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Proceedings of the Eighth NRC/ASME Symposium on Valve and Pump Testing

Held at
Renaissance Washington DC Hotel
Washington, DC
July 12-14, 2004

Jointly Sponsored by:
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Abstract

The 2004 Symposium on Valve and Pump 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 and regulatory issues associated with the testing of valves and pumps used in nuclear power plants. The symposium provides an opportunity to discuss improvements in testing that help to ensure the continued reliable performance of valves and pumps. The participation of industry representatives, regulatory personnel, and consultants provides for 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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Acknowledgments

The Steering Committee, the American Society of Mechanical Engineers, and the U.S. Nuclear Regulatory Commission acknowledge the efforts of the Session Chairs, authors, and panel members for their invaluable contribution to the success of the symposium. We also would like to express our gratitude to the NRC and ASME executives for their remarks at the Opening Session of the symposium. We further recognize the participation by international representatives which provides a broad perspective to the valve and pump issues currently under consideration in the United States. We sincerely appreciate the excellent work of Ms. Monique King and other members of the NRC publications and graphics staff in preparing the proceedings for the symposium.

Disclaimer and Editorial Comment

Statements and opinions advanced in the papers presented at the Eighth NRC/ASME Symposium on Valve and Pump 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, English units have been used as an expression of current industry practice with metric units also indicated where possible.

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Session 1(a): Pumps

Session Chair

Artin Dermenjian

Sargent & Lundy Corporation

Precursors to Cracked or Bent Shafts in High Pressure Centrifugal Charging Pumps

Shawn D. Comstock
Rick D. Raymer
Wolf Creek Nuclear Operating Corporation

Introduction

Certain high pressure centrifugal charging pumps supplied to the Nuclear Industry have a history of problems with shaft bending and cracking. These pumps are relied upon for High Pressure Safety Injection (HPSI) for small break loss of coolant accidents. The Pacific Pumps division of Dresser Industries originally supplied the pump that is the subject of this paper to the nuclear industry, a Pacific 2.5 RLIJ 11 stage-charging pump. The techniques used at Wolf Creek Nuclear Operating Corporation (WCNOC) to diagnose vibration results and identify the precursors to a cracked or bent shaft are the main focus of this paper.

Initial Problem

In October 2000, the outboard bearing housing horizontal vibration test point exceeded the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (O&M) calculated alert range. A number of adjustments were made on the pipe hangers, u-bolt clamps and pump hold down bolts. As a result of these changes, vibration values fell below the alert range. In December 2001, vibration values began to trend upwards again. By August 2003, the outboard bearing housing horizontal vibration test point once again exceeded the ASME O&M calculated alert range. We made addition adjustments on the pump hold down bolts. Once again we were successful in reducing the vibration values below the alert range. However, the most recent step change in vibration performance on the pump outboard bearing in the horizontal direction caused WCNOC a great deal of concern. Considering we were preparing to begin our 13th refueling outage, we had to take another close look at the data that lead to the most recent change. A number of issues led us to make the recommendation to replace the pump rotating assembly.

Callaway is Wolf Creek's sister plant with nearly an identical design and plant layout. One of Callaway's HPSI pumps failed with a cracked shaft in 1992. Extensive troubleshooting was performed in an attempt to identify the cause of the vibration increase and to determine if shaft bending or cracking precursors were present.

Data Analysis

Evidence indicated that a resonance condition was responsible for some of the vibration problems we were experiencing. When equipment operates within 20% of its natural frequency, normal vibration can be magnified exponentially. The closer equipment operates in relation to its natural frequency, the greater the magnification of normal vibration. Refer to Figure 1 - "HPSI Pump Resonant Condition Vibration Magnification Factor" to see how changes in the natural frequency of the machine affect vibration at the pump's operating speed of 80 hertz (Hz). Figure 1 reflects a prediction of vibration performance with relation to this specific application using the formula obtained from reference 1.

Resonance Basics

Resonance is simply the natural frequency of a component or combination of components (assembly). All structures have a resonant frequency. If you impact the structure with enough force to make it move, it will vibrate briefly at its natural frequency. A structure will have a resonant frequency in each of its 3 directional planes (x, y and z, or as we call them, horizontal, vertical and axial). Resonance serves to *amplify* the vibration due to whatever vibration force is present at (or near) that resonant frequency. It is important to note that resonance does not cause vibration - it amplifies it.

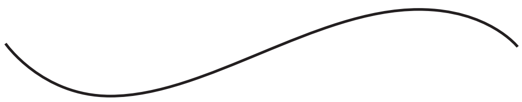
Critical Speed Basics

A pump shaft has what is referred to as a "bending mode". The point at which the turning speed of a pump shaft matches its natural frequency is called its first critical speed. When a pump is at the first critical speed, the shaft bends in the shape indicated by the figure below. Most pumps operate above their first bending mode. Furthermore, the duration that a pump spends in this region of operation as its rotational speed accelerates is so short that the vibration at this point goes unnoticed. Good design practices ensure the operating speed is greater than 20% of the shaft rotational speed.

Pump Shaft First Bending Mode

At the pump's second critical speed, the shaft bends into an s-shaped curve as indicated below.

Pump Shaft Second Bending Mode



Like a structural resonance that is being excited, the pump shaft vibration amplitude will be magnified as shown in Figure 1. The critical speed of a shaft is determined by its mass and stiffness. Normal wear results in increased looseness between parts, thus changing the critical speed of the shaft.

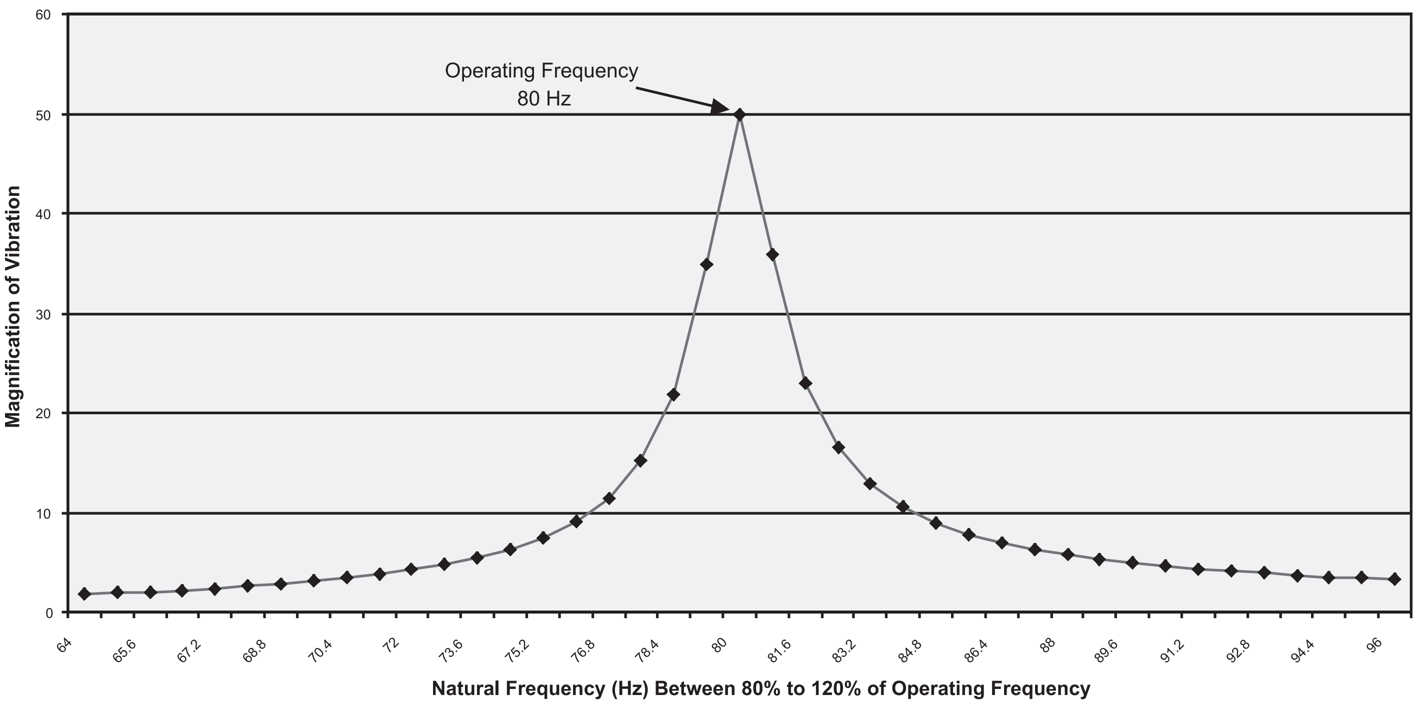
HPSI Pump Application

Based on information from Flowserve, the pump shaft 2nd critical speed is approximately 84 hertz. As a result of normal wear and subsequent loosening of mating parts, the critical speed of the shaft begins to decrease. In this particular component, as the critical speed decreases it becomes closer to the operating speed of the pump. Likewise, the vibration amplitude of the pump shaft increases as a result of amplitude magnification. We also discovered that the pump outboard bearing housing had a natural frequency of approximately 84 Hz. Based on historical spectra, impact and modal data, we suspect that normal wear allowed the pump shaft amplitude to increase enough to excite the natural frequency of the pump outboard bearing housing. Notice how the actual vibration results in Figure 2 closely mirror those predicted by the resonant amplification curve in Figure 1.

Corrective Action Strategy

If left unattended, resonance problems typically get worse until a catastrophic failure occurs. However, it is possible to change the stiffness or mass of a structure to shift the resonant frequency away from the operating frequency. Resonance is a magnifier of vibration, not a cause, so it is

Figure 1 - HPSI Pump Resonant Condition Vibration Magnification Factor



also possible to reduce the vibration problem by improving vibration performance. Another factor in resonant vibration is the amount of dampening that is present. Increasing the dampening factor results in a reduction of the resonance magnification. Based upon the industry data at hand and the pump's original vibration performance prior to the step change, it was determined that de-tuning and dampening were the most effective means to improve the situation. Piping adjustments and pump outboard frame hold down bolting adjustments were performed which successfully changed the resonant frequency, resulting in vibration performance below the surveillance alert range. Figure 2 - "HPSI Vibration Performance" shows a trend of the vibration levels at various points.

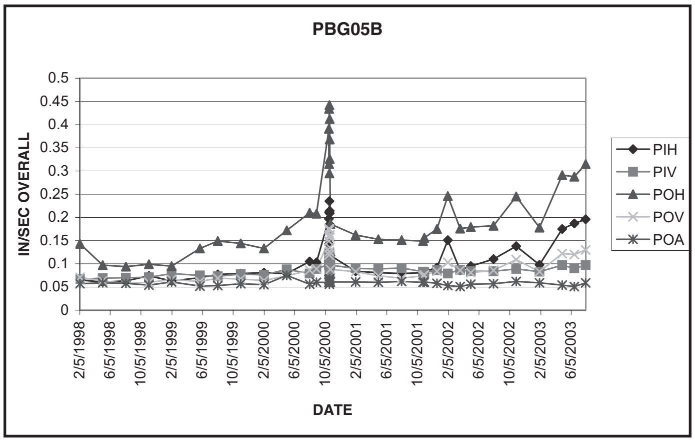


Figure 2 - HPSI Vibration Performance

The point descriptions in Figure 2 correspond to pump inboard horizontal (PIH), pump inboard vertical (PIV), pump outboard horizontal (POH), pump outboard vertical (POV) and pump outboard axial (POA).

Industry Data

In follow-up to the successful detuning and dampening of the outboard structure of the pump, an investigation was performed to determine the extent of the condition and to predict future performance for maintenance planning purposes. Data obtained from Callaway and the Institute of Nuclear Power Operations (INPO) Equipment Performance and Information Exchange (EPIX)[1] revealed a history of vibration and shaft failure problems with this model of pump at several other sites.

A search of the Nuclear Plant Reliability Data System (NPRDS) system using the keywords "Pacific Pumps" identified 573 hits. Other keywords were used to narrow the search and, after review, 12 records were identified that had descriptions of problems that closely matched those at Wolf Creek or shaft failures as indicated by Table 1.

A search of all EPIX records on the keywords "Pacific Pumps" revealed 670 hits. Other keywords were used to narrow the search and 3 informative records were found. Record number 558 from Byron 2 was very informative. It is dated 5/15/2003 and describes an event where both of their charging pumps failed over a relatively short period of time. Byron's B train pump failed with a broken shaft on 11/11/2002. Byron's A train pump subsequently failed due to high vibration on 2/25/03. This report also identified an industry trend with 34 pump failures out of 122 total pumps; 26 of which were failures due to cracked or broken shafts. Table 2 reflects the failure types described in the search.

***Table 1* – NPRDS Reports of HPSI Vibration or Shaft Problems**

Plant Unit	Discovery Date	Failure Cause Category	Problem
Salem 2	6/18/1988	Unknown	High Vibration
Salem 2	7/15/1988	Unknown	High Vibration
Beaver Valley 1	7/19/1977	Engineering/Design	Broken Shaft
Beaver Valley 1	7/29/1994	Age/Normal Usage	Shaft Failure
Connecticut Yankee 1	9/10/1992	Manufacturing Defect	High Vibration
Sequoyah 1	2/15/1991	Unknown	Cracked Shaft
Callaway 1	4/10/1991	Unknown	High Vibration
Callaway 1	2/3/1992	Unknown	Broken Shaft
North Anna 1	9/21/1983	Unknown	High Vibration
North Anna 1	8/29/1989	Unknown	High Vibration
North Anna 1	4/29/1991	Age/Normal Usage	Bent Shaft
North Anna 2	8/26/1983	Engineering/Design	Bent Shaft

Table 2 – Chemical and Volume Control System (CVCS) Industry Pump Failures	
Failure Type	**Number of Failures**
Complete shaft failure	20
Cracked Shaft	6
Bent Shaft	3
Pump Seizure	5

Recent NRC Data

NRC Information Notice 2001-06, "Centrifugal Charging Pump Thrust Bearing Damage Not Detected Due To Inadequate Assessment of Oil Analysis Results and Selection of Pump Surveillance Points,"[2] describes a pump bearing damage event with this model of pump. A 40-fold increase in the oil particulate count was observed prior to the bearing failure. No change in vibration performance was identified. This incident highlights the importance of not relying upon a single predictive maintenance technology for the determination of pump condition.

Performance Monitoring

Based upon industry data relating to resonance problems, it was decided that condition monitoring of the vibration, phase angles (or direction of vibration) and structural resonance was an effective strategy for assuring the pump's operational capability. The purpose of this approach was to monitor and predict the rate of pump degradation for maintenance planning. This enabled a prediction of vibration performance to tell when in the future the pump would reach the point that its performance would become a concern in relationship to its safety function mission time.

Between October of 2000 and April of 2003, there were two other spikes in vibration as indicated by Figure 2. These were determined to be related to system flow conditions and temperature of the process fluid. Subsequent testing verified that this was a temporary condition not related to an increasing trend in vibration performance.

New Variable Introduced

During April 2003, a modification to replace the lubrication piping to the bearing housings was implemented. This modification replaced hard piping with high-pressure flexible hose to mitigate problems with leakage in the oil system thought to be related to the vibration of the pump. The post maintenance tests identified that this changed the outboard bearing housing's natural frequency to 83.45 Hz, nearer to the operating frequency of the pump at 80 Hz. This resulted in an increase in vibration that exceeded the ASME O&M Code Alert range. The test frequency was doubled in accordance with ASME O&M requirements while a new effort began to detune and dampen the structure.

Using the year 2000 maintenance history from this pump and the modal analysis model developed in 2003, a new action plan was developed. The new action plan would change the structure's response to excitation. Based on the modal model, relative movement was occurring between the pump in the area of the outboard end hold down bolts and mating support structure. Data collected on 8/1/03 included an impact test on the outboard bearing housing. The 8/1/03 impact test identified that the resonant frequency of the outboard bearing housing increased from 5007 cycles per minute (CPM) to 5040 CPM. This shifted the resonant frequency away from the operating frequency of the pump and should have resulted in lower vibration readings. Instead of the expected response, the vibration at both the outboard and the inboard bearing housings increased. This is the first time that the equipment has not responded as expected following changes in operational characteristics.

Wolf Creek subsequently increased the hold down bolts to 425 foot-pounds to eliminate the looseness that was thought to be contributing to the step change in vibration performance. Although vibration performance improved at PIH and POH on the 8/25/03 test after increasing hold down bolt torque, the levels did not return to the normal range. Additionally, no bolts were found loose and were at the as-left torque used to improve performance in the past. The pump hold down bolts were now at the maximum torque allowed by the vendor.

This change in performance closely represents the characteristics described by industry operating experience prior to the occurrence of a cracked or bent shaft. With a refueling outage only a month and half away, the decision was made to add work to the outage scope and replace the rotating assembly.

Insights

Industry data revealed that problems with these pumps have plagued the industry. These pumps are not operated at their best efficiency point (BEP) during normal operation or full flow check valve testing. At Wolf Creek, the normal flow for the safety-related charging pumps is at about 50% of the BEP. This undoubtedly has contributed to an increased wear rate. Minimization of run time is an effective strategy to ensure long-term reliability. Many plants have replaced their non-safety related positive displacement charging pumps with a more reliable centrifugal charging pump, including Wolf Creek and Callaway.

With this particular model of pump, a step change in vibration performance is an early warning sign of degrading vibration performance that can quickly lead to a cracked or bent shaft. However, a step change is not always noticed before failure as described by EPIX/NPRDS reports. Under these circumstances, the crack or bend is initiated on the other side of the "heavy spot" of the shaft. A shift of vibration phase angles can identify the beginning of a crack or bending when this is the situation.

Bump testing enables the determination of structural resonance. This was an important test that enabled us to rapidly pinpoint the structural resonance problem. Taking these readings while the pump is known to be operating acceptably for comparison in the future can provide valuable insight about what may have triggered a step change in vibration.

High-speed data acquisition to measure the critical speeds of the shaft during pump start up is another approach that can identify problems with the rotating element leading to a pump failure. Vibration increases at the turning speed when each critical speed is reached as the pump speed increases. The vibration/revolutions per minute (RPM) data can be compared over time to see if the critical speed of the shaft is changing; thus indicating a problem with the internal rotating elements.

Modal analysis can be utilized to better understand how the structure is vibrating. Modal analysis of our B train pump showed looseness between two mating parts, even though the bolting in the area was at the maximum torque. Understanding how this structure vibrated enabled a more effective plan to de-tune this resonance and dampen vibration.

Oil Analysis has been proven as an effective means to monitor this type of pumps bearings for damage. NRC Information Notice 2001-06 describes the details of this event.

Wolf Creek has had numerous problems with the B train pump and very little problems with the A train pump. Callaway has experienced this phenomenon as well. The run time on Wolf Creek's pumps has been approximately the same over the life of the plant. Wolf Creek's B train rotating assembly was replaced in 1997 and lasted until 2003. The A train pump has never had its rotating assembly replaced.

These two pumps differ in physical piping design. For example, the B train recirculation line is a schedule 160 pipe, as opposed to the A train pump which has a schedule 80 pipe. Therefore, the B train pump operates at a slightly lower recirculation flow than the A train pump. Therefore, the B pump experiences a higher normal wear rate due to low flow operation than the A pump. Vibration measurements on discharge piping in the area during troubleshooting on the B train were compared to the A train. The B train piping vibration was significantly higher than the A train piping. This information suggests that the system piping design may play an important role in the resonant sensitivity of the pump. As stated before, any vibration is significantly magnified by structural resonance. Minor initiating events such as increased looseness due to normal wear, changes in process fluid temperatures, different flow configurations, small changes in rotational balance, minor shifts in alignment, and minor changes to stiffness of the structure can lead to a high cycle fatigue situation. Maintenance can be performed to improve performance and correct these problems, but each time this situation occurs the ability of the component to withstand this fatigue is lessened.

Flowserve Corporation, formerly Ingersoll-Dresser Pump Company, is the manufacturer of Pacific RLIJ, 11-stage, centrifugal pumps. Flowserve provides replacement parts for these pumps with upgraded materials and improved designs. Wolf Creek chose to replace the outboard bearing housing with an improved design provided by Flowserve. This design does not have the structural resonance problem of the original equipment. Flowserve also offers upgraded rotating elements that use stiffer materials to address operation near the shaft's second critical speed.

Conclusions

Predictive maintenance technology is very important for ensuring the long term reliability and performance capabilities for these pumps. These pumps are more sensitive to changes in vibration performance and structural integrity than most other safety-related pumps as evidenced by the number of industry reports of degradation and failure. An effective condition monitoring strategy, minimization of run-time, and upgrade of critical parts is recommended to ensure trouble-free operation.

References

1 – www.inpo.org - Institute of Nuclear Power Operations Web Site

2 - NRC Information Notice 2001-06, "Centrifugal Charging Pump Thrust Bearing Damage Not Detected Due To Inadequate Assessment of Oil Analysis Results and Selection of Pump Surveillance Points"

WHAT HAPPENS WHEN A PUMP NO LONGER OPERATES AT OPTIMUM CONDITIONS?

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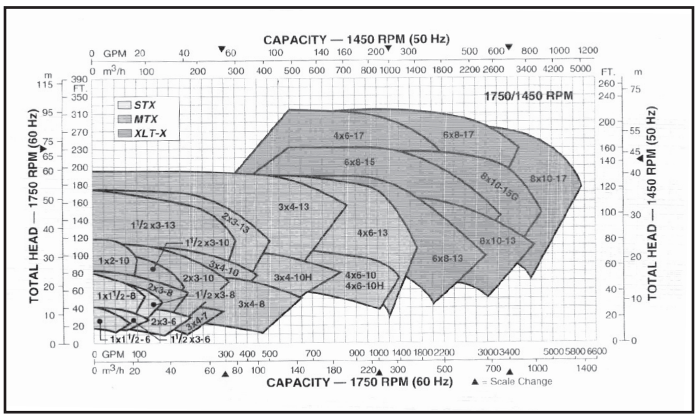
Abstract

With renewed attention to energy conservation, efficiency and equipment reliability, it is important to review implications of pumps operating to the left of the best efficiency point (BEP). Low efficiency, high radial loads, noise, vibration - become a real problem when that happens. Damage to the seal, shaft, couplings and poor reliability are a real and direct result of such operation. This paper examines the effect of pumps operating at off-design condition, with regard to efficiency and energy consumption.

Introduction

Let's explore the effect of such operation on *pump efficiency* and estimate wasted energy. There are also significant negative effects on radial load, cavitation damage, and other aspects, but, at this time, we will focus on the issue of energy only. The larger the pump, the more energy is wasted when a pump operates off-peak. A full range of ANSI pumps for chemical services, for example, as offered by pump manufacturers, may consist of many sizes, to span a wide range of flows – with larger sizes reaching over 4000 gallons per minute. Even larger sizes, such as encountered at power generation utilities (boiler feed pumps, circulating, screen wash, etc.) would have this issue even more emphasized.

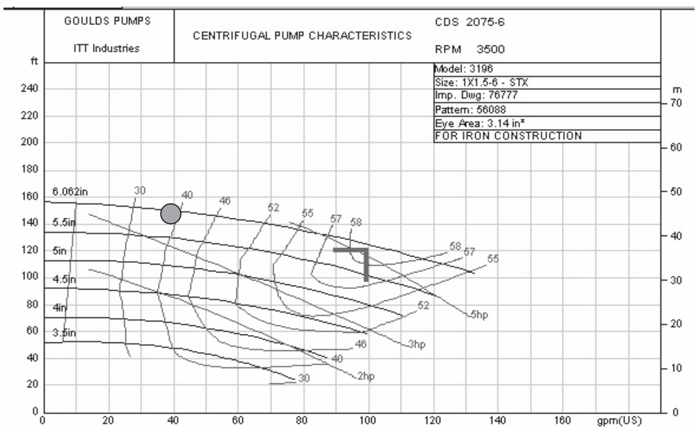
Hydraulic Coverage for a typical pump type range



The graph above is called an Overall Hydraulic Coverage Chart. For each size, a head-capacity curve at the maximum and minimum impeller diameter is plotted (sometimes, minimum diameter is not shown in order to make the chart less cluttered). This allows one to make an approximate selection of a pump size, and then to look up the individual detailed hydraulic performance curve for that size, to finalize the details.

Let's consider a case of a relatively small pump first. For example, if a pump user is looking for a pump to pump 40 gallons per minute (gpm) at 140 feet head, a 1x1.5-6 pump size (with approximately 6" impeller diameter) would be picked. The pump will work, but unfortunately will not be operating at its optimum design point.

Figure 2



As evident from the hydraulic curve for this pump size, this pump will have 40% efficiency (circle). Its design point (angle), however, is at 58% efficiency, i.e. the pump operates to the left of its BEP point for the impeller diameter required to achieve the desired head.

In this example, note that a horsepower (hp) line that passes near the operating point is approximately 4 hp, which is roughly 3 kilowatts (kW). How much does it cost to operate this pump if running continuously, 365 days per year, at, say $0.07 per kilowatt-hour?

3 (kW) x 24 (hr/day) x 360 (days/year) x 0.07 ($/kW-HR) = $1814

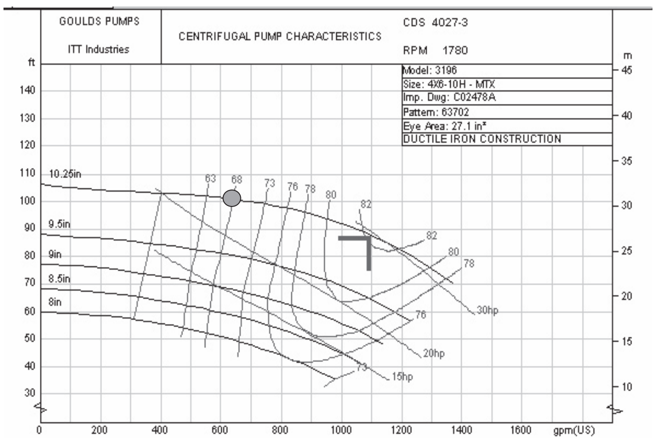
Now, what would it cost if the efficiency was somehow improved to the same 58% that this pump enjoys when operating at the design point? Obviously, if a pump runs more efficiently, it will take less power. In fact, the power (and thus cost) would be inversely proportional to efficiency:

1814 x (40/58) = $1251

The net savings would thus be 1814 – 1251 = $563, which is 31% less

Next, let's consider a somewhat larger pump. Say we have a 4x6-10H size operated at 600 gpm and producing 100 feet of head:

Figure 3



Again, the pump is off the efficiency peak. It operates at approximately 65%, whereas its peak efficiency at that diameter (10.25") could be 82%! Now, the energy dollars become more pronounced. Its power consumption is approximately 25 hp (19 KW), according to horsepower lines in the proximity to operating point:

19 x 24 x 360 x 0.07 = $11,491

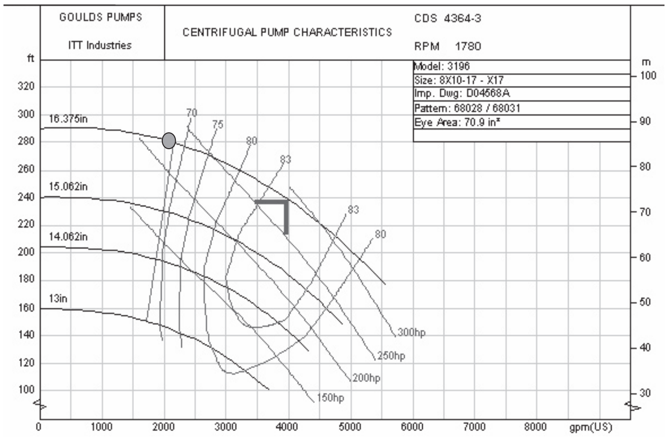
But it would be less if efficiency was restored to the designed 82%:

11491 x (65/82) = $9,108

The savings would be: 11,491 – 9,108 = $2,382, i.e. about 21% in this case

Let's next take even larger size, 8x10-17:

Figure 4



Let's assume this pump operates at 2000 gpm (280 feet head), instead of a peak point of 4000 gpm. The efficiency at the actual operating point is only 70% instead of the potentially achievable 83% by this pump.

The horsepower at the operating point is roughly 225 hp (168 KW), and the yearly energy bill is:

168 x 24 x 360 x 0.07 = $101,516

At restored efficiency, this would be:

101,516 x (70/83) = $85,616

The net savings would be:

101516 – 85616 = $15,900

For larger sizes, the energy savings could be even greater.

As you can see, the net savings depend on how far back away from the Best Efficiency Point the pump operates. Unfortunately, this problem exists in all too many actual installations in the field. Many pumps, procured and installed years ago, often no longer operate at the originally intended hydraulic conditions. As operating conditions change, the pump is simply throttled further and further away from the BEP. The result – dollars literally "burned", - not to mention other problems (high loads, shaft breakage, etc.).

Obtaining a smaller pump is one approach. But, a smaller pump may still not (and usually does not) have the hydraulics sized to hit the operating point "dead on". It may help somewhat, but is expensive and not as efficient. The user choice is limited only to the pump sizes available, as standard, from the pump manufacturer's catalog, and even with a large number of sizes in the catalog, it is virtually impossible to cover each and every variation of the operating conditions. So, the user is forced to settle for the "second best", but not the optimum. More importantly, however, is the issue of economics and feasibility of *piping* change, to accommodate a proposed pump downsizing. Piping changes alone can often cost more then a pump.

Sometimes a better solution might be to have a new impeller, custom-designed and sized for your operating conditions. By doing that, a pump performance will essentially "shift" or "slide" to exactly where the Best Efficiency Point is, - and the net losses become zero. Such approach is effective, and the investment is minimal, with a payback of less than a year, and often just a few months.

Not only ANSI single stage overhung-impeller pump designs can benefit from this approach. Cooling water between-bearing pumps are known to have benefited greatly with improved impeller hydraulics. When a metal impeller is replaced with structural engineered composite material (80% lighter then metal), the combined effect of hydraulic fine-tuning with reduced weight (and thus load) can be dramatic. Rotordynamics benefits of such approach are obvious, and savings immediate. Other pump types, such as vertical multistage river intake pumps, condenser, circulating, etc. can have similar issues, and could be likewise retrofitted with improved hydraulics designs, - quickly, efficiently, and economically.

Conclusions

If you suspect that your pump is not operating at the optimum conditions, have it evaluated for the potential energy savings upgrade. Obtain your pump's hydraulic curve and indicate the desired operating condition. Have the potential energy savings evaluated, as a function of your operating conditions in relation to the actual pump BEP point. Then examine the evaluated costs, and impact of rotordynamics, and consider engineering recommendations, provided by your technical team, or an outside consultant. You may be surprised how much money you may potentially save.

Dr. Lev Nelik, P.E., APICS

President

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Consulting and Troubleshooting

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New Monitoring Technology for Pump Health

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Abstract

Power plant owners and operators are concerned with the "health" of their active components – particularly their pumps. Pump health at power plants is typically determined by the combined assessment of a number of system parameters. No single parameter provides an indicator of pump health, but engineers can incorporate multiple parameters into an overall health assessment.

Advancements in data processing and graphical presentation have significantly improved the ability of engineers to monitor system parameters. Quickly and easily an engineer may graph the pressure in a system over a given period and compare it to other parameters recorded over the same interval. The ability to graphically view parameters on the same time scale allows the engineer to correlate and assess component health.

Each of these activities requires time to apply the skill and judgment of a qualified engineer to the correlation of parameters, and each correlation is based on judgment. Therefore each conclusion is subjective. However, with the advent of the newest monitoring technology these correlations can be pre-programmed into a monitoring tool that constantly monitors these parameters and alerts the engineer only when the parameters indicate degradation. If this tool were also able to automatically "learn" data patterns from individual data streams in order to employ pattern recognition technology the accuracy of the tool would be significant. This would result in a highly accurate, objective, and continuous pump health assessment that effectively becomes "health by exclusion" – i.e. pump health is assumed unless the monitoring tool alerts the engineer.

This paper will describe the fundamental elements that make up such a monitoring system and describe the advantages that the system provides to the power plant professional performing pump health assessment. The paper will also note the potential future applications of such a system and some of the potential hurdles to implementation.

Introduction

Appropriately evaluating the parameters measured during component testing can be a challenge. However the combination of patented signal analysis algorithms and data processing technology can provide a solution for monitoring the health of components that operate routinely or continuously. This approach to monitoring the health of components starts with signal analysis algorithms that allow any chosen group of signals to be "modeled" by a methodology known as similarity-based modeling. A model is a recreation of the pattern of the group of signals that is compared to the signal outputs in real-time. The comparison is the difference between the model (called the estimate) and the actual signal. This difference is called the residual. As any signal (or signals) deviates from its normal pattern the residual shows certain patterns of behavior that provide early warning of degrading condition.

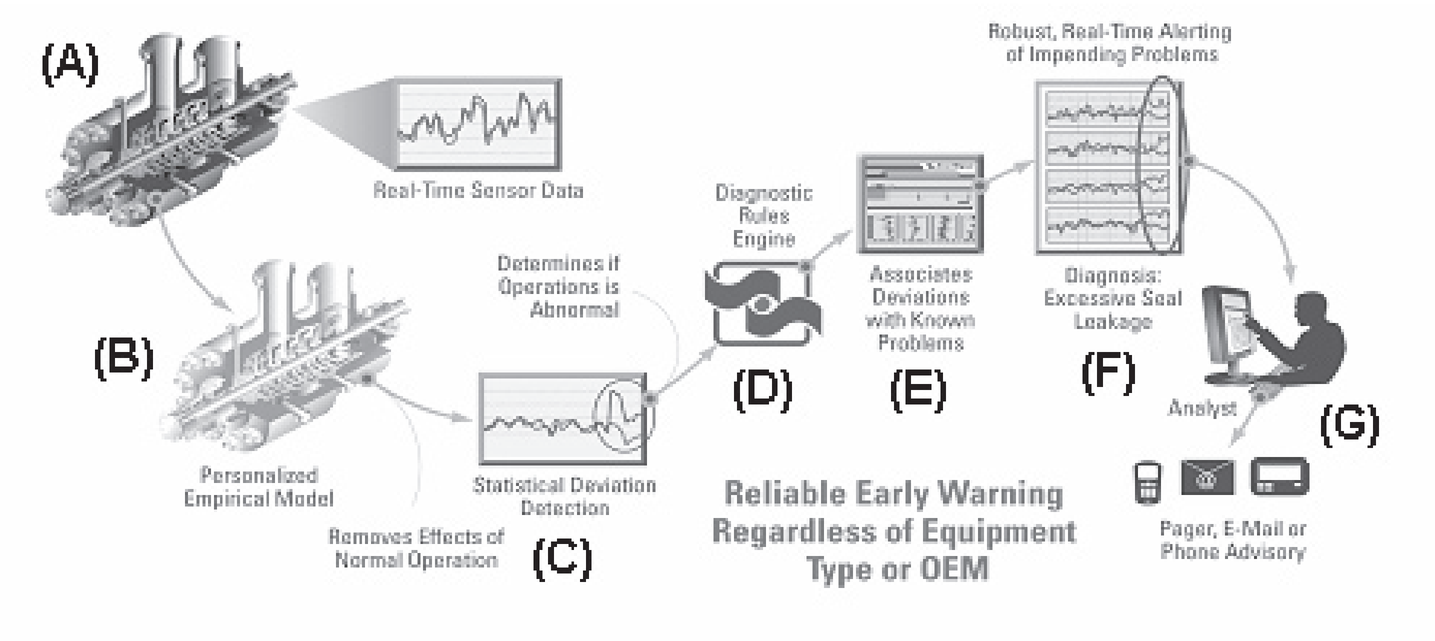
The component health analyst can program the system to provide alerts when the residual exceeds certain thresholds for certain levels of sensitivity. These alerts notify the analyst when a component or signal should be investigated for degradation. When a number of assets are monitored in this manner the health analyst allows the system to monitor the health of those components. Properly set up this system results in "health by exclusion" in that the analyst responds only to those components and signals that deviate from normal behavior and cause alerts.

