criteria that incorporated the limits from applicable design documents. If the HPCI pump had degraded to the lower limit of the test acceptance criteria, it would not have been able to meet the design basis discharge pressure and flow requirements. Following the identification of the issue the licensee entered the issue into the corrective action program and verified the operability of the pumps based on actual test results. Additionally, the licensee intends to change the test procedures.

NRC Perspective - Transitioning to ASME OM-2009 Division 1, Mandatory Appendix III “Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants” (Formerly ASME OM Code Case OMN-1)

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

Abstract

The American Society of Mechanical Engineers (ASME) has recently issued the 2009 Edition of the Code for Operation and Maintenance of Nuclear Power Plants (OM Code). *(Reference 1)* One of the major changes in the 2009 Edition of the OM Code is the addition of Mandatory Appendix III “Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants” (formerly ASME OM Code Case OMN-1). This paper provides insights from an NRC staff perspective on transitioning to the new ASME OM Code Mandatory Appendix III.

Background

The National Technology Transfer and Advancement Act of 1995 (Public Law 104-113) requires that if agencies establish technical standards, they must use technical standards developed or adopted by voluntary consensus standards bodies unless the use of such standards is inconsistent with applicable law or is otherwise impractical. Public Law 104-113 requires Federal agencies to use industry consensus standards to the extent practical; however, it does not require Federal agencies to endorse a standard in its entirety. The law does not prohibit an agency from generally adopting a voluntary consensus standard while taking exception to specific portions of the standard if those provisions are deemed to be “inconsistent with applicable law or otherwise impractical.”

The ASME OM Code establishes requirements for preservice testing (PST) and inservice testing (IST) and examination of certain components to assess their operational readiness in light-water reactor nuclear power plants. The OM Code was developed and is maintained by the ASME Committee on Operation and Maintenance of Nuclear Power Plants. This document is periodically updated through new Editions and/or Addenda. The ASME OM Code is a national, voluntary consensus standard and Public Law 104-113 requires government agencies to consider its use.

The Code of Federal Regulations (CFR) 10 CFR 50.55a, "Codes and Standards," defines the requirements for applying industry codes and standards to boiling or pressurized water-cooled nuclear power facilities. The NRC applies voluntary consensus standards by approving and mandating the use of Editions and Addenda to the ASME OM Code in 10 CFR 50.55a through the rulemaking process. The first Edition and Addendum to the OM Code that 10 CFR 50.55a incorporated was the 1995 Edition and the 1996 Addendum. The requirements of the OM Code became regulations once they were incorporated into 10 CFR 50.55a. More specifically,10 CFR 50.55a(b)(3)(ii) addresses the incorporation of the ASME OM Code provisions for testing of motor-operated valves (MOVs).

10 CFR 50.55a(b)(3)(ii) (2011 Edition) states that "Licensees shall comply with the provisions for testing motor-operated valves in ASME OM Code ISTC 4.2, 1995 Edition with the 1996 and 1997 Addenda, or ISTC-3500, 1998 Edition through the latest edition and addenda incorporated by reference in paragraph (b)(3) of this section, and shall establish a program to ensure that motor-operated valves continue to be capable of performing their design basis safety functions."

The 10 CFR 50.55a(b)(3)(ii) requirement has two elements:

1. Plant IST programs must meet the ASME OM Code requirements
2. Plants must have an MOV program that provides continued assurance of the capability of MOVs to perform their design basis safety functions

The second element was a direct result of Generic Letters (GL) GL 89-10, *(Reference 2),* GL 95-07, *(Reference 3),* and GL 96-05 *(Reference 4).* GL 89-10 requested licensees to verify the design basis capability of their safety-related MOVs by dynamic testing where practicable. GL 95-07 requested licensees to address concerns of potential pressure locking and thermal binding of power-operated gate valves. GL 96-05 requested licensees to develop programs to periodically verify MOV design basis capability. The provisions in GL 96-05 superseded GL 89-10.

The ASME OM Code subgroup committee for MOVs combined these two elements by developing ASME OM Code Case OMN-1, “Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light Water Reactor Power Plants OM Code-1995, Subsection ISTC.” A Case is the official ASME method of handling a reply to an inquiry when study indicates that the Code wording needs clarification, or grants permission to use alternative methods. Code Cases are written as a question and a reply, and are usually intended to be incorporated into the Code at a later date. A Code Case is not considered a part of the ASME OM Code or its addenda. ASME has agreed to publish Cases issued by the Operation and Maintenance Committee concerning the OM Code as part of the updated service to the OM Code. The ASME OM Code Case OMN-1 original inquiry and reply was as follows:

> *Inquiry:* What alternative rules, to those of OM Code, Subsection ISTC, may be used for preservice and inservice testing to assess the operational readiness of certain electric motor-operated valve assemblies in light-water reactor power plants?
>
> *Reply:* It is the opinion of the Committee that, in lieu of the rules for preservice and inservice testing to assess the operational readiness of certain electric motor-operated valve assemblies in light-water reactor power plants in OM Code-1995*,* Subsection ISTC, except for ISTC 4.3, the following alternative requirements may be applied. Electric motor-operated valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their required function (Category A) must also be seat leakage rate tested in accordance with the requirements of ISTC 4.3.

The NRC staff reviews Code Cases and publishes a listing of Code Case acceptability in Regulatory Guide (RG) 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code” *(Reference 5).* Cases found to be unacceptable are listed in RG 1.193 “ASME Code Cases Not Approved For Use” *(Reference 6).* Approved Code Cases may be used by licensees without submitting a request to the NRC, provided they are used with any identified limitations or modifications. OM Code Cases not yet endorsed by the NRC may be implemented through 10 CFR 50.55a(a)(3), which permits the use of alternatives to the Code requirements referenced in 10 CFR 50.55a provided the proposed alternatives result in an acceptable level of quality and safety and provided their use is authorized by the NRC.

ASME OM Code, 2009 Edition, Mandatory Appendix III is the end result of ASME OM Code Case OMN-1 which was written in 1995 and first appeared as a supplement to ASME OMa Code 1996 Addenda. The supplement was not considered part of the OM Code but was included in the 1996 Addenda as a convenience to the end user. The NRC staff reviewed and approved, with conditions, the use of ASME OM Code Case OMN-1. OMN-1 was revised in the ASME OM Code 2001 Edition. The revision was very minor in nature and did not change the technical content or methodology. The changes included an update to the Code Case expiration date and a few editorial language improvements. OMN-1 was revised again in the ASME OMb Code 2006 Addenda. This time, the revision was a major change which incorporated years of feedback and assessments to improve the overall alternative testing approach. The NRC staff reviewed the revision made in the 2006 Addenda and concluded that the alternative continued to be acceptable with conditions. RG 1.192 is currently being revised to update Code Case acceptability for OMN-1 and other ASME Code Cases. In the ASME OM Code 2009 Edition, OMN-1 was revised again with a minor change. The change was minor in detail in that it removed reference margin flow charts but did not alter technical content or methodology. The name of the Code Case was updated to a standard ASME format designating a revision change and the resulting name of the latest Code Case revision is OMN-1-1. This latest update was published as a supplement to the ASME OM Code 2009 Edition. For those end users who desire the reference margin flow charts, OMN-1 was also published in the ASME OM Code 2009 Edition. OMN-1-1 was incorporated into ASME OM Code 2009 Edition as Mandatory Appendix III. Appendix III also incorporates ASME OM Code Case OMN-11 that addresses risk-informed aspects for implementing Code Case OMN-1.

During the next update to 10 CFR 50.55a, the NRC staff will evaluate the incorporation by reference of ASME OM Code 2009 Edition, including Mandatory Appendix III. The NRC staff will determine whether to include any modifications or limitations for the implementation of ASME OM Code 2009 Edition. As part of this review, the staff will determine whether any conditions in RG 1.192 regarding the acceptance of ASME OM Code Cases OMN-1 and OMN-11 need to be included in 10 CFR 50.55a for the implementation of Mandatory Appendix III to the ASME OM Code 2009 Edition.

NRC Staff Perspective

There have been many industry questions and/or concerns about transitioning to Mandatory Appendix III requirements. The following discussion will attempt to answer those questions and/or concerns from an NRC staff perspective. The information being provided by this perspective must not be confused with interpretation of the ASME OM Code requirements. End users with interpretation questions must follow the process of submitting their inquiries to the ASME OM Code Committee. The following NRC staff perspective analysis reviews each section of Mandatory Appendix III and provides an applicable comment.

Division 1, Mandatory Appendix III
Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants

III-1000 INTRODUCTION

III-1100 Applicability

This Mandatory Appendix establishes the requirements for preservice and inservice testing to assess the operational readiness of active motor-operated valves (MOVs) in light-water reactor (LWR) power plants.

> **Comment:** Per ASME OM Code 2009 Edition Subsection ISTA, (General Requirements), paragraph ISTA-1100 (Scope), bullet (a), "These requirements apply to pumps and valves that are required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, in mitigating the safe shutdown condition, or in mitigating the consequences of an accident." Licensees are cautioned to review the population of MOVs that are required to meet this action statement. The IST program scope may not be the same scope that was specified for addressing GL 89-10 and GL 96-05 concerns. Licensee IST and MOV program engineers should consult their licensing basis.

III-1200 Scope
See para. ISTC-1200.

> **Comment:** Paragraph ISTC-1200 specifies valves that may be exempt from the test requirements. Questions or clarification of this section should be forwarded to the ASME OM Code Committee for interpretation.

III-2000 SUPPLEMENTAL DEFINITIONS

full cycle exercise: *full stroke of the valve from and back to its initial position.*
motor-operated valve (MOV): *a valve and its associated electric motor driven mechanism for positioning the valve, including components that control valve action and provide position output signals*
MOV functional margin: *the increment by which an MOV's available capability exceeds the capability required to operate the MOV under design basis conditions.*
stem factor: *the ratio of stem torque to stem thrust in rising-stem valves.*

> **Comment:** None.

III-3000 GENERAL TESTING REQUIREMENTS

III-3100 Design Basis Verification Test

A one-time test shall be conducted to verify the capability of each MOV to meet its safety-related design basis requirements. This test shall be conducted at conditions as close to design basis conditions as practicable. Requirements for a design basis verification test are specified in applicable regulatory documents. Testing that meets the requirements of this Mandatory Appendix but conducted before implementation of this Mandatory Appendix may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.
(b) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an engineering analysis shall be documented that supports applicability to the in situ conditions.
(c) Justification for testing at conditions other than design basis conditions and for grouping like MOVs shall be documented by an engineering evaluation, alternate testing techniques, or both. Where design basis testing of the specific MOV being evaluated is impracticable or not meaningful (provides no additional useful data), data from other MOVs may be used if justified by engineering evaluation. Sources for the data include other plant MOVs or test data published in industry testing programs. Where analytical techniques are used to verify design basis capability, those techniques shall be justified by an engineering evaluation.
(d) For certain valve types (i.e., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an engineering evaluation of operating experience may be used to verify design basis capability.
(e) The design basis verification test shall be repeated if an MOV application is changed, the MOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an engineering evaluation, alternative testing techniques, or both.

> **Comment:** This Code provision requires the demonstration of design-basis capability for each MOV within the IST program. Following the initial demonstration of MOV design-basis capability, the IST program will maintain the design-basis capability by periodic exercising and diagnostic testing. For those MOVs within the scope of the GL 89-10 and GL 96-05 programs, the testing and/or engineering analysis performed to close out those generic letter concerns may be used to meet

this requirement. For MOVs that were outside of the scope of GL 89-10 and GL 96-05 but within the IST program, a one time test and/or engineering analysis is required. In both cases, it is expected that licensees will have the design basis verification test and/or engineering evaluation analysis formally documented for each MOV in the IST program.

III-3200 Preservice Test

Each MOV shall be tested during the preservice test period or before implementing inservice testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Mandatory Appendix but conducted before implementation of this Mandatory Appendix may be used. Only one preservice test of each MOV is required unless, as described in para. II-3400, the MOV has undergone maintenance that could affect its performance.

> **Comment:** This paragraph has the same requirements as ISTC-3100. There is no impact or change in requirements when transitioning to Mandatory Appendix III.

III-3300 Inservice Test

Inservice testing shall commence when the MOV is required to be operable to fulfill its required function(s), as described in para. III-1100, and shall be sufficient to assess changes in MOV functional margin consistent with section III-6000.
(a) MOVs may be grouped for inservice testing as described in para. III-3500.
(b) Inservice tests shall be conducted in the as-found condition. Activities shall not be conducted if they invalidate the inservice test results. If maintenance is needed between the inservice tests, see para. III-3400. As-found testing is not required prior to maintenance activities as long as the MOV is not due for an inservice test. If maintenance activities are scheduled concurrently with an MOVs inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity.
(c) The inservice testing program will include a mix of static and dynamic MOV performance testing. The mix of MOV performance testing may be altered when justified by an engineering evaluation of test data.
(d) Dynamic MOV performance testing is not required for certain valve types (i.e., ball, plug, and diaphragm valves), with acceptable operating experience.
(e) Remote position indication shall be verified locally during inservice testing or maintenance activities.

Comment: Inservice testing shall commence when the MOV is required to be operable. Grouping is allowed as discussed. Inservice testing shall be conducted in the as-found condition. This is an important aspect of the MOV test program. The gathering of as-found test data helps to validate design assumptions, such as stem-to-stem nut coefficient of friction, packing loads, and actuator efficiencies. The test program will include a mix of static and dynamic testing. Engineering evaluation of static and dynamic test data can justify altering the mix of static and dynamic valve testing. For those plants that participated in the Joint Owners Group (JOG) MOV Periodic Verification Program, the licensee can rely on the engineering evaluation based on the MOV dynamic testing program conducted by the JOG to support its mix of static and dynamic testing. The JOG program is described in the JOG final program document MPR-2524-A *(Reference 7).* Participating JOG plants must implement the recommendations of the final JOG program document consistent with the NRC safety evaluation report dated September 2006 and its supplement dated September 2008 (*Reference 8)*. The MPR-2524-A engineering evaluation does not eliminate the need for dynamic testing completely. Should a valve be subjected to a change in valve service conditions and/or have a modification or repair which would disallow the valve's qualifying basis, dynamic testing would be required to establish the new basis for the valve. Further, some MOVs or their service conditions are outside the scope of the JOG program. Licensees will be responsible for establishing activities that satisfy Mandatory Appendix III for those MOVs or their service conditions.

III-3310 Inservice Test Interval.

The inservice test interval determination shall include the following:
(a) The inservice test interval shall be determined in accordance with para. III-6440.
(b) If insufficient data exist to determine the inservice test interval in accordance with para. III-6400, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer inservice test interval.
(c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per para. III-3400 may be used to satisfy this requirement.

Comment: The IST interval for determining static and dynamic tests shall be determined in accordance with paragraph III-6440. The specified test interval of every two refueling cycles or 3 years (whichever is longer) until sufficient data exists to justify a longer test interval for a MOV or MOV group is an acceptable approach. The adequacy of the diagnostic test interval for each MOV must be evaluated and adjusted as necessary, but not later than 5 years or three refueling outages (whichever is longer) from initial implementation. The maximum inservice test interval shall not exceed 10 years. As of today, industry data cannot support extension beyond the current 10 year limit. However, this topic can be revisited and the Code updated when sufficient data exists. For applicable licensees, the JOG program includes provisions for testing intervals for those MOVs within the scope of the program.

III-3400 Effect of MOV Replacement, Repair, or Maintenance

When an MOV or its control system is replaced, repaired, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined, or the previously established inservice test values shall be confirmed before the MOV is returned to service. If the MOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required after replacement, repair, or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in section III-9000, Records and Reports.

Comment: This paragraph has the same requirements as ISTC-3310. There is no impact or change in requirements when transitioning to Mandatory Appendix III.