Feedwater (FW) pump data from the Arizona Public Service Palo Verde Nuclear Generating Station are used to provide an illustration of this monitoring method as embodied in SmartSignal's Equipment Condition Monitoring (eCM) system.

Monitoring Architecture

The monitoring approach described employs similarity-based modeling. Figure 1 illustrates its components.

Figure 1 – Monitoring Architecture



The monitoring system "flow" starts with real-time sensor data collected by a data historian (i.e. plant computer), **(A),** for a system or component. The sensors are chosen to represent the key correlating input and output values. The data is fed into a separate server where a personalized, empirical model captures the patterns and relationships of the group of signals **(B)**. A brief overview of this model is provided in the next section. The monitoring process compares the actual signal to an estimate of the normal signal behavior to generate a residual signal – i.e. the difference between the normal and the estimated behavior **(C)**. As any signal (or signals) within a group begins to deviate from its "normal" behavior the residual will demonstrate that a statistical deviation is occurring. The ability of this method to detect individual signal deviations in a group of signals provides early warning of degraded conditions.

Early warning is enhanced by the diagnostic rules engine of the monitoring process **(D)**. The diagnostic rules engine alerts the analyst when specific conditions (rules), programmed by the analyst **(E)**, are met. In the case of pumps, analysts can write rules that focus on failure mechanisms and rely on the sensor to provide early warning that a degraded condition exists. By reflection, when the system is in operation the analyst may determine that an active component is not degraded based on an absence of alerts. The diagnosis is directed to the analyst by means of a web-based application **(F)**. The analyst can then review and evaluate the equipment status **(G)** and contact the appropriate individuals.

To briefly explain the monitoring architecture shown above, the major steps an analyst would follow using this process are described below.

Training

The heart of the monitoring system is the ability to model a group of signals by recreating the patterns found in a set of signals during normal operation. The analyst imports data and then designates “good” operating data to train the model. The diagram below illustrates the screen where the analyst chose “good” data for training. The dark columns indicate ranges of data the analyst has chosen for training the model and can be adjusted by simple “point-click-drag” operations.

The analyst is working with a group of sensors. In this case the sensors are the pump speed, flow, suction and discharge pressures. The green vertical lines indicate the data chosen for training.

The sensors are chosen to represent the key correlating input and output values of the system. For example, the discharge pressure remains nearly constant but the pump speed increases when the suction pressure lowers to compensate for the additional work necessary for the required head.

The behavior of each sensor shows some correlation to the behavior of the other sensors within that group. The analyst chooses which sensors to include within the model to capture the range of correlated behavior that indicates good or healthy operation. The program then analyzes the patterns of correlation found within the designated training regions to generate estimates of the behavior of the group. Once training data has been selected, as shown above, the analyst tests the model.

Testing (Good Data)

The diagram below demonstrates the results of a test of the model shown above. Due to variation in correlation and normal process deviation a model will not perfectly match actual signals. If the analyst determines that his model does not work well enough then another cycle of designating “good” data ensues and is repeated until the model is satisfactory. Once satisfied, the analyst saves the model and activates the real-time data feed. At that point the model is “on-line” and monitoring equipment. However, the analyst will need to create or modify the alerts that the system provides.

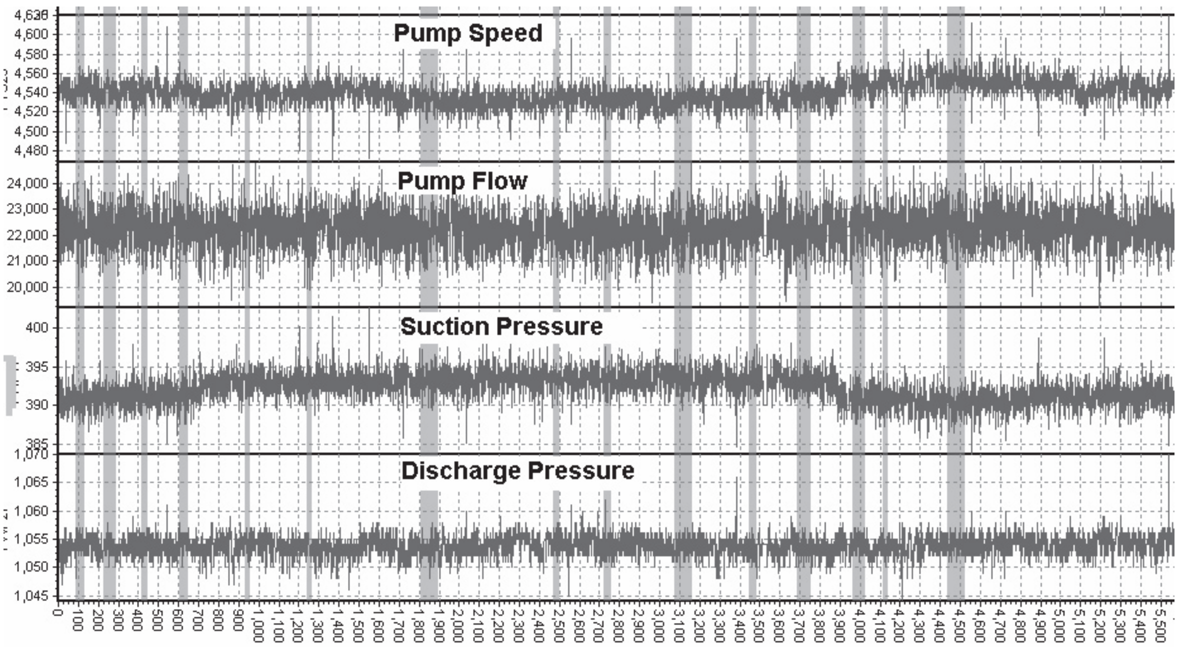


Figure 2 – Training Data Chosen for FW Pump Model
[X-axis = sample #, Y-axis = magnitude of signal
highlighted columns = data chosen as training data]

In Figure 3, an actual signal (darker = blue) is overlaid by the estimated signal (lighter = green) for the same pump parameters. In the next Figure, 4, the residual (difference between the actual and estimate) is displayed for the same parameters. Note that the residual generally distributes normally about zero. When the residual shifts from this distribution the analyst can conclude that something has changed. In some cases a sensor or data feed has a problem. In other cases the signal is indicating degradation of a component. Notice also that the magnitude of the residual is significantly smaller than the magnitude of the signal itself. For these four signals the magnitude of the residual runs between 0.2% and 2% of the signal which gives much greater sensitivity to identification of changes in the signal.

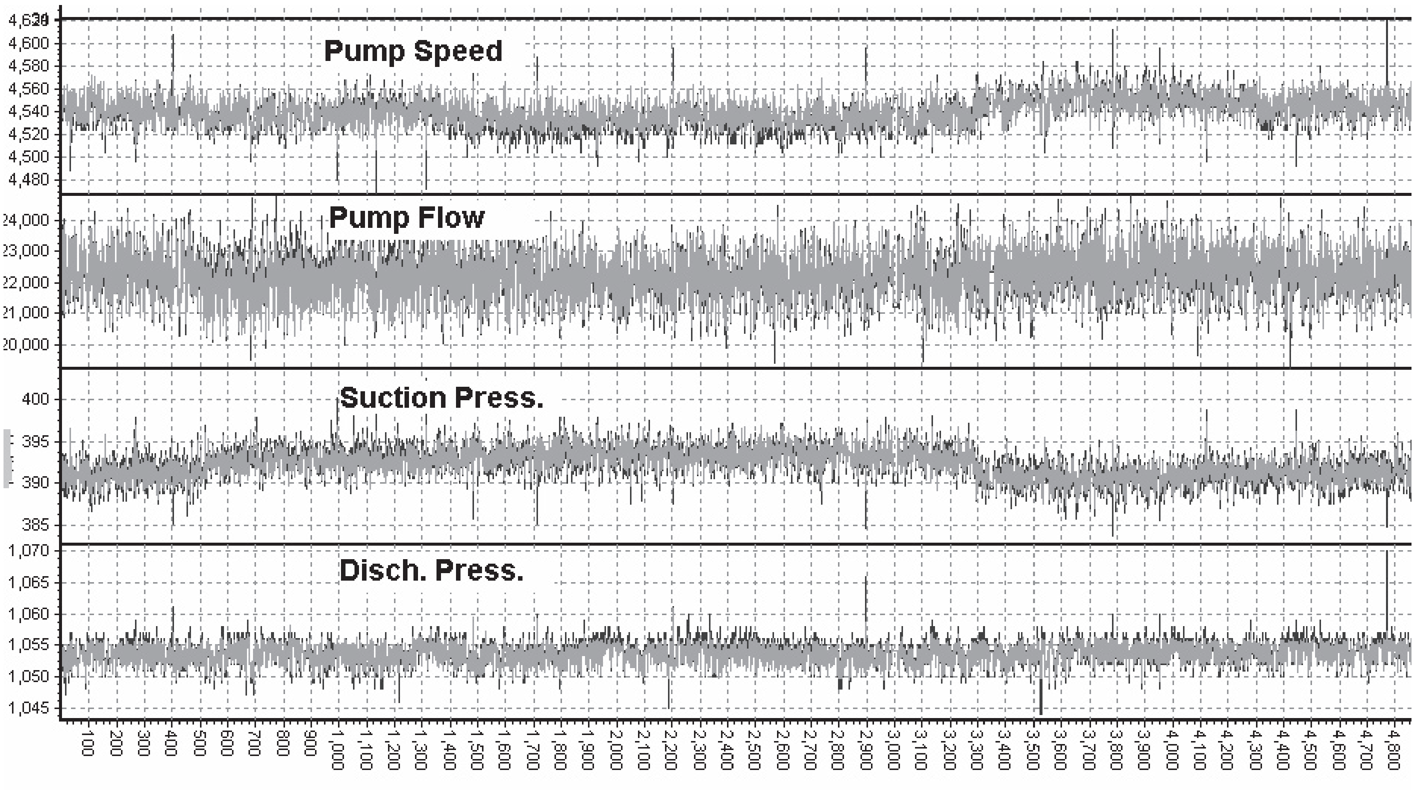


Figure 3 – Test Results for FW Pump Model (good data)
[X-axis = sample #, Y-axis = magnitude of signal,
dark line = actual signal, light line = estimated signal]

Testing (Faulted Data)

In a simple test of the sensors shown in Figure 4 a total 2% increase was incrementally added to the pump speed over an eight-month period, see Figure 5. The dark line at the top of the Pump Speed chart indicates that the sensor exceeded the pre-programmed threshold and would have provided an alert to the analyst. The threshold is variable, and the analyst can choose a more sensitive level. The alert occurred at about a 1.35% speed increase. Note that this approach detects faulted behavior when pump speed has increased from approximately 4550 rpm to 4600 rpm – typically undetectable due to the signal magnitude. This is about a three-sigma deviation of the individual signal.

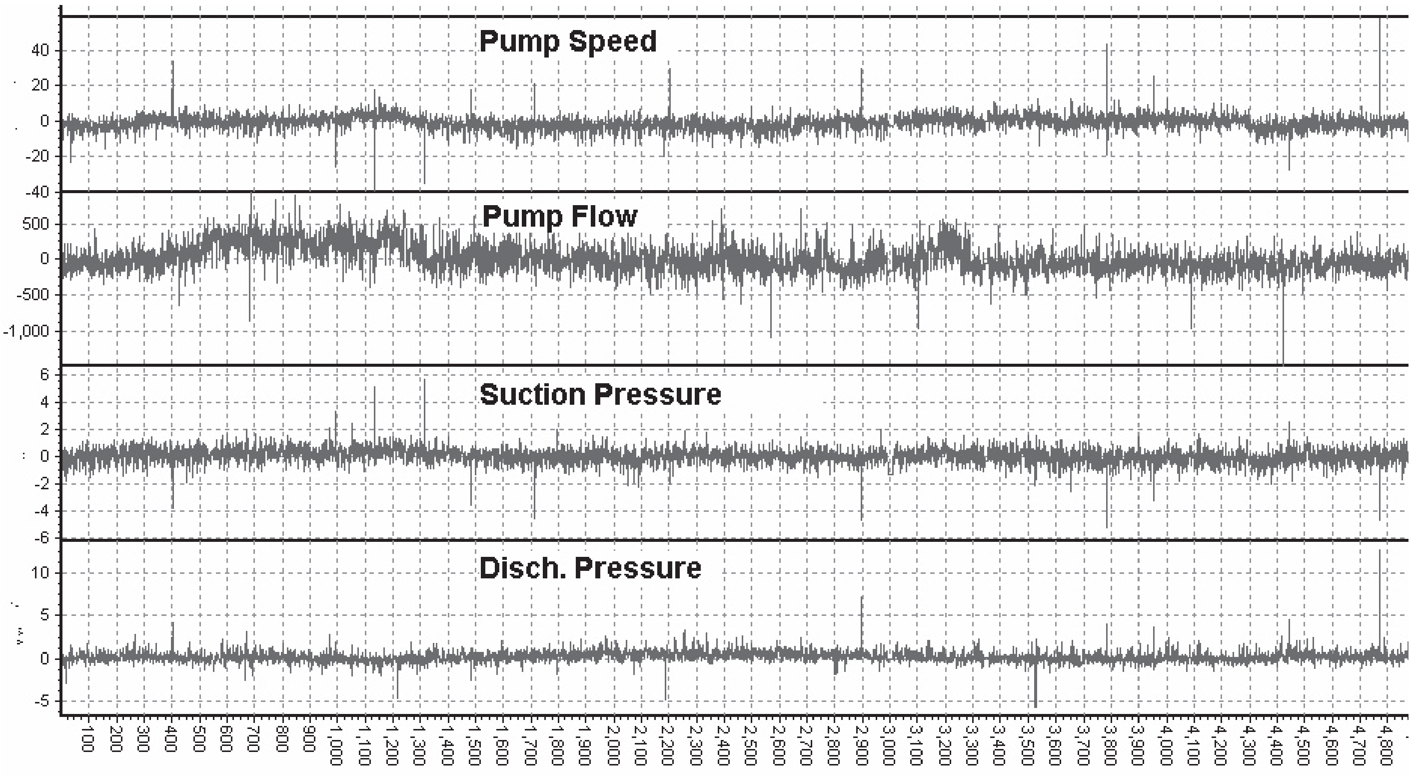


Figure 4 **– Test Results (residual only) for FW Pump (good data)**
[X-axis = sample #, Y-axis = magnitude of residual, dark line = residual]

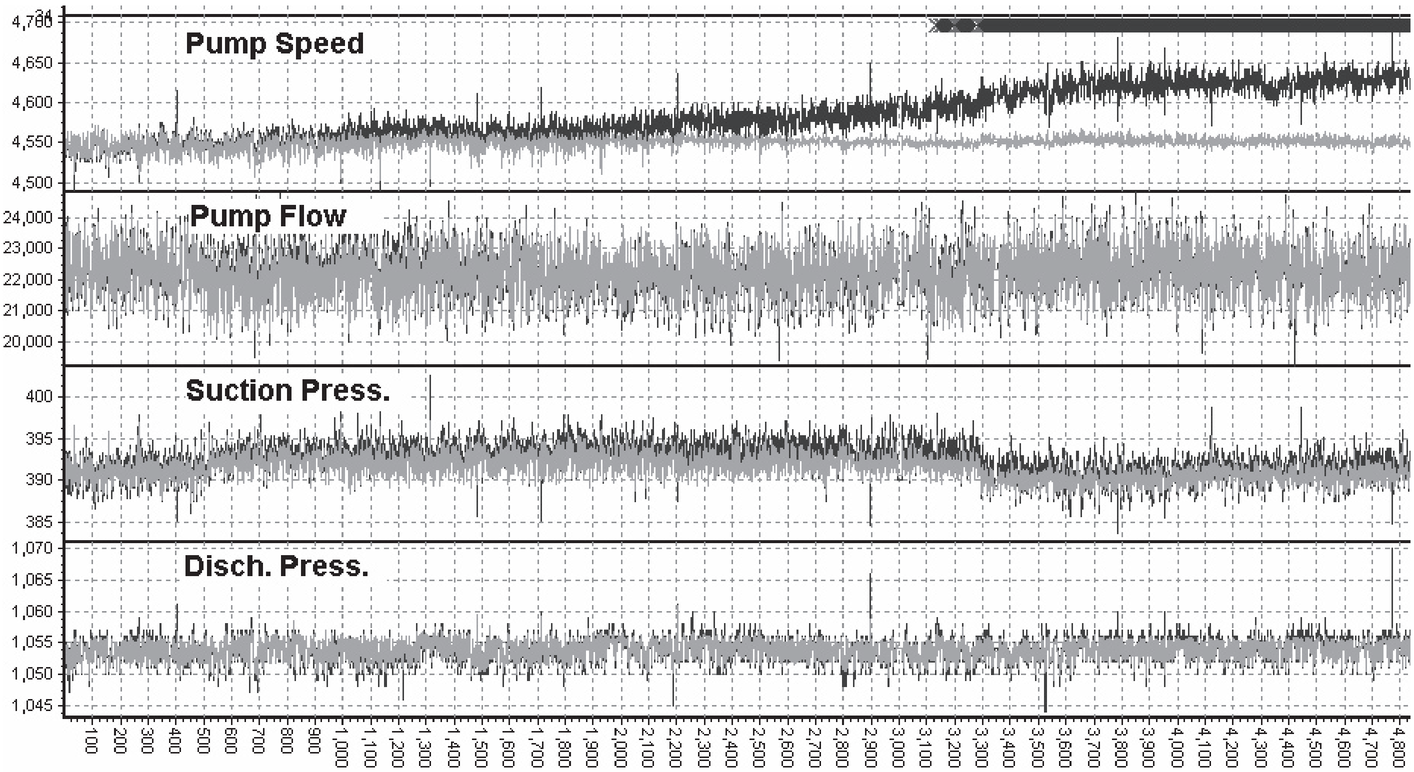


Figure 5 **– Test Results for FW Pump Test (speed increase)**
[X-axis = sample #, Y-axis = magnitude of signal,
dark line = actual signal, light line = estimated signal,
dark line at top-right of chart = alert]

For the same signals (same faulted test) the residual chart for the pump speed is shown below. The residual shows a steady rise with time and does not exhibit a normal distribution about zero.

This demonstration is simple and could be more complex. Only one signal is faulted, and the value rises at a steady rate. The alert level is fairly high and could be programmed to alert earlier. More complex models may include more sensors than shown for this model. Furthermore, the analyst may program the diagnostic rules engine to focus on multiple signals that highlight a specific failure mechanism.

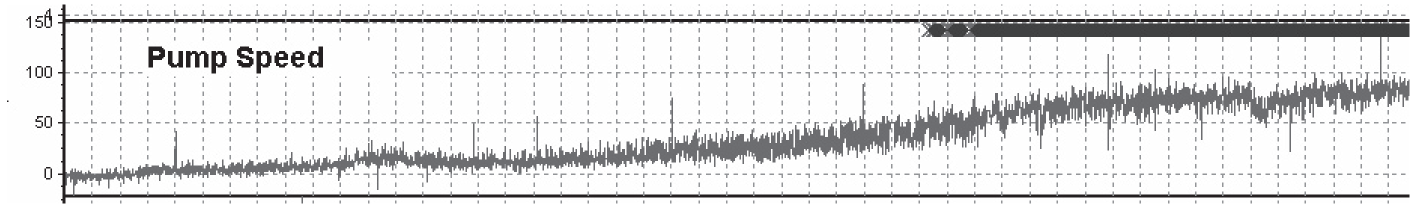


Figure 6 **– Test Result (residual only) for FW Pump Test**
[X-axis = sample # (not shown), Y-axis = magnitude of residual,
dark line = residual, dark line at top-right of chart = alert]

Diagnostic Rules

The analyst creates and edits rules that alert the analyst or operator to conditions requiring attention. An example of rule logic is shown below

Rule #1 Name: Pump Motor Winding Hot

Rule is true when:

Pump Motor Winding Temp > Threshold

<u>And</u>

Rule #2 is false

Result: Post alert to watchlist

Rule #2 Name: Pump Motor Problem

Rule is true when:

Pump Motor Winding Temp > Threshold

<u>And</u>

Pump Motor Amps > Threshold

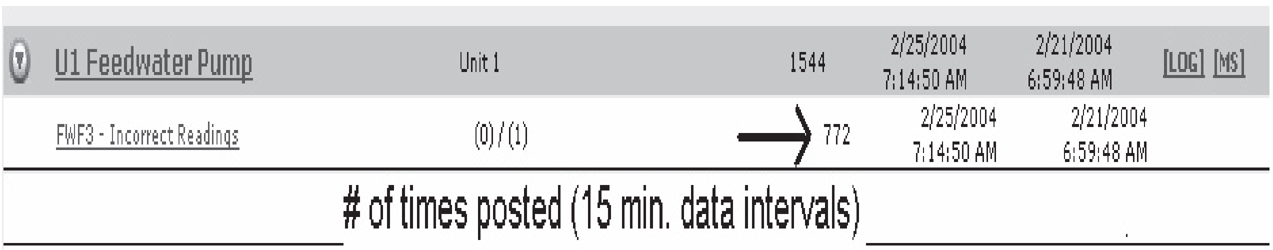
Result: Post Alert to watchlist

The result of any rule "posting" is a listing on a "watchlist", a web-browser-based viewer that provides access to charts of the sensors. In the example shown, rules have been combined to provide more meaningful information to the analyst and operator because a single sensor indicating behavior outside the range of normal behavior could have several causes. However, by not allowing that rule to be true by associating it with another rule presents a more meaningful alert to the analyst or operator.

Figure 7 illustrates a "watchlist" posting for a FW Pump. This example is provided to explain how the watchlist is used by the analyst, but it does not incorporate the rules identified above. A diagnostic rule which causes a posting is shown below the machine monitored (see Figure 7), and analysts can view both the number of posts and first/last date of the postings.

When a rule posts, the watchlist is automatically updated. When the analyst clicks on the rule, a page opens with the respective sensor graphs. Figure 8 shows the result of a posting to the watchlist for the rule shown above.

Figure 7 – Watchlist View for FW Pump



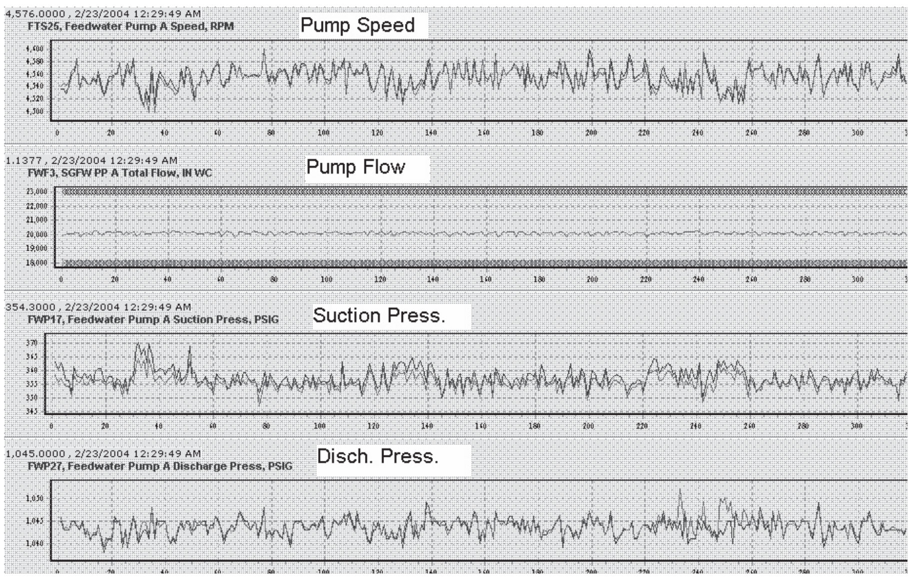


Figure 8 **– Watchlist Chart View for FW Pump**
[X-axis = sample #, Y-axis = magnitude of signal
dark line = actual signal, light line = estimate]

Summary and Conclusions

A monitoring process that employs similarity-based modeling has been very briefly described. An analyst creates empirical models involving multiple sensors by the following steps:

1. Import data to train a model
2. Select the data that designates "good" operation
3. Test the model (reselecting if needed until the test is satisfactory)
4. Create diagnostic rules to generate alerts

This monitoring process provides certain distinct advantages for monitoring active components at power plants. The patented signal analysis algorithms provide accurate estimates of groups of signals. The real-time monitoring and diagnostic rules result in constant monitoring in which the analyst only responds to alerts. Signal correlation provides the ability to screen out the effects of normal operation (e.g. a bearing temperature increasing due to an ambient temperature increase) and still provide early warning of signal problems or degraded conditions. The advantage of this process is that the analyst can assume "health by exclusion" for monitored assets and is directed only to areas where the asset is not performing satisfactorily.

The ability to closely monitor active components such as power plant pumps offers the power plant professional an alternative to routine testing. For high-value assets, or those requiring routine testing, this could translate into savings for the utility. However, proper application of this technology requires analysts who can identify "good" behavior and not train equipment on existing faults. When applied properly, the monitoring process described briefly above can be a powerful tool for power plant owners and operators who are concerned with the "health" of their active components – particularly their pumps. The analyst can create empirical models for each component, test those models, build diagnostic rules for those models then activate those models so that they are monitoring component health in real time.

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DESIGN, TESTING, AND IMPLEMENTATION OF MODIFICATIONS TO THE DAVIS-BESSE HPI PUMPS FOR DEBRIS LADEN WATER OPERATION

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Robert Schrauder, John O'Neill, and Steven Osting
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ABSTRACT

Following a loss of coolant accident (LOCA) in a pressurized water reactor (PWR), the emergency core cooling system (ECCS) pumps initially pump cooling water from a storage tank into the containment building. When the storage tank volume is depleted, the ECCS is placed in recirculation mode operation. While in recirculation mode, the ECCS pumps remove heat from containment by drawing suction from the containment emergency sump, directing the flow through a heat exchanger, and then pumping the flow back into containment. Following a LOCA, the containment emergency sump likely will contain debris generated by the blowdown forces of the break on nearby insulation, structures, coatings, and the like. The sump also may contain debris generated by effects of the environmental conditions on materials inside containment. The containment emergency sump design includes a strainer to prevent potentially damaging debris from reaching the ECCS pumps and equipment. However, debris particles smaller than the strainer mesh size may still be transported to the ECCS pumps.

The High Pressure Injection (HPI) pumps at the Davis-Besse Nuclear Power Station were discovered to have flow passages inside the pumps that were smaller than the containment emergency sump strainer mesh. The sump strainer mesh size is 4.8 millimeters (mm) (0.188 inch), while there are flow passages in the pump internals as small as 0.15mm (0.006 inch). Preliminary reviews by FirstEnergy, the plant owner/operator, determined that the pumps may not operate as designed with debris in the pumped water. Of particular concern was the hydrostatic bearing that provides shaft support at the end of the shaft. The bearing design included 2.8mm (0.109 inch) diameter orifices at the inlet to the bearing pockets. Large debris particles could plug these orifices and degrade bearing operation. In addition, the close clearances between the hydrostatic bearing pockets and the bearing shaft sleeve were as small as 0.15mm (0.006 inch) radially. Thus, debris particles may flow to the bearing pockets, but not be able to leave the pockets. Sufficient debris in the pockets could also degrade bearing operation. Additional analysis of the pump determined that the HPI pump has its first critical speed slightly above operating speed with original design close clearances at the stage-to-stage wear rings and bushing support (typically about 0.25mm (0.010 inch) radially). The debris in the pumped water following a LOCA likely will wear these close clearances and increase the clearances. Calculations showed that the first critical speed could decrease to the normal operating speed of 3550 revolutions per minute (rpm) if the clearances increased sufficiently. Pump operation at the critical speed could result in significant vibrations. Finally, pump hydraulic performance would also decrease with increased clearances as stage-to-stage leakage increases. Thus, pumping debris laden water following a LOCA potentially could degrade the ability of the HPI pumps to perform their intended safety function.

This paper describes the results of the comprehensive project to resolve these concerns with HPI pump operation. Overall, the concerns were resolved through a combination of pump modifications, analyses, qualification testing, and in-plant testing. The modifications included changes to the hydrostatic bearing and bearing supply flow path design to ensure proper operation with debris in the pumped water (including adding new strainers in the pump internals), as well as changes to internal pump components to increase their tolerance to debris. Qualification testing was performed to confirm proper function of the design modifications and to determine the wear rates of the pump close clearances. The testing program was performed using full scale pump components along with debris laden water with debris concentrations based on the predicted debris generation in the Davis-Besse containment. Design analyses to support the specific design modifications were performed. In addition, rotordynamics analyses of the pump were performed to demonstrate satisfactory vibration levels with increased close clearances, and hydraulic performance analyses were performed to demonstrate satisfactory hydraulic performance with increased close clearances. In-plant testing of HPI pumps was performed to determine pump vibration levels

and hydraulic performance with enlarged close clearances to benchmark analysis models and demonstrate acceptable pump operation with the clearances increased.

The results of the analyses and testing demonstrated that the modified pumps would operate as desired and perform their intended safety functions following a LOCA. However, some results developed during the testing indicate that the unmodified pumps may not have been able to perform their intended safety functions for all postulated accidents. In addition, the detrimental effects of debris on pump components were greater than expected. These results are also discussed in this paper.

BACKGROUND

Potential deficiencies were identified regarding the ability of the Davis-Besse High Pressure Injection (HPI) pumps to perform their design functions following a loss of coolant accident (LOCA). The postulated deficiencies concerned the potential for debris in the pumped fluid to affect pump operation. The containment emergency sump screens have a 4.8mm (0.188 inch) mesh. Thus, particles as large as 4.8mm (0.188 inch) could pass through the sump screens and enter the Emergency Core Cooling System (ECCS) piping when the ECCS is in recirculation mode operation taking suction from the containment emergency sump. The HPI pump design includes flow passages smaller than 4.8mm (0.188 inch) diameter that could plug or be impacted by the debris. In addition, the debris could cause wear of the close clearances in the pump, resulting in critical operating speeds near or at the running speed and reduced hydraulic capability. It was postulated that reliable pump operation can not be ensured under those conditions.

Various options to address the identified concerns were considered, including replacement of both HPI pumps and associated motors with new pumps and motors. The selected corrective action was to modify the existing pumps and confirm with test and analysis that the modified pumps would operate successfully with debris laden water.

HPI PUMP CONFIGURATION/DESIGN

The Davis-Besse High Pressure Injection (HPI) pumps were manufactured by B&W Canada and supplied during initial plant construction. The HPI pumps are horizontal, eleven stage centrifugal pumps, powered by 450 kilowatts (kW) (600 horsepower (HP)) electric motors. The design pressure is 13.8 Megapascals (MPa) (2000 pounds per square inch gage (psig)) and the design temperature is 150°C (300°F). The design and manufacturing code was the November 1968 ASME Pump & Valve Code, Class II.

A cross section of the pump configuration is shown in Figure 1. The pump design includes the following key elements:

- The eleven stages are arranged in a “2-9” configuration. Flow enters the pump and immediately enters the first stage. The second stage is adjacent to the first stage and pumps the flow through internal passages most of the length of the pump to the third stage which is located at the end of the pump furthest from the motor. Stages three through eleven are adjacent and pump the flow back to the pump discharge which is located opposite from the inlet.
- The main radial shaft supports are a roller bearing outside the pump, the central volute bushing located between the second stage and the eleventh stage, and a hydrostatic bearing located at the end of the pump adjacent to the third stage.
- There are two wear rings on each impeller, one on the suction side of the impeller and one on the discharge side. In addition to sealing, these rings may also provide radial support.
- The hydrostatic bearing supply flow is from two take-offs on the fourth stage volute. The bearing supply flow is routed through tubing back to the hydrostatic bearing, with the bearing discharge flow entering the third stage suction. The minimum flow cross section between the take-off and the bearing pockets are the orifices in the bearing that are 2.8mm (0.109 inch) diameter.

The HPI pump design includes a number of close clearances that could be impacted by pumping debris laden water. These clearances are as small as about 0.15mm (0.006 inch) normal design. Table 1 provides a summary of the close clearances affected by debris, and identifies the materials of the wearing surfaces.

APPROACH TO RESOLVE PROBLEM

The containment emergency sump screens have a 4.8mm (0.188 inch) mesh. Thus, particles as large as 4.8mm (0.188 inch) could pass through the sump screens and enter the Emergency Core Cooling System (ECCS) piping when the ECCS is in recirculation mode operation taking suction from the containment emergency sump. The evaluation of the HPI pump identified several concerns related to HPI pump operation while in ECCS recirculation mode. These concerns, which involve the impact of debris on flow passages in the pump smaller than 4.8mm (0.188 inch), are summarized in Table 2. The resolution approach for operation with debris laden water must address each of these concerns.

The overall approach for resolving the concerns with HPI pump operation with debris laden water is based on a combination of design modifications, testing, and analyses. The principal elements of the approach are summarized in Table 3.

MODIFICATIONS

The objectives of the pump modifications were to:

- Prevent debris that could plug the hydrostatic bearing orifices from reaching the hydrostatic bearing.
- Modify the bearing design so that debris that reaches the hydrostatic bearing can exit the bearing pockets so that sufficient flow is maintained through the bearing pockets.
- Minimize the wear of the close clearances while pumping debris laden water.

Several modifications were made to the HPI pumps to improve the pumps' tolerance to debris operation. These modifications are summarized below.

Strainer Installation and Location of Hydrostatic Bearing Supply Take-off

In the original HPI pump design, the take-off for the hydrostatic bearing supply was provided by two holes/ports at the periphery of the 4th stage volute. The pump modifications include adding strainers over the take-off ports to prevent large debris that could plug the bearing orifices from reaching the hydrostatic bearing orifices. In addition, the take-off ports were moved to the impeller discharge hub side of the 5th stage volute under the impeller and just above the wear ring. The radial location of the strainer in the pump and the configuration of the stages is shown in Figure 2. Moving the take-off to this location will reduce the concentration and size of debris available to reach the hydrostatic bearing, as well as increase the flow velocity over the strainer to keep it from plugging, based on the following effects:

- The centrifugal effect from the high circumferential flow velocity produces a radial pressure gradient that tends to "throw" the debris towards the outside of the volute and away from the take-off port which is located close to the shaft.
- The stage-to-stage leakage flow paths in the pump will result in water leaking from the 6th stage back into the 5th stage through the discharge hub wear ring and then past the take-off port. This leakage flow will likely be a major source of water to flow into the take-off port. The clearance between the impeller discharge hub and the wear ring is about 0.25mm (0.010 inch) radially. This close clearance will function as an additional strainer, reducing the amount of debris over 0.25mm (0.010 inch) in size that enters the take-off port.
- At the original location of the take-off port, at the volute periphery, the flow velocity varies depending on the pumped flow rate. At the new location of the take-off port under the impeller the circumferential flow velocity is essentially constant over all pump flow rates. The high velocity keeps the surface of the strainer clear of debris to prevent plugging.

Moving the take-off port to the 5th stage and adding the strainer required modifications to the 4th stage and 5th stage volutes and the hydrostatic bearing supply tubing. The modification activities for the volutes included plugging the flow holes in the 4th stage volute and modifying the 5th stage volute by machining recesses, counterboring, and drilling new flow holes through the solid sections of the volute to fit the strainer. Figure 3 illustrates the modification activities on both volutes.

Two strainers were installed, one over each hydrostatic bearing supply tube inlet. The strainers were welded in machined recesses at locations 180° apart. The strainers are constructed from 3mm (1/8 inch) thick sheet. Each strainer has 434 holes with a minimum diameter on the front face of 1.27mm (0.050 inch). The holes provide ample flow area while minimizing the pressure drop through the strainer. The strainer is tapered as shown on Figure 4. The taper prevents debris that is roughly the same size as the minimum diameter from getting lodged in the hole as it flows through the strainer. One potential concern for a stainless steel strainer is erosion of the surface when hard particles are flowing across it. If there is erosion on the face, the minimum diameter of the tapered hole increases as does the maximum size of potential debris that would enter the hydrostatic bearing. To reduce this effect, the strainers are fabricated from Haynes 25 alloy (AMS 5537) instead of stainless steel. Haynes 25 is a cobalt alloy that has significantly better erosion resistance than stainless steel.