III-3500 Grouping of MOVs for Inservice Testing

Grouping MOVs for inservice testing is permissible. Grouping MOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping MOVs:
(a) MOVs with identical or similar motor-operators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of MOVs shall be validated by appropriate inservice testing of one or more representative valves.
(b) Test results shall be evaluated and justified for all MOVs in the group.

Comment: As noted in the comments on Section III-3300, the JOG final program document MPR-2524-A (Reference 7) is an example of an engineering evaluation where valves are grouped into classifications based on key parameters:

- Type of valve

- Type of DP stroking the valve undergoes
- Disk-to-seat materials
- Disk-to-body guide materials
- Type of fluid in system
- Valve factor or apparent disk-to-seat coefficient of friction
- Shaft material
- Bearing material
- Presence or absence of a hub seal
- Bearing friction coefficient

These key parameters, coupled with the valve risk and margin, help identify applicable test intervals.

III-3600 MOV Exercising Requirements

III-3610 Normal Exercising Requirements. *All MOVs, within the scope of this Mandatory Appendix, shall be full cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 mo. Full cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full stroke exercising of an MOV is not practical during plant operation or cold shutdown, full stroke exercising shall be performed during the plant's refueling outage.*

III-3620 Additional Exercising Requirements. *The Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:*
(a) MOVs with high risk significance,
(b) MOVs with adverse or harsh environmental conditions, or
(c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions).

> **Comment:** These requirements represent a change from the quarterly stroke time testing previously required in ASME OM Code section ISTC-3500 and ISTC-3510. The licensee must consider the impact on its Probabilistic Risk Analysis regarding changes of the exercise interval from quarterly to every 24 months for MOVs with high risk significance. The licensee must consider the impact on MOV performance when modifying the exercise interval, such as high temperature areas that might degrade the stem lubricant or gearbox grease.

III-3700 Risk-Informed MOV Inservice Testing

Risk-informed MOV inservice testing that incorporates risk insights in conjunction with performance margin to establish MOV grouping, acceptance criteria, exercising requirements and testing interval may be implemented.

III-3710 Risk-Informed Considerations. *The Owner shall consider the following when incorporating risk insights in the inservice testing of MOVs:*
(a) develop an acceptable risk basis for MOV risk Determination
(b) develop MOV screening criteria to determine each MOVs contribution to risk
(c) finalize risk category by a documented evaluation from a Plant Expert Panel

III-3720 Risk-Informed Criteria. *Each MOV shall be evaluated and categorized using a documented risk ranking methodology. This Mandatory Appendix provides test requirements for high and low safety significant component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.*

III-3721 HSSC MOVs. *HSSC MOVs shall be tested in accordance with para. III-3300 and exercised in accordance with para. III-3600. HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer exercise interval is small.*

III-3722 LSSC MOVs. *In meeting the provisions of this Mandatory Appendix, including exercising in accordance with para. III-3600 and the determination of proper MOV test interval in section III-6000, risk insights shall be applied to inservice testing of LSSC MOVs by the following:*
(a) LSSC grouping shall be technically justified, but the provision for similarity in subpara. III-3500(a) may be relaxed. The provisions in subpara. III-3500(b) related to evaluation of test results for MOVs in that group continue to be applicable to all MOVs within the scope of this Mandatory Appendix.
(b) LSSC MOVs may be associated with an established group of other MOVs. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with section III-6000, and applied to all LSSC MOVs associated with that group.
(c) LSSC MOVs that are not associated with an established group shall be inservice tested, in accordance with para. III-3300, using an initial test interval of three refueling

cycles or 5 yr (whichever is longer) until sufficient data exist to determine a more appropriate test interval as described in para. III-6440.
(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with para. III-3310.

> **Comment:** These requirements incorporate OM Code Case OMN-11, Rev. 0, reaffirmed 1999A Addenda. RG 1.192 accepted the use of Code Case OMN-11 with conditions.

III-4000 TO BE PROVIDED AT A LATER DATE

> **Comment:** None

III-5000 TEST METHODS

III-5100 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

III-5200 Test Conditions

Test conditions shall be sufficient to determine the MOV's functional margin per para. III-6400. Test conditions shall be recorded for each test per section III-9000.

III-5300 Limits and Precautions

Testing limits and precautions include
(a) MOV exposure to dust, moisture, or other adverse conditions shall be minimized when normally enclosed compartment covers are removed while performing tests.
(b) Manufacturer or vendor limits and precautions associated with the MOV and with the test equipment shall be considered, including the structural thrust and torque limits of the MOV.
(c) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.
(d) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the MOV by the particular testing performed.

III-5400 Test Documents

Approved plant documents shall be established for all tests specified in this Mandatory Appendix and shall provide for
(a) methodical, repeatable, and consistent performance testing
(b) collection of data required to analyze and evaluate the MOV functional margin in accordance with section III-6000

III-5500 Test Parameters

Sufficient test parameters shall be selected for measurement to meet the requirements of section III-6000 in determining the MOV functional margin.

> **Comment:** The requirements for sections III-5000, III-5100, III-5200, III-5300, III-5400, and III-5500 represent common elements found in ASME OM Code Section ISTA and ISTC, GL 89-10, GL 96-05, and 10 CFR 50 Appendix B. Plants transitioning to Mandatory Appendix III should have no to minor impact with meeting these requirements for MOVs addressed as part of the GL 89-10 and GL 96-05 programs.

III-6000 ANALYSIS AND EVALUATION OF DATA

III-6100 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each MOV within the scope of this Mandatory Appendix. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the valve operating requirements. Thrust, torque, or other measured engineering parameters correlated to thrust or torque consistent with paras. III-6100 through III-6500, may be used to establish the acceptance criteria. Motor control center testing is acceptable if correlation with testing at the MOV has been established. When determining the acceptance criteria, consider the following sources of uncertainty:
(a) test measurement and equipment accuracy
(b) valve and actuator repeatability (e.g., torque switch repeatability)
(c) analysis, evaluation, and extrapolation method
(d) grouping method

III-6110 Parameter Measurements. *MOV margins may be expressed in terms of stem force or other parameters, if those parameters are consistent with paras. III-6100 through III-6500.*

III-6200 Analysis of Data

Data obtained from a test required by this Mandatory Appendix, shall be analyzed to determine if the MOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each MOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per para. III-6430, does not meet the acceptance criteria, the MOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

III-6300 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each MOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating MOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable MOVs to establish appropriate time intervals for future test activities.

> **Comment:** The requirements for sections III-6000, III-6100, III-6110, III-6200, and III-6300 represent common elements found in ASME OM Code Section ISTA and ISTC, GL 89-10, GL 96-05, and 10 CFR 50 Appendix B. Plants transitioning to

Mandatory Appendix III should have no to minor impact with meeting these requirements for MOVs addressed as part of the GL 89-10 and GL 96-05 programs.

III-6400 Determination of MOV Functional Margin

The Owner shall demonstrate that adequate margin exists between valve operating requirements and the available actuator output capability to satisfy the acceptance criteria for MOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in MOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

III-6410 Determination of Valve Operating Requirements.

Design basis valve operating requirements, including stem factor for rising stem valves, shall be determined from
(a) measurements taken during testing at design basis conditions, or
(b) analytical methods using valve parameters determined from testing at conditions that may be extrapolated to design basis conditions, or
(c) application of justified industry methodologies.

III-6420 Determination of Actuator Output Capability

III-6421 Available Output Based on Motor Capabilities. *Available actuator output shall be determined based on motor capabilities at the motor's design basis conditions. Considerations shall include*
(a) rated motor start torque
(b) minimum voltage conditions
(c) elevated ambient temperature conditions
(d) operator efficiency
(e) other appropriate factors

III-6422 Available Output Based on Torque Switch Setting. *Where applicable, the available output shall be determined based on the current torque switch setting. For MOVs where testing does not sufficiently load the MOV to cause torque switch trip (e.g., butterfly and ball valves), available output based on the current torque switch setting shall be determined analytically from test data. Considerations shall include*
(a) calibration of the torque switch spring pack
(b) the current torque switch setting
(c) repeatability of torque switch operation

III-6430 Calculation of MOV Functional Margin. *MOV functional margin shall be calculated as the difference between the available actuator output and valve operating requirements. Available actuator output is determined as*
(a) design basis motor operator capability for limit switch controlled strokes, or
(b) the lesser of design basis motor operator capability or motor operator capability at the current torque switch setting for torque switch controlled strokes

III-6440 Determination of MOV Test Interval. *Calculations for determining MOV functional margin shall account for potential performance related degradation. Maintenance activities and associated intervals can affect test intervals and shall be considered. The inservice test interval shall be set such that the MOV functional margin does not decrease below the acceptance criteria.*

> **Comment:** The requirements for sections III-6400, III-6410, III-6420, III-6421, III-6422, III-6430, and III-6440 represent common elements found in GL 89-10, and GL 96-05. Plants transitioning to Mandatory Appendix III should have no to minor impact with meeting these requirements for MOVs addressed as part of the GL 89-10 and GL 96-05 programs. For those plants that participated in the JOG, valve test intervals are based upon valve classification, risk, and margin. For those valves or their service conditions that were not covered by the JOG program, the requirements of III-3310 apply until sufficient test data is available to determine the test interval.

III-6500 Corrective Action

If the MOV performance is unacceptable, as established in para. III-6400, corrective action shall be taken in accordance with Owner's corrective action requirements.

III-6510 Record of Corrective Action. *The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.*

> **Comment:** The requirements for sections III-6500, and III-6510 represent common elements found in ASME OM Code Section ISTA and ISTC. Plants transitioning to Mandatory Appendix III should have no to minor impact with meeting these requirements.

III-7000 TO BE PROVIDED AT A LATER DATE

Comment: None

III-8000 TO BE PROVIDED AT A LATER DATE

Comment: None

III-9000 RECORDS AND REPORTS

III-9100 Test Information

Pertinent test information shall be recorded or verified for MOV testing, described in section III-3000. The following information shall be considered along with the information requirements in ISTA/ISTC:
(a) MOV plant-specific unique identification number.
(b) motor, valve, actuator nameplate data.
(c) test equipment unique identification numbers and equipment calibration dates.
(d) test method and conditions, described in section III-5000, including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, electric motor-operator orientation, and piping configuration near the MOV.
(e) breaker setting/fuse size and motor starter thermal overload size, if used.
(f) MOV torque and limit switch configuration and settings.
(g) MOV performance test procedure and other approved plant documents containing acceptance criteria.
(h) name of test performer and date of test.
(i) system flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.
(j) significant observations: any comments pertinent to the test results that otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic MOV action noted either during or preceding performance testing and any other pertinent design information that can be verified at the MOV.

III-9200 Documentation of Analysis and Evaluation of Data

The documentation of acceptable MOV performance, which has been analyzed and evaluated in accordance with section III-6000, shall include, as a minimum:

(a) values of test data, test parameters, and test information established by paras. III-5500 and III-9100
(b) summary of analysis and evaluation required per paras. III-6200 and III-6300
(c) statement(s), by an individual qualified to make such a statement through the Owner's qualification requirements, confirming that the MOV is capable of performing its intended safety function
(d) test results and analysis shall be evaluated by qualified individuals and documented to include signature and date. Independent verification shall be by individuals qualified to verify those specific analyses and evaluations through the Owner's qualification requirements.

> **Comment:** The requirements for sections III-9000, III-9100, and III-9200 represent common elements found in ASME OM Code Section ISTA and ISTC, and GL 89-10 and GL 96-05. Plants transitioning to Mandatory Appendix III should have no to minor impact with meeting these requirements for MOVs addressed as part of the GL 89-10 and GL 96-05 programs.

Conclusion

ASME OM Code-2009 Mandatory Appendix III specifies provisions for testing MOVs to provide assurance that they are capable of performing their safety-related function. Mandatory Appendix III incorporates the guidance in ASME OM Code Cases OMN-1 and OMN-11 to replace quarterly stroke-time testing with periodic exercising and diagnostic testing. The NRC staff accepted Code Cases OMN-1 and OMN-11 with conditions in RG 1.192. The NRC staff will evaluate whether any limitations or modifications are necessary for the implementation of Mandatory Appendix III when ASME OM Code 2009 Edition is incorporated into 10 CFR 50.55a. Plants that are transitioning to ASME OM-2009 Edition Mandatory Appendix III are reminded that questions concerning interpretation of the OM Code requirements must be directed to the ASME OM committee.

References

1) ASME OM-2009 Code for Operation and Maintenance of Nuclear Power Plants

2) USNRC Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"

3) USNRC Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves"

4) USNRC Generic Letter 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Power-Operated Valves

5) USNRC Regulatory Guide 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code”

6) USNRC Regulatory Guide 1.193, “ASME Code Cases Not Approved For Use”

7) MPR Associates Inc. topical report MPR-2524-A, “Joint Owners Group (JOG) Motor Operated Valve Periodic Verification Program Summary”

8) USNRC Safety Evaluation Report dated September 2006 on JOG MOV Periodic Verification Program and its supplement dated September 2008.

History of the ASME Code and NRC Regulatory Requirements with Respect to Inservice Testing of Pumps and Valves

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

Abstract

The Code of Federal Regulation Section 10 CFR 50.55a requires that certain American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3 pumps and valves meet the inservice testing (IST) requirements specified in the applicable ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code). The regulation also requires that an initial 10-year program be established for the IST of pumps and valves which must be updated every ten years to meet the latest applicable ASME OM Code requirements incorporated by reference in 10 CFR 50.55a. During the 1980s, these IST programs, including relief and alternative requests, were submitted to the NRC for review and approval. The NRC review of IST programs entailed verifying that the program was based on the applicable ASME Code Edition and Addenda, and that the program covered testing of all appropriate pumps and valves, and that relief and alternative requests were authorized in accordance with regulatory requirements. The NRC completed its review of all IST programs around 1995. Once the reviews of the IST programs and associated relief and alternative requests were completed, subsequent reviews of the ten year updates were limited to changes to previously approved programs. This primarily involved new relief and alternative requests from revised OM Code requirements or modified relief and alternative requests to existing ones. Since around 1995, the NRC spent most of its resources reviewing new proposed or modified relief and alternative requests

In 1971, the ASME Boiler and Pressure Vessel Code (ASME Code), Section XI requirements were incorporated by reference into 10 CFR 50.55a. The IST requirements were approved in 1973 by ASME and incorporated into Subsections IWP and IWV of the ASME Code, Section XI. These IST requirements have been in existence for 40 years and have been required to be implemented in the design and operation of nuclear power facilities. This paper summarizes the history, development,

and evolution, as well as implementation of the ASME Codes and NRC requirements with respect to IST of pumps and valves.

Introduction

Prior to 1954, atomic energy was only allowed to be for military use. Since the Atomic Energy Act of 1954 was enacted, which declared that atomic energy may be used for free competition in private enterprise, nuclear power energy became a hot commodity and many utilities in the electric power industry wanted to engage in building nuclear power plants. By the end of 1970, the regulatory group in the Atomic Energy Commission (AEC), which was renamed the Nuclear Regulatory Commission (NRC) by the Energy Reorganization Act of 1974, had issued construction permits (CPs) and operating licenses (OLs) to 109 plants. By comparison, in the next four decades, only 48 CPs were issued. Today we have 103 plants in operation, and the rest of the plants with CPs or OLs were either cancelled, shutdown, or decommissioned.

Back in the early 1960s, the reactor vessel received much of the attention of the AEC and industry. Various standards and inspection requirements were developed and incorporated into ASME Code, Section XI to ensure the safety and integrity of the reactor vessel. However, in the late 1960s, it became apparent that other safety-related components (e.g., pumps and valves) also played a very important role in keeping and maintaining safe operation and safe shut down of nuclear reactors. To ensure the operational readiness of safety-related pumps and valves, the AEC and the nuclear industry recognized that certain functional or performance testing needed to be developed and required for these pumps and valves. In the late 1960s, the AEC and the industry developed a proposal for an inservice testing (IST) program of pumps and valves. Based on the proposal, the IST requirements were approved in 1973 by ASME and incorporated into the ASME Code, Section XI in Subsection IWP, for pumps, and Subsection IWV, for valves.