Hydrostatic Bearing

The hydrostatic bearing design was modified to make it more tolerant to operation with debris laden water. The modified bearing design is shown in Figure 5. Features of the modified design include:

- "Escape" grooves were included between the bearing pockets and the bearing outlet. These grooves allow debris larger than the bearing close clearance around the pockets to exit the bearing.

- The bearing pocket configuration was changed from a rectangle to an "8" pattern. The "8" pattern bearing with grooves has comparable load carrying capability as the original rectangle bearing without grooves.
- The "8" pattern is based on an "H" pattern bearing developed by Pump Guinard, the original designer of the pump class. Qualification testing showed that the bearing pockets and orifices in the "8" bearing would not fully plug under debris loading. Furthermore, extrapolation of testing conducted earlier by Pump Guinard from their "H" design showed the "8" bearing would still provide adequate stiffness as a hydrodynamic bearing if flow were lost. Since the bearing is not expected to plug and hydrodynamic capability is not required, this capability was not verified for the HPI pump. The feature was included for defense in depth.

Hardfacing of Wear Components

All critical wear surfaces in the pump were modified to apply hardfacing on the wear surfaces. The following components were replaced with new components with hardfacing:

- Suction wear rings
- Discharge wear rings
- Central volute bushing and central shaft sleeve
- Hydrostatic bearing and outboard bearing sleeve

The impeller hubs at the wear ring locations were already coated with tungsten carbide alloy LW-5 to achieve a wear resistant surface, so replacing that hardfacing was not required.

The replacement stationary wear parts were hardfaced with a 0.75mm (0.030 inch) minimum thickness coating of Stellite 6 on the wear surface. Replacement rotating wear parts were hardfaced with a 0.75mm (0.030 inch) minimum thickness coating of Stellite 12 on the wear surface. The wear combination of Stellite 6 on Stellite 12 was selected based upon (1) experience of reliable performance in safety-related applications, including with Pump Guinard pumps, (2) good corrosion resistance in stagnant PWR reactor coolant environment, and (3) demonstrated successful performance as a wear couple.

The base material of the replacement wear parts was changed to Inconel Alloy 600 to be a suitable substrate for the hardfacing. Inconel Alloy 600 was selected for the base material because its thermal expansion properties are similar to Stellite, its good corrosion resistance in a stagnant PWR reactor coolant environment, and Stellite is easy to apply to Inconel 600.

Design Analyses

Design analyses were performed to demonstrate the acceptability of the modifications. The analyses included:

- Three dimensional finite element stress analyses of the modified pump volute with the new strainer cavity. These analyses demonstrate that the volute stresses are acceptable under worst case loading.
- Three dimensional finite element stress analyses of the strainer. These analyses demonstrate that the strainer will not fail under worst case differential pressure loading.
- Seismic analysis of the volute, strainer, and bearing supply tubing. These analyses demonstrate that seismic loads will not impact pump operation.
- Equivalency evaluations were prepared to demonstrate that the replacement hardfaced parts were equivalent to the original parts in "form, fit, and function". These evaluations were performed considering critical dimensions, materials, and changes from the original design.
- Hydraulic analysis of the supply flow path to and through the hydrostatic bearing. These analyses were performed to demonstrate that the changes have minimal impact on hydrostatic bearing and pump hydraulics and to demonstrate that the hydrostatic bearing would operate similarly following the modifications.
- Failure modes and effects analysis was performed to determine the potential failure modes for the modified pump design and to determine the effects of the failure modes. This analysis showed that no new failure modes are introduced by the modifications or component replacements (with new materials)

QUALIFICATION TESTING

The objectives of the qualification testing were:

- Obtain component-specific wear data for the suction wear ring, discharge wear ring, central volute bushing, and hydrostatic bearing.
- Measure flow rates through the suction wear ring, discharge wear ring, central volute bushing, hydrostatic bearing, and hydrostatic bearing supply strainer.
- Confirm that the hydrostatic bearing orifices and supply pockets do not become plugged with debris to the point that the bearing cannot perform its intended function.
- Demonstrate that the hydrostatic bearing strainers will prevent large debris in the bearing supply flow from getting to the bearing.

- Demonstrate that the hydrostatic bearing strainers do not become plugged with debris to the extent that they prevent an adequate supply of water from reaching the bearing.

Overview

The qualification testing program was implemented using full scale mock-up fixtures of the critical components of the HPI pump. Pump parts and components that were modified or replaced as part of the modifications were tested using the new design. The qualification test program was implemented as a series of separate effects tests, with each test fixture/test loop representing a separate feature of the HPI pump design. Separate effects mock up testing is a representative approach to place HPI pump parts under the expected detrimental conditions they would face post-LOCA. Based on the comprehensive nature of the separate effects tests and the acceptable results, it was concluded that a test of the actual HPI pump with debris laden water was not required.

The key elements of the mock-up test program include:

- The test fixture designs match the critical characteristics of HPI pump components
- The test fixtures use full scale pump components
- The test program and test fixtures included the capability to pause/re-start tests to determine interim results
- The individual separate effects fixtures provided a flexible platform for evaluating alternate modifications before choosing the preferred design for final testing.

The testing of each component consisted of a series of tests with clean and debris-laden water. Each component was initially tested with clean water to obtain baseline data and assure that the facility and the test fixture were operating correctly. Following the clean water tests, the components were subject to a series of tests with debris-laden water. Following the debris testing, all of the test articles with close running clearances were tested again on clean water to assess the effects of wear on their flow characteristics.

The general arrangement of the test facility is shown in Figure 6. A central tank (Tank 1) capable of holding approximately 34 cubic meters (9,000 gallons) of water was used as the ultimate source of supply. During debris testing, the water in the tank was supplemented by a mixture of debris intended to represent the important characteristics of the debris that might be present in the containment emergency sump at Davis-Besse after a LOCA. The tank was equipped with a total of four agitators – two vertical paddle-type agitators and two submersible pumps – to help keep the debris in suspension.

The test loops for the suction wear ring (Loop 1), the discharge wear ring (Loop 2), the central volute bushing (Loop 4), and the hydrostatic bearing supply strainers (Loop 5) were supplied directly from Tank 1. The hydrostatic bearing tester (Loop 3) was supplied indirectly from Tank 1 via one of the hydrostatic bearing supply strainers in Loop 5. The Loop 5 fixture included two hydrostatic bearing supply strainers. The output of one of the hydrostatic bearing supply strainers was used to continuously supply Tank 2 in Loop 3. The hydrostatic bearing supply pump takes suction on Tank 2 and supplies the hydrostatic bearing. Tank 2 is agitated by the combined action of an external paddle-type agitator and the return of excess flow from the bearing supply pump. A return pump takes suction on Tank 2 and returns water to Tank 1 as necessary to control the water level in Tank 2. Figure 7 shows the configuration of a typical test loop.

Test Fixture Design/Equivalency Evaluation

The test fixtures for the close clearance components in the pump (the wear rings, central volute bushing, and hydrostatic bearing) were constructed similarly. The pump component to be tested was installed in a fixture that recreated the configuration in the HPI pump, and an external pump was used to create a pressure difference across the clearance and a simulated flow through the pump. The flows through the clearance were measured during the testing and the clearances were measured periodically during the testing by disassembling the fixtures.

The test fixture for the hydrostatic bearing supply strainers (Loop 5) was a single stage centrifugal pump with similar configuration and critical dimensions as a stage of the HPI pump. The strainers are installed in the pump volute in the same radial location as in the HPI pump. The design of the Loop 5 pump precluded simulating the discharge side of the volute and the strainer effect from flow passing through the discharge wear ring. As a result, the amount and size of debris present at the strainer surface for the Loop 5 pump is considered to be greater than what would be present in the HPI pump (i.e., a conservative testing approach).

Detailed evaluations were performed to demonstrate that the test fixtures and test loops were sufficiently representative of the HPI pump. The evaluation of the test fixtures and test loops considered the main attributes of design configuration, flow fields, operating conditions, and debris characterization.

Design Configuration

The proper mock-up of the design configuration ensures that the flow areas, wear couples, etc., are suitably representative. The following critical characteristics were evaluated:

- Key dimensions – the sizes of the fixture components as well as the clearances between components
- Materials – the hardness and strength of the parts used to represent the components

These critical characteristics were confirmed for each fixture by performing detailed receipt inspections of the fabricated fixtures.

Flow Fields

Proper representation of the flow fields is necessary to model the flow of debris through the fixture and the pump, in particular near and through close clearances. Appropriate flow fields were established based on the dimensional and operational characteristics of each test fixture. The operating conditions were controlled via the velocity and direction of inlet flow to each fixture and the motor rotational speed driving the rotating parts. The following critical characteristics were evaluated regarding the flow conditions in the test fixtures:

- Flow velocities (direction and magnitude) into the test fixtures
- Flow directions and profiles near the inlets to the close clearances
- Differential pressures across the close clearances that drive flow through the clearance

The inlet flow velocities were determined by calculation using the flow areas through the HPI pump and test fixture and the simulated pump flow rate. The flow profiles near the close clearances were evaluated using computational fluid dynamics (CFD) modeling leading to qualitative evaluation of the flows through the test fixtures compared to the HPI pump. The differential pressures were determined by calculation using the HPI pump design and the simulated flow conditions.

All flow fields in the test fixtures are representative of the corresponding flow fields in the HPI pumps.

Operating Conditions

The HPI pumps operate at different conditions depending on the size of postulated pipe breaks and the time frame following the pipe break. The selection of the operating conditions for performing mock-up testing is based on an evaluation of these pump operating conditions and the potential for pump degradation.

For the purposes of establishing the qualification test program, the critical characteristics for selecting the pump operating conditions are:

- The simulated pump operating conditions must be comparable to the conditions that would exist following a LOCA when the HPI pumps are performing their required safety functions.
- The simulated pump operating conditions should represent conditions that maximize the potential for pump degradation due to pumping debris laden water.
- The simulated pump operating conditions must match pump operating conditions with the expected debris concentrations that would be present in that operating mode.

The evaluation of the HPI pump operating conditions determined that the limiting conditions for pump degradation are long term boron precipitation control cooling following a large break LOCA. This condition includes the worst case debris in containment following a large break LOCA with pump head/flow conditions of about 57 cubic meters per hour (m3/hr) (250 gallons per minute (gpm)).

Debris Characterization

Selection of the debris for use in qualification testing is a critical aspect of the qualification testing program. Since the testing is performed to investigate the effects of debris on pump internal components, the debris used in the testing must be representative of the debris that could reach the HPI pump following a LOCA.

Determination of the appropriate debris for mock-up testing is a multi-step process involving the following major activities.

1. Debris Generation – Determine the various types and quantities of debris that would exist in a post-LOCA containment environment and have the potential to be transported to the containment sump.
2. Debris Transport – Of the debris that would be in the containment in a post-LOCA environment, determine the type and quantities of debris that could be transported to the containment emergency sump during recirculation operation. For evaluating the HPI pumps, all debris that can be transported to the sump is assumed to pass through the sump strainer and reach the HPI pumps.
3. Debris Critical Characteristics – Establish the characteristics of each debris type that are essential for mock-up testing (e.g., particle sizes, quantities, types of material, material properties, etc.).
4. Representative Debris for Testing – Using the critical characteristics for the debris, select representative debris to be used in the mock-up testing.

As discussed above, the limiting condition for debris generation is a large break LOCA. The analyses performed for the HPI pump modification testing were based on the analyses performed for the design of the containment sump strainer. The key difference is that the debris generation and transport analyses were modified to ensure that conservative assumptions were used for evaluating conditions downstream of the sump, at the inlet to the HPI pump instead of evaluating conditions at the sump strainer. The result was the determination of the types, sizes, and quantities of the debris expected to flow through the HPI pumps. These results were used to select representative debris materials for the qualification testing. The debris used in the test program is summarized in Table 4.

Test Results

The key results of the qualification testing were:

- As shown in Figure 8, the suction wear rings and impeller suction hubs showed no significant wear or flow increase from operations with debris. This is believed to result from the impeller causing the debris to be “thrown” to the periphery of the volute, away from the suction wear ring.
- The discharge wear ring showed minimal wear, but there was significant wear of the rotating impeller discharge hub. As shown in Figure 9, wear-through of the tungsten carbide coating led to a deep wear groove in the softer hub material. Abrasive wear by accumulation of debris appeared to be the major mechanism for the wear. The discharge wear ring results differ from those of the suction wear rings because there is no impeller at the inlet to the discharge wear ring to force the debris away from the clearance inlet.
- The hydrostatic bearing orifices operated without plugging. The bearing experienced minor and temporary flow-rate reductions during testing, probably as a result of minor debris accumulations in the bearing. Debris, mainly fiber and fine particles captured by the fiber, tended to collect in the bearing, primarily at the pocket islands and in the inter-pocket running clearances. Significant wear of the rotor sleeve occurred as a result of this debris. The sleeve hardfacing was worn to a clearance about two to three times the original clearance, but not through the hardfacing. The bearing showed no tendency to bind during operation and the flow remained sufficient for the test duration. The bearing and shaft sleeve after testing are shown in Figure 10.
- The central volute bushing showed minimal wear, but there was significant wear of the rotating sleeve. The sleeve hardfacing of the outboard sleeve was worn to a clearance about two to three times the original clearance, but not through the hardfacing. The final condition of the sleeve is shown in Figure 11.
- The hydrostatic bearing supply strainers worked well. The flow to the hydrostatic bearing remained constant throughout the testing.

IN-PLANT TESTING

The in-plant testing was performed primarily to support benchmarking of the rotordynamics and hydraulic analysis models. The testing also showed that the pumps operate satisfactorily with the close clearances increased. Two tests were performed. The baseline test was performed using an essentially new pump with design close clearances. The second test was performed using the spare pump, which had the close clearances machined and increased to twice the design clearance. The in-plant tests were expanded pump surveillance tests. Special instrumentation was installed and the pumps were tested over the complete range of operating flows. The pump vibration levels and hydraulic performance were recorded over the flow range.

The baseline testing was performed using the P58-1R HPI pump. This pump had been installed new at Davis-Besse in 2001. Since the pump internal assembly was relatively new, the close clearances in the pump (wear rings, hydrostatic bearing, and central volute bushing) were comparable to the original design clearances (i.e., “1X”). The objectives of the baseline pump test were to:

- Establish a baseline for the nominal close clearance case. This allows subsequent test(s) with increased close clearances to provide direct measure of the effects of increasing the clearances on pump head/flow and vibration.
- Provide detailed measurements for use in validating the rotordynamics model and the pump hydraulic performance model.

The worn pump testing was performed using the spare HPI pump element (P58-1O). This pump element was recently removed from service. The pump element was disassembled and the close clearances in this pump element were increased to twice the normal values. The clearances at the hydrostatic bearing, central volute bushing, and wear rings were all increased. The value of twice normal clearances was selected (1) because typical maintenance approaches with similar rotating equipment is to refurbish the pump when clearances reach twice normal, and (2) it was expected that the actual close clearance wear during recirculation mode operation would be about this amount or less. The objectives of the worn pump test were to:

- Demonstrate that large amounts of wear of pump wear rings and bearings (wear to twice the normal clearances) does not result in unacceptable pump performance.
- Confirm the rotordynamics model predictions of the effects of increased clearances on pump vibration. This confirmed model could then be used to assure that other potential wear conditions which were not measured in the in-plant test would not result in unacceptable pump behavior.
- Provide additional pump hydraulic performance data for validating the pump hydraulic performance model.

In addition to the baseline and worn pump tests, post-modification testing was performed for both pumps re-installed in the plant. This testing demonstrated that the pumps operate satisfactorily after reassembly with modified and replacement parts.

ANALYSES

Wear, hydraulic, and rotordynamic analyses were performed to demonstrate the modified HPI pumps are acceptable for operation under normal and debris operating conditions.

Wear Analyses

The objective of the wear analyses was to estimate, using the results of the qualification testing, the "worn conditions" of the HPI pump close clearances after pumping debris laden water in the post-LOCA environment. The worn conditions are evaluated using hydraulic and rotordynamic analyses to demonstrate adequate performance of the HPI pumps following a LOCA.

The increases in the HPI pump close clearances following a LOCA were predicted based on analysis and the results of qualification testing using HPI pump components under debris loading conditions. The wear of the close clearances resulted from a combination of erosive and abrasive wear as the debris flowed through the clearance. Abrasive wear is dependent on several factors, including debris type and concentration, surface material and condition, etc. As a result, it is difficult to predict wear rates without testing of the actual conditions. Thus, the predictions for wear of the pump close clearances were based primarily on the results of the qualification testing.

The results of the qualification testing for each close clearance were used to develop predictions for clearance increases during post-LOCA operation. Two adjustments were made to the test results. First, the results were adjusted based on measured flow through the clearance. Since the wear is a function of the volume of debris flowing through the clearance, the wear rates were adjusted based on the ratio of flow through the test fixture clearances compared to the expected flow in the HPI pump. Second, the results were extrapolated to 30 days of operation. (Wear testing durations varied from 21 to 24 days for the various test fixtures). The results of the wear predictions provide a conservative estimate of the clearance increase following a LOCA.

Essentially all wear in all the test fixtures was on the rotating components. The stationary components experienced very little, if any wear. Table 5 provides a summary of the predictions for the worn conditions for the close clearances as a function of time following the LOCA. The results for individual components are discussed below.

- Suction Wear Ring – The suction wear ring and impeller hub surfaces exhibited relatively little wear during the testing. The predicted clearance increase after 30 days is only about 0.10mm (0.004 inch) (diametral), compared to an initial diametral clearance of 0.50mm (0.020 inch).
- Discharge Wear Ring – Measurable wear was seen across the impeller hub during testing. In addition, a deep groove developed near the clearance exit. Based on these results, the length of the wear ring clearance post-LOCA is assumed to be shorter by the length of the groove and the clearance width over the remaining hub surface is predicted to increase by about 0.94mm (0.037 inch) (diametral) after 30 days (compared to an initial diametral clearance of 0.50mm (0.020 inch)).
- Central Volute Bushing – The central volute bushing sleeve exhibited wear during the testing. The predicted clearance increase after 30 days is about 0.64mm (0.025 inch) (diametral), compared to an initial diametral clearance of 0.33mm (0.013 inch).
- Hydrostatic Bearing – The wear of the shaft sleeve during testing was not uniform. Different regions of the sleeve experienced different amounts of wear due to the flow fields in the bearing and the locations were debris became lodged. The first 10mm (0.4 inches) from the axial ends of the bearing wore the least (edge of the bearing). The middle of the bearing under the orifices wore slightly more (center of the bearing). The most wear occurred between the middle of the bearing and the edge of the bearing (central portion of the bearing). The predicted clearance increases after 30 days are between 0.46mm (0.018 inch) and 1.17mm (0.046 inch) (diametral), compared to an initial diametral clearance of 0.36mm (0.014 inch).

Hydraulic Analyses

The objective of the hydraulic analyses was to demonstrate that the HPI pump would perform satisfactorily and provide the necessary head/flow for all required operating conditions, including following a LOCA.

The approach used to evaluate the hydraulic capability of the HPI pumps was to use a hydraulic model of the pump to predict head/flow capability in the worn condition for comparison to the required capability based on HPI system safety functions.

The HPI pump hydraulic model was constructed from a first principles model of the pump. The model is based on the head/flow characteristics of the HPI pump impellers and includes the leakage flows through the close clearances at the wear rings, central volute bushing, and hydrostatic bearing. The widths of the close clearances are inputs and the model automatically calculates the hydraulic resistance of each leakage flow path based on the flow area and pump conditions. The hydraulic model was benchmarked using measured head/flow performance during in-plant testing.

The required hydraulic capability for the HPI pumps is based on the HPI system safety functions. Immediately following a LOCA, the required head/flow capability is that assumed in the small break LOCA safety analyses (essentially the quarterly surveillance test acceptance criteria). Long term hydraulic capability following the LOCA is based on boron precipitation control requirements. In boron precipitation control mode following a LOCA, the HPI flow through the auxiliary pressurizer spray line is the flow required to remove the decay heat plus an additional flow to prevent stagnation in the reactor vessel and any flow through the pump minimum flow line. The required boron precipitation control flow rate shortly after a LOCA is 57 m3/hr (250 gpm). In the plant safety analyses this minimum flow was assumed to remain constant for the duration of the period after the LOCA. Additional analyses were prepared for this evaluation taking into consideration the decrease in decay heat following the LOCA. This analysis showed that the required flow capability dropped significantly after several days following the LOCA.

The predicted worn conditions as a function of time (Table 5) were used as the input conditions for the hydraulic model to predict pump capability following the LOCA. In addition, the required capability was determined as a function of time following the LOCA. The results of these calculations are shown in Figure 12. This figure shows that the hydraulic capability of the HPI pumps decreases slowly until about 30 days following the LOCA, then remains relatively high after even longer periods. However, the required capability decreases rapidly following the LOCA. Within one day following the LOCA the required capability is less than about 45 m3/hr (200 gpm) at about 365 m (1200 feet) of head. After 30 days the required capability is only about 23 m3/hr (100 gpm) at about 150 m (500 feet) of head. Thus, the modified HPI pumps have considerable margin between the required and available hydraulic capability.

Rotordynamics Analyses

The objective of the rotordynamics analyses was to demonstrate that the HPI pump would operate satisfactorily, without excessive vibration, over the full range of pump flows for the predicted increase in close clearances.

The rotordynamic model of the HPI pump is a finite element model developed with the ANSYS general purpose computer program. The shaft is represented by beam elements, the impellers are represented by lumped masses with rotary inertia, the roller bearing is represented by spring elements, and the hydrostatic bearing and wear rings are represented by stiffness and damping matrices.

The stiffness and damping characteristics of the hydrostatic bearing, wear rings and central volute bushing depend on the pump operating conditions. As pump flow is increased, the differential pressure across each pump stage decreases and the stiffness of the rotor support elements decreases. The stiffness of these elements also decreases as the components wear. The stiffness of these elements was calculated based on the predicted worn conditions. In addition, the discharge wear rings are conservatively not modeled in the rotordynamic analysis because no appreciable flow was measured through the discharge wear rings for over half of the mock-up testing. Without flow, the discharge wear ring does not develop rotordynamic stiffness.

The HPI pump is considered to be acceptable if the vibration amplitudes allow the predicted minimum steady state film thicknesses in close clearances to be maintained. Figure 13 compares the results of rotordynamic analyses for the HPI pump with the new "8" pocket design hydrostatic bearing for nominal design clearances (1X) and the original rectangular pocket hydrostatic bearing for nominal design clearances. The hydrostatic bearing modifications have an insignificant effect on overall rotor-dynamic performance.

The expected rotordynamic performance of the HPI pump with the new hydrostatic bearing was evaluated at Days 10, 20, and 30 following a LOCA event. Support stiffness was based on the increases in clearances shown in Table 5. Figure 14 shows the predicted rotor deflections when the pump is running for the design case and for the three wear conditions. The maximum rotor deflection occurs at the hydrostatic bearing end of the rotor for Day 30 wear.

The predicted maximum deflection at the suction wear ring closest to the hydrostatic bearing is 0.10mm (0.004 inch). The limit on deflection is set by the suction wear rings. At Day 30, the suction wear ring and hydrostatic bearing radial clearances are predicted to be 0.30mm (0.012 inch) and 0.53mm (0.021 inch) respectively. Metal-to-metal contact would occur first at the suction wear ring closest to the hydrostatic bearing. At Day 30, there is 0.20mm (0.008 inch) of margin (0.30mm – 0.10mm = 0.20mm) (0.012 inch- 0.004 inch = 0.008 inch) in shaft deflection predicted to accommodate rotordynamic vibration.

Figure 15 shows the results of modal analyses. The nominal 1X clearance results from Figure 14 are included for comparison. The Day 10 first mode natural frequency crosses the pump running speed at 90 m3/hr (400 gpm) indicating a critical speed at that point. Day 20 and Day 30 first mode natural frequencies are less than the running speed for all pump flow rates.

Forced response analyses were performed to determine the expected rotor vibration amplitude in the post-LOCA condition. Scoping analyses indicated that the most limiting location in the pump for forced vibration is at the hydrostatic bearing. At this location, the forced vibration displacements in the worn condition were the greatest. Figure 16 shows the forced response results for LOCA conditions. The vibration amplitude at the hydrostatic bearing is plotted as a function of pump flow rate for the three wear conditions. The maximum vibration amplitude is 0.03mm (0.0012 inch). This is well within the 0.20mm (0.008 inch) available based on the rotor deflection analysis.

CONCLUSIONS

The main results of the design, analysis, and testing activities were:

- The modifications to the HPI pumps satisfy all applicable design criteria and assure that the pumps will operate successfully with the defined post-LOCA debris conditions. In addition, the modifications do not negatively affect "form, fit, or function," so the pump will continue to operate satisfactorily under normal, clean water conditions.
- The limiting condition for HPI pump operation with post-LOCA debris is long term boron precipitation control cooling following a large break LOCA. This condition has maximum debris in the containment emergency sump combined with a relatively low flow, high head pump condition.
- Qualification testing under debris loading of the modified hydrostatic bearing and a mock-up of the hydrostatic bearing supply strainer shows that the bearing and strainer will function adequately.
- Qualification testing of the HPI pump close clearances, coupled with wear analyses, determined that the suction wear rings would experience minimal increase in clearance under debris laden water service. The discharge wear rings showed significant clearance increase along with "grooving" at the exit of the clearance. The central volute bushing and hydrostatic bearing showed measurable wear (approximately three times the original clearance). Essentially all wear was on the rotating component; the stationary components experienced very little wear. These test results were used to determine the worn condition that would exist following a LOCA.
- Rotordynamic analyses for the HPI pump worn condition predicted to exist after 30 days post-LOCA show the pump will function satisfactorily. The maximum predicted pump vibrations are within the acceptance criteria and the bearing support system is adequate to support the weight of the rotating assembly.
- Hydraulic analyses for the HPI pump worn condition predicted to exist after 30 days post-LOCA show that the HPI pump has significant hydraulic margin for the limiting condition of boron precipitation control cooling.
- In-plant testing of an HPI pump modified to increase the close clearances to twice normal values showed satisfactory pump operation with vibration levels no greater than with normal clearances even with the pump operating near critical speed. This testing was used to qualify the rotordynamic and hydraulic analyses.

Based on the results described above, the modified Davis-Besse HPI pumps will operate satisfactorily under normal conditions and while pumping debris laden water following a postulated LOCA.

Table 1. HPI Pump Close Clearances

Clearance	Design Clearance[1] mm (inch)	Wearing Component/Material[2, 3]	
Central Volute Bushing	0.28 – 0.36 (0.011 – 0.014)	Shaft Sleeve/ Bronze B143, Alloy 903	Bushing/ Hardened 17-4PH SS
Suction Wear Ring	0.48 – 0.53 (0.019 – 0.021)	Impeller Hub/ Tungsten Carbide Coating	Wear Ring/ Hardened 17-4PH SS
Discharge Wear Ring	0.48 – 0.53 (0.019 – 0.021)	Impeller Hub/ Tungsten Carbide Coating	Wear Ring/ Hardened 17-4PH SS
Hydrostatic Bearing	0.30 – 0.38 (0.012 – 0.015)	Shaft Sleeve/ Bronze B103, Grade D	Bearing/ 431 SS

Notes:
1. All clearances are listed as diametral clearances.
2. Smaller diameter, rotating component listed first
3. Materials prior to modifications

Table 2. Concern Summary

Concern	Description
Hydrostatic Bearing Orifice Plugging	The supply flow to the hydrostatic bearing is taken off the fourth stage discharge and directed back to the bearing assembly which is at third stage pressure. There are two supply tubes in parallel; each tube is 9.5mm (0.375 inch) outside diameter, with 1.25mm (0.049 inch) wall. The supply flow enters the bearing assembly where it is distributed circumferentially around the bearing and through orifices into five bearing pockets. There is a single orifice feeding each pocket. The orifice diameter is about 2.8mm (0.109 inch). Since the containment emergency sump mesh is 4.8mm (0.188 inch), debris could pass through the sump mesh, flow to the HPI pump, enter the bearing supply tubing and plug the orifices. If the flow to the bearing pockets is reduced or the resistance of the orifice changes, the bearing may not function properly and reliable pump operation could be impacted.
Hydrostatic Bearing Pocket Plugging	The hydrostatic bearing design includes tight clearances (0.15 to 0.20mm (0.006 to 0.008 inch) radially) between the outlet of the bearing pockets and the shaft sleeve. All flow into the bearing pockets must pass through this clearance to enter the third stage suction flow. Since the containment emergency sump mesh is 4.8mm (0.188 inch), debris could pass through the sump mesh, flow to the HPI pump, enter the bearing supply tubing, flow to the bearing pockets, and then become lodged or stuck in the pockets. If the flow to the bearing pockets is reduced, the bearing may not function properly and reliable pump operation could be impacted.
Close Clearance Wear	The close clearances in the HPI pump are small. The clearances are as small as 0.15mm (0.006 inch) on the hydrostatic bearing, 0.14mm (0.0055 inch) on the central volute bushing, and 0.24mm (0.0095 inch) on the wear rings. A preliminary rotordynamics analysis of the HPI pump showed the pump first critical speed slightly above the normal operating speed for design flow and design clearances. During debris loading conditions, these clearances will wear and increase. When the clearances increase, the critical speed will decrease. Depending on the amount of wear, the critical speed could reduce to the operating speed, resulting in excessive vibration. The increased vibration could impact reliable pump operation. As the clearances increase, the stage to stage leakage through the close clearances will also increase. This increase in leakage will decrease pump hydraulic capability. The resulting pump hydraulic performance in the worn condition must satisfy the applicable design requirements.

Table 3. Resolution Approach Summary

Concern	Modifications	Testing	Analysis
Hydrostatic Bearing Supply Orifice Plugging and Bearing Pocket Plugging	• A strainer was installed in the pump volute at the take-off for the hydrostatic bearing supply flow to preclude debris larger than the orifice diameter from reaching the orifice. • The location of the take-off for the hydrostatic bearing supply flow was relocated to an inner radius on the pump volute discharge wear ring side to reduce the concentration and size of debris present at the supply line take-off. • "Escape" grooves were added to the hydrostatic bearing pockets to allow debris larger than the bearing clearance to leave the pockets. • The hydrostatic bearing pocket design was modified to increase the bearing stiffness so that the bearing with grooves has a stiffness comparable to the existing bearing.	• Mock-up testing of the strainer in the new supply line take-off location confirmed that the strainer will continue to provide flow (i.e., it will not fully plug with debris). • Mock-up testing of the strainer in the new supply line take-off location was used to obtain the debris loading for testing of the hydrostatic bearing. • Mock-up testing of the hydrostatic bearing assembly was performed with the debris laden water that could reach the bearing to confirm proper operation (maintain adequate supply flow to and through the bearing orifices and bearing pockets).	• The strainer design and volute modification were evaluated to demonstrate structural adequacy. • Rotordynamic bearing analyses were performed to confirm adequate stiffness and load carrying capacity of the new hydrostatic bearing design. • The modified hydrostatic bearing hydraulics (new take-off location and strainer) were included in the evaluation for pump hydraulic performance. • A failure modes and effects analysis was performed to assess the potential for, and implications of, postulated failure modes. • Engineering evaluations were performed to demonstrate that the mock-up testing fixtures, including mockup of the hydrostatic bearing intake flow through the strainer are suitably representative of the HPI pump critical characteristics.

Table 3. Resolution Approach Summary (continued)

Concern	Modifications	Testing	Analysis
Close Clearance Wear – Operation near Critical Speed Close Clearance Wear – Reduced Hydraulic Performance	• The components with wear surfaces were replaced with new components with hardfaced surfaces to minimize wear during debris operation. The suction wear rings, discharge wear rings, hydrostatic bearing and shaft sleeve, and central volute bushing and shaft sleeve were replaced.	• Mock-up testing was performed of the pump close clearances to determine wear rates while pumping debris laden water. Wear rates were determined for the hydrostatic bearing, suction wear ring, discharge wear ring, and central volute bushing, and associated rotating parts. • In-plant testing was performed for a relatively new HPI pump and a spare HPI pump artificially worn to large clearances (twice the normal design). Flow and hydraulic performance data and detailed vibration data were acquired for both tests to demonstrate that the pumps operated satisfactorily with the increased clearances.	• The results of mock-up wear testing were used to benchmark models to predict the increases in the close clearances during pump operation with debris laden water. • Rotordynamic analyses were performed to demonstrate that pump operation with the close clearances opened to the predicted worn conditions would not detrimentally affect pump operation and vibration levels would be acceptably low. The model was benchmarked using vibration data from the in-plant testing. • Hydraulic analyses were performed to demonstrate that pump performance with the close clearances opened to the predicted worn conditions would satisfy required head/flow requirements. The model was benchmarked using hydraulic performance data from the in-plant testing. • Engineering evaluations were performed to demonstrate that the mock-up testing fixtures are suitably representative of the HPI pump critical characteristics.

Table 4. Debris Characterization for Testing

Debris Type	Simulated Debris	Material Size Characteristics
Fibers	chopped E-glass fibers	Lengths = 1.6mm, 3mm, and 6mm (0.0625”, 0.125”, and 0.25”) Diameter = 8 µm
Dirt, Dust and Rust	Magnetite (iron oxide)	5.6% = 80 mesh 6.0% = 100 mesh 29.8% = 200 mesh 57.7% < 200 mesh
Concrete	Silica	Type 110, 570 and 2040 silica sand (sieved to obtain proper size distribution)
Coating particles	“Plasti-grit” (urea formaldehyde)	Stream Table Mix (sieved to obtain proper size distribution)
Coating chips	Chopped Plastic Chips (PVC)	Thickness = 0.25mm (0.010”) 0.031” < Diameter < 0.066”
Coating flakes	Plastic Chips (PVC)	Thickness = 0.25mm (0.010”) Diameter = 3mm (0.125”)

Table 5. Predicted Post-LOCA Diametral Clearances

Clearance	Clearance Following LOCA mm (mils)			
	0 Days	10 Days	20 Days	30 Days
Suction Wear Ring	0.51 (20.0)	0.56 (22.2)	0.59 (23.2)	0.61 (24.1)
Discharge Wear Ring	0.51 (20.0)	0.81 (31.9)	1.12 (44.2)	1.44 (56.6)
Central Volute Bushing	0.33 (13.1)	0.65 (25.5)	0.81 (31.8)	0.97 (38.0)
Hydrostatic Bearing Edge	0.36 (14.0)	0.59 (23.3)	0.83 (32.6)	1.06 (41.9)
Hydrostatic Bearing Interior	0.36 (14.0)	0.74 (29.3)	1.13 (44.6)	1.52 (59.9)
Hydrostatic Bearing Center	0.36 (14.0)	0.51 (20.0)	0.66 (26.0)	0.81 (32.0)

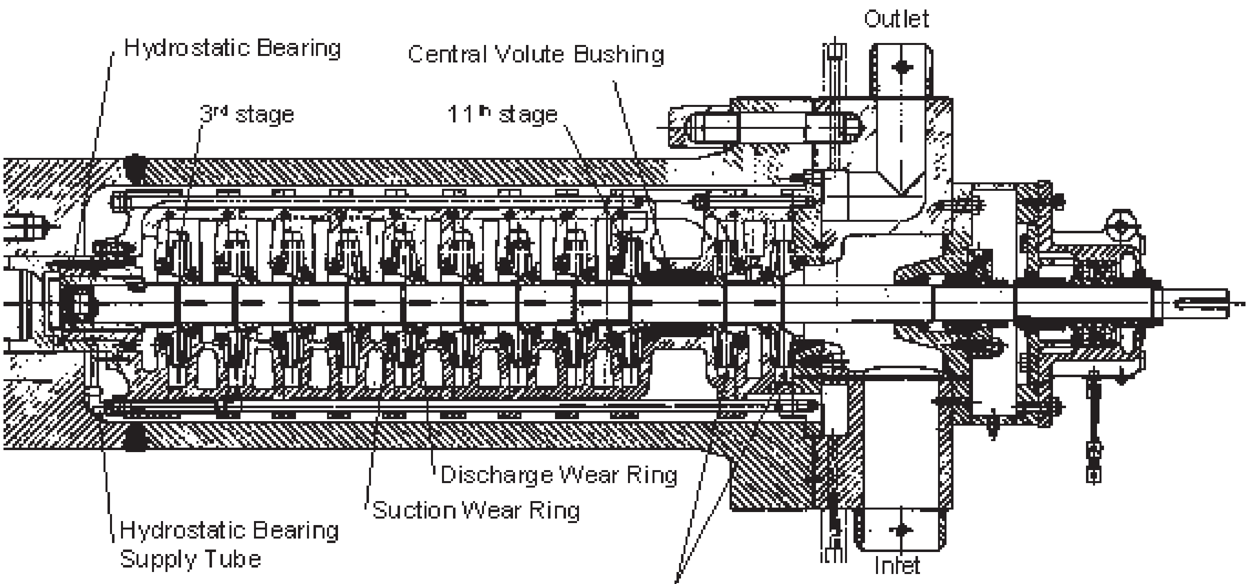


Figure 1. HPI Pump Configuration

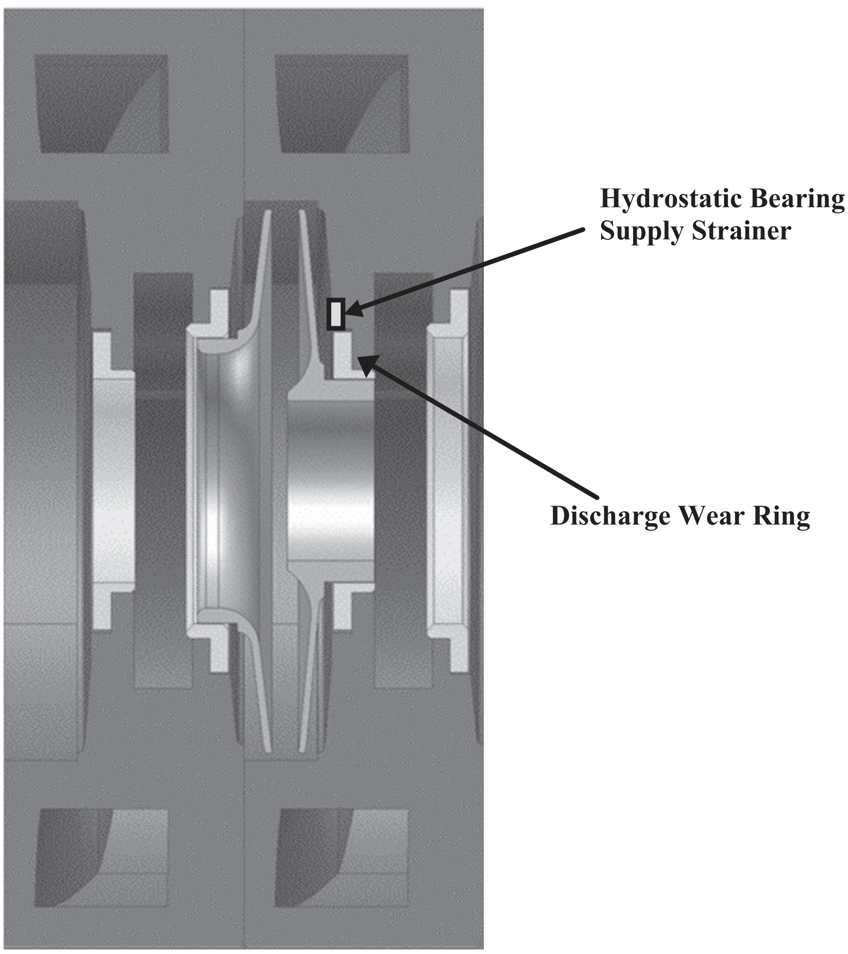


Figure 2. Hydrostatic Bearing Strainer Location

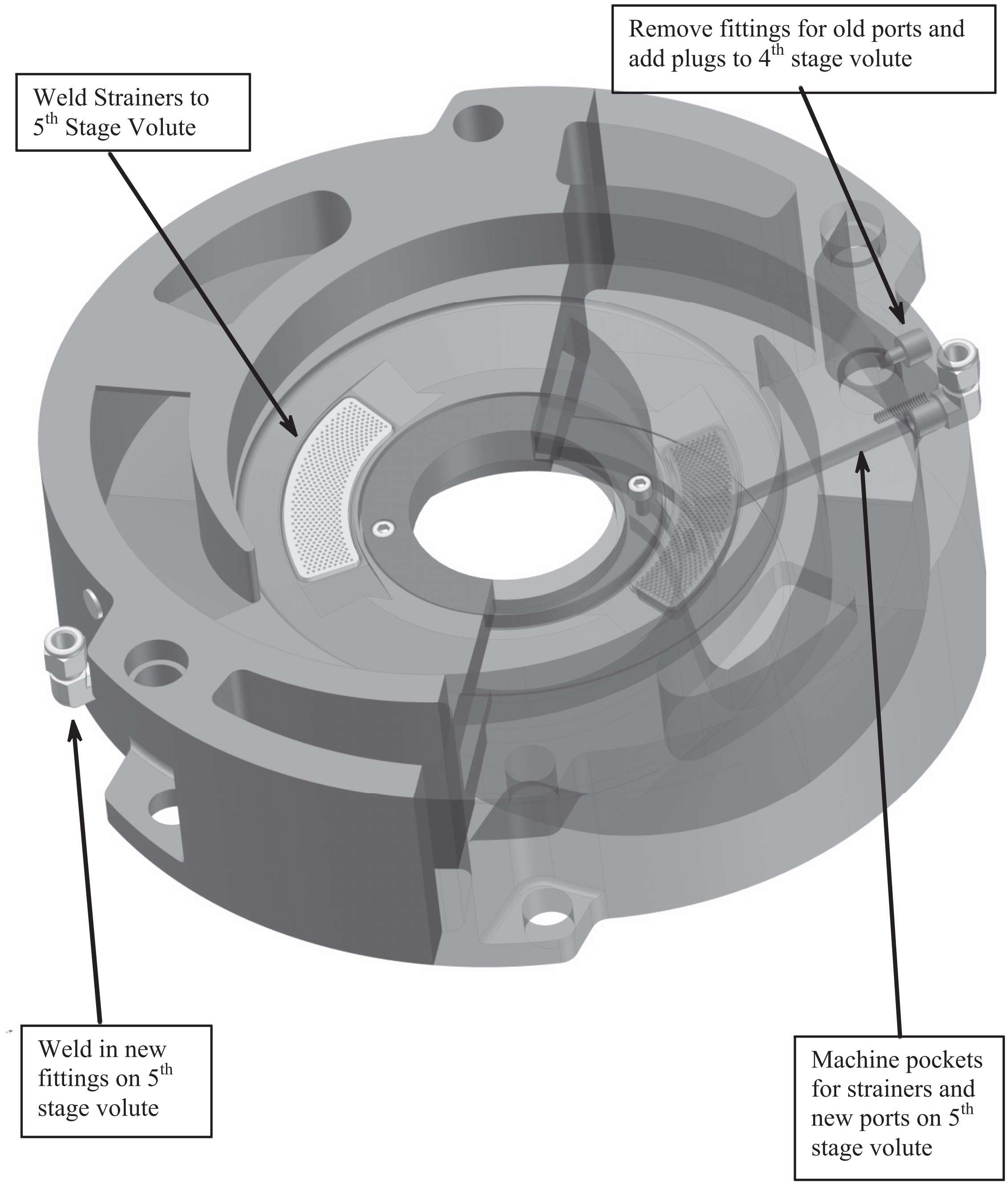


Figure 3. Volute Modifications

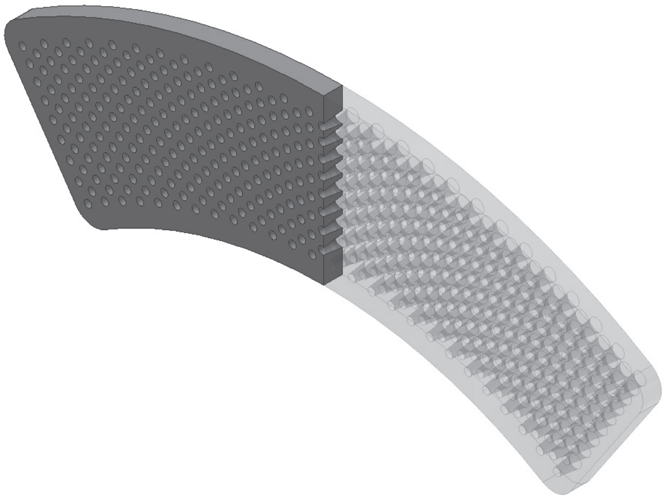


Figure 4. Hydrostatic Bearing Supply Strainer

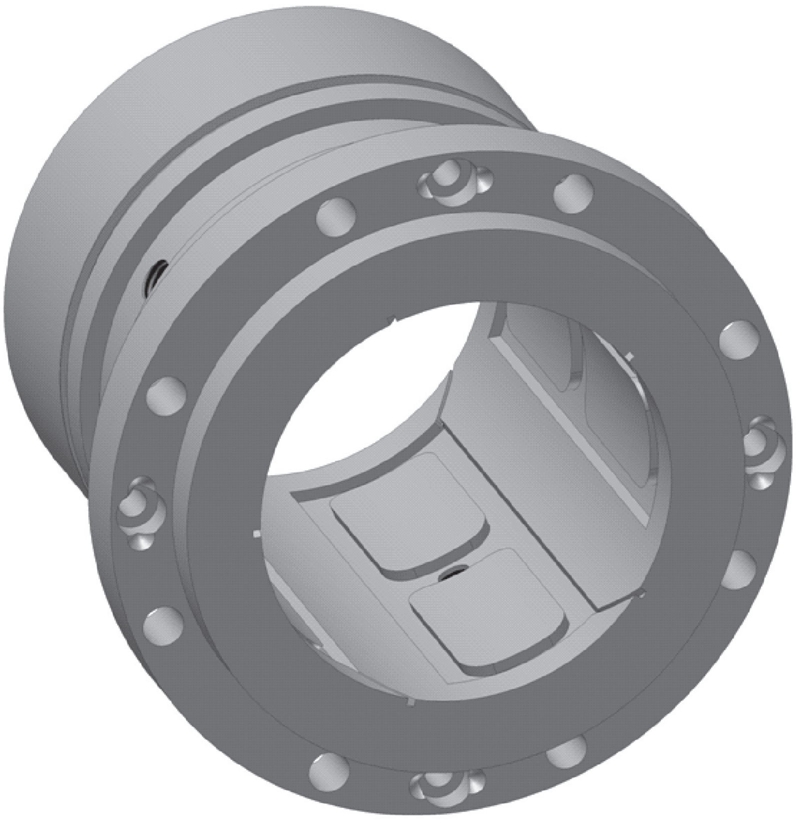


Figure 5. Modified Hydrostatic Bearing Design

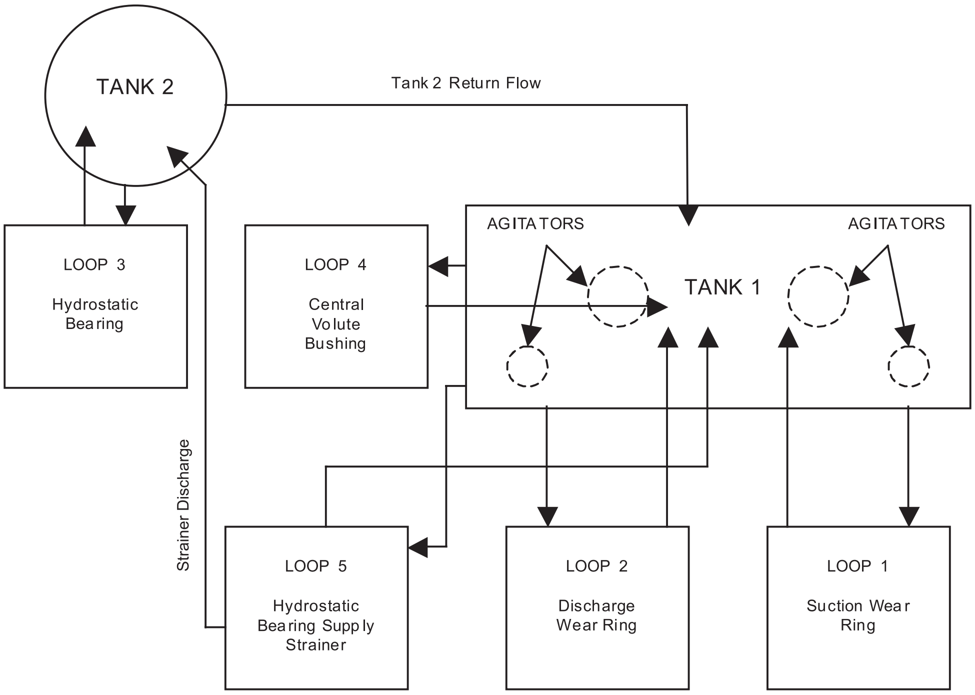


Figure 6. General Layout of Test Facility

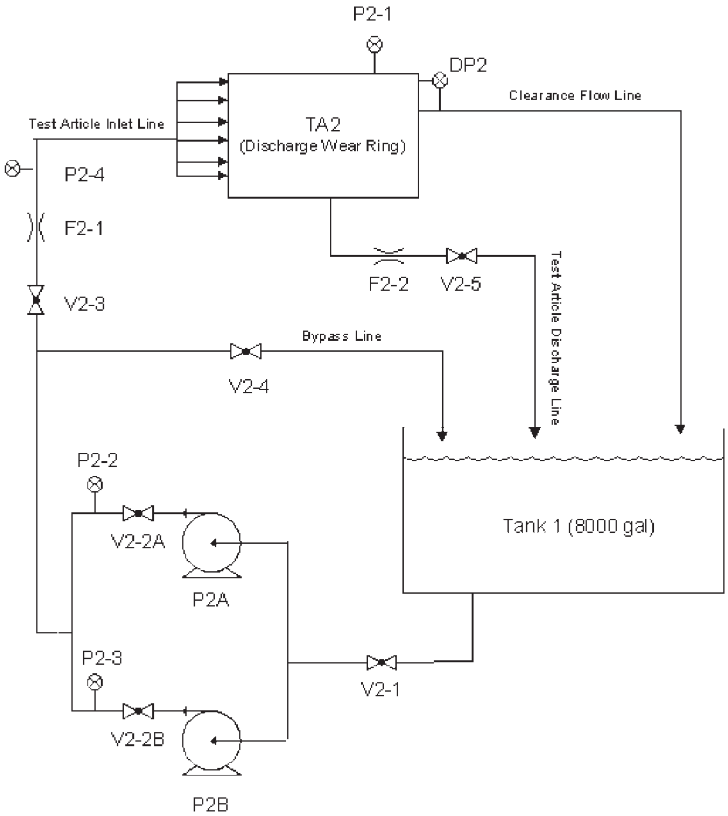


Figure 7. Typical Test Loop

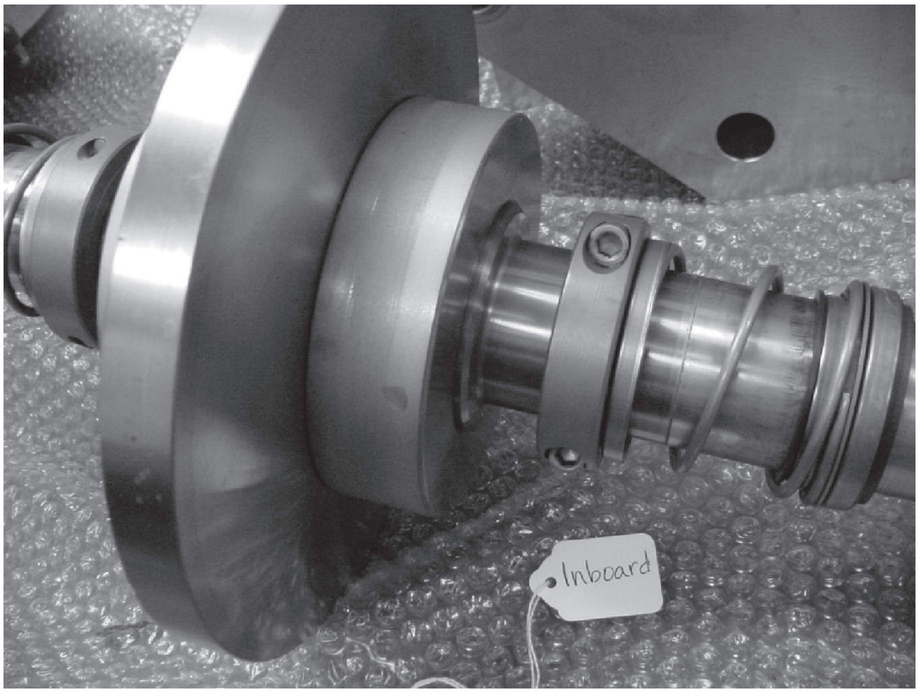


Figure 8. Suction Wear Ring Test Fixture After Testing

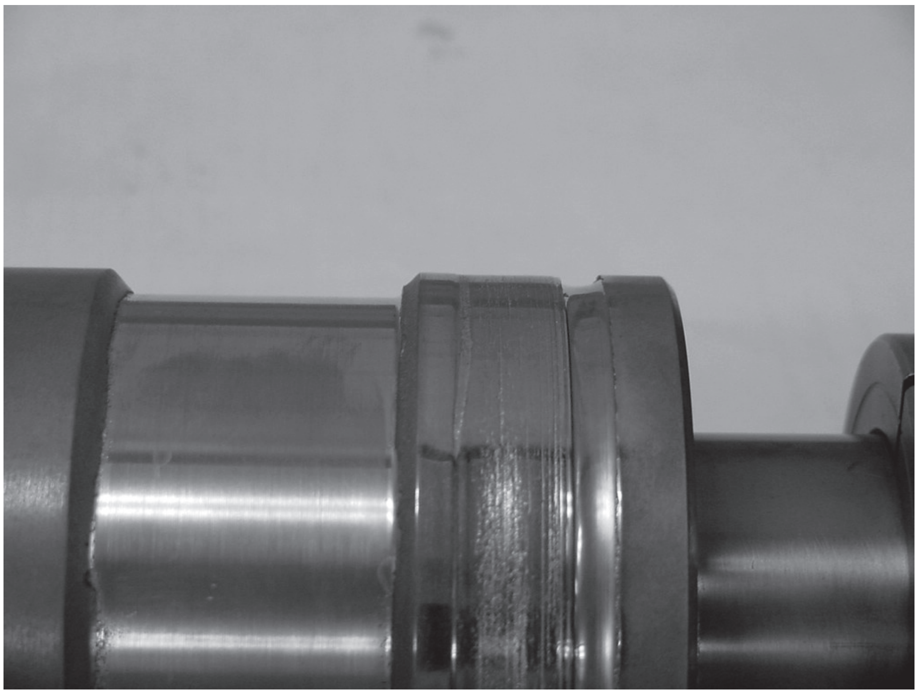


Figure 9. Discharge Wear Ring Test Fixture After Testing

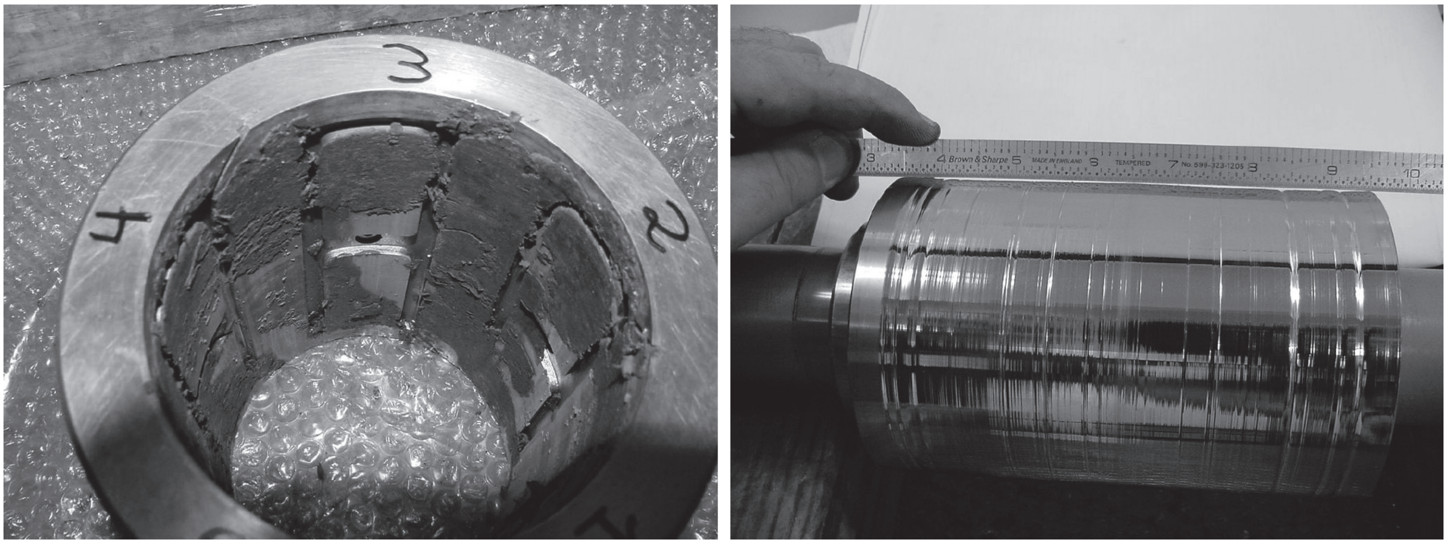


Figure 10. Hydrostatic Bearing and Shaft Sleeve Test Fixture After Testing

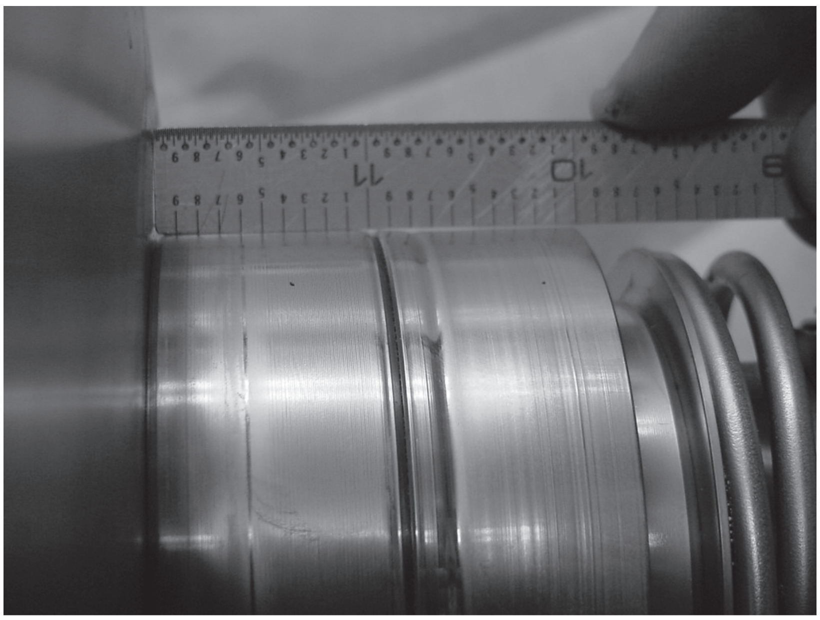


Figure 11. Central Volute Bushing Test Fixture After Testing

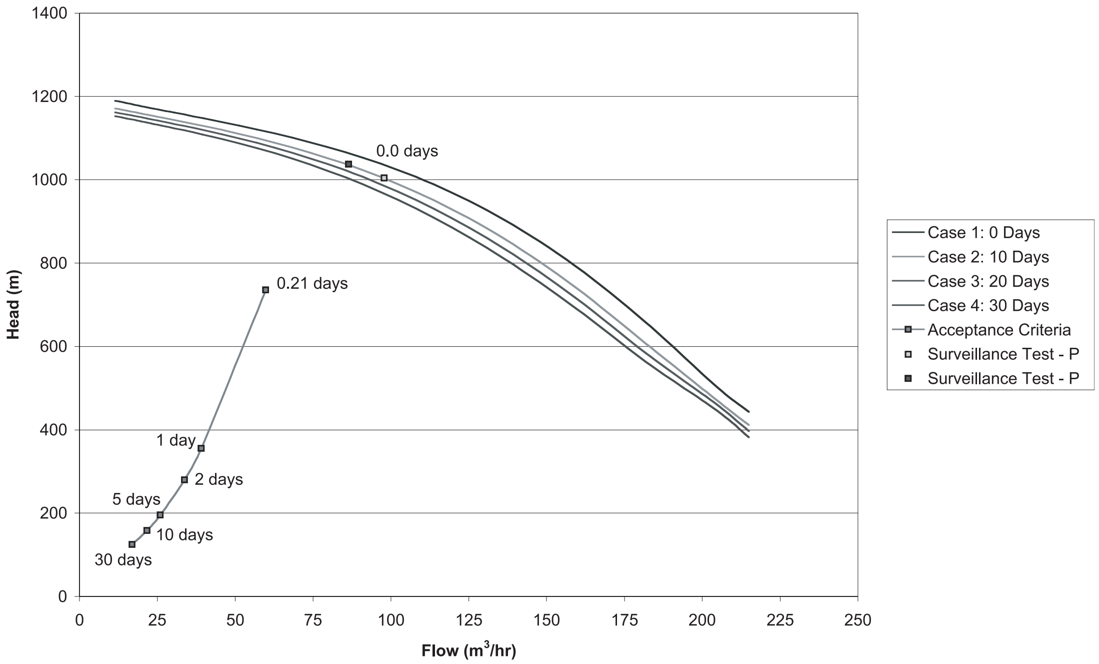


Figure 12. Hydraulic Analysis Results

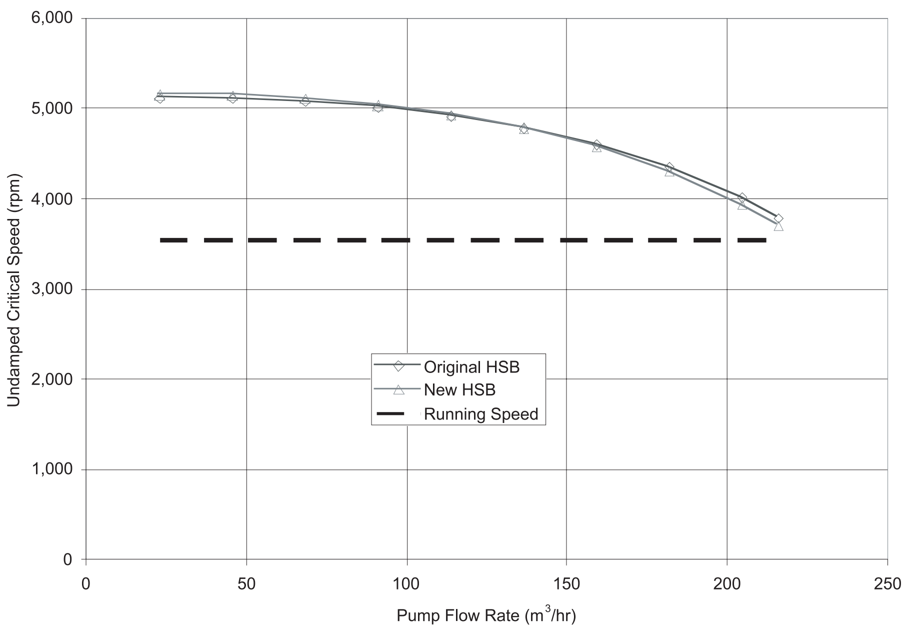


Figure 13. Critical Speed Map Comparing Effect of Original & New HSB's

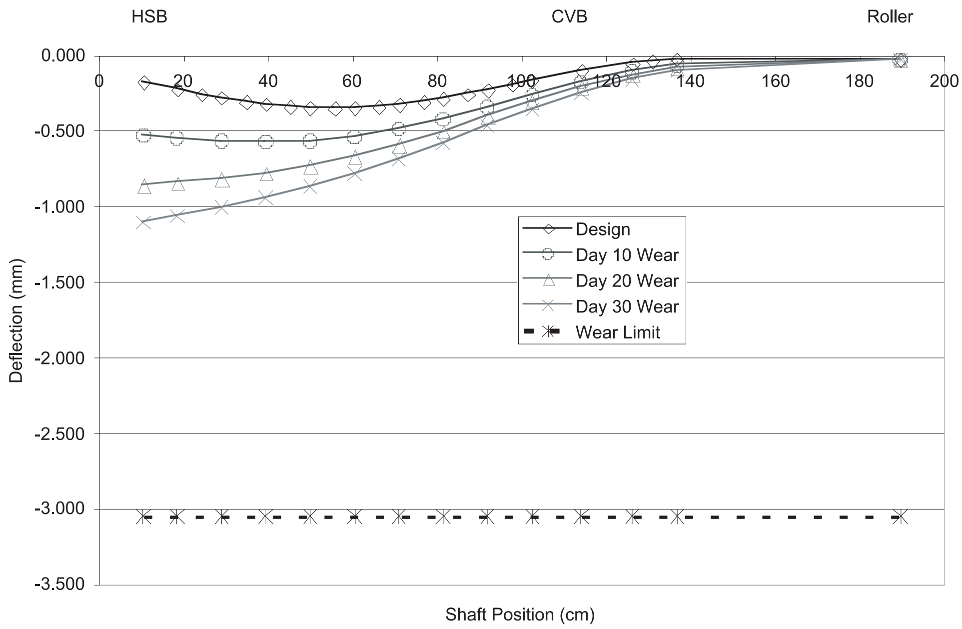


Figure 14. Rotor Deflection for HPI Pump with LOCA Conditions

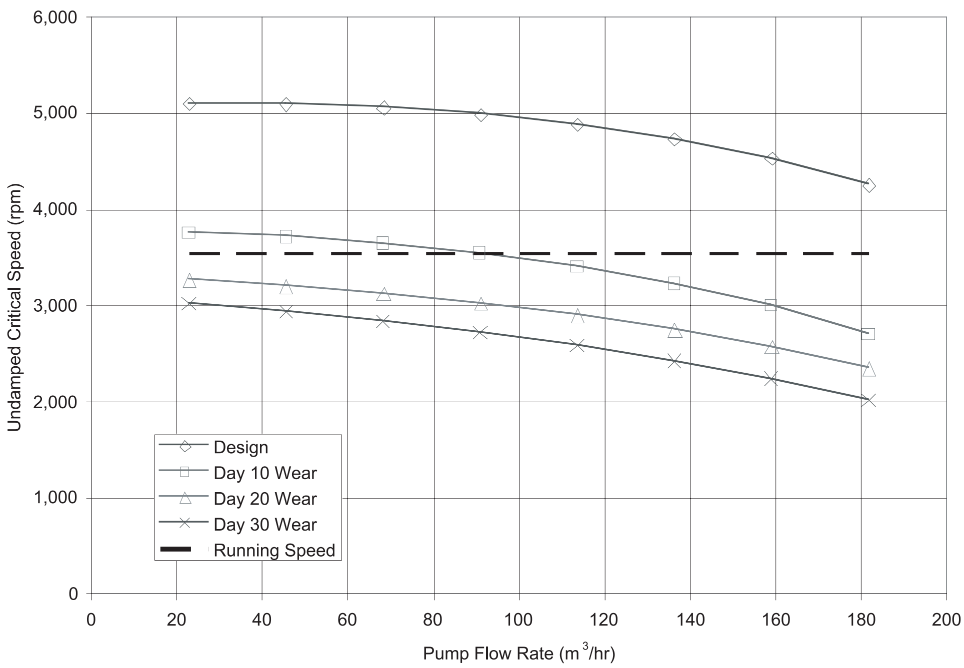


Figure 15. Critical Speed Map for HPI Pump with LOCA Conditions

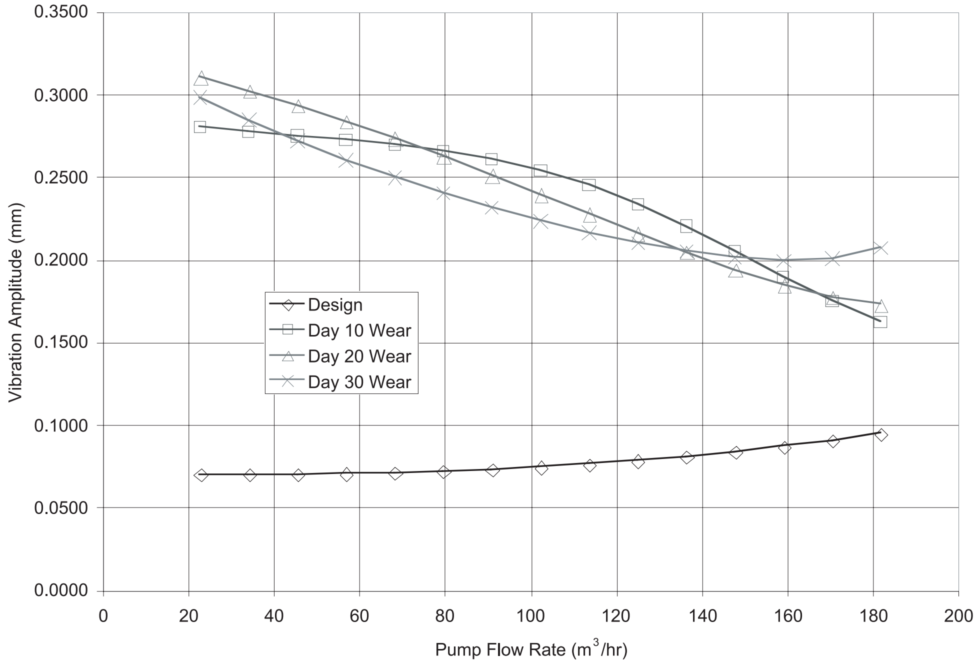


Figure 16. Forced Response Results for HPI Pump LOCA Conditions

Web-Based Applications for Pump and Valve Condition Monitoring Pump and Valve Seal Designs

Doug VanTassell

Evan Niemkiewicz and Joseph A. Passarelli
Insert Key Solutions, Inc.
http://www.InsertKey.com

Abstract

In the Utility Industry, companies have had difficulties in applying software technologies to standardize processes, facilitate communication between departments, and automate the generation of Performance Indicator Reports as pertaining to pump and valve condition monitoring and related seal designs and configuration management. This paper describes the development of two Web-Based Applications, PlantIQ™ and SmartSeal™, that have been implemented by large Nuclear producers to address these issues. These applications are an extension of existing infrastructure and are flexible and adaptable to the changing business needs of individual plants and corporate management. They have been designed with a simple, consistent user interface requiring minimal training and the Web-Based architecture keeps implementation costs low and facilitates integration with other systems.

1. Introduction

Pump and valve Condition Monitoring and the Management of their Sealing Designs and Configurations are maintenance processes that can benefit from the application of Web-Based Technologies. Standardization and the sharing of information are key elements to successful programs especially in a distributed environment of multiple sites; however, it has been cost prohibitive to extend the Computerized Maintenance Management System (CMMS) to automate these processes. In recent years, the implementation and deployment of Web-Based Applications as an augmentation to the Information Technology (IT) infrastructure has become cost effective with the advancement in development technologies and methodologies. In addition, it is now possible to provide a full-featured user interface in a browser that was thought only possible in client-server applications.

Condition Monitoring diagnostic technologies, computer programs, analysis techniques, communication flows, and performance metrics can vary significantly between plants, even though they are part of the same company. Analysis results of diagnostic data such as Periodic Vibration, Thermography, Lube Oil Analysis, etc. are often stored in spreadsheet and word processing applications on the hard drives of individual engineers, and are only shared in specific circumstances or discussed briefly in meetings. Data integration tools often lack the database infrastructure to represent the plant Equipment Hierarchy and to store the analysis results for each piece of Equipment and Technology. Plant personnel often spend significant time communicating equipment condition and gathering and organizing information in order to satisfy corporate Performance Indicator (PI) reporting requirements. A single Web-Based Application installed centrally and accessed throughout the Intranet can facilitate these needs.