Since 1971, the IST requirements for pumps and valves have come a long way from a dozen pages in the ASME Code, Section XI, to ten times this size in a stand-alone document in the current ASME OM Code. The following summarizes the history, development, and evolution as well as implementation of the ASME Codes and the NRC requirements with respect to IST of pumps and valves.

ASME Code Requirements

As the industry identified that pumps and valves in nuclear power plants would have important safety function roles, the ASME started work to develop an industry standard for IST of these pumps and valves. A draft standard was developed around 1970, and an approval from the ASME was obtained in 1971 to include the draft standard in the ASME Code, Section XI. In the Summer 1973 Addenda of the ASME Code, Subsections, IWP on pumps, and IWV on valve testing, were approved by ASME and added to Section XI. In 1975, a new ASME Operations and Maintenance of Nuclear Power Plants (O&M) Committee was formed to review and update the Section XI requirements specifically for IST of pumps and valves for operating plants. To facilitate the review in these areas, the previous Section XI subgroup on pumps and valves was transferred to the ASME O&M Committee in 1979 and a new Working Group under the ASME O&M Committee was established in 1984 to review and develop pump and valve standards. In 1987, ASME O&M developed and published two standards, Part 6 for pumps and Part 10 for valves (later renamed OM-6 and OM-10). These two standards were approved by the American National Standards Institute (ANSI) on July 14, 1988, and added to ASME/ANSI OM-1987, which was incorporated by reference in the 1989 Edition of the ASME Code, Section XI. In 1990, a transition was implemented in which OM Part 6 and OM Part 10 were incorporated into the ASME OM Code-1990, ”Code for Operation and Maintenance of Nuclear Power Plants.” This ASME OM-1990 is a replica of OM-6 and OM-10 and was issued in 1991 to replace the ASME Code, Section XI, Subsections IWP and IWV.

The ASME O&M Committee was chartered to develop, revise, and maintain codes and standards applicable to the safe operation of nuclear power plants. The committee’s persistent and devoted effort to seek and select improved testing methods, parameters, acceptance criteria, and innovative techniques that accomplished the intended objectives of IST has resulted in frequent updates and revisions to the ASME OM Code requirements.

1. History and Updates of ASME Code Requirements for Pumps

Prior to 1976, Subsection IWP of the ASME Code, Section XI required that IST of pumps be performed on a monthly basis. At that time, a monthly pump test was in agreement with the system-oriented pump test schedule required by plant technical specifications (TS). These TS pump tests were normally performed at close to pump design flow rate. Around 1976, IST of pumps in accordance with ASME Code, Section XI requirements was being implemented for all safety-related pumps including certain standby pumps. During the first three years of implementation, certain pumps were being over tested and resulted in unacceptable accelerated degradation, particularly for standby pumps that were being tested on mini-flow test lines. Therefore, the ASME Section XI Code Committee proposed that this test frequency be changed to quarterly.

The NRC concurred with the proposed test interval as specified in 1979 Winter Addenda to the ASME Code, Section XI.

In 1983, and 1986, ASME Code, Section XI was updated but no significant changes were introduced in Subsection IWP. However, in the 1988 Addenda, Subsection IWP was replaced by ASME/ANSI OM Part 6, later renamed OM-6, which was incorporated as Subsection ISTB into the ASME OM Code-1990. The following are major changes contained in Subsection ISTB:

- Deleted suction pressure, bearing temperature and lubrication requirements
- Specified different acceptance criteria for centrifugal, vertical line shaft, and positive displacement pumps
- Changed the run time between stabilization and data collection from five minutes to two minutes
- Provided vibration acceptance criteria in velocity units
- Increased the upper end acceptable range of pressure differential or flow rate from 1.03 to 1.10

In 1995, the ASME OM Code-1990 was updated and the following major changes were incorporated into Subsection ISTB of the ASME OM Code-1995:

- Pumps were reclassified in Group A and Group B, and the pump tests were classified into Group A, Group B, and Comprehensive tests.
- Different test requirements and acceptance criteria were specified for centrifugal, vertical line shaft, and non-reciprocating/reciprocating positive displacement pumps.
- Instrument accuracy of pressure and pressure differential measurements for comprehensive tests were tightened from ± 2% to ±1/2%.

From 1996 to present, no significant changes in the ASME OM Code have been made for IST of pumps.

2. History and Updates of ASME Code Requirements for Valves

Prior to 1976, IST specified in Subsection IWV of ASME Code, Section XI was required for all ASME Code Class 1, 2, and 3 valves, and seat leakage tests were also required for all Category A valves including containment isolation valves.

In 1983, and 1986, ASME Code, Section XI was updated but no significant changes were made to Subsection IWV. However, in the 1988 Addenda, Subsection IWV was replaced by ASME/ANSI OM Part 10, later renamed OM-10, which was incorporated as Subsection ISTC into the ASME OM Code-1990. The following are major changes contained in Subsection ISTC:

- Clarified the scope and included relief valves
- Allowed testing of certain check valves to be extended to a refueling outage frequency
- Changed the acceptance criteria for stroke time testing of power operated valves
- In lieu of quarterly exercise testing, allowed disassembly, reassembly and inspection to be used for check valve testing on a refueling outage frequency
- Identified testing requirements in OM-1 for safety/relief valves
- Deleted containment isolation valves from IST leak testing requirements
- Deleted trending and corrective action from leak testing requirements for Category A valves
- Started issuing OM Code Cases for acceptable alternatives to ASME OM Code requirements

In 1998, the ASME OM Code-1990 was updated and the following major changes were incorporated into Subsection ISTC of the ASME OM Code-1998:

- Added bi-directional testing requirements for check valves

- Specified separate testing requirements for motor-operated valves, pneumatically-operated valves, hydraulically-operated valves, and solenoid-operated valves

- Added allowance for a Condition Monitoring Program as an acceptable alternative to check valve testing

- Added test requirements for manual valves

- Added instrumentation requirements for valve testing

In 2000, manual valve test requirements were added to ASME OM Code-2000 and were required to be performed every five years. In 2006, the test frequency for manual valves was reduced to every two years. This revision was incorporated into the ASME OM Code-2009. In ASME OM Code-2009, another update was added with mandatory Appendix III testing requirements for active electric motor-operated valves (MOVs).

NRC Regulatory Requirements

1. History of 10 CFR 50.55a

In 1971, the ASME Code, Section XI requirements were incorporated by reference into 10 CFR 50.55a. In 1977, major revisions were made to reflect which 10 CFR 50.55a requirements licensees needed to meet depending on when their construction permit (CP) was issued. For CPs issued prior to January 1, 1971, 10 CFR 50.55a(g)(1) required that the components shall meet the IST requirements for pumps and valves to the extent practical. This is because prior to 1971, there were no regulatory requirements to perform IST and for the handful nuclear power plants in operation, IST of pumps and valves were addressed and required by “custom” plant technical specifications. For CPs issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) required that the plant be designed and provided with access to perform IST tests set forth in ASME Code, Section XI in effect six months prior to the date of the CP issuance. This was because the IST requirements for pumps and valves had been published by ASME for six months and had been incorporated into 10 CFR 50.55a(g) at the time when the CP was issued. For CPs issued on or after July 1, 1974, the applicant should have been fully aware of the IST requirements and therefore, 10 CFR 55.55a(g)(3) required that the plant be designed to implement all applicable IST requirements that were set forth in ASME Code, Section XI or the ASME OM Code at the time when the CP was issued.

Another significant change to 10 CFR 50.55a that was introduced in 1977 was the 40-month update requirement which was later modified in 1980 to a ten-year update requirement. 10 CFR 55.55a(g)(4)(i) required that an IST program be updated every 10 years to comply with the IST requirements of the latest Code incorporated by reference in 10 CFR 50.55a. The NRC expected that as time went on, better and improved codes and standards would be developed by the ASME, and implementation of these updated codes offered the potential to improve IST effectiveness in detecting and/or predicting degradation or failure. Therefore, 10 CFR 50.55a acted as a forward looking regulation with the intent to implement new, better, and more effective IST methods and techniques included in the ASME OM Code.

The NRC also expected that implementation of the revised Code requirements could be impractical or result in a hardship or burden to some licensees. Therefore, the regulation allowed licensees to submit alternative requests under 10 CFR 50.55a(3)(i) and (3)(ii), and relief requests under 10 CFR 50.55a(g)(6)(i), which was replaced by a new section, 10 CFR 50.55a(f)(6)(i), in 1993. 10 CFR 50.55a(g)(6)(i) or (f)(6)(i) may only be used to address new or updated requirements. For plants with a CP issued prior to 1971, (g)(6)(i) or (f)(6)(i) may be used for granting relief requests, because all IST requirements are deemed to be new for plants with a CP issued prior to 1971.

No significant changes regarding IST requirements were made to 10 CFR 50.55a from 1985 through 1992 except that in 1989, the 1986 Edition of ASME Code, Section XI was included by reference in 10 CFR 50.55a.

In 1988, ASME Code, Section XI, Subsections IWP and IWV were replaced by ASME/ANSI OM-6 and OM-10, which were incorporated as Subsections ISTB and ISTC into the ASME OM Code-1990. To reflect the removal of the IST requirements from ASME Code, Section XI, a new section, 10 CFR 50.55a(f), specifically written with the requirements for IST of pumps and valves, was added in 1993 to 10 CFR 50.55a. Furthermore, another new section 10 CFR 50.55a(b)(viii), was specifically added which referenced the applicable ASME OM Code. The ASME OM Code-1987 Edition through the 1988 Addenda was incorporated by reference into this newly added section in 1993.

In 2000, 10 CFR 50.55a(b)(viii), referencing the ASME OM Code, was replaced by a new section, 10 CFR 50.55a(b)(3). This new section which incorporated the ASME OM-1995 Edition and the 1996 Addenda by reference contained the following limitations and modifications:

- 10 CFR 50.55a(b)(3)(i) addressed the implementation of “Quality Assurance” requirements of NQA-1, “Quality Assurance Requirements for Nuclear Facilities,” and required that when applying the OM Code, the requirements of NQA-1 are acceptable, as permitted by the applicable OM Code, provided that the licensee use the 10 CFR 50, Appendix B, quality assurance program in conjunction with the OM Code requirements.

- 10 CFR 50.55a(b)(3)(ii) addressed the implementation of “MOV stroke-time testing,” and required that licensees shall comply with the provisions of stroke time testing in the applicable OM Code. Additionally, licensees needed to establish a program to ensure that MOVs continue to be capable of performing their design basis safety functions.

- 10 CFR 50.55a(b)(3)(iii) addressed the implementation of Code Case OMN-1, “Alternative Rules for Preservice and Inservice Testing for Certain Electric MOV Assemblies in the Light Water Power Plants,” and required that licensees choosing to apply the Code Case apply all of its provisions including the following:

  (A) The adequacy of the diagnostic test interval for each MOV must be evaluated, as necessary, but cannot be later than five years or three refueling outages, whichever is longer, and

  (B) When extending exercise test intervals for high-risk MOVs beyond a quarterly frequency, licensees shall ensure that the potential increase in core damage frequency and risk associated with the extension is small and consistent with the intent of the Commission Safety Goal Policy Statement.

- 10 CFR 50.55a(b)(3)(iv) addressed the implementation of OM Code Mandatory Appendix II, “Check Valve Condition Monitoring Program,” and required that when applying Appendix II, the following modifications applied:

  (A) Valve opening and closing functions must be demonstrated when flow testing or other methods are used,

  (B) The initial interval for tests and associated examinations may not exceed two fuel cycles or three years, whichever is longer, and any extension of this interval may not exceed one fuel cycle per extension with the maximum interval not to exceed ten years, and

  (C) If the Appendix II condition monitoring program is discontinued, then the OM Code requirements must be re-implemented.

- 10 CFR 50.55a(b)(3)(v) addressed the inservice inspection and testing requirements for snubbers. This modification stipulated that, in lieu of applying the requirements of ASME Code, Section XI, licensees could use ASME OM Code, Subsection ISTD, "Inservice Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Power Plants," contained in 1995 Edition through the 1996 Addenda. (Note that snubbers are part of IST program but are not addressed in this paper.)

Prior to 2004, any ASME Code Case that was endorsed and listed in NRC Regulatory Guides (RG) 1.147 and 1.192 could be implemented without prior NRC approval. However, in 2004, a change was made to 10 CFR 50.55a(f) with respect to implementation of ASME OM Code Cases. 10 CFR 50.55.a(f) stipulated that only those code cases listed in RGs 1.147 and 1.192 that were incorporated by reference into 10 CFR50.55a(b) could be applied without prior NRC approval. RG 1.147 (June 2003) and RG 1.192 (June 2003) were incorporated by reference into 10 CFR 50.55(b) in 2004, and remained unchanged through 2010. In 2004, the ASME OM-1995 Edition through 2000 Addenda were incorporated by reference into 10 CFR 50.55a with one exception:

- 10 CFR 50.55a(b)(3)(vi) - Manual valves needed to be exercised on a 2-year interval rather than on the 5-year interval allowed by the ASME OM Code.

In 2005, the ASME OM-1995 Edition through 2003 Addenda was incorporated by reference into 10 CFR 50.55a with one change. 10 CFR 50.55a(b)(3)(iii), which implemented Code Case OMN-1, was removed from 10 CFR 50.55a since it was endorsed by the NRC in RG 1.192 (June 2003), as an acceptable alternative to the ASME OM Code requirements. This Code Case was also incorporated into the ASME OM Code-2009 Edition, as Mandatory Appendix III.

In 2008, 10 CFR 50.55a was revised to incorporate pumps and valves for facilities whose design certification or combine operating license (COL) was issued under 10 CFR Part 52, on or after November 22, 1999. The only update made in 2009 and 2010 was the incorporation of the ASME OM Code-1995 through ASME OM Code-2004, by reference, into 10 CFR 50.55a.

2. <u>History of RG 1.147 and RG 1.192</u>

Since March 1981, the NRC has issued RG 1.147 and subsequent revisions of the "Inservice Inspection Code Case Acceptability ASME Section Division I," which listed the ASME Code Cases acceptable for use. 10 CFR 50.55a allows, without prior NRC approval, implementation of the Code Cases listed in RG 1.147 for ISI programs. After incorporating the ASME OM Code by reference into 10 CFR 50.55a, the NRC recognized the need for a new RG that would endorse OM Code Cases. In June 2003, the NRC issued RG 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code," which listed the OM Code Cases acceptable for use in the IST program.

In 2004, the NRC amended 10 CFR 50.55a with respect to implementation of ASME Code Cases. New requirements were established in paragraphs 50.55a(b)(4), (b)(5) and (b)(6) in which NRC's RGs 1.84, 1.147 and 1.192 were incorporated by reference into the regulations. These RGs list those ASME Code Cases that are approved by the NRC (with or without conditions). Specifically, RG 1.192 lists ASME OM Code Cases that are approved by the NRC (with or without conditions). As the NRC issues revisions to these ASME-Code-Case RGs, the regulations in 10 CFR 50.55a(b)(4), (b)(5), and (b)(6) are amended to reflect the latest revision of the RGs. The issuance of revisions to the ASME-Code-Case RGs is coordinated with the issuance of the amended rule for 10 CFR 50.55a to ensure they are issued concurrently. However, per these new requirements, prior NRC approval is required to implement those RG-listed ASME Code Cases that are not yet incorporated by reference in 10 CFR 50.55a.