Pump and valve sealing designs and configurations are detailed and require a significant number of fields and calculations that are specific to the plant application and component types used. The CMMS is effective for creating, scheduling, executing, and closing out Work Orders for repacking and replacing seals in pumps and valves. However, the complicated nature of sealing designs, and the fields and calculations required, have made it impractical and not cost effective to manage this data in the CMMS. Original Equipment Manufacturers (OEMs), sealing vendors, and service providers do provide tools, but they are often limited to specific applications and the materials and pumps and valves they supply and service. Plant engineering and maintenance personnel are therefore left with using tools like Microsoft Excel and Access to create localized databases to manage detailed information regarding pump and valve sealing designs and configurations. These processes and databases, however, can vary significantly between departments and sites, even within the same company.

The application of Web-Based technologies for automating business processes has a number of inherent benefits. With the pervasive use of the Internet for business and personal needs, users have become comfortable and familiar with the controls and the point and click navigational techniques implemented in standard Web-Browsers such Microsoft Internet Explorer. This lowers training costs when business applications are implemented using the same techniques and standards. Information Technology departments benefit from the server-based architecture that has minimal client desktop requirements. Change management and software maintenance are streamlined, resulting in lower deployment costs. In addition, integration between Web-Based applications can be extremely simple and low cost, and can result in high value to the end-user.

The remaining Sections of this paper discuss the implementation, results, and conclusions drawn from the collaborative effort of AP Services, Inc. and Insert Key Solutions, Inc. in applying Web-Based Technologies to address the needs described in the preceding paragraphs.

2. Implementation

AP Services, Inc. and Insert Key Solutions, Inc. have developed Web-based applications for automating and standardizing pump and valve condition monitoring and sealing design management. The tools are extremely flexible with configurable fields and forms and can match specific company processes and terminology. They are installed centrally as a single instance that can support an entire enterprise of sites, and can be integrated with existing applications such as diagnostic systems and the CMMS. In addition, user interfaces and the technical architecture have been designed to be simple in order to keep training and implementation costs low. These applications have been commercialized as PlantIQ™ and SmartSeal™, respectively, and are presented in the following Sections.

Condition Monitoring (PlantIQ™)

PlantIQ™ is a Web-Based software application that was developed to specifically address Component Health Reporting in the Nuclear Power Industry. It is focused on satisfying Equipment Reliability guidelines (AP-913) as recommended by the Institute of Nuclear Power Operations (INPO), specifically in the area of Performance Monitoring. The best example of implementation is that it has been installed in a large Nuclear Utility that has 10 distributed sites and 17 total reactors, and it has been implemented for more than 2 years.

Primary users are diagnostic data collectors especially related to PdM technologies, component engineers, and system managers. However, all organizational levels in a company interface with the application and can quickly retrieve information or perform data entry functions. On the Home Page, Figure-1, is a real-time Performance Indicator (PI) that demonstrates the health of the equipment throughout an enterprise of sites. A corporate manager, director, or VP can view this screen to obtain high level status information, and can also drill-down on any of the colored boxes to retrieve and view additional detail. Because of the communication that is facilitated, phone calls to the plant requesting status and related equipment health information are eliminated. Maintenance and Engineering personnel at the plant can therefore be focused on more value-added activities and expanding the Condition Based Maintenance Program to include more components.

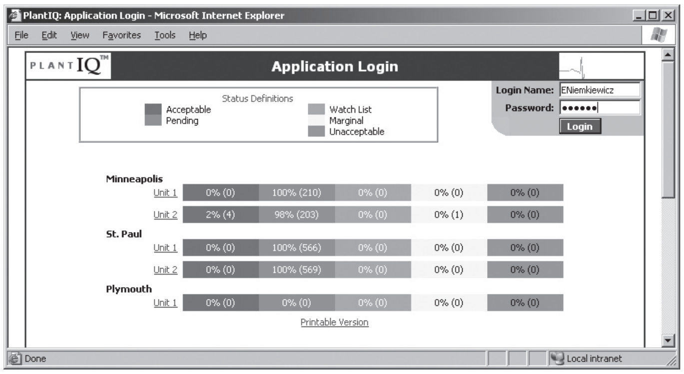


Figure-1 Home Page Performance Indicator

The core feature of the application is the Equipment Matrix, Figure-2, which includes Equipment and Condition Indicators. The equipment is organized in a hierarchical fashion, representing the actual equipment tag hierarchy used in the plant. The rows in the matrix or equipment can be filtered by the user based on complex criteria including System and Equipment Ownership, Component Category and Type, and Status levels. In addition, the Condition Indicators, or columns in the matrix, can also be configured based on the desire or specialty of the user. A person who focuses on rotating machinery, for example, can choose condition indicators such as Periodic Vibration, Thermography, Lube Oil Analysis, Operator Rounds, etc.; and, a switchyard specialist can choose indicators such as Dissolved Gas in Oil (DGA), Acoustics, Thermography, etc. These indicators are persistent upon login and can be easily adjusted by the user.

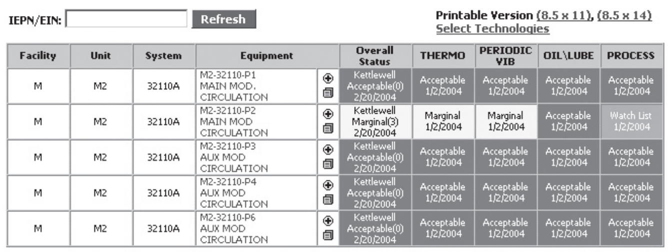


Figure 2 – Equipment Matrix

The condition indicator columns in the Equipment Matrix can also be drilled into to reveal more detailed data. Technology Exam reports are behind each colored block and can be manually populated or automatically generated through interfaces to underlying systems. Computerized Maintenance Management Systems (CMMS), Periodic Vibration Systems, Lube Oil Databases, and Process Historians are all good candidates for integration. Once the interfaces are built, Technology Exams not only reveal analysis results, but can link directly to detailed diagnostic data.

Another important feature of the Equipment Matrix is a column dedicated to Overall Health. The Component Owner, whose name is displayed in this column, is responsible for reviewing information from all the condition indicators and making an overall judgment. The detailed reports behind the overall status are called Equipment Assessments. Equipment Assessments, as shown in Figure-3, can have associated Technology Exams and File Attachments as supporting evidence, and these are permanently stored in the database. They can be queried as input into future condition assessments based on Component Type, Manufacturer, and from many other attribute fields.

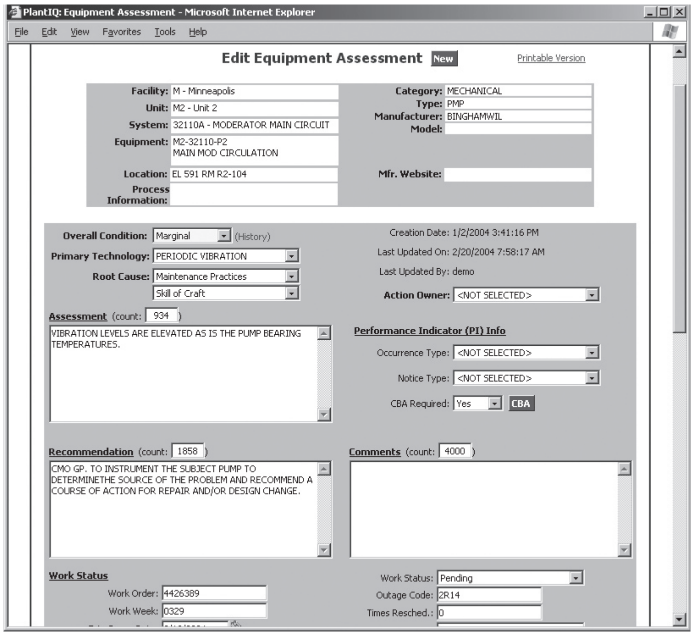


Figure 3 – Equipment Assessment

In addition to acting as 'Case Histories', Equipment Assessments collect the data necessary to generate real-time Performance Indicators (PIs). A sample PI is shown in Figure-4. As Equipment Assessments are created and updated, the summary data for PIs is automatically created. Fields on the Equipment Assessment forms can be customized to the specific process and terminology used by the sites, and custom PI Reports can be created. Reports are created using the Seagate Crystal Report Designer and the users have the ability to set complex criteria when running the reports through the application interface. It is possible for System Administrators to add custom reports to the system with no programming effort.

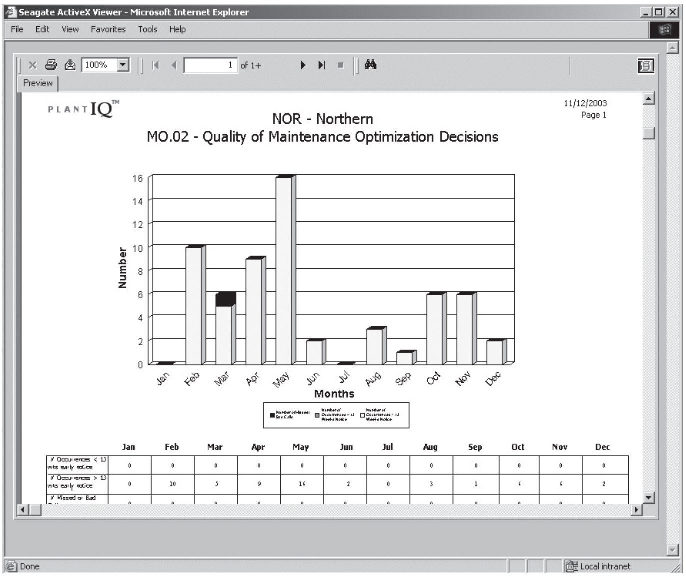


Figure 4 – Example Performance Indicator

Communication is further facilitated through the use of Email Notifications. During the creation or editing of Technology Exams and Equipment Assessments, the user can send an Email Notification with summary information to the Equipment and/or System Owner. If the user requires more information, an embedded hyperlink can be clicked that opens a new browser window and navigates to the detailed report with read-only Security Privileges. In addition, users can request to be notified by emails when specific events on Technology Exams or Equipment Assessments are edited or added.

Seal Designs (SmartSeal™)

SmartSeal™ is a Web-Based application that was developed to manage the documentation, maintenance, and configuration control of pump and valve packing, gaskets, and pressure seals. It provides an extension to the CMMS which is usually generic in its implementation and focused on work planning and scheduling, execution, and closeout. SmartSeal™ integrates equipment, maintenance work control, and procurement data with specific sealing information, to provide a complete view of sealing design and maintenance. Terminology and calculations can be configured with no programming effort in order to comply with changing corporate standards. Since the application is Web-Based, all the information, including equipment and work control data, can be integrated and shared with other applications. SmartSeal™ has been implemented in a large utility with three Nuclear Stations.

Primary users are engineers in plant maintenance and engineering departments that interface with processes related to pump and valve sealing design and maintenance. Screens have been configured by the utility to meet the needs of component engineers with specific engineering data, maintenance engineers with work planning and history and diagnostic test results, and the maintenance craft with standard packing and sealing datasheets designed for specific groups. The user interface has been designed to provide self-service communication between groups, thereby eliminating unnecessary phone calls and emails requesting status and information.

The application implements a standard process for the verification and revision control of sealing designs and configurations. Each configuration record has a status of Future, Installed, or History and a verification status of Unverified or Verified. A future record contains information about a packing, gasket, or pressure seal configuration that is currently not installed in an operating system. A future record status means that a user can prepare and finalize all packing gasket or pressure seal information before the configuration is installed into an operating system. For a packing configuration record to reach the installed status, it must have originally existed as a future record, has been verified, and then installed. All installed records must be verified. It is not possible for an unverified record to be in the installed status. Once a packing record reaches the status of History, it remains in the system for reference purposes only and cannot be modified.

The software provides a Material Association feature, Figure-5, which is a user-definable catalog that can be searched for specific parts and materials and to associate them to a particular pump or valve. The catalog can be searched by plant stock code, vendor stock code, material types, and specific measurements. Material datasheets and bill of material reports can be automatically generated that include part and material lists, along with the association to specific pieces of equipment.

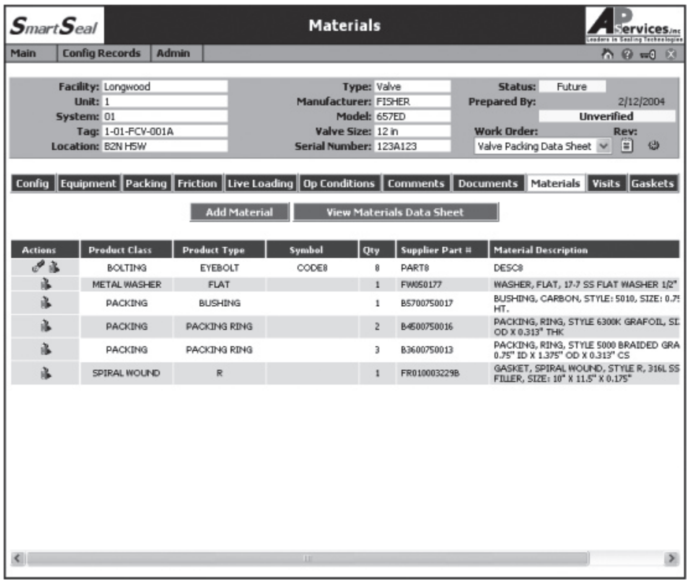


Figure 5 – Example Material Association

One of the key technical challenges that were overcome was to create configuration screens that were completely configurable by the system administrator. A system administrator can add or remove fields, change the sort order and location of fields, change text labels and headings, and modify calculated fields on each of the configuration forms. The format of datasheets used by the craft can be administered with the same degree of control. An example of a configurable form for packing details is included in Figure-6.

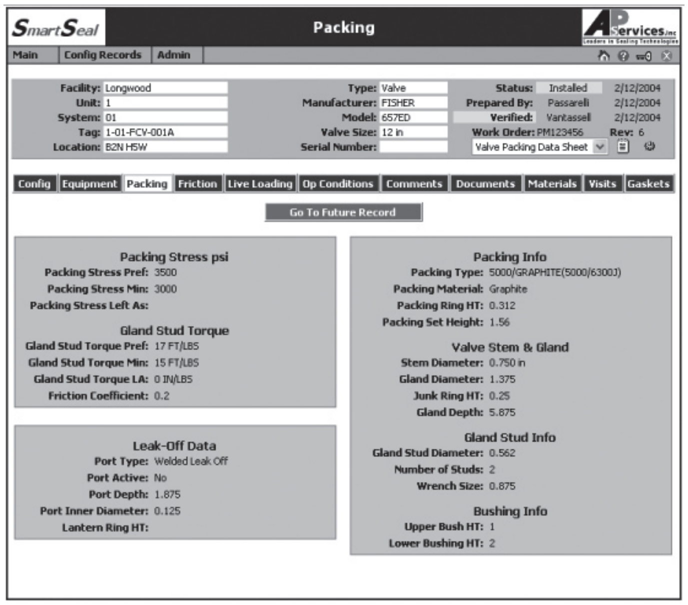


Figure 6 – Example Packing Details

The application provides a framework for tracking all maintenance activity including diagnostic tests, leak tracking, re-packing, and the results of walk downs and surveillances. These events are stored chronologically and a permanent history is stored in the database for future reference. Figure-7 demonstrates the visit tracking functionality in the application.

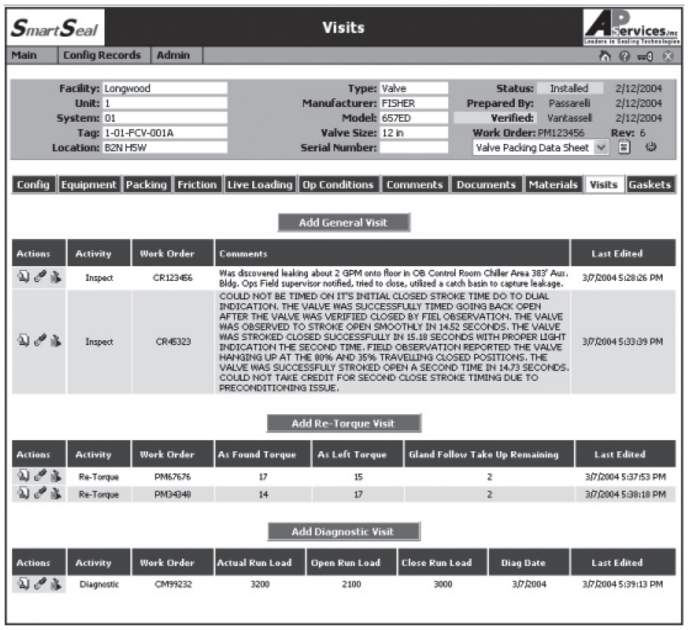


Figure 7 – Visit Tracking

In addition, the software has been implemented with a library of hundreds of configuration images to provide a visual representation of packing and sealing information, and to further aid the communication process. Functionality was created to upload and relate documents such as drawings, manuals, and flow sheets to specific pieces of equipment for easy retrieval. An area for managing gaskets and all the related configuration information also exists, an example of which is shown in Figure-8.

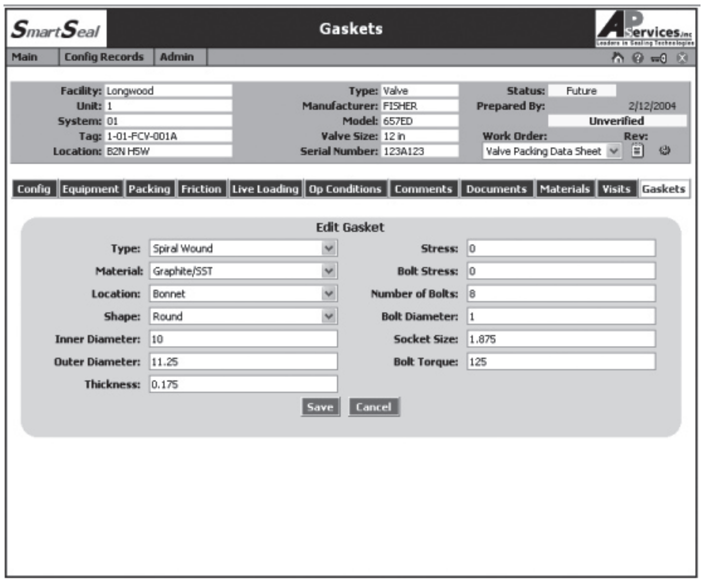


Figure 8 – Example Edit Gasket Detail

Technical Architectures

PlantIQ™ and SmartSeal™ have the same architecture and have been developed using the same technologies and methodologies. They are designed to be installed in a 2-tier environment consisting of a Web Server and Database Server. The desktop interface is displayed with Microsoft Internet Explorer 5.0 with very little reliance on client side controls. PlantIQ™ requires the Seagate Crystal ActiveX Viewer for viewing and exporting reports; and, both applications require MSXML3.0 components which in most cases are already installed on the client PC.

The presentation layers consist of Microsoft Active Server Pages (ASP) that can be rendered by Microsoft Internet Information Services 4.0/5.0. The Web Server operating system can be Microsoft Windows NT or 2000 and should have the latest service packs applied. In addition, PlantIQ™ requires the installation of the Seagate Crystal Reports Web Component Server, and both applications require ASP Upload 3.0 to be installed on the server.

Both applications support and can be installed in the Microsoft SQL Server and Oracle Relational Database Management Systems (RDBMS). The database objects consist of Tables, Stored Procedures, Functions, Indexes and Triggers; and, security is controlled at the application level through tables of user information. Both applications have tools and methodologies for loading and converting data from existing and supporting systems.

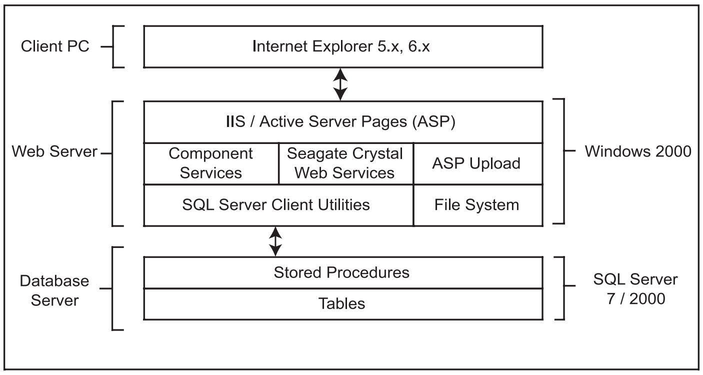


Figure 9 – Technical Architecture

3. Related Work

Condition Monitoring

There are a number of software products that are commercially available that address Condition and Performance Monitoring and have some impressive display capabilities. They are primarily focused on data integration and supporting hard-core analysis though the use of trends, calculations, and the application of statistical models. However, they usually do not promote the integration of all sources of information that are inputs into maintenance decision-making; and, they do not address other key elements that are time consuming to the maintenance engineer and technician.

One common deficiency is the lack of a repository for storing analysis results in a searchable database format. Analysis results are usually textual reports (problem statement, recommendation, Work Order information, action plans, status fields, etc.), and engineers are often left with no choice but to store this information in unsupported spreadsheet files and home-grown Microsoft Access Databases. In these formats, it is difficult to track, trend, and query this data and to share it with individuals at other plants. In the maintenance decision-making process, these reports are as important as the detailed diagnostic data and need to be considered in future analyses. It is very important to be able to search previous occurrences based on component type and other attributes to be able to identify trends and reoccurring problems. PlantIQ™ provides this functionality as a by-product of automating the normal Condition Monitoring process and not as an extra chore bestowed on the engineer.

Because most tools do not store analysis results, they also are not capable of supporting the automated generation of Performance Indicator (PI) Reports. It is at the overall condition assessment level of a piece of equipment where most PI data is generated. Simple elements such as the status, the primary technology indicator responsible for the assessment, cost benefit information, and whether it was detected or missed by the condition-based maintenance program, can be used to generate meaningful results. Here again, PlantIQ™ provides a flexible and powerful reporting infrastructure that supports current and future PI reporting requirements of the company.

Seal Designs

Seal design and configuration management software is readily available in the current marketplace, most of which is provided by individual sealing material manufacturers. These tools tend to focus on vendor specific processes and do not extend to support related procedures and other data consumers. In addition, most have not been developed to address the specific needs of the utility industry and can not be configured to address enterprise needs due to the traditional client-server architecture. Without a Web-Based architecture, data contained in the application is only accessible by those users that have the software installed on their desktop, resulting in a situation similar to storing the data in a Microsoft Excel spreadsheet or Access database. Obscure or non-standard desktop database engines are often used in existing products, making it difficult to integrate data from other sources and equally challenging to make seal design information available to other applications. SmartSeal™ provides utilities with a powerful and flexible software tool that can meet the needs of their current pump and valve sealing program. Because it is web-based and developed on standard enterprise databases, it can be integrated with existing and future applications with minimal effort.

4. Summary, Results, and Conclusions

PlantIQTM and SmartSealTM have been successfully implemented in large nuclear energy producing organizations. The Web-based architecture of the applications helps solve common business process problems such as the sharing of information, standardization of processes, and the integration of data and improve condition monitoring and the management of sealing designs. The following bullets provide additional results and conclusions in support of this summary:

- Software programs PlantIQ™ and SmartSeal™ have been developed and implemented to support corporate and an enterprise of sites with a single, centralized installation. With simple 2-tier architecture, hundreds of users can be supported with acceptable performance. The applications are also capable of monitoring and managing tens of thousands of pieces of equipment with an efficient database design, within standard database platforms such as Microsoft SQL Server and Oracle.

- Implementing Web-Based applications assists in standardizing processes. Initial presentation of integrated Performance Indicators with data from multiple sites demonstrated inconsistencies in the process. Communication was quickly initiated between the sites and corporate in order to agree on standards, and to close any terminology and expectation gaps. Sites then began to compete in order to improve Performance Indicator results.
- Engineering and Maintenance departments can save significant time and resources by implementing self-service applications that share information and reduce manual communication processes for status and information requests. Incorporating simple functionalities such as email notifications and 'read only' access can provide high value at low implementation costs.
- The generation of Performance Indicator Reports can be automated, saving significant corporate and plant man-hours. These PIs can be real-time and can be created as a by-product of the process, as opposed to an extra task on the engineer.
- With proper planning during development, it is very easy to integrate these Web-Based applications to provide significant value.
- When Web-based applications are implemented, it is easy to integrate condition monitoring data and results with sealing designs and configuration management. The simplest example is creating a reference or hyperlink to sealing design and configuration management data from a component in the condition monitoring tool.

5. Future Benefits

The majority of the integration work between applications with regard to pump and valve condition monitoring and sealing design and configuration management has been internal within a company. Interfaces are created with the CMMS and other diagnostic systems and tools. However, little effort has focused on integration with industry sources such as INPO's EPIX failure database, various Electric Power Research Institute (EPRI) data sources, and OEM databases for product catalog information and purchasing. Technologies such as XML (Extensible Markup Language) which are commonplace in other industries and facilitate business to business integration have not been wide applied in the Utility industry. Exposing information on the Internet with secure sharing and on-demand querying will become more prevalent.

Reevaluation of Comprehensive Pump Testing and Pump Design Flow Considerations

David Kanuch
Altran Corporation

ABSTRACT

This paper has been developed as a result of the Task Group of SG-ISTB responsible for reevaluating the Comprehensive Pump Test (CPT) requirements for certain pumps and is considered a work-in-progress. As a result of several inquiries submitted to the committee, the Sub Group has responsibility for evaluating the issues and formulating responses and/or changes to the Code as necessary. The observations and considerations presented in this paper are my own and not to be interpreted as that of ASME, the NRC nor Altran Corporation.

This paper will describe the background of CPT, current industry concerns and issues with the CPT, discussion of alternatives to the CPT, and concluding plans to address future Code changes as necessary.

Coupled with this paper is the evaluation and actions underway to address the term "pump design flow rate". The ASME OM Code 1994 and later editions have incorporated comprehensive pump testing. One of the requirements of the comprehensive pump test is to establish reference values within ± 20% of pump design flow rate. No definition of "pump design flow rate" is provided. This paper will discuss actions underway to address this issue.

Background - Pump Design Flow Rate

The ASME OM Code 1994 and later editions have incorporated comprehensive pump testing. One of the requirements of the comprehensive pump test is to establish reference values within ± 20% of pump design flow rate. No definition of "pump design flow rate" is provided.

The intent of this change to the Code addressed the testing of pumps using minimum flow lines, which have limited ability in detecting pump degradation. Testing of pumps at higher flow rates and on the portion of the pump curve which is well sloped, increases the ability to detect degradation. The Code change to perform comprehensive pump testing within ± 20% of pump design flow rate ensures that the pump is tested at a point at which pump degradation is readily detectable. However, the current Code does not define *Pump Design Flow Rate.*

Typically, the pump designer will select the design of the pump based on the procurement specifications which include required system flow, pressure and temperature. The pump is then designed such that the Best Efficiency Point (BEP) and pump design flow include all system demands and optimizes power consumption, smoothness of operation and component reliability.

In general, the manufacturer will try to design the pump such that the design point is as close to the BEP as possible. This optimizes the performance of the pump. The BEP is typically at a substantial flow rate and on a portion of the curve that is well sloped.

However, for some older plants, cases have been identified where the pumps' have been designed for much more capacity than is required by the system. In theses cases, the BEP flow cannot be achieved by using the as-built system configuration. The pumps can deliver the flow required by the system to perform its safety function, thus the system required flow would be considered the pump design flow.

As an example, a boric acid transfer pump operates during normal power operations at minimum flow conditions to recirculate the boron injection tank contents. Typically, these flow rates may be less 20 gpm (gallons per minute). During accident conditions, the pump must be capable of delivering a higher flow (60 gpm). However, in some cases the pump is designed such that the BEP is more than twice the design point (125 gpm). See Attachment 1, Boric Acid Transfer Pump Characteristic Curve.

In other cases some pumps have been designed such that the rated conditions supplied by the designer are well above the best efficiency of the pump. The attached containment spray pump curve indicates a design point at run out conditions (2000 gpm). This is the manufacturers' rated condition of the subject pump. In this case the BEP is approximately 1300 gpm. The accident analysis flow for the subject pump is 1450 gpm (between the rated and BEP flow points). See Attachment 2, Containment Spray Pump Characteristic Curve.

A proposed change to the Code is necessary to alleviate the inconsistencies in what is defined by each plant as "*Design Flow Rate*" for each pump. The following Proposed Code Change would benefit the industry and allow the Owner to determine and document a point on the curve where pump testing may be performed and degradation be detected. This point may be based on system flow requirements, design or rated conditions, Best Efficiency Point, or any other point where testing is effective in detecting mechanical and hydraulic degradation during subsequent testing.

Comprehensive Pump Testing

The ASME OM Code 1994 and later editions have incorporated comprehensive pump testing (CPT) to ensure that pumps are periodically tested at, or near design flow conditions. Typically, the design point is at a substantial flow rate that is on a portion of the pump curve that is well sloped. Degradation at the design flow conditions is more easily detected than at a minimum flow condition where the pump curve is generally flat. Comprehensive Testing was included to consider the requirements of Generic Letter 89-04 that testing at minimum flow was inadequate.

Testing at or near design flow conditions provides reasonable assurance that the pump will perform its intended design function during accident conditions. However, because the comprehensive test interval was extended to two years, the Code requires that more accurate pressure instrumentation be used when performing the comprehensive pump test and tightened the acceptance criteria.

The intent of the present Code addresses the issue of minimum flow testing, which has limited ability in detecting pump degradation. Testing of pumps at higher flow rates and on the portion of the pump curve that is well sloped, increases the ability to detect degradation.

Current Summary of Code Changes for Group A, B and Comprehensive Pump Testing

General

The Owner is required to categorize all pumps as either group A or B. Group A and B tests are required to be performed quarterly, while the CPT is performed biennially for all pumps. Group A and B tests are performed within ± 20% of pump design flow rate if practicable, while the CPT is *required* to be performed within ± 20% of pump design flow rate. For the group A and CPT, a minimum run time of 2 minutes after conditions are stable is required prior to recording the test parameters. No minimum run time exists for the group B test.

Instrumentation

Instrumentation accuracy requirements are the same for all parameters and all test types except that pressure measurement instrumentation for the CPT is required to be ± 0.5 % versus ± 2% for the group A and B tests.

Test Procedure

All tests are performed with the pump operating at a specified reference point. For the group B test, either the differential pressure or flow rate is determined and compared to its reference value. For the group A and CPT, the pump is operated at either the differential pressure of flow rate reference point (set parameter) while the other parameter is determined and compared to the reference value. Vibration measurements are not required for the group B test.

Acceptance Criteria (Centrifugal)

The vibration criteria for the group A and CPT are identical. The hydraulic criteria lower required action ranges are the same (0.9 x Ref) for all tests. The hydraulic criteria upper required action ranges are the same for the group A and B (1.10 x Ref) while the CPT upper required action range is 1.03 x Ref. No alert range exists for the group A and B hydraulic parameters.

Discussion

The CPT was developed and incorporated into the ASME OM Code to ensure that all pumps, required to be in the Inservice Testing Program, are periodically tested within ± 20% of the pump design flow rate. This OM Code requirement institutes the following two fundamental IST requirements.

1. The CPT ensures that each pump is tested periodically at a substantial flow rate point on the curve which is well sloped and where degradation may be easily detected.
2. Also, by performance of this substantial flow test, the pump is verified to be capable of performing its intended design function. It is important to note that the purpose of IST is to assess component operational readiness and not system requirements. In general, the plant Technical Specifications govern the requirements of system operability.

The intent of the ASME OM Code requirements is to ensure that components (pumps and valves) that are required to perform specific functions in accident mitigation and shutting the reactor are assessed periodically to provide reasonable assurance of operational readiness.

In the case of group A pump testing where the pump is tested periodically at or near design flow (± 20% of pump design flow rate), the pump is tested at a point on the curve which is well sloped and where degradation may be easily detected. Additionally, testing at this point on the curve (substantial flow) provides reasonable assurance of operational readiness. The fundamental requirements of the IST requirements are therefore met by performance of the pump test at or near design flow.

Issues

Several issues exist with the 1994 through 2000 edition of the ASME OM Code regarding the testing of group A pumps.

1. Current quarterly group A pump testing coupled with biennial CPT is far more effective in assessing pump operational readiness than a quarterly group B coupled with a CPT provided the Group A test is performed at substantial flow rate and is at a point on the curve that is well sloped.
2. Group A pump testing at or near design flow (± 20% of pump design flow rate) is far more effective at assessing the pumps' operational readiness than a biennial CPT. Albeit, the pressure instrumentation is more accurate, the frequency of performance will not yield enough data over the life of the plant to equally assess the performance of a routine group A test at or near design flow rate.
3. Several plants have expressed concerns with exceeding CPT hydraulic acceptance criteria while performing a quarterly group A test. Engineering judgment in this case is the only means for a plant to maintain the operability requirements of their respective Technical Specifications. This issue should not reside in the interpretation of the Code.

   (Note: This should not be an issue. The current Code does not address this issue)
4. In general, for all pump types, only the hydraulic acceptance criteria in the latest OM Code differs between group A and a CPT test. The mechanical vibration acceptance criteria and alert ranges are identical for various pump types. While the CPT has an alert range for hydraulic performance, the group A does not (for centrifugal).

   (Note: Although the CPT employs an alert band for hydraulic criteria, the corrective action requirements specify that the test frequency be doubled or the condition corrected. The resultant test frequency would equate to one year.)
5. Pumps that operate routinely, (group A) are in most instances more susceptible to mechanical and hydraulic degradation and failure than pumps that are operated only for testing (group B) and are in standby during normal plant operations. It is recognized that group A pumps, therefore should receive a higher care regime than a group B pump.
6. Group A Quarterly testing at substantial flow rates (at a point on the curve that is well sloped) and where degradation is easily detected, provides reasonable assurance of the pumps' operational readiness. Quarterly pump testing at substantial flow rates represents a better overall test philosophy compared to the method involving a periodic reduced flow test, supplemented by a biennial CPT.

Conclusion

Therefore any pump (Group A or B) that is routinely Group A tested at a flow rate that is equivalent to the comprehensive pump test flow rate need not have an additional comprehensive pump test requirement.

Group B pumps which are not routinely Group A tested, would still require a biennial comprehensive pump test. Note that the Code allows a Group A test to be substituted for a Group B test.

Proposed Code Change – Comprehensive Pump Testing

Remove CPT requirement for any pump that is routinely tested at a flow rate which is equivalent to the CPT flow rate. This can easily be done by adding a Note to the Frequency Table, ISTB-3400-1. The following summarizes the Code change:

TABLE ISTB-3400-1 Add to Comprehensive Test Column "Note 1"

TABLE ISTB-3400-1 Add under GENERAL NOTE "(1) If a Group A test is performed quarterly at a reference flow rate that is equivalent to the comprehensive pump test flow rate, a comprehensive pump test need not be performed."

Proposed Code Change – Pump Design Flow Rate

The proposed change to the Code is presented below. This change effectively removes all references to the term *Pump Design Flow* and requires the Owner to establish a pump test flow rate that is effective for detecting degradation. The following summarizes the change:

ISTB-1400 Add "(c) establish a pump test flow rate for each pump. In the context of ISTB, the pump test flow rate is determined by considering system flow rate requirements and pump best efficiency point. The specified pump test flow rate shall be effective for detecting mechanical and hydraulic degradation during subsequent testing[1]. The pump test flow rate and its basis shall be recorded in the Pump Records, ISTB-9100."

ISTB-1400 Add "Note 1. Except for positive displacement pumps, this pump test flow rate is at a relatively high flow point on the pump curve where relatively small changes in flow rate results in relatively large changes in differential pressure."

ISTB-3300(e)(1) Revised as "Reference values shall be established at the pump test flow rate for the comprehensive test, if practicable. If not practicable, the reference point flow rate shall be established at a point effective for detecting mechanical and hydraulic degradation."

ISTB-3300(e)(2) Revised as "Reference values shall be established at the pump test flow rate 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.

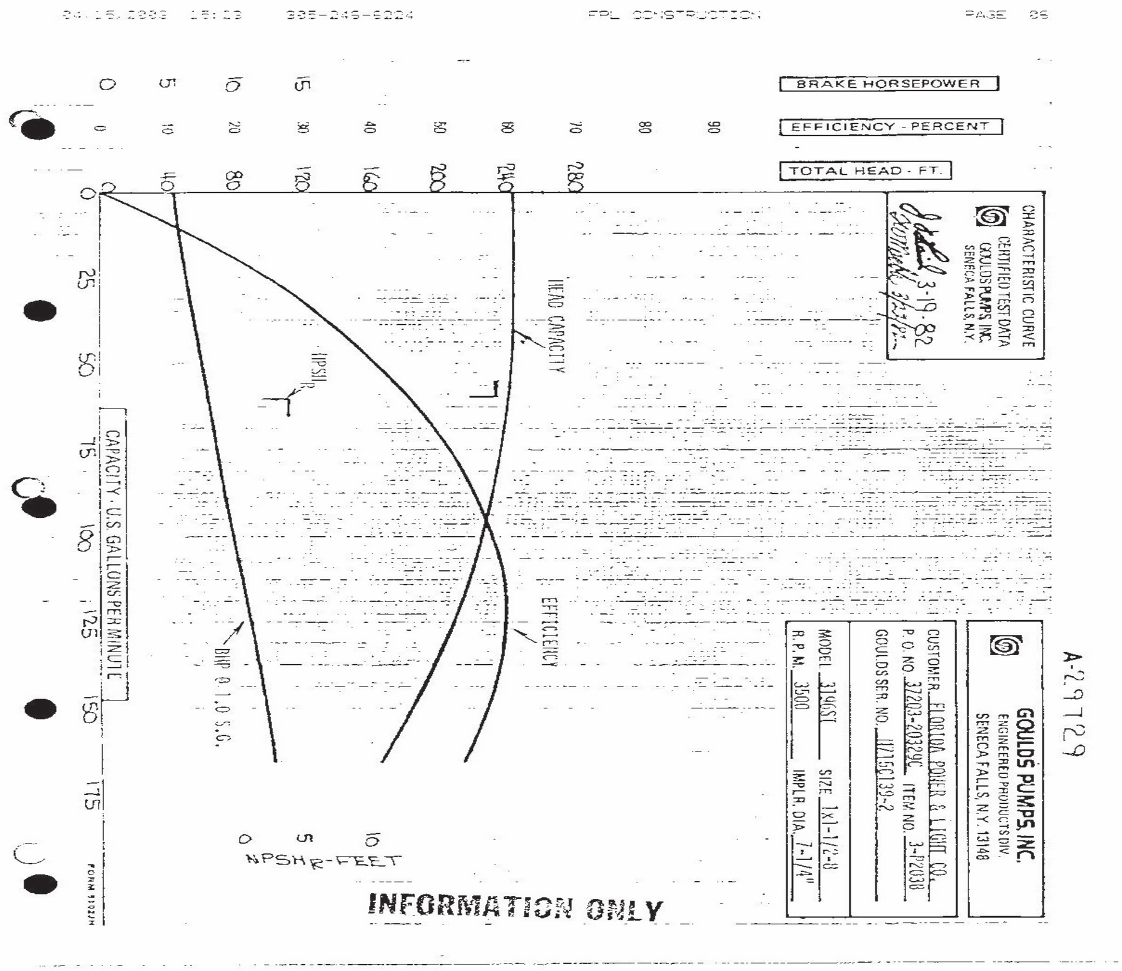
ISTB-5110(a) Revised as "….If practicable, these points shall be from pump minimum flow to at least the pump test flow rate…."

ISTB-5210(a) Revised as "….If practicable, these points shall be from pump minimum flow to at least the pump test flow rate…."

ISTB-9100(d) Add "(d) the pump test flow rate and its basis."

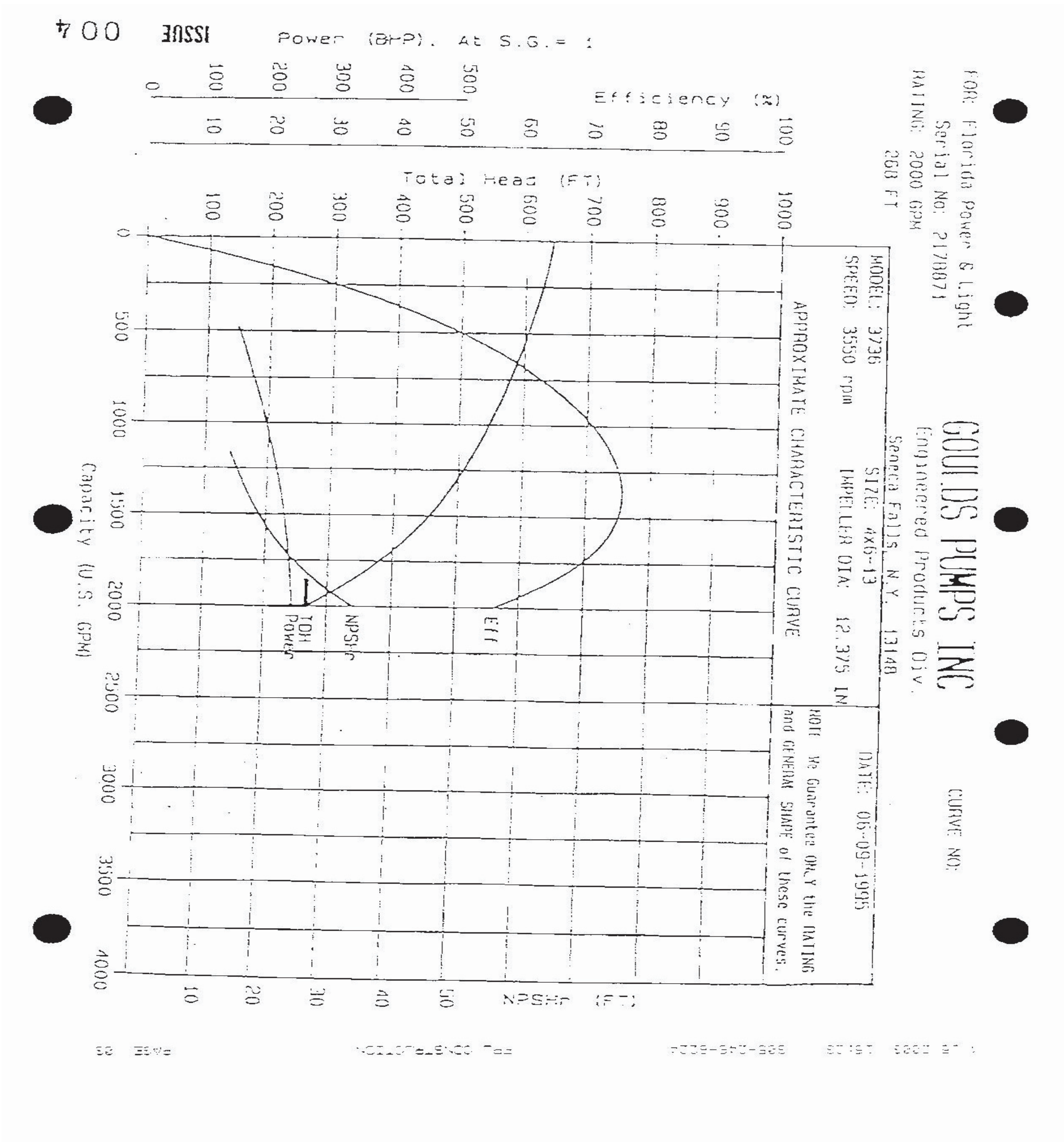
Attachment 1

Boric Acid Transfer Pump Characteristic Curve



Attachment 2

Containment Spray Pump Characteristic Curve



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Inservice Testing Owner's Group (ISTOG)

Shawn Comstock
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Abstract

The purpose of the ISTOG is to collect, integrate, and share industry knowledge, resources, and products so that owners will benefit from improved implementation of their inservice testing 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.

The 8th NRC/ASME Symposium on Valve and Pump Testing will mark the official introduction of the IST Owner's Group (ISTOG). This presentation spot will be an open session of the IST Owner's Group that will cover topics of interest determined by feedback from every IST Owner who chose to participate. At the conclusion of the session, a question and answer period will be held to address specific survey topics more in-depth or to cover areas not addressed by the IST Owner's community that participated in the survey.

Introduction

The IST Owner's group was an idea that initially came to fruition in 2003. Gregg Joss of Ginna organized a joint meeting for Appendix J and IST Engineers in conjunction with the ASME Committee for Operation and Maintenance for Nuclear Power Plants and the Nuclear Industry Check Valve Group at the June meetings in Scottsdale. The meeting was a resounding success and punctuated the need for a group dedicated to the implementation of both Appendix J and Inservice Testing implementation. In the months that followed, Gregg Joss of Ginna and Shawn Comstock of Wolf Creek worked together to organize a Steering Committee. Today, the ISTOG Steering Committee is a 7 member team comprised of Bob Parry, David Chiang, Gregg Joss, Jeff Neyhard, Leonard Firebaugh, Shawn Comstock and Wavel Justice. The IST Owner's Group is open to any interested parties that wish to participate in activities dedicated to the improvement of Inservice Test Program implementation.

True North Consulting's Ron Lippy and Don Horn hosted the first open ISTOG Steering Committee meeting in conjunction with the December Nuclear Industry Check Valve Group meetings held in Orlando, Florida. This meeting included the participants of an IST Training seminar provided by True North Consulting during that week. Significant progress was made in the formalization of the group and those present agreed to formally introduce the IST Owner's Group at the 8th NRC/ASME Symposium on Valve and Pump Testing.

Industry Need

In the nuclear industry, the position of IST Engineer is not a highly sought after responsibility. This is evidenced by the turnover rate, which has averaged about 50% over a three-year period. In addition to the high turnover rate, the more experienced people in this field are getting nearer to retirement every day. Numerous complexities are interwoven into the position of IST Engineer that requires an understanding of multiple ASME Codes and NRC Regulations to be effective in the application of this Program Management responsibility. In addition to this complexity, knowledge about the numerous changes with ASME Codes and NRC Regulations is important to understand how modern IST Program elements have evolved into their present state to avoid the mistakes of the past. The IST Owner's Group seeks to provide an industry support network for the IST Engineer to turn to for answers.

IST Issues of Interest

Different surveys have been conducted to determine what IST Engineers are concerned about. Several different areas of interest emerged. This paper will discuss each one briefly; however, the intent of these discussions is to provide an overview for an interactive discussion at the 8th NRC/ASME Symposium on Valve and Pump Testing rather than an in-depth analysis of each subject. The top two areas of interest in 2003 were Preconditioning and Leak Testing vs. Close Testing. The complete list of topics of interest identified to date is as follows (in no particular order):

- Preconditioning
- Risk-Informed IST Implementation/transition guidance
- Flow Loop issues
- Position Papers (Endorsed by ISTOG or Used by utility)
- Condition Monitoring Justifications
- NRC Q&A – guidelines for unwritten processes
- Relief Request templates
- Guidelines for limiting values
- Skid-Mounted How-To (justifications)
- Practical/Practicable differences
- Sample valve passivity (how to justify passive classifications)
- Code Class 1,2,3, Augmented Guide
- Leakage Testing Versus Flow Diversion
- Design Flow Rate guide
- GL 89-04 applicability and NRC new viewpoint
- Code implementation Relief Request Guideline
- Submittal process (program and relief request how-to)
- PMT Guidance
- RCS PIV testing improvement project
- NUREG 1482 development participation
- CV Condition Monitoring How-To
- Terminology Guide
- Condition Monitoring vs Performance Based difference
- Instrumentation accuracies for pump testing
- Compliance with Ambient and Media Temperature Correlation Rules

Preconditioning

by Shawn Comstock

Preconditioning has to be one of the most mobile targets involving the IST Engineer. Preconditioning is described by NRC Information Notice 97-16, “Preconditioning of Plant Structures, Systems, and Components Before ASME Code In-Service Testing or Technical Specification Surveillance Testing”[1]. Some preconditioning is acceptable and some is not.

Acceptable preconditioning is the alteration, variation, manipulation, or adjustment of the physical condition of a plant structure, system, or component (SSC) before Technical Specification surveillance or ASME Code testing for the purpose of protecting personnel or equipment or to meet the manufacturer’s recommendations. Preconditioning for purposes of personnel protection or equipment preservation should outweigh the benefits gained by testing only in the as-found condition. This preconditioning may be based on the equipment manufacturer’s recommendations or on industry-wide operating experience to enhance equipment and personnel safety. This preconditioning should be evaluated and documented in advance of the surveillance.

Unacceptable preconditioning is the alteration, variation, manipulation, or adjustment of the physical condition of an SSC before or during technical specification surveillance or ASME Code testing that will alter one or more of an SSC’s operational parameters which results in acceptable test results. Such changes could mask the actual as-found condition of the SSC and possibly result in an inability to verify the operability of the SSC. In addition, unacceptable preconditioning could make it difficult to determine whether the SSC would perform its intended function during an event in which the SSC might be needed. Influencing test outcome by performing valve stroking, preventive maintenance, pump venting or draining, or manipulating SSCs does not meet the intent of the as-found testing expectations described in NUREG-1482, “Guidelines for In-service Testing at Nuclear Power Plants” (April 1995)[2], and may be unacceptable.

Leakage Testing Versus Flow Diversion

by Shawn Comstock

Leakage testing versus flow diversion is another topic of interest to IST Engineers. Under the ASME O&M Code, in-scope valves with a specific analyzed leakage limit are classified as Category A valves, which requires a leak test at least every 2 years. Valves in the scope of IST without a specific limit, which often prevent flow diversion, are classified as Category B valves and do not have to be leak tested. IST Engineers are often challenged on the issue of why a valve is not leak tested.

Certain valves have a calculated limit for a specific application. These are ASME Category A valves. Other valves prevent flow diversion and the allowable amount of flow is system dependent, so the amount of leakage allowed at any given time can vary. The IST OM Code is a component-based code and not a system based code (like the Appendix J program); therefore, it is not the purpose of the IST program to perform system leakage tests.

Condition Monitoring Justifications

by Shawn Comstock

Use of an option under the modern IST OM Code for check valve testing involves the research and justification of activities for use in a check valve condition monitoring program. The two purposes of adding check valves to a condition monitoring program are to either optimize test and maintenance activities or to improve reliable performance. Overall industry check valve performance could be enhanced if this documentation is shared between sites on an Internet database. This would also improve the IST Engineer's ability to rapidly implement check valve condition monitoring activities in a comprehensive manner that incorporates the industry's best practices.

RCS PIV Testing Improvement Project

by Shawn Comstock

Every site is required to follow a Technical Specification for quantifying the leakage of pressure isolation valves (PIV) that comprise the reactor coolant system (RCS) boundary. This testing often impacts the refueling outage critical path schedule. Outage Managers working with the Westinghouse Owner's Group have consistently identified this task as a top 10 area for improvement. With the current level of experience and knowledge in our industry about RCS PIV performance, it is believed that the incorporation of a performance based or condition monitoring approach as an alternative in plant Technical Specifications can maintain an acceptable level of safety assurance at a reduced impact to the outage schedule. ISTOG is an organization uniquely positioned to provide the technical expertise for this project.

Practical/Practicable Differences

by Wavel Justice

When ASME Section XI Articles IWP and IWV were replaced by OM Part 6 and Part 10, the term practical was replaced by practicable. The stated reason for the change is that practicable describes that which can be placed into effect and practical describes that which is also sensible and worthwhile. Given enough money and time any test is practicable and you would not need cold shutdown or refuel only testing. Practical is clearly the intent of the Code in many cases.

Submittal Process (Program and Relief Request How-To)

by Wavel Justice

In the past, there have been two major differences in the way Owners have submitted their IST program plans and relief requests. Some have submitted their programs just to be filed (information only) and relief requests to be approved, while others have submitted both their program and relief requests for approval. In the past, specialized contractors were available for detailed program reviews upon request. Today, the NRC typically reviews only the relief requests and performs a spot check of other areas of the program plan. Because the number of relief requests has significantly decreased in the 10-year IST program plans since the adoption of the 1995 OM Code, licensees' IST program plan reviews are reviewed by the NRC staff without the need for specialized contractors.

NRC approval is required to take exception to those Code rules specified in 10CFR50.50a and generally requires specific submittals. However, submittals are not always required. For those plants that are still on OM-6 and OM-10 (Section XI Code, IWP and IWV plants), there are a few NRC approved positions for acceptable Code implementation available as described in Supplement 4 to Generic Letter 89-04 (NUREG-1482). NUREG-1482 contains very specific language that must be followed to document such implementation in IST programs, but acceptability of these methods is specifically addressed. Any plant updating to current 10CFR50.55a rules would be adopting the OM Code, not the Section XI Code (OM-6 and OM-10), and should be aware that some of the guidance in NUREG-1482 for testing may be obsolete or inappropriate for use with the OM Code.

The NRC staff is currently updating NUREG-1482 to ensure that the inservice testing guidance is consistent with the latest OM Code incorporated by reference in 10CFR50.55a.

For relief request format, it is this writer's opinion that the recommended format in NUREG-1482 described by section 2.5 is acceptable in the absence of new NRC guidance.

Compliance with Ambient and Media Temperature Correlation Rules

by Wavel Justice

The use of documented correlation factors is an alternative to testing valves by simulating ambient temperatures, and using a test medium (fluid and temperature) for which they are designed. Nuclear utility plant owners, through the ASME OM Code and Pressure Relief Device Users Group (PRDUG), are currently addressing compliance with these rules. Several implementation issues are discussed in the "Summary of Public Workshops Held In NRC Regions On Inspection Procedure 73756, Inservice Testing Of Pumps And Valves"[4], Section 2.4. These issues reflect the uncertainty and lack of clarity as to what these OM rules require.

It is believed that failure to have the correlation documentation does not represent any operability or safety concerns. Rules used in previous IST Ten-Year Intervals did not contain the new documentation rules, but yet they were still considered by the NRC, and the nuclear industry, to be adequate for the safe operation of our plants. When the NRC reviewed OM Part 1 for endorsement in 10 CFR 50.55a, they had to consider expediting rule adoption of any new rules that meets certain safety significance criteria. The lack of NRC expedited rulemaking is a fair indicator that the new OM Part 1 documentation rules are not an operability or safety concern. The nuclear industry has discussed the failure to have the correlation documentation required by the new rules for several years without any safety issues being raised.

GL 89-04[6] Applicability and NRC New Viewpoint

by Wavel Justice

The current GL 89-04[6] endorses NUREG-1482[2] which includes 1995 updated responses (Current Considerations) to the original GL 89-04[6] positions, questions, and responses. Another update or overhaul of NUREG-1482[2] is being worked on by the NRC (no specific due date). The NRC/ASME Symposiums and ASME OM Code Committee meetings provide venues for industry folk to get a preview of the future NRC Future Current Considerations. Hopefully, the ISTOG will become a venue for NRC/IST Engineers interfaces that will help form future NRC considerations.

Position Papers (Endorsed by ISTOG & Guidance for Their Use by Utilities)

by Gregg Joss

The ISTOG will develop Technical Positions (TP) on various IST issues deemed important to the ISTOG membership. ISTOG will implement a process for researching and developing TP's with the Steering Committee (SC) having final responsibility for their approval. Once approved, the SC will distribute the TP to all ISTOG members for consideration of adoption at their facility using the 10 CFR 50.59 review process for all associated changes. On an "as deemed appropriate" basis, the SC will create a Topical Report to be sent to the NRC detailing the TP conclusions and associated bases.

NUREG 1482 Revision (Development and Reviewer Role)

by Gregg Joss

ISTOG is very interested in being given the opportunity to become a part of the NUREG 1482[2] document revision and review team. By incorporating an ISTOG review team in the process, valuable program owner and field testing experience will provide a "users" contribution that currently does not exist. In addition, many of the inevitable post-issuance questions and clarification requests could be avoided or resolved while still in the draft revision development or pre-issuance phase of the review process. ISTOG is pursuing NRC permission to provide this type of formal role.

Code Class 1, 2, 3 Versus "AUGMENTED" IST Components

by Gregg Joss

When choosing to include non-Code class components as "augmented" (refer to General Questions 1.1.1, 1.1.2, and 1.1.3 of the "Summary of Public Workshops Held In NRC Regions On Inspection Procedure 73756, Inservice Testing Of Pumps And Valves"[4] and NUREG 1482[2], section 2.2 and Question Group 53 in Appendix A) in the IST program, many different approaches are employed. Approaches range from treating an augmented component identical to a full-fledged Code class 1, 2 or 3 component including all applicable tests and test periodicity, to loosely following the Code requirements with no compensatory requirements when Code test provisions cannot be met. ISTOG intends to develop a guide which will assist IST program owners with documenting the inclusion of augmented components and establish a standard approach for establishing the testing requirements of such components utilizing existing regulatory guidance and industry "best practices".

Terminology Guide

by Leonard Firebaugh

Due to turnover of personnel it may be desirable to have a document that compiles in-service testing terminology used in the nuclear industry. This would be a compilation of terms and common acronyms used by various industry groups as well as major documents including the NRC, ASME, ISTOG, Code of Federal Regulations, NUREGs, etc. A brief explanation for each term as well as the source and an example of usage could be given. Industry standardization would not be a goal for this guide.

Relief Request Templates

by Leonard Firebaugh

A recommended format and content for relief requests as well as several examples are contained in NUREG-1482[2]. However it may of benefit to have a set of industry relief request templates written against specific requirements and/or specific equipment types that a utility could pull off the shelf and use with only minor changes. This would especially be useful as an owner is required to implement newer additions of the Code if the templates have been generated by the first wave of owners.

Code Implementation Relief Request Guideline

by Leonard Firebaugh

Industry experience with writing a successful relief request continues to be mixed. Original guidance is contained in NUREG-1482[2] as well as more recent format guidance in an NEI document to which the NRC has agreed. However, recent experience with the NEI format received feedback from the NRC that it did not contain enough information. This ISTOG guideline would set the industry standard for level of detail and format necessary for a relief request that has NRC and industry concurrence.

NRC Q & A – Guidelines for Unwritten Processes

by Jeffrey Neyhard

The ISTOG will provide a guideline that establishes a uniform approach to be used when the IST Program Manager desires to gain insights from the regulator. The ISTOG will work with the NRC to ensure the guidance is consistent with NRC established policies. The intent is to capture acceptable communication processes that are currently undocumented. The scope will be refined as the various undocumented processes are identified.

Guidelines for Limiting Values

by Jeffrey Neyhard

The ISTOG will provide a guideline for the consistent selection of valve stroke time limiting values when no component specific Design Limiting Value is identified. When the Licensing Basis or the Design Basis provide a limiting value, the most conservative of the documented numbers is used as the limiting value for IST. When no documented limiting value is available, engineering judgment is used to obtain a limiting value. Obtaining a limiting value by engineering judgment can be simplified to a formula. In preparing the guideline the ISTOG will compile information from utility sources to ensure the various methodologies are considered. The purpose of the guideline is to ensure uniformity and consistency in the application of engineering judgment to a diverse population of valves.

PMT Guidance

by Jeffrey Neyhard

The ISTOG will provide a guideline for the consistent selection of Pre-Maintenance ("As Found") and Post-Maintenance Tests (PMT) as part of scheduled or corrective maintenance. The guideline is intended to also include Appendix J Owners Group information that provides for consistent decision making when using valve diagnostic data in lieu of performing as-left leak rate tests. The guideline will consist of tables that identify typical IST components, their multiple maintenance activity types and the pre-maintenance and post-maintenance tests to consider ensuring program compliance.

Sample Valve Passivity (How to Justify Passive Classifications)

by Jeffrey Neyhard

The ISTOG will provide a guideline for justifying passive valve classifications. Industry feedback identified that the approach to passive valve classification is inconsistent between utilities. The questions and answers from both NUREG-1482[2] and the "Summary of Public Workshops Held In NRC Regions On Inspection Procedure 73756, Inservice Testing Of Pumps And Valves"[4] indicate the need for additional clarification and guidance in this area.

Risk Informed IST (RI-IST) Implementation/Transition Guide

by David Chiang

One of the benefits of RI-IST is that the testing frequency of pumps and valves can be extended depending on the component's risk ranking. Typically, High Safety Significant Components (HSSCs) retain their Code specified test frequencies whereas Low Safety Significant Components (LSSCs) benefit from the testing interval extensions as defined in the RI-IST program description. LSSCs are grouped by component attributes and the selected attributes should satisfy NRC criteria provided in NUREG-1482[2]. With the current industry trend of short outages and system train related, it is critical to align the RI-IST components such that they are tested with the system train outage. If the component train and the system train is not aligned, it is then necessary to baseline component train-system train such that they are in synchronization for future outages and testing.

Flow Loop Issues

by David Chiang

In NUREG 1482[2], NRC staff position 9, the NRC has stated its position on using minimum-flow return lines with or without flow measuring flow devices. The NRC has delineated the conditions when flow measuring devices are required. In the 1998 Edition, 1999 and 2000 Addenda of the OM Code[5], ISTB-5121(c), 5221(c) & 5321(c), the Code stipulates that in systems where resistance cannot be varied, flow rate and pressure shall be determined and compared to the reference value. In systems that have non-instrumented minimum flow lines, the licensee will have to seek relief from this Code requirement. It has been found that the NRC is not consistent in granting relief. Some plants have been granted relief and others have been denied. There should be consistency throughout the industry on this issue.

Design Flow Rate Guide

by David Chiang

There has been much discussion within the industry as to the intent of Design Flow Rate. Messrs. Bedi and Colaccino of the NRC in their paper presented at the 7th NRC/ASME Symposium on Valve and Pump Testing (NUREG/CP-0152, Vol. 4)[3] alluded that some licensees have interpreted the Design Flow Rate as the best efficiency point (BEP) of the pump. Some plants, due to their system configuration, cannot test their pumps at the BEP. Other licensees take the position that the Design Flow Rate is the OEM flow rate when the pump was purchased. Furthermore, the Design Flow Rate can be interpreted as the accident flow rate, that is what the pump was designed for. Over the years, the accident flow rate for some systems has changed due to regulatory changes. Therefore it can be seen that there is certainly inconsistency in the interpretation of Design Flow Rate and it needs to be consolidated.

Check Valve (CV) Condition Monitoring How-To

by Bob Parry

Check Valve Condition Monitoring provides the Owner with process flexibility to implement changes in their IST Check Valve Program. This issue will deal with elements necessary to start a Condition Monitoring Program to add value to the station not only in improved performance, but also in optimizing all of the various activities that check valves are subjected to. Some practical applications such as coordinating the Appendix J leak rate Option B Performance testing with the IST closure demonstrations, reducing the number of valves subjected to disassembly, performance monitoring techniques, outage philosophies, etc., will be discussed. These gains offset the costs associated with implementing the program, and offer improved component reliability.

Skid-Mounted How-To (Justifications)

by Bob Parry

Under certain Code Editions/Addenda, integral or skid mounted equipment can be exempted from the Code provided it is tested under another program to verify that the component can perform the intended function. What are the particulars in determining if a component is skid mounted? What does integral mean? Once selected, how are they tested? How are they documented?

This feature is largely associated with the Diesel Generator sub-systems, although other skid systems, techniques and provisions of this program will be discussed and, until the

ASME OM Sub Group on Diesel Generators completes their effort to establish levels of performance monitoring with trending of specific parameters, this guidance will provide the implementation requirements.

Condition Monitoring vs. Performance Based Difference

by Bob Parry

What are the differences between performance monitoring and condition monitoring? Are some time based? Are some conditional in the selection of activities? Are reviews or analysis of results required for some? Are there requirements for trending with one and not the other? Is there a feedback requirement with one program that suggests alternate activities should be specified at the next available opportunity, or are we just looking for "SATs"? What other programs are called performance based? What programs are called condition monitoring?

Instrumentation Accuracy Considerations for Pump Testing

by Bob Parry

What are the essential elements of an IST Instrumentation program? Is the expectation that the permanent plant devices used for IST remain in calibration for the entire calibration interval? If so, what measures need to be taken? What tracking should be done to ensure requirements are being met? What records need to be maintained? What needs to be done on pump overhauls? What criteria and what bases should be provided to the various support organizations? What documents are essential for such a program?

Conclusion

The IST Owner's Group is an organization dedicated to improving the quality of life for the IST Engineer. The collaboration of industry expertise through ISTOG will improve implementation guidance and industry responsiveness in the field of Inservice Testing.

References

1 - NRC Information Notice 97-16, "Preconditioning of Plant Structures, Systems, and Components Before ASME Code In-Service Testing or Technical Specification Surveillance Testing"

2 - NUREG-1482, "Guidelines for In-service Testing at Nuclear Power Plants" (April 1995)

3 - NUREG/CP-0152, Vol. 4, "Seventh NRC/ASME Symposium on Valve and Pump Testing"

4 – NRC Memorandum - 1997 Summary of Public Work Shops

5 – ASME Operation and Maintenance of Nuclear Power Plants 1998 Edition, 1999 and 2000 Addenda

6 – NRC Generic Letter 89-04, "Guidance On Developing Acceptable Inservice Testing Programs"

Session 1(b): Valves I

Session Chair

Kevin G. DeWall

Idaho National Engineering and Environmental Laboratory

Hopkinson Model 9054 Actuator Environmental Qualification and Testing

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Abstract

As part of Bruce Power's restart activities for Bruce Nuclear Generating Station "A", Units 3 and 4 - motor operated valves installed in our High Pressure Emergency Coolant Injection System required environmental qualification (EQ) upgrades, baseline maintenance and testing. The twelve inch Hopkinson parallel slide gate valves are operated with Hopkinson Model 9054 actuators. The actuator is controlled with limit switches only as the torque switch was removed from the control logic. This paper shares the results of the application calculations, EQ testing, actuator overhaul, actuator torque stand testing, and in situ differential pressure testing.

Introduction

This paper describes the steps Bruce Power had to take to qualify and return to service sixteen High Pressure Emergency Coolant Injection electric motor operated valves as part of our Bruce Nuclear Generating Station "A" Unit 3 and 4 Restart Project. This is an opportunity to share operating experience information on electric motor valve actuators that do not deal with Limitorque or Rotork with others in the Nuclear power industry.

Each operating Unit at Bruce Nuclear Generating Station "A" relies on eight Hopkinson Model 9054 electric motor operated valves to open allowing high pressure emergency coolant injection water to enter and cool the reactor. The valves are Hopkinson twelve inch, ANSI 900, NC1, parallel slide, venturi port gate valves. Bruce Power refers to these valves as D2O Isolation Valves as they isolate our heavy water Heat Transport System from the light water Emergency Coolant Injection System.

In 1993, the D2O Isolation Valves and actuators were modified to resolve reliability problems. The valve stem, yoke and anti rotation device were strengthened. The motor horsepower and output torque was reduced. The limit switch with torque switch back-up logic was changed to two out of three limit switch only logic (Torque switch was removed). One Limit switch was internal to the actuator and four are mounted on the yoke. These modifications allowed pullout torque to be available one hundred percent of the valve stroke and ensure the valves would survive the output torque and thrust.

Our Environmental Qualification Program had been suspended in 1997 due to Bruce A lay-up when Unit 3 and 4 were shut down and staff were reassigned within Ontario Power Generation. The EQ project had to be reactivated and completed as part of Bruce Power's Bruce A restart project. Bruce A's Hopkinson actuators were never previously environmentally qualified. Engineering had to choose between replacing the actuators or risking a test program to qualify them. Knowing that a Limitorque actuator could survive the test conditions even with its Nebula grease and its gaskets not needing to seal out the test environment, our Hopkinson actuator stood a good chance of success. We chose not to replace the actuators due to weak link concerns with the valve. We had just resolved them with the modifications mentioned above.

The Hopkinson representatives recommended some seal changes to protect the limit switch compartment and Hylomar sealant on joints. The motors would be rewound to the Bruce Power EQ specification. The limit switch would be replaced. A baseline overhaul would be completed. Due to resourcing conflicts, actuator overhauls were contracted out to the Hopkinson representative.

Findings:

Qualification testing –Actuator Steam environment, motor temperature test

A test actuator was subjected to a steam chamber at required accident temperature conditions (120 degrees Centigrade) and duration. The actuator performed its required safety function. The only casualty of the test was 2 of 8 micro switches used in the limit switch were wetted and failed. Our EQ engineering contractor decided it was easier to remove the internal limit switch from the poised logic circuit than to risk delays by iterative testing and correction. We would only use the internal limit switch for the test circuit to lower our exposure to pullout torque while performing tests.

Prior to the steam chamber test, we had rewound the motors to meet our EQ specifications. After the rewind, the motor was placed in an oven to bring its steady state temperature and subjected to a locked rotor torque test. A dynamic test was not possible in the rewind shop. No appreciable change in stall torque was noticed due to the elevated temperature.

Acceptance testing –Failures on torque test bench

All sixteen actuators were returned to the Station. The contractor completed internal inspections, replaced required bearings, upgraded the seals, and installed EQ motor and logic connections. They had even shipped a torque stand from England to test the actuators after they were rebuilt. The contractor was advised that we would be performing acceptance testing on our own torque test bench which allows us to measure actuator output torque with and without a thrust load applied. An allowable torque loss of less than ten percent of rated torque plus 1.4 foot-pounds of torque for every one thousand pounds of thrust applied is expected.

Bruce Power maintenance staff had experience on eight similar Hopkinson actuators previously tested and our torque loss acceptance criteria was achieved. With a thrust rating of 60,000 pounds, our loading criteria of using 54,000 pounds presented no apparent challenge to the actuators. This thrust rating was confirmed with Hopkinson many years prior and is included in many of their publications. Figure 1 shows Hopkinson's Actuator Division Data Sheet 70263 that confirms the rated thrust for a 9054 actuator.

The first actuator to be subjected to the torque stand testing was rejected immediately. While applying a compressive thrust load, the thrust bearing failed to carry the load. The drive shaft was being jacked right out of the actuator. A circlip had popped out of its retaining groove in the output shaft allowing unrestrained axial movement to occur. For this to occur so quickly under no load, it was suspected that the circlip was not seated in its groove allowing it to pop out. The circlip can be seen holding the sleeve in place on the output shaft above the helical wheel in the figure below. The circlip is required for the actuator to perform its open safety function.

The second actuator met the torque stand testing acceptance criteria.

The third actuator was able to complete unloaded thrust testing, but suddenly stopped rotating when the thrust bearing was loaded. The actuator had seized. Based on earlier experiences testing Hopkinson actuators, contact and galling between the thrust bearing and the output shaft were suspected. This is known to happen when the thrust bearing is installed incorrectly.

Testing the rest of the actuators continued in an attempt to obtain eight acceptable actuators to be used for our Unit 4. Only five of sixteen actuators ended up being accepted for service. Some were rejected for seized thrust bearings and some for having unacceptably high parasitic torque losses when thrust load was applied. Eleven bad actuators were prepared for return to the contractor for repairs. The contractor wanted all 16 returned, as they had no idea why some actuators were acceptable and others were not. The contractor was convinced we were overloading the actuator. We were convinced the contractor used non OEM parts to repair. All actuators were returned for re-inspection and repairs.

Circlip 23

The contractor disassembled all sixteen actuators. Sticking to the thrust overloading theory, they told us the actuators had a rated thrust of zero pounds and that we had overloaded circlip 23. This was an unbelievable statement coming from a manufacturer's representative who supplies rising stem gate valves and actuators! Circlip 23 (item 23 on actuator drawing) retains a sleeve with hammerblow lugs on it and is keyed to the output shaft. The sleeve and circlip also carry the tensile stem load on the thrust bearing in order to open a valve. The circlip had dished, indicating it had yielded. The contractor advised us that the only way the actuator would carry a thrust load was to replace the circlip with a split retaining ring or threaded collar modification. Our EQ contract engineers quickly sided with the manufacturer's representative. However, the thought of a modification did not appeal to us as this actuator had been in service for 20 years and we have 400 or more similar actuators in service. We also had documentation supporting our position that loading the actuator to 90% of rated thrust is not overloading it. Bruce Power told the manufacturer's representative contractor to recheck their calculations and verify the zero thrust comment.