IV. Implementation of 10 CFR 50.55a and ASME OM Code Requirements

To comply with the IST requirements of 10 CFR 50.55a, all licensees were required to submit IST programs to the NRC for review. In early 1980, a large number of IST programs were submitted and they were all in different forms and formats. The first big challenge during the NRC review was to determine the scope of what pumps and valves should be included in the IST program. The second challenge was to determine how to perform the review of such a huge number of IST programs and relief and alternative requests. To perform the review of the IST programs, vast amounts of time and resources were required. To expedite these reviews, the NRC contracted with Idaho National Engineering Laboratory to conduct the reviews of the baseline IST programs. In 1989, the NRC issued review guidance in Generic Letter (GL) 89-04 which provided information regarding program format and scope as well as acceptable relief and alternative requests. In 1995, the NRC published NUREG-1482, which summarized the lessons learned from the review of the IST programs and relief and alternative requests. In NUREG-1482, the NRC discussed the regulations, the components to be included in the IST program, cold shutdown justifications, refueling outage justifications, and acceptable requests for relief from and alternatives to the ASME OM Code requirements. In 2004, NUREG-1482, Revision 1 was issued. This reflected regulatory changes up to and including the 2003 version of 10 CFR 50.55a.

Around 1995, the NRC completed its review of the baseline IST programs for all operating plants. Subsequent reviews of the ten year updates for each plant were limited to changes to previously approved programs. This primarily involved new relief and alternative requests from revised ASME OM Code requirements or modified relief and alternative requests to supplement existing ones. Since 1995, the NRC has spent most of its resources reviewing new proposed or modified relief and alternative requests, in lieu of performing new baseline IST program reviews.

Conclusion

IST programs are intended to identify problems by collecting relevant data on a periodic basis, evaluating the performance of pumps and valves based on inservice test results, and trending performance changes over time. The test information collected from IST activities may provide some indication of operability and availability of the component at the time of the test, but the primary goal of the IST program is to monitor critical components for degradation and the rate of degradation so that timely action can be taken to correct deficiencies prior to an actual failure resulting in degraded plant safety systems and unplanned plant shutdowns. An effective IST program offers the best potential for focusing maintenance toward the most critical areas by identifying degradation of important components early enough to be able to schedule required maintenance. Therefore, continued focus by the ASME and NRC on incorporating better and more effective testing techniques and trending methods into the ASME OM Code and NRC regulations is very important in achieving the full potential of IST programs.

References

1. 10 CFR 50.55a, “Codes and Standards.”

2. GL 89-04, “Guidance on Developing Acceptable Inservice Testing Program.”

3. NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants.”

4. RG 1.84, “Design, Fabrication, and Material Code Case Acceptability, ASME III.”

5. RG 1.147, “Inservice Inspection Code Case Acceptability ASME Section Division I.”

6. RG 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code.”

TIME LINE OF MAJOR ASME CODE REVISIONS AND 10 CFR50.55a UPDATES

ASME CODE		MAJOR CHANGES	YEARS REFERENCED IN10 CFR 50.55a and UPDATES
SECTION XI, IWP AND IWV	1971 Summer 1973 Addenda	Draft IST requirements developed and incorporated in Section XI	1971 thru 1976 Incorporated Section XI by reference into 10 CFR 50.55a Added 10 CFR 50.55a(g) for ISI/IST
SECTION XI, IWP AND IWV	1974		1977 thru 1979
SECTION XI, IWP AND IWV	1977	Pump test changed from monthly to quarterly Required on-line flow measurement	1980 thru 1981 Added 40-month update requirement in 10 CFR 50.55a (g)(4)(iv)
SECTION XI, IWP AND IWV	1980		1982 thru 1985 Modified update requirement from 40-month to 10-year
SECTION XI, IWP AND IWV	1983		1986 thru 1988
SECTION XI, IWP AND IWV	1986		1989 thru 1992

SECTION XI, IWP AND IWV	1989 1988 Addenda	Section XI references OM-1987 Part 6 and Part 10 **Changes in Part 6 for pump test** Deleted suction pressure, bearing temperature and lubrication requirements Specified different acceptance criteria for centrifugal, vertical line shaft, and positive displacement pumps Changed the run time between stabilization and data collection from 5 minutes to 2 minutes Provide vibration acceptance criteria in velocity units Increase the upper end acceptable range from 1.03 to 1.10 **Changes in Part 10 for valve test** Clarified and included relief valves in the scope Allowed testing of certain check valves to be extended to refueling outage frequency Change the acceptance criteria for stroke time testing of power operated valves Allowed disassembly, reassembly and inspection to be used for check valves on a refueling outage frequency Identified testing requirements in OM-1 for safety/relief valves Deleted containment isolation valves from IST leak testing requirements Deleted trending and corrective	1993 thru 1997 Added 10 CFR 50.55a(f) specifically for IST of pumps and valves Added 10 CFR 50.55a(b)(viii) for reference of ASME OM Code replacing ASME Code, Section XI

		action from leak testing requirements for Category A valves Started issuance of OM Code Cases for acceptable alternatives	
SECTION XI, IWP AND IWV	1992		1998 thru 1999
OM CODE, ISTB AND ISTC	1995	ISTB for pumps and ISTC for valves **Changes in ISTB for pump test** Pump tests were classified into Group A, Group B and Comprehensive test. Different test requirements and acceptance criteria were specified for centrifugal, vertical line shaft, and non-reciprocating/reciprocating positive displacement pumps. Instrument accuracy of pressure and pressure differential measurements for comprehensive tests were tightened from ±2% to ±½%	2000 thru 2002 Included 4 modifications to OM Code in 10 CFR 50.55a (b)(i)/(ii)/(iii)/(iv) Replaced 10 CFR 50.55a(b)(viii) by 10 CFR 50.55a(b)(3) for referencing ASME OM Code
OM CODE, ISTB AND ISTC	1998	**Changes in ISTC for valve test** Added bi-directional testing requirements for check valves	2003 thru 2004 Added one additional modification to ASME OM Code in 10 CFR 50.55a

		Specified separate testing requirements for motor-operated valves, pneumatically-operated valves, hydraulically-operated valves, and solenoid-operated valves Added Condition Monitoring Program as an acceptable option for check valve testing Added manual valve test every 5 years in OMa-1999 Addenda Added instrumentation requirements for valve testing	(b)(vi)
OM CODE, ISTB AND ISTC	2001	**ISTC for valve test** Incorporated 5 year manual valve test frequency	2005 thru 2008 Removed 10 CFR 50.55a (b)(iii) modification In 2008, added facilities with combined license issued under 50.52
OM CODE, ISTB AND ISTC	2004		2009 thru 2010
OM CODE, ISTB AND ISTC			2010 to present In process to incorporate 2005 addenda and 2006 addenda into 10 CFR 50.55a, and expected to be published in 2011

Papers Not Presented in a Symposium Session

Update on ISTOG Activities for 2011

Ed Cavey
ISTOG Chairman
Newport, Michigan, USA

Abstract

This presentation will introduce the InService Testing Owners Group (ISTOG) to those attendees who are unfamiliar with our group, highlight ISTOGs accomplishments, and will brief the attendees on our current and planned activities. ISTOG was formed several years ago to provide a forum for Inservice Testing (IST) experts to share knowledge and experience. This dynamic group is dedicated to promoting high standards for nuclear plant pump and valve testing. New IST engineers are helped tremendously by having access to more experienced peers. ISTOG is also embarking on a new mission to create detailed technical documents which cover specific American Society of Mechanical Engineers (ASME) Code for Operations and Maintenance of Nuclear Power Plants (OM Code) implementation guidance. These documents will be targeted to the areas of OM Code implementation which have been identified as the most relevant and needed. Such guidance standards, developed from a large pool of knowledgeable experts with field IST experience and reflecting best practices, will provide benefit to the entire industry. Two examples of planned guidance documents are:

- Allowable variance from fixed reference values during pump testing

- Post maintenance testing and controls for packing adjustments / backseating of power operated valves

ISTOG has already developed several excellent position papers and best practices documents such as:

- Guidance on pre-conditioning as it relates to IST

- Standard for IST Program Manager position qualification

- Check Valve Condition Monitoring guideline (developed jointly with the Nuclear Industry Check Valve Group)

- Guidance for implementation of Motor Operated Valve (MOV) Code Case OMN-1 (developed jointly with Motor Operated Valve Users Group)

ISTOG members who post a question to the community using our email distribution network typically receive a dozen or more responses within a few days. Personnel with experience specific to the question often share documentation related to investigations

and analysis. By collecting and organizing all of these Q&A topics, ISTOG has created a powerful database of IST-related operating experience. A current and growing collection of 415 individual pump and valve testing topics with a total of over 2840 related postings can be found at our members' website.