Engineering investigation - Circlip application, shaft hardness, groove

Circlip 23 presented an engineering challenge- why did it work when Bruce Power's Maintenance department rebuilt and tested the actuators and fail when the contractor-repaired actuators were tested?

Bruce Power tested three output shafts and sleeves to see if we could yield a circlip in our maintenance shop. Our mechanics proceeded to load the sleeve, drive shaft and circlip to 61,655 pounds. The first test only caused the circlip to deflect 0.031 inch indicating the circlip was holding. Upon disassembly the circlip showed no signs of yielding only that shear contact had occurred. A second drive shaft only caused 0.028 inch deflection of the circlip when loaded. Again, no yielding was observed. A third drive sleeve finally revealed circlip bending – the clip was bending and sliding out of the retaining groove. The mechanics stopped applying load immediately.

Inspection of the sleeve revealed the edge contacting the circlip was not sharp. As a result, the circlip was experiencing a bending load instead of a shear load. The circlip groove in the drive shaft was also yielding. We measured the hardness of the drive shaft and estimated its yield strength to be near 65,000 pounds per square inch (psi).

We advised the contractor to inspect all the drive sleeve grooves and square up the sleeves to re-establish shear loading on the circlip and ensure the dimensions are within Hopkinson's allowable fits and tolerances. Skeptical that this would work, they agreed to try it and place an assembled output shaft, sleeve and circlip in their press, and press to thirty tons and proceed to the rated capacity of the press if the circlip held. They tested the assembly and were within manufacturer's allowable deflection. A load of ninety tons was applied and the circlip held although it did distort. The sleeve material yielded solid into the output shaft, which required machining to disassemble. The proof test was successful.

Based on the test results, Circlip 23 could once again be used for service. The circlip application was no longer in question. We had to purchase new output shafts and square up the sleeve surface or replace them to ensure the circlip was shear loaded.

Acceptance testing- ready for service

All sixteen actuators were overhauled and returned to Bruce Power. They were tested on our torque test bench. We disassembled any actuators that exceeded our parasitic loss criteria and improved bearing fits.

Typical pullout torque, stall torque and current readings at varying voltages are shown in Table 1. Our actuators were returned to the field acceptable for use.

Nuclear Safety Surprise – 5.5 MPa raised to 7.6 MPa DP Impact on Check Valve testing

The actuators have sufficient torque to open the D2O isolator valves based on our engineering calculations and uncertainties. Surprising results of a study performed by our Nuclear Safety Department concluded that some of the valves could see a higher differential pressure than originally expected due to the head pressure of our Heat Transport pumps. This raised the differential pressure from 5.5 Megapascals (MPa) (800 pounds per square inch differential (psid)) to 7.6 MPa (1103 psid) that four of the eight valves would be required to open against. This situation only becomes a risk if we depressurized a pipe section between the D2O isolators and a check valve in order to test stroke the check valve. Based on our extensive torque stand data, we were able to reevaluate our requirements. If the voltage was high enough, the actuators could still produce the required torque needed to open the valve. To confirm this, we had to determine our valve factor to ensure thrust capability was adequate by performing in situ differential pressure testing.

Our electrical engineers were able to determine that our voltage was high enough provided our class II inverters were available when the check valve testing was being conducted. This was added as a prerequisite to performing the check valve stroke test.

Differential pressure testing on four inlet header valves produced a 0.7 valve factor that we used for non differential pressure tested valve calculations. The high valve factor is higher than anticipated. Reasons for a high valve factor are:

- The D2O isolators have a nickel based hardfacing which Hopkinson calls "Platnam" instead of stellite.
- Differential pressure testing was done at a lower temperature and pressure than the valve would see at accident conditions.
- Instrumentation accuracy.
- Choice of mean seat diameter. The overlap of disc and seat was used to determine mean seat diameter.

Internal inspection history of these valves shows no signs of internal damage. The combination of actuator test data and differential pressure test data has been used to determine the valves will perform their safety function.

Conclusion

Through the use of qualification testing and the collection of actuator test data, Bruce Power was able to return all sixteen valves and actuators to nuclear safety service. The use of a torque test stand for electric motor operated actuators with controlled tensile and compressive thrust load capability located several operation problems. Most testing was done in a shop environment, minimizing the number of test strokes done at the valve. While the technical issues encountered are unique to Bruce Power's Hopkinson actuators, it demonstrates the work and knowledge provided by US utilities can be applied by others to improve equipment performance. The process allowed us to locate and neutralize a bad limit switch seal, reveal poor overhaul practices, resolve application problems, and collect test data to support safety analysis.

Figure 1

ELECTRIC ACTUATOR FIGURE 9054

Standard Specification

Output torque	600 lbf ft (814 Nm)
Output speed	24 rev/min (50 Hz) 29 rev/min (60 Hz)
Thrust	60,000 lbf (266 kN)
Maximum output shaft turns	100 Std. (1,000 special)
Drive	Detachable bronze or steel, external or internal sleeve
Maximum spindle (stem) acceptance	3" (76·2 mm)
Construction	Totally enclosed weatherproof to CSA enclosure 4, CEGB 569701 and IEC 144 (IP55)
Ambient temperature	70 °C maximum
Hand-wind ratio	10:1
Lubrication	Grease

Power supply	3 phase 50/60Hz
Motor	3 HP (2·2 kW) rating 30 minute valve duty. Speed 940 rev/min. ✱ Insulation Class 'B'. Fitted with thermostat
Cable entries	Detachable undrilled gland plate
Weight	589 lb (267 kg)
Travel limit switches*	3 at Open position 2 at Close position
Torque limit switches*	1 in Opening direction 1 in Closing direction
*Single pole changeover type.	
Optional extras	Mechanical indicator Position transmitter Push buttons Isolator switch Selector switch Contactors Transformer Interposing relays Anti-condensation heater

✱ TYPICAL FULL LOAD 50HZ 6 POLE MOTOR

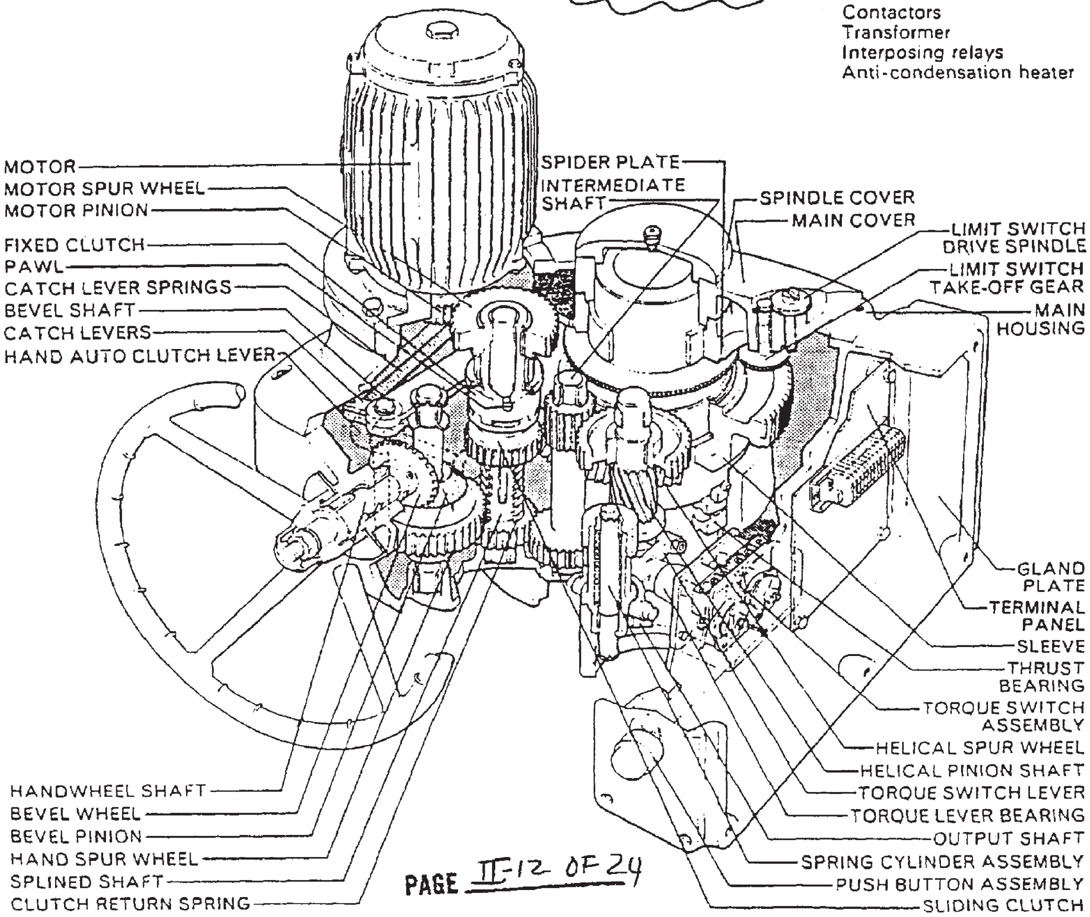

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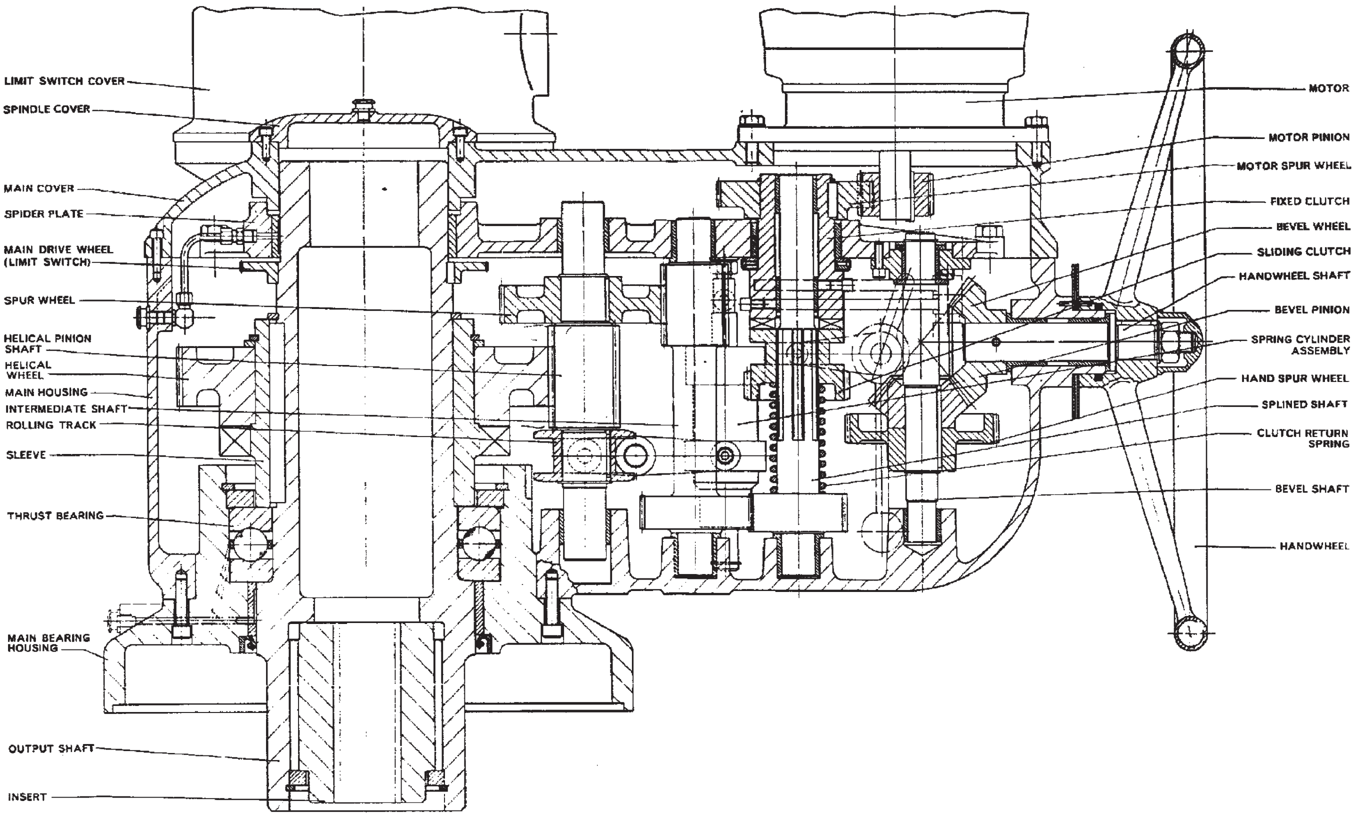
Figure 2



SECTIONAL ARRANGEMENT OF GEAR BOX ASSEMBLY FOR FIG 9053/4 ACTUATOR

Table 1 Typical pullout torque, stall torque and current readings at varying voltages

Valve/ Voltage	Pullout torque in foot pounds/Amps rms	Stall torque in foot pounds/Amps rms	Parasitic torque loss in foot pound when thrust loaded
3-34330-MV6@ 591V	993/29.4	859/35.3	17
3-34330-MV6@ 565V	957/22.8	824/32.9	17
3-34330-MV6@ 450V	577/16	422/24.1	17
3-34330-MV6@ 400V	448	327	17

Entergy
Waterford 3 S.E.S
Hydraulic Operated Valve (HOV) Program

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Abstract

In general, Hydraulically Operated Valves (HOV) are the least populous of the Power Operated Valves at a Nuclear Power Plant. Motor Operated Valves (MOV), Air Operated Valves (AOV) and Solenoid Operated Valves are usually more numerous. Although small in population, HOVs are often used in important applications, especially when diverse modes of force are required. At Waterford 3 (W3), the six important HOVs are: Main Steam Isolation Valves (MSIV), Main Feedwater Isolation Valves (MFIV), and Shutdown Cooling Isolation Valves (SCIV). The MOV and AOV Programs have improved the reliability of MOVs and AOVs. A similar approach is being applied to HOVs. The three key elements of the HOV program are Design Basis Review, Diagnostic Testing, and Program Administration. Among these key elements, diagnostic testing of the HOV is the most difficult element. By applying knowledge from MOV and AOV testing, Waterford 3 has successfully implemented HOV diagnostic testing of selected valves. This program has been in place for the last two refueling outages. In the future, this testing may be extended to all six safety-related HOVs and also to Balance of Plant (BOP) valves. This presentation will focus on HOV diagnostic testing including the test method, test results, and resulting benefits that will improve HOV reliability and performance.

I. Background

In 2000, a number of Condition Reports (CRs) were issued to identify the problems associated with the SCIVs and MFIVs. Because of the above problems and considering the issues in NRC Regulatory Summary Issue 2000-03, "Resolution of Generic Issue 158: Performance of Safety Related Power Operated Valves under Design Basis Conditions," the W3 Business Plan assigned an action to Components Engineering to explore the feasibility of HOV diagnostic testing and the expansion of the AOV program to include HOVs. The intent of the action was to improve HOV reliability.

The feasibility study indicated:

Phase 1 – Design Basis Reviews (DBR):
Unlike the MOV and AOV Programs, the DBR calculations of all six safety related HOVs were previously approved.

Phase 2 – HOV Diagnostic Testing:
Prior to W3 RF 11 (April, 2002), Engineering studied the operation of safety related HOVs, combined testing techniques used within the MOV and AOV programs, and evaluated the available commercial diagnostic test systems. This study concluded that diagnostic testing of HOVs was feasible. During RF 11, HOV diagnostic testing began on the MFIVs and SCIVs.

Phase 3 – Program Administration: In progress.

II. HOV Diagnostic Test Equipment

In general, the testing techniques of MOVs are:

- Switch Actuation Monitoring: The actuation of torque switch and limit switches are monitored via current or voltage change.
- Motor Current Measurement: The motor current is monitored by a current (amp) probe.
- Motor torque is indirectly measured via the motor power or spring pack displacement which is correlated to a specific motor torque.
- Thrust/Torque Measurement: The stem thrust/torque is directly measured with permanently mounted strain gauge sensor on the stem. The stem thrust / torque could also be measured indirectly via a calibration file that is applied to the sensor readings (e.g., yoke mounted sensor, portable calibrator). The strain gauge is used to measure the valve stem thrust/torque.

The testing techniques of AOVs are:

- Pressure Measurement: The pressure sensors are used to measure the air pressure. In general, the maximum operating pressure of AOVs is approximately 120 pounds per square inch gage (psig).
- Thrust Measurement: The same strain gauge technique of MOVs is used on AOVs.
- Travel Transducer is used to measure the stem position during travel.
- In addition to the above, current probe, voltage measurement, Gauss sensor and acoustic sensor can also be used to monitor the Solenoid Operated Valve (SOV) operation and/or desired signals.

Criteria for Selecting HOV Diagnostic Test System/ Components

The components of HOV actuators are accumulators, SOVs, pneumatic valves, air or electrical pumps, pilot hydraulic valves and their control logic circuits. As a result, the HOV diagnostic test system requires the combined techniques of AOVs and MOVs. The HOV diagnostic equipment should have the following capabilities:

- High pressure measurement (hydraulic and nitrogen): the diagnostic system and pressure sensors shall be capable of acquiring high pressure data. The HOV pressure could exceed 5,000 psig.
- High thrust measurement: The output thrust of an HOV is much higher than the output thrust of an AOV or MOV. The HOV thrust could easily exceed 100,000 lbs.
- The measurement data are obtained and displayed in the same time reference.
- All other sensor measurements of AOV and MOV test equipment (e.g. travel transducer, current probe and voltage sensing device, Gauss sensor and acoustic sensor).

III. Shut Down Cooling Isolation Valves

Waterford has two SCIVs with one valve for each train. Each valve is located inside containment and between the Reactor Coolant System (RCS) isolation valves and outside containment isolation valves (SI 401A/B and SI 407A/B). This valve has an active safety function to close and remain in the close position during a Containment Isolation Actuation Signal (CIAS). This valve also has safety function to open fully and remain open under post accident Shut Down Cooling (SDC) entry conditions at 200F containment temperature. The open function is interlocked with pressurizer pressure to prevent over pressurization of the Low Pressure Safety Injection (LPSI) piping. The valve and actuator are designed as follows:

SCIV Size/Type	Design Pressure Unit: Pound per square inch gage (psig)	Design Temp	**Design Closing Thrust**
14” Flex Wedge Gate	2485 psig	650°F	33,819 lbs (Ref: Waterford ECM91-076 Rev 2)
Actuator	Normal Position	Failure Position	**Hydraulic Pump Max Operating Pressure**
Paul Munroe	Locked Closed	Closed	3000 psig

Description of SCIV Actuator

The valve is opened by the hydraulic force that acts on the bottom side of the piston. The valve is closed by the nitrogen pressure acting on the top side of the piston providing a store motive force. Upon initiation of a closed signal, four trip SOVs relieve the hydraulic pressure under the piston and drain the hydraulic fluid back to the reservoir.

Results & Benefits of SCIV Diagnostic Testing

Testing Results:

- Quickly identified problem (e.g., pump capability, internal leakage)
- Obtained dynamic response of nitrogen and hydraulic pressure
- Verified pressure switch settings
- Confirmed proper operation of sub-components (SOV, pneumatic valves etc.)

Benefits:

- Effective tool for future trending of hydraulic pump and SOV performance or for detecting other degradation (e.g., seal leakage)
- Condition monitoring in lieu of time based preventive maintenance
- Confirmation of sub-component operation helps eliminate and minimize Preventive Maintenance (PM) tasks

IV. Main FeedWater Isolation Valves

Waterford has two Main Feedwater Isolation Valves (MFIV), one for each redundant train. This valve has an active function to close under Feedwater or Main Steam Line Break (FWLB / MSLB). The valve requires a five-second closure per Technical Specifications.

The valve and actuator are designed as follows:

MFIV Size/ Type	Design Pressure	Design Temp	**Stem Diameter**
20” Double Disc Gate	1400 psig	480°F	3.75 inches
Actuator	Normal Position	Failure Position	**Design Closing Thrust w/ Two Accumulators**
Hydraulic/ Pneumatic (Anchor/ Darling)	Opened	Fail “As Is”	108,525 lbs

Description of MFIV Actuator

The MFIVs are controlled by hydraulic actuators. These actuators utilize a hydraulic/pneumatic control system with accumulators in conjunction with 3 way SOVs and 4 way hydraulic (pilot) valves to control hydraulic pressure within the actuator and thus open and close the valves. The valve accumulators (2) are precharged with nitrogen and then hydraulic fluid is added to achieve the desired operating pressure. Eleven gallon accumulators with integral piston stop tubes have been installed to provide a controlled volume in which to measure the nitrogen pressure. Both accumulators are required to actuate during FWLB/MSLB conditions for rapid valve closure. The 4 way hydraulic valves which control the flow path of hydraulic fluid within the actuator assembly are air operated. Solenoid operated valves control the air to the 4 way hydraulic valves, to direct hydraulic fluid flow. The MFIV are designed to “Fail As Is” on loss of electrical or air supply. Therefore, air accumulators are installed to ensure valve closure after a loss of instrument air. These accumulators are to ensure the valves can be closed within 1.5 hours from accident initiation.

Results & Benefits of MFIV Diagnostic Tests

Testing results:

- The initial diagnostic test revealed that after MFIV successfully closed, there was no closing force to maintain the valve in the close position. This behavior was similar to an MOV actuator with a non-locking gear set.
- The measured closing force with two accumulators (~ 110,000 lbs) agreed with the design closing force of 108,525 lbs.
- The bottom piston hydraulic pressure was significantly lower than expected for the MFIV.
- Confirmation of sub-component operation helps eliminate and minimize PM tasks.

Deficiency Identification:

- Non-locking closure stem force was corrected by modification.

Other benefits are:

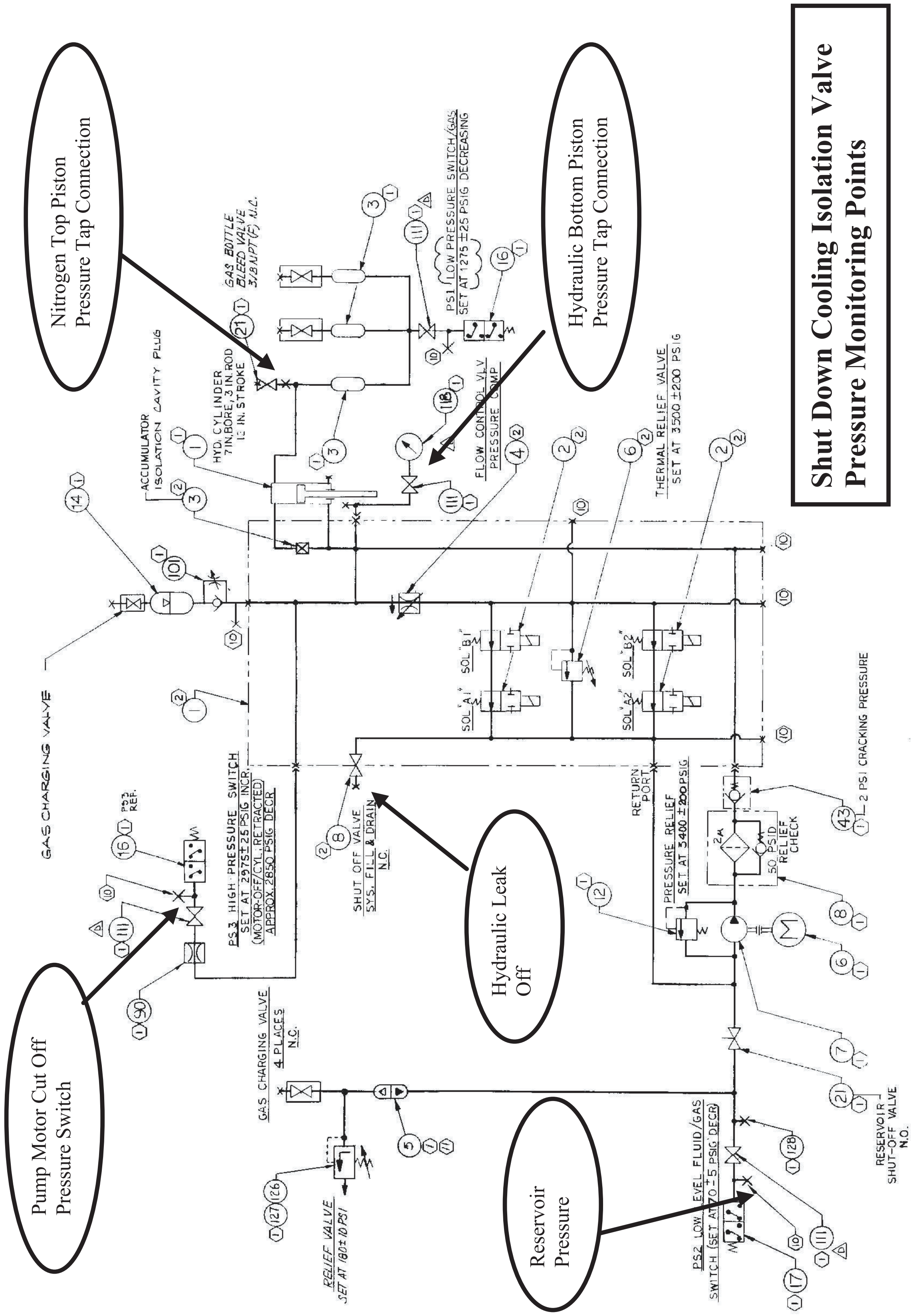
- Effective tool for future trending of the control pilot valves (SOV & pneumatic valves).
- Effective tool for future trending of other degradation (e.g., leakage).

FUTURE ACTIVITIES

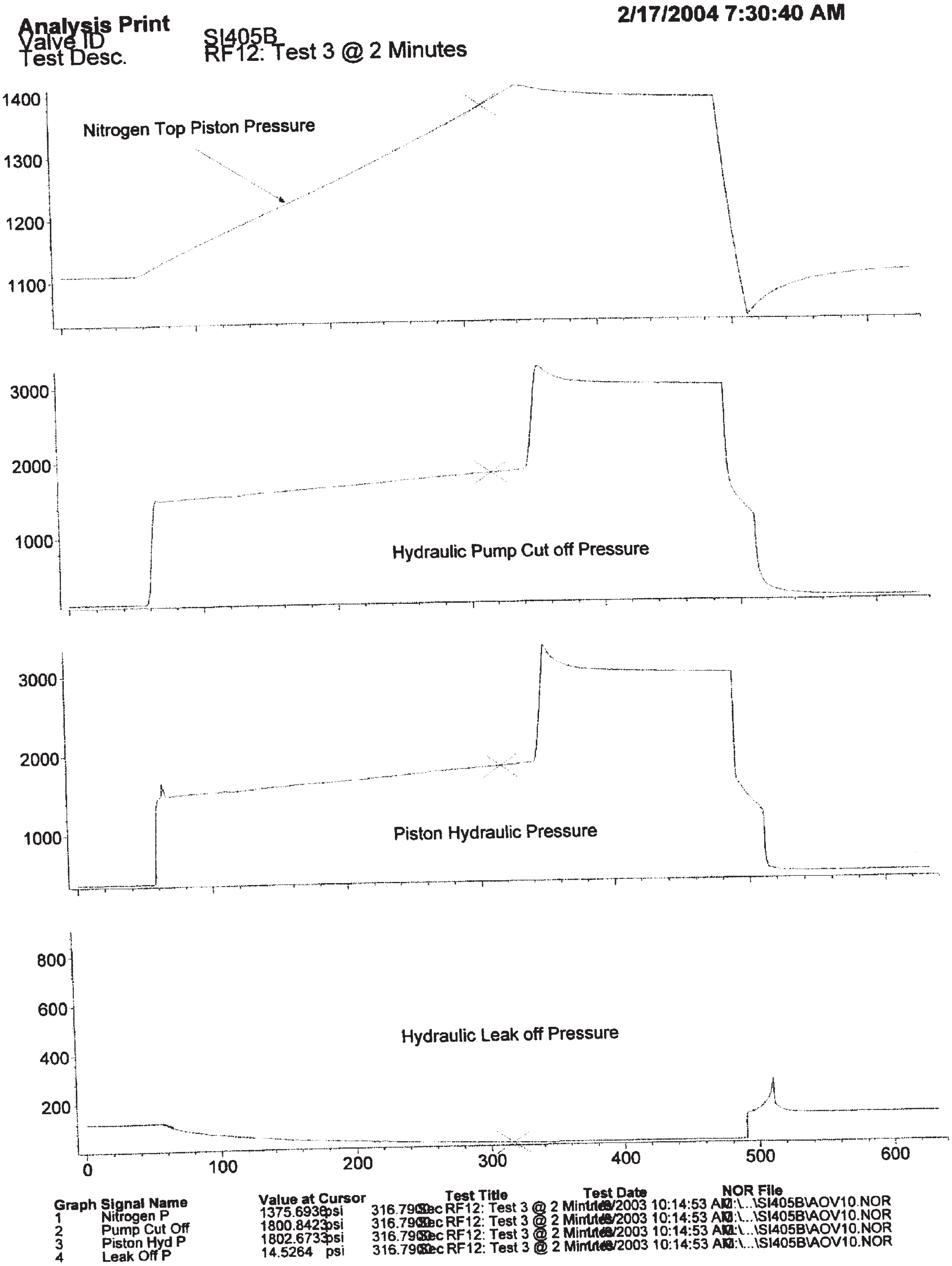
1. Perform HOV diagnostic tests on Main Steam Isolation Valves.
2. Apply HOV testing method to Balance of Plant (BOP) valves (e.g., main turbine isolation / throttle valves, Moisture Separator Reheater (MSR) intercept valves).

V. Conclusions

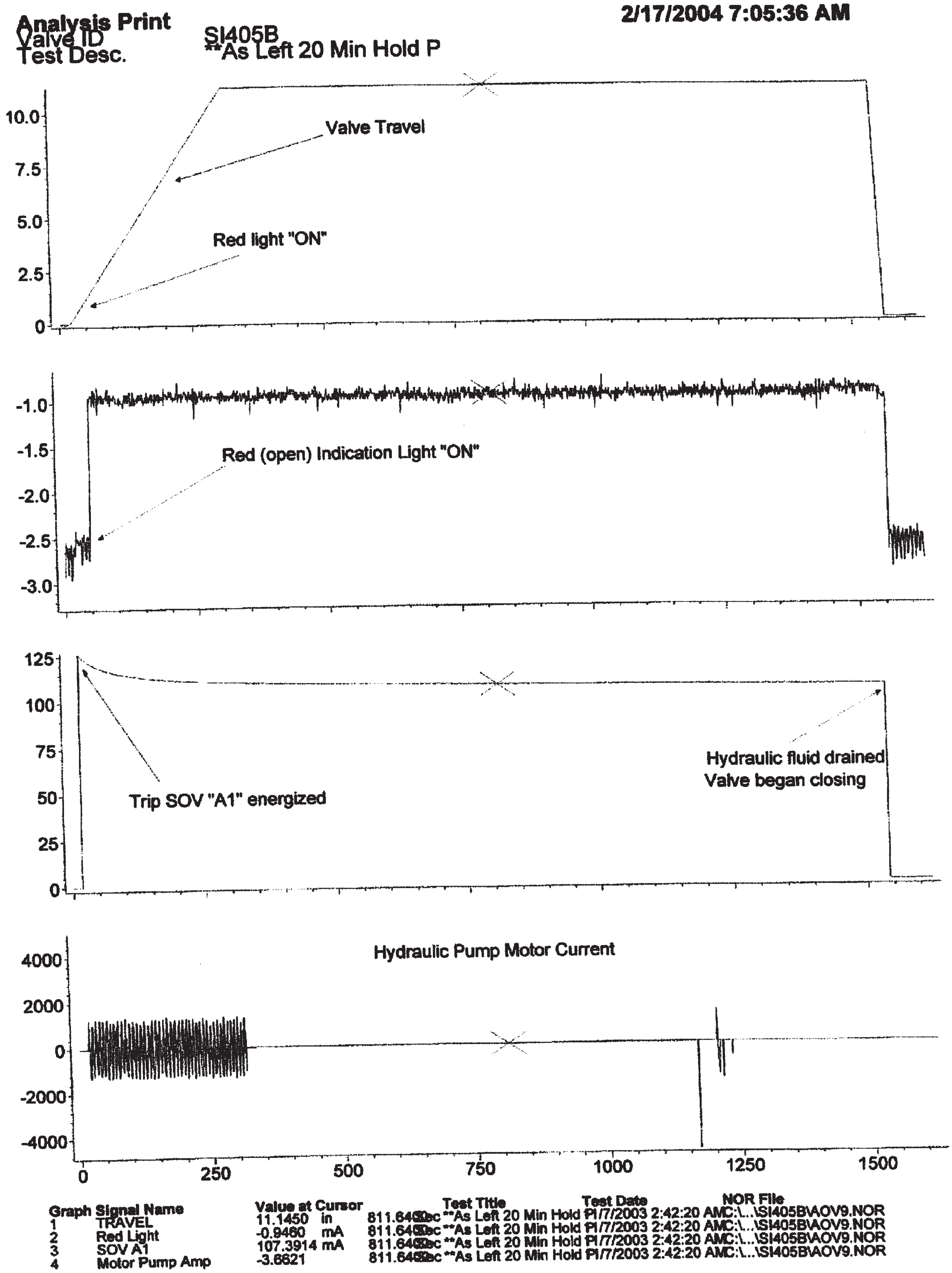
1. The benefits of MOV / AOV diagnostic testing are applicable to HOVs. HOV diagnostic testing is an excellent tools for:
   - ❋ Troubleshooting
   - ❋ Trending
   - ❋ Verifying HOV settings
   - ❋ Evaluating actuator output thrusts
2. Utilizing the HOV diagnostic testing should improve HOV reliability in the same way as MOV & AOV programs.
3. Because of high hydraulic / gas pressure and stem force, HOV diagnostic testing shall require extra cautions / attention.