Introduction

The ISTOG Charter contains the following Purpose and Objectives statements:

PURPOSE

ISTOG collects, integrates, and shares industry knowledge, resources, and products so that members will benefit from improved implementation of IST programs. The benefits of this collaborative effort include cost reduction, error reduction, improved performance, aging workforce knowledge capture for future generations, and increased regulatory influence.

OBJECTIVES

To accomplish the ISTOG purpose, the following objectives have been established:

- Provide forum for joint discussions and resolution of IST issues through communication between ISTOG members and other industry organizations, e.g. ASME and the Nuclear Regulatory Commission (NRC).
- Provide a mechanism for making recommendations on IST issues to industry organizations, e.g., ASME and NRC.
- Provide improved plant safety and availability through recommendations of improved IST.
- Capture knowledge and experience of industry personnel in the IST field.

The ISTOG action items for 2011 are dominated by the effort to provide recommendations to the NRC for the proposed NUREG-1946. In 2010 the NRC released a draft version of the new NUREG-1946 which was planned to supersede NUREG-1482. IST owners from all over the nation were concerned due to the possible loss of many guidance areas [from NUREG-1482] which had helped form the very basis of modern IST programs. The ISTOG Steering Committee commissioned a survey intended to identify and prioritize the various guidance areas being dropped in NUREG-1946. That survey result and the actions being taken in 2011 by ISTOG are discussed in this paper.

NUREG-1482 Related Activity

The ISTOG survey on NUREG-1482 guidance began by assembling a listing of the important topical areas within the NUREG. That listing is as follows:

NUREG Section	Element description
3.1.1	Guidance on preparing acceptable Cold Shutdown Justifications (CSJ) / Refueling Outage Justifications (ROJ) deferrals
3.1.1.2	Testing during power ascension
3.1.3	IST exam scheduling, including discussion on grace
3.4	Skid-mounted components
4.1.2	Check valve non-intrusive testing
4.2.1	Limiting stroke time values for Power Operated Valves (POVs)
4.4.2	Post Maintenance Testing (PMT) following packing adjustments / backseating
4.4.4	Pressure Isolation Valve (PIV) testing
5.2.2	Use of pump reference curves
5.3	Variance from fixed reference values
5.5.2	Use of tank level change in lieu of flow measurement
5.5.3	Use of tank level change in lieu of differential pressure (DP) measurement
5.1	Alternatives to Comprehensive Pump Testing requirements

IST Program Managers were asked to rank each of these items in a 1-5 scoring system where 5 identifies critical guidance important to IST Programs. A score of 1 would indicate that loss of this guidance area from the NUREG would not be significant.

15 utilities responded to the survey and the scores for each NUREG section were tabulated. The following were the survey results:

NUREG Topical Area	Score
Guidance on preparing acceptable CSJ / ROJ deferrals	3.1
Testing during power ascension	3.2
IST exam scheduling, including discussion on grace	3.9
Skid-mounted components	3.3
Check valve non-intrusive testing	2.9
Limiting stroke time values for POVs	2.7
PMT following packing adjustments and backseating	4.1
PIV testing	3.2
Use of pump reference curves	4.0
Variance from fixed reference values	4.3
Use of tank level change instead of flow measurement	3.1
Use of tank level change instead of DP measurement	3.3
Alternatives to Comprehensive Pump Testing requirements	3.3

Based on the survey results, the ISTOG Steering Committee attempted to bin each of the topical areas into the following categories:

1) ISTOG - A Position Paper could be created by ISTOG to capture the essential elements of the NUREG topical area. This position paper would provide program implementation guidance to IST owners as a replacement for the "loss" of the NUREG 1482 guidance.
2) ASME - The topical area identified is such that ASME ISTB or ISTC should reconcile the loss of the NUREG guidance as an OM Code change or a new Code Case.

The items categorized as ASME reflect guidance which might be construed as OM Code clarification. The goal was to coordinate with the ASME OM Code committees to seek appropriate OM Code changes or new Code Cases that provide the necessary guidance to IST Program owners. It was felt that the new alignment of ISTOG annual meetings with the winter ASME OM committee meetings would provide a solid mechanism for such cooperation.

The following is a listing of the NUREG topical areas by the ownership categorization:

NUREG Topical Area	Ownership
Guidance on preparing acceptable CSJ / ROJ deferrals	ISTOG
Testing during power ascension	ASME
IST exam scheduling, including discussion on grace	ASME
Skid-mounted components	ISTOG
Check valve non-intrusive testing	ISTOG
Limiting stroke time values for POVs	ISTOG
PMT following packing adjustments and backseating	ISTOG
PIV testing	ASME
Use of pump reference curves	ISTOG
Variance from fixed reference values	ISTOG
Use of tank level change instead of flow measurement	ASME
Use of tank level change instead of DP measurement	ASME
Alternatives to Comprehensive Pump Testing requirements	ASME

During the ISTOG meeting held in Clearwater Beach, FL during December 2010, there were many hours of discussion on the topical areas highlighted above. The NRC representatives at the meeting provided feedback that indicated intent to consider restoring some of the NUREG-1482 guidance in the new NUREG 1946. The ISTOG welcomed the opportunity to provide consensus recommendations for all of these key items.

One issue in particular, allowable variance about the fixed reference value, was very challenging because of the many strong opinions on the subject. ISTOG sought to achieve a full consensus recommendation while the ASME ISTB Committee also sought to develop improved guidance. This issue is very important to plant IST personnel because it directly affects the testing methodology for all IST-scope pumps. I believe that the ISTOG recommendation is aligned with the planned changes to ISTB, and it is hoped that the upcoming revision to NUREG-1946 (or 1482) will reflect the overall consensus.

ISTOG has also recently released a revised position paper on preconditioning. Preconditioning has been a topic of great interest in recent years due to increasing attention by the NRC. This position paper provides IST program managers with an excellent source of information intended to prevent situations where unacceptable preconditioning could occur.

ISTOG has also been upgrading and enhancing the "ISTOG OE" database. Since the group's inception in 2004, there have been a tremendous number of email questions and answers. These individual "Q&A" topics represent a very useful source of information to new or inexperienced IST Engineers. The ISTOG OE database is well organized and searchable. High level bins are Pump, Valve, and General IST, with several further groupings under each. One example of a recent Q&A topic was a question regarding lower than expected baseline performance data following a pump replacement. Ten responses came from veteran IST Engineers within 2 days. Some responses requested additional information from the question initiator in order to provide more accurate responses. Another example was a simple survey of plants to determine which plants continue to perform partial stroke tests of Main Steam Isolation Valves while at power. That request elicited 23 responses within 4 days, and several of those responses provided important amplifying information related to the issue. Archival and query access to this IST Q&A database is an important product being provided by ISTOG to its members.

Conclusion

The Inservice Testing Owners group is providing its members with an organized, effective forum to share ideas and problems. ISTOG is also producing written consensus standards addressing key industry-wide topics, as well as acting as a single interface for representing owners before such groups as ASME and the NRC.

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References

www.istog.net - Note that much of this website content is available only to actual members of ISTOG.

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

The 2011 Symposium on Valves, Pumps, Snubbers, and Inservice Testing, jointly sponsored by the Board on Nuclear Codes and Standards of the American Society of Mechanical Engineers and by the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic, and regulatory issues associated with the inservice testing programs at nuclear power plants, including design, operation, and testing of valves, pumps, and snubbers that help ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives regarding the improvement of inservice testing programs and methods for valves, pumps, and snubbers at nuclear power plants.

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