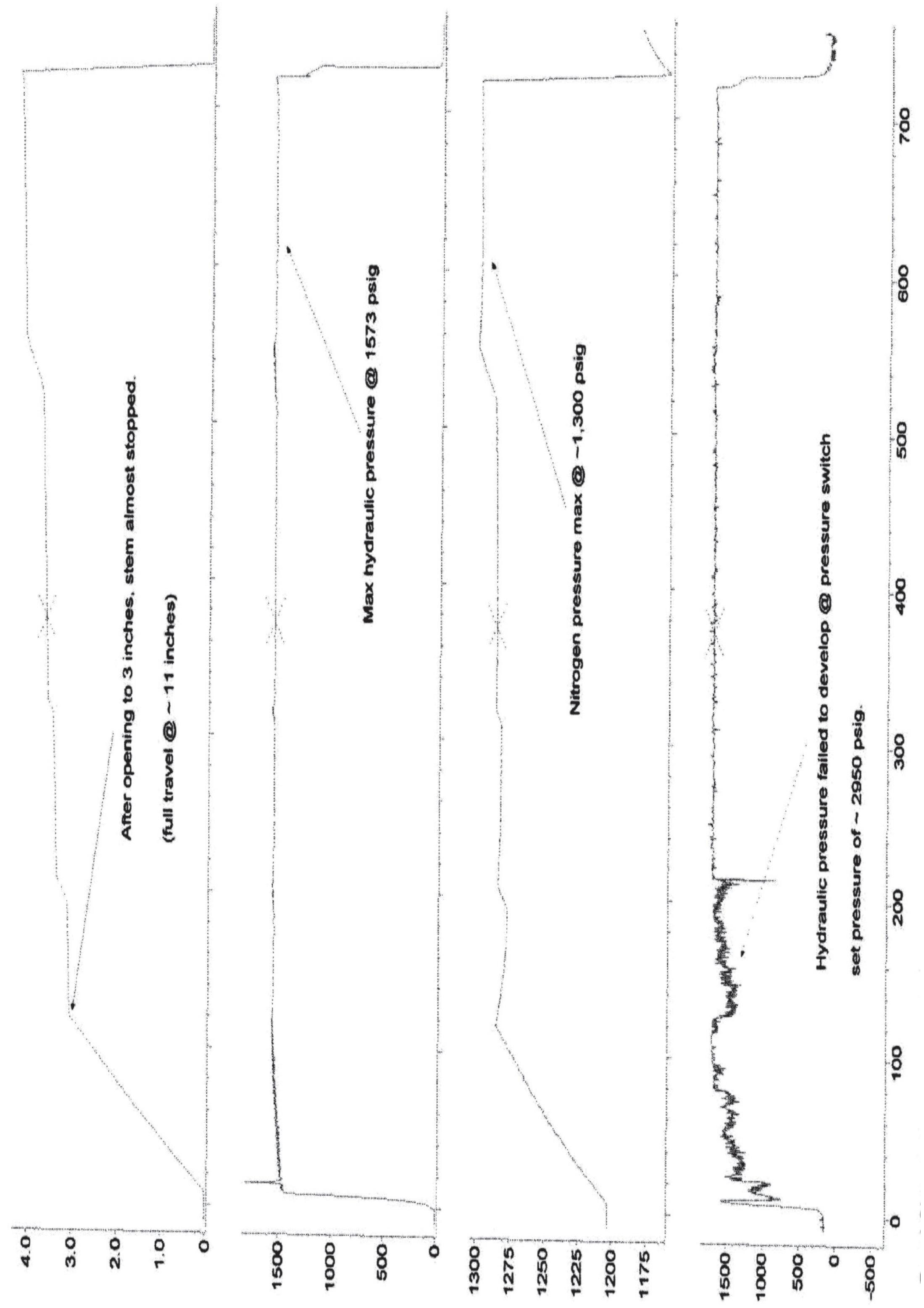


Shut Down Cooling Isolation Valve Pressure Monitoring Points

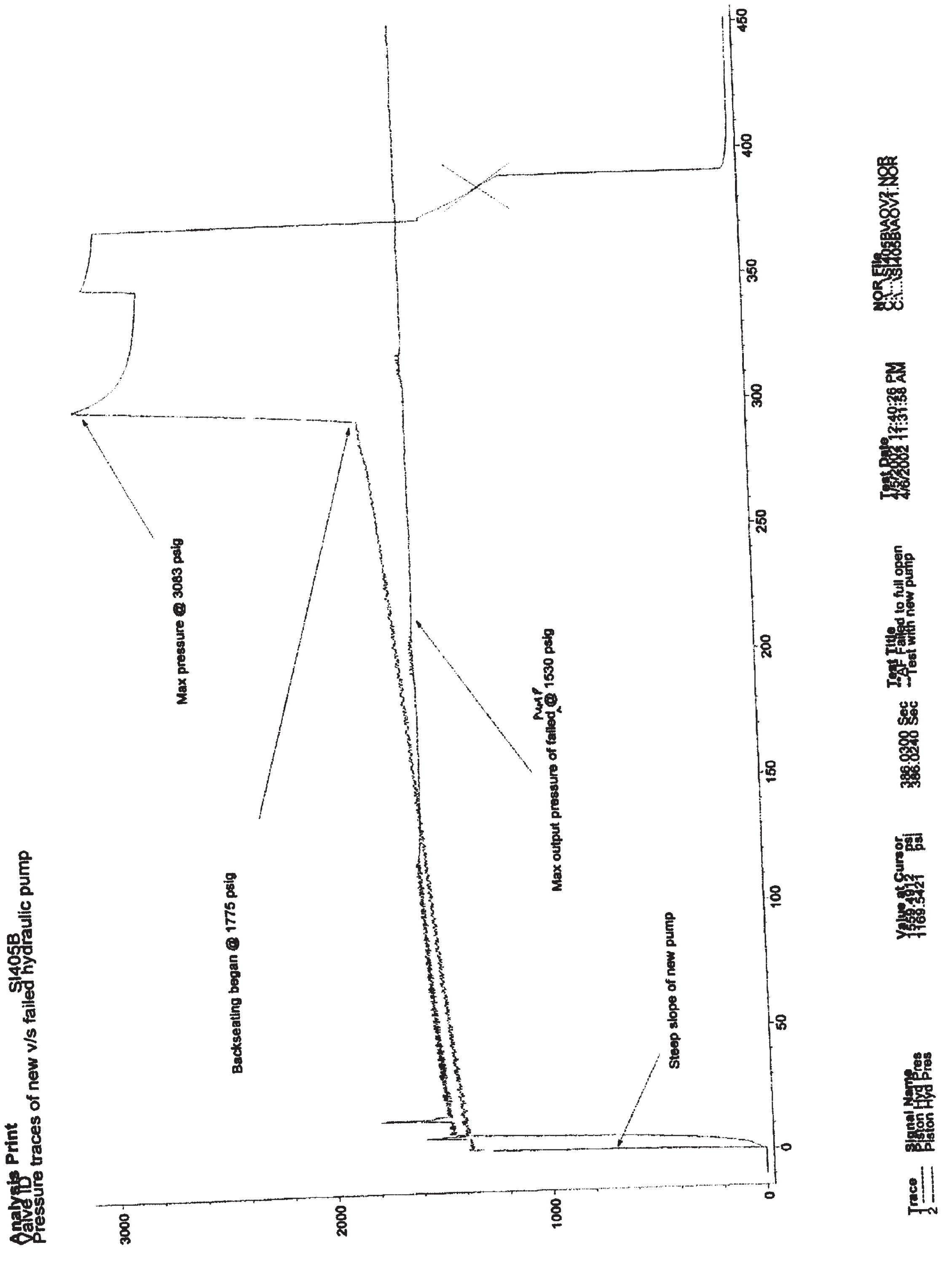


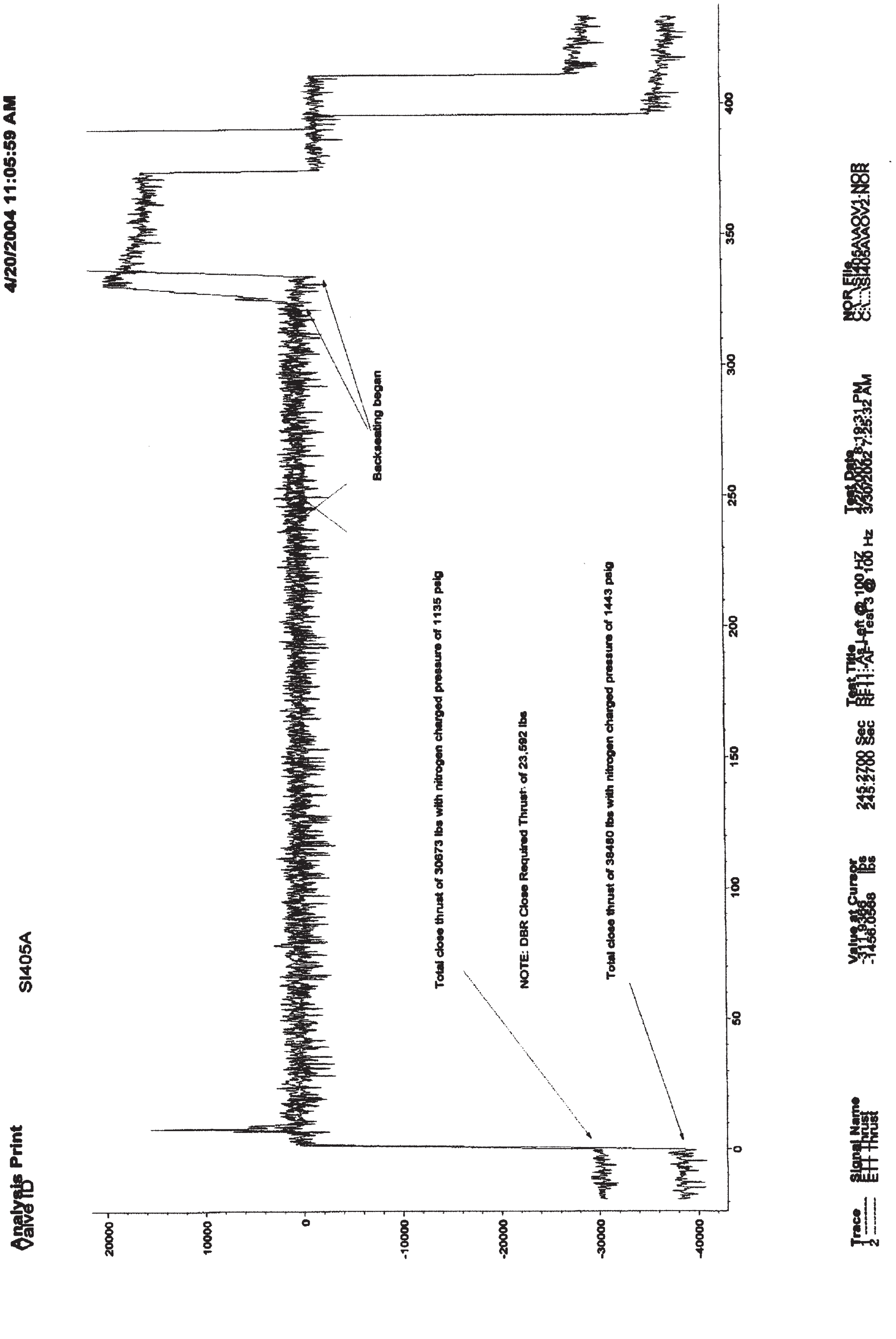
Shut Down Cooling "B" Valve


Analysis Print
2/17/2004 7:05:36 AM
Valve ID SI405B
Test Desc. **As Left 20 Min Hold P
Valve Travel
Red light "ON"
Red (open) Indication Light "ON"
Trip SOV "A1" energized
Hydraulic fluid drained
Valve began closing
Hydraulic Pump Motor Current
0 250 500 750 1000 1250 1500
Graph Signal Name Value at Cursor Test Title Test Date NOR File
1 TRAVEL 11.1450 in 811.64?sec **As Left 20 Min Hold P1/7/2003 2:42:20 AMC:\...\SI405B\AOV9.NOR
2 Red Light -0.9460 mA 811.64?sec **As Left 20 Min Hold P1/7/2003 2:42:20 AMC:\...\SI405B\AOV9.NOR
3 SOV A1 107.3914 mA 811.64?sec **As Left 20 Min Hold P1/7/2003 2:42:20 AMC:\...\SI405B\AOV9.NOR
4 Motor Pump Amp -3.6621 811.64?sec **As Left 20 Min Hold P1/7/2003 2:42:20 AMC:\...\SI405B\AOV9.NOR

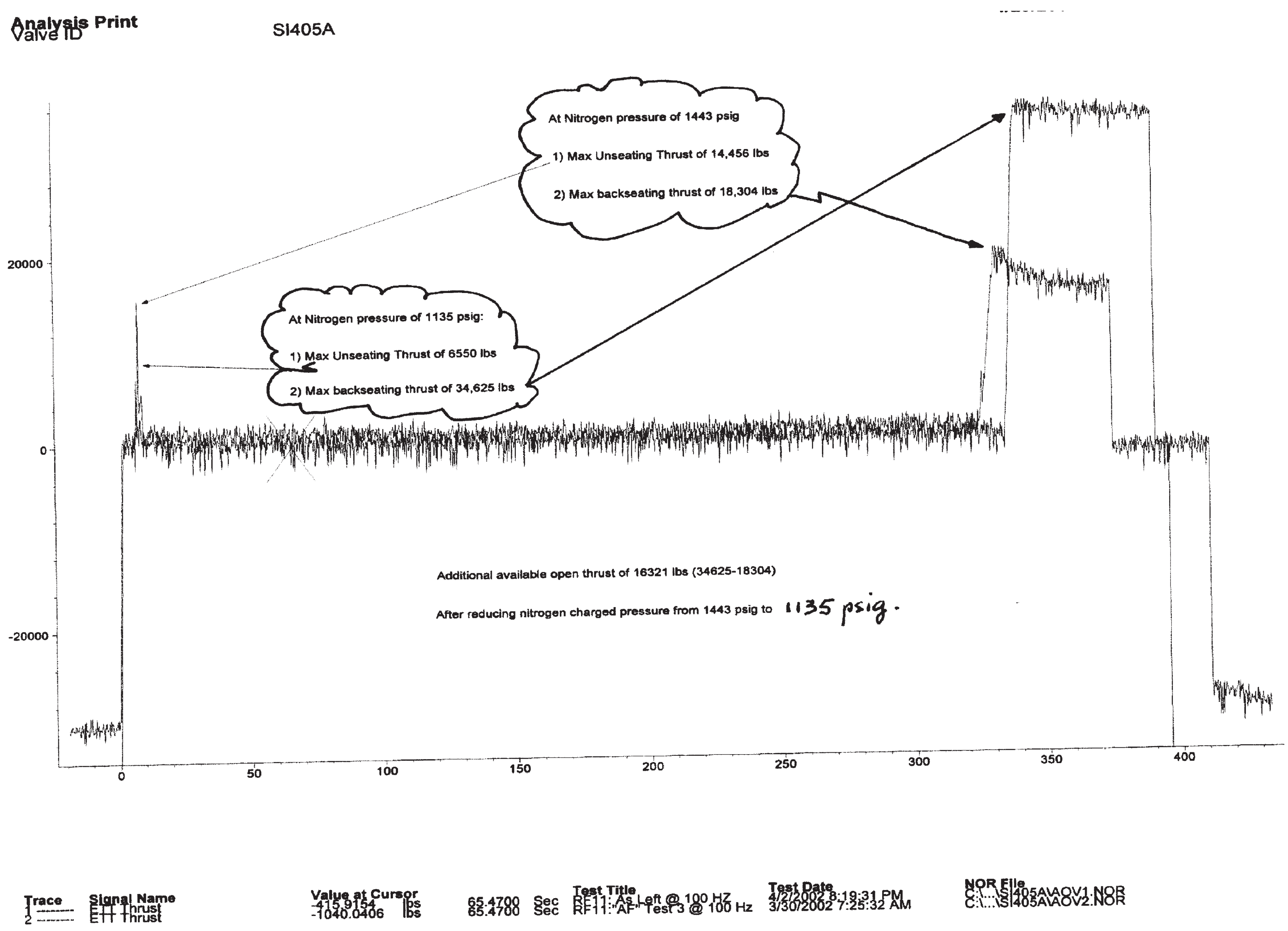


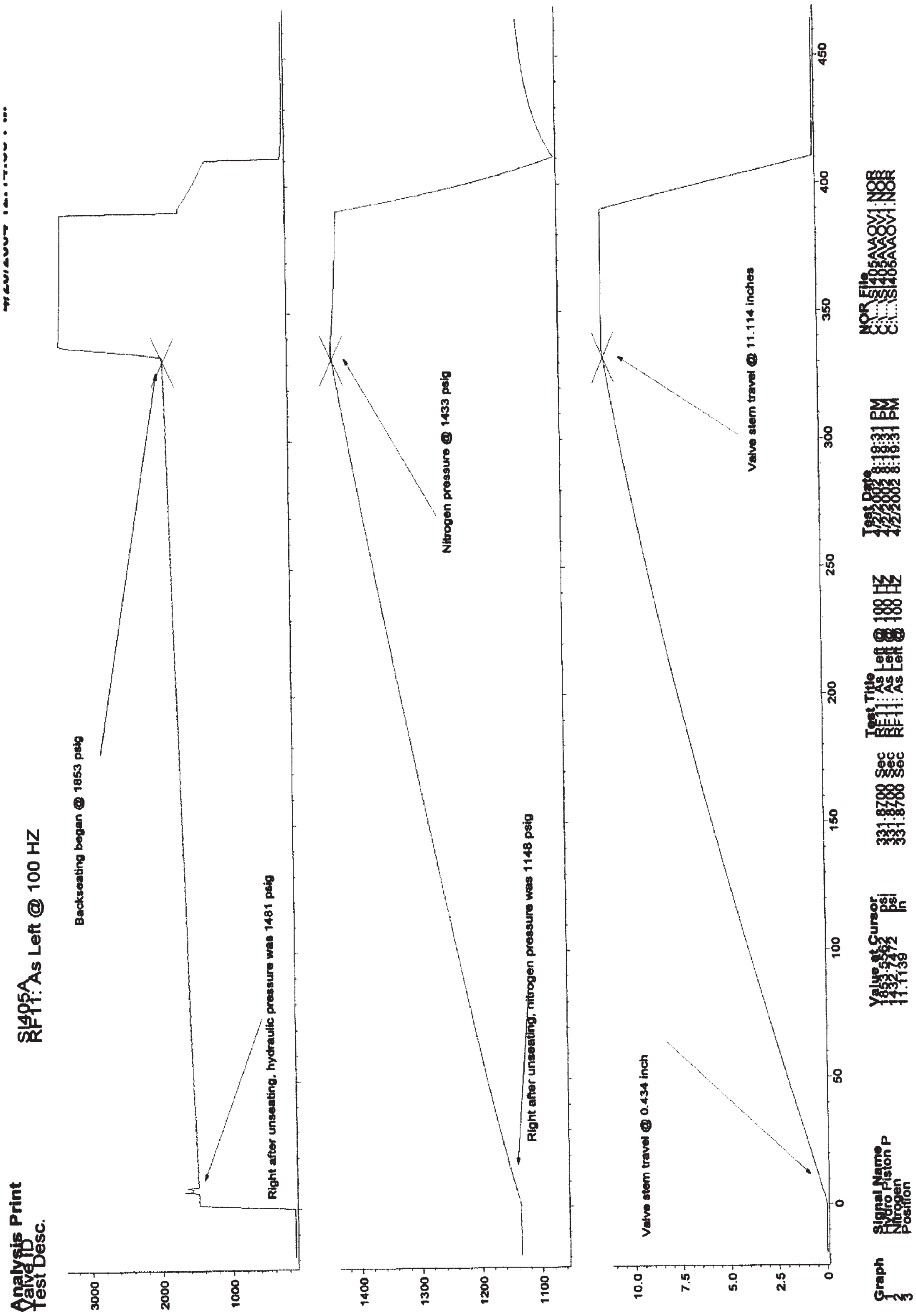
Shut Down Cooling "B" Valve Hydraulic Pump Failure

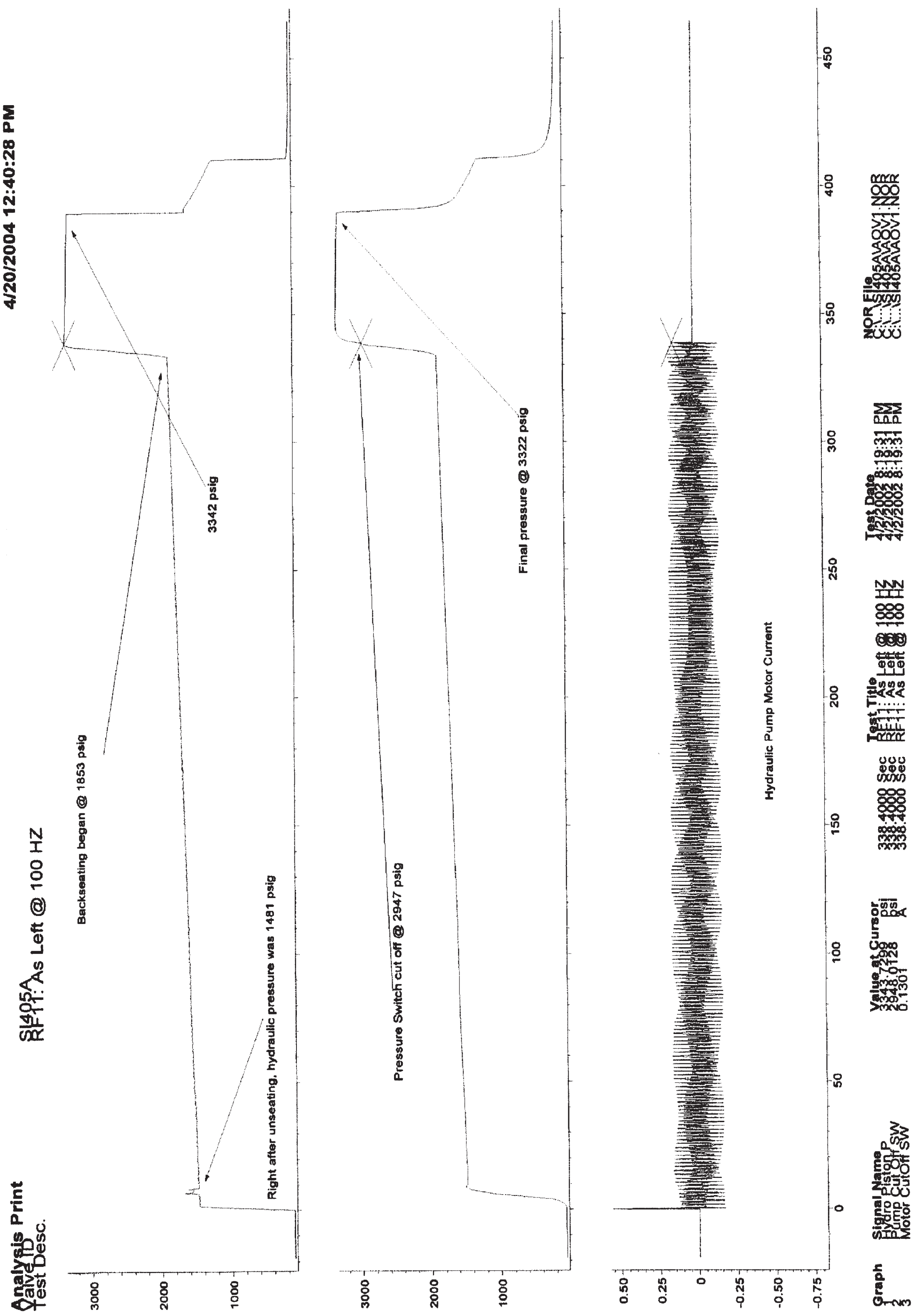

Analysis Print
Valve ID SI405B
Pressure traces of new v/s failed hydraulic pump
Max pressure @ 3083 psig
Backseating began @ 1775 psig
Max output pressure of failed pump @ 1530 psig
Steep slope of new pump
3000
2000
1000
0
0
50
100
150
200
250
300
350
400
450
Trace
Signal Name
Piston Hyd Pres
Piston Hyd Pres
Value at Cursor
Test Title
Test Date
NOR File



Shut Down Cooling "A" Valve
Before & After Nitrogen (Optimum) Settings

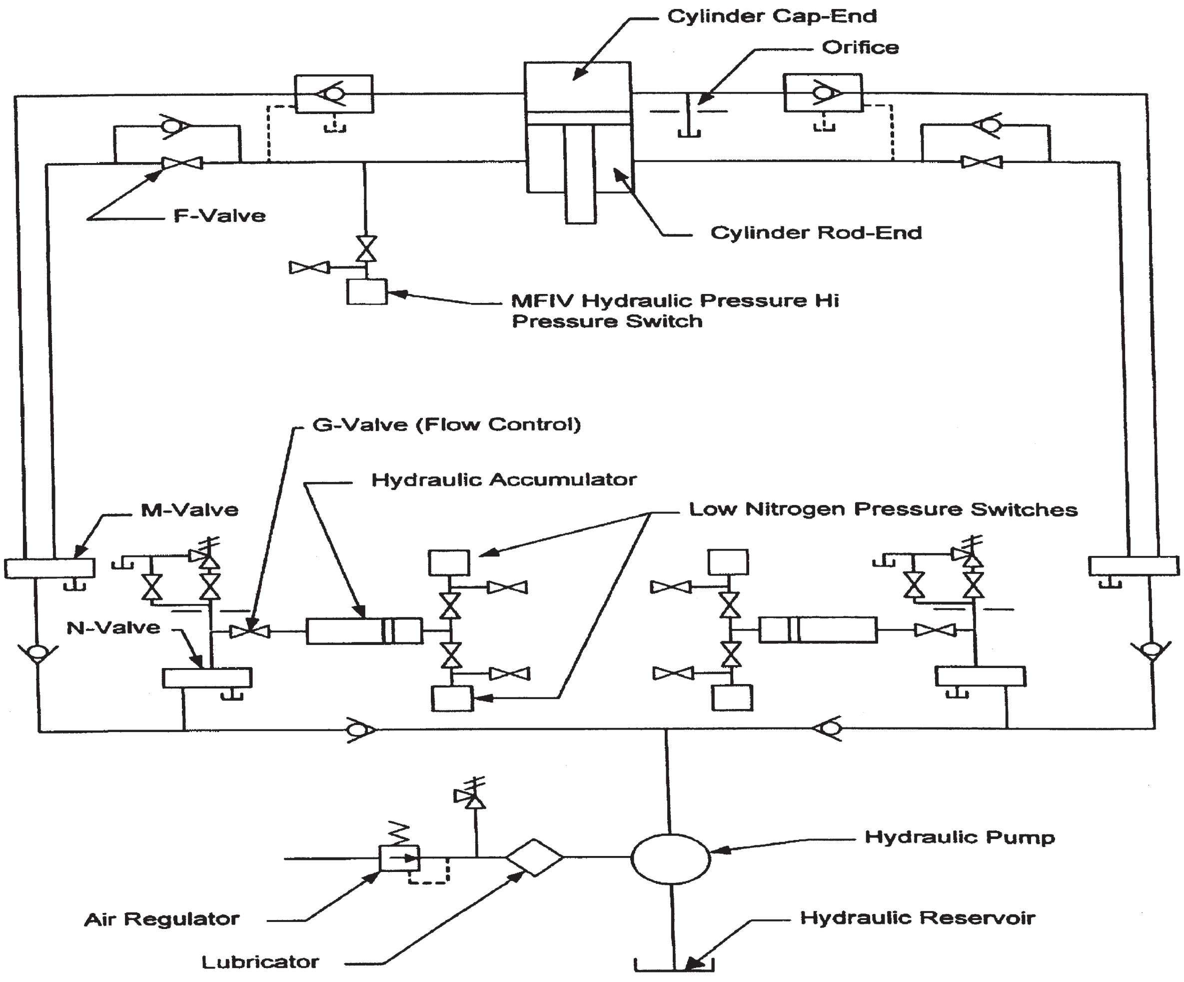

Analysis Print
Valve ID
SI405A
At Nitrogen pressure of 1443 psig
1) Max Unseating Thrust of 14,456 lbs
2) Max backseating thrust of 18,304 lbs
At Nitrogen pressure of 1135 psig:
1) Max Unseating Thrust of 6550 lbs
2) Max backseating thrust of 34,625 lbs
20000
0
-20000
0
50
100
150
200
250
300
350
400
Additional available open thrust of 16321 lbs (34625-18304)
After reducing nitrogen charged pressure from 1443 psig to 1135 psig.
Trace
1
2
Signal Name
ETT Thrust
ETT Thrust
Value at Cursor
-415.9154 lbs
-1040.0406 lbs
65.4700 Sec
65.4700 Sec
Test Title
RF11: As Left @ 100 HZ
RF11: "AF" Test 3 @ 100 Hz
Test Date
4/2/2002 8:19:31 PM
3/30/2002 7:25:32 AM
NOR File
C:\...\SI405A\AOV1.NOR
C:\...\SI405A\AOV2.NOR

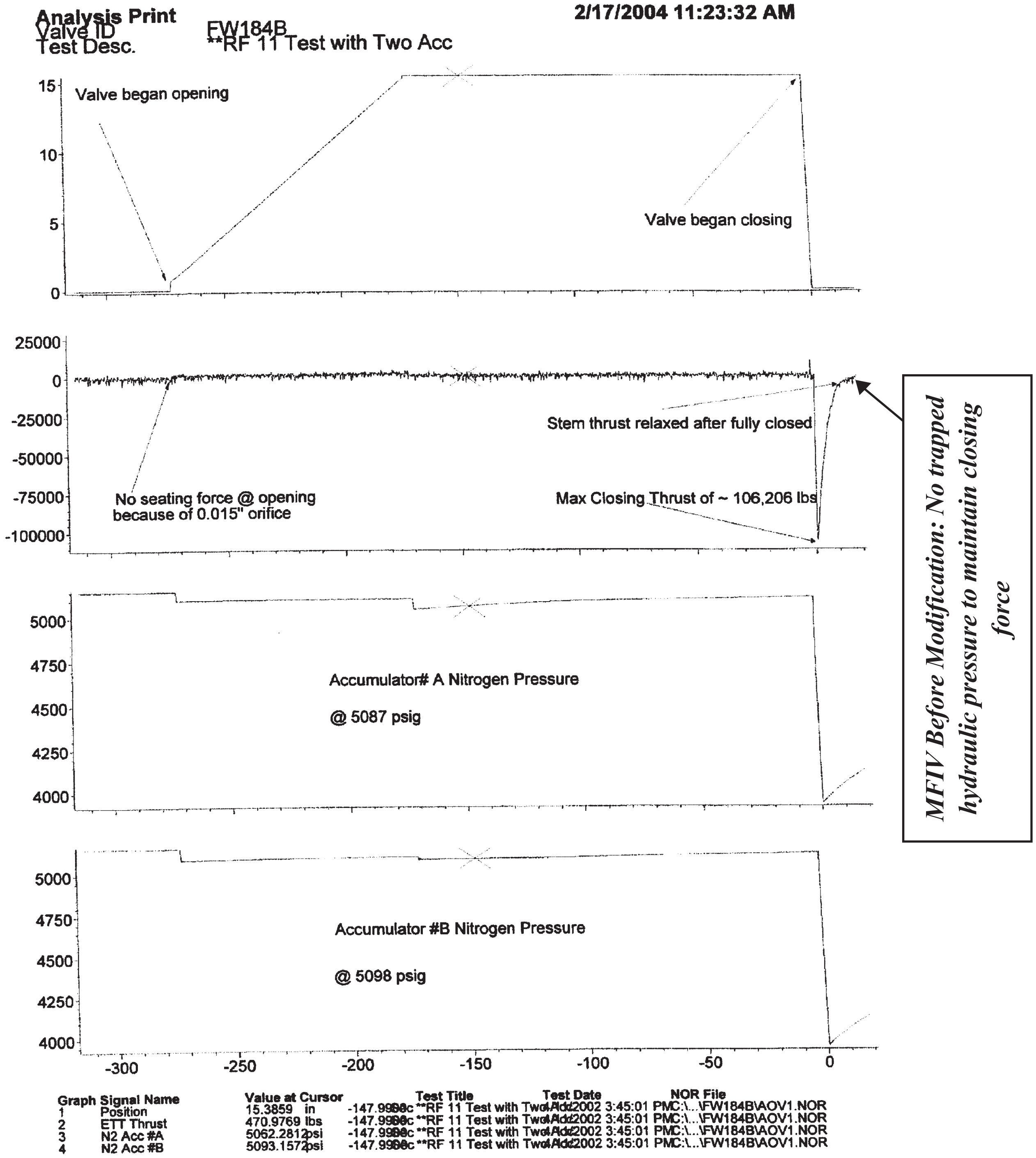

Analysis Print
Valve ID SI405A
Test Desc. RF11: As Left @ 100 HZ
Backseating began @ 1853 psig
Right after unseating, hydraulic pressure was 1481 psig
Nitrogen pressure @ 1433 psig
Right after unseating, nitrogen pressure was 1148 psig
Valve stem travel @ 11.114 inches
Valve stem travel @ 0.434 inch
Graph
Signal Name
Hydro Piston P
Nitrogen
Position
Value at Cursor
Test Title
Test Date
NOR File

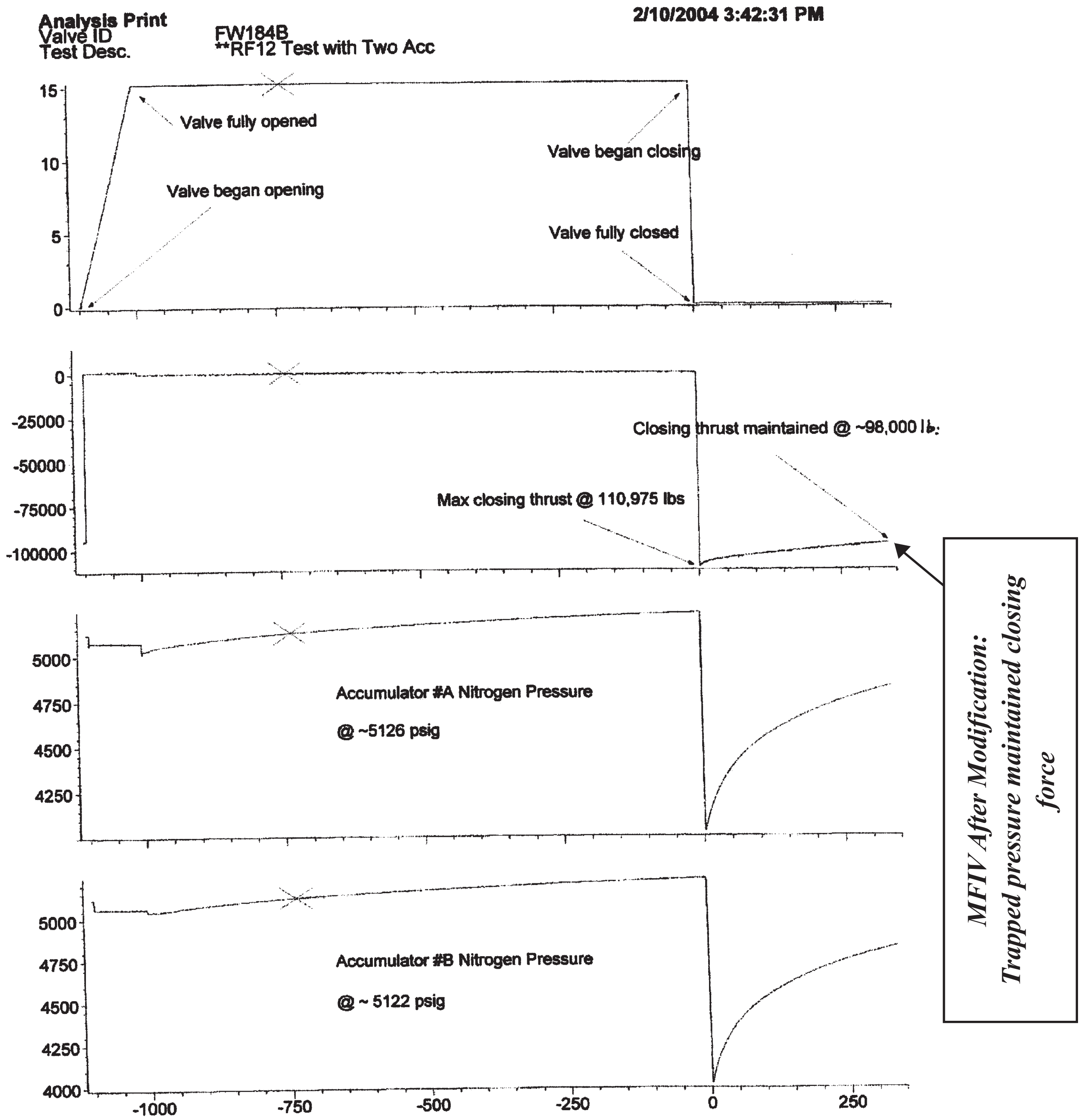


4/20/2004 12:40:28 PM
Analysis Print
Valve ID
Test Desc.
SI405A
RF11: As Left @ 100 HZ
Backseating began @ 1853 psig
3342 psig
Right after unseating, hydraulic pressure was 1481 psig
Pressure Switch cut off @ 2947 psig
Final pressure @ 3322 psig
Hydraulic Pump Motor Current
Graph
1
2
3
Signal Name
Hydro Piston P
Pump Cut Off SW
Motor CutOff SW
Value at Cursor
3343.7299 psi
2948.0128 psi
0.1301 A
338.4000 Sec
338.4000 Sec
338.4000 Sec
Test Title
RF11: As Left @ 100 HZ
RF11: As Left @ 100 HZ
RF11: As Left @ 100 HZ
Test Date
4/2/2002 8:19:31 PM
4/2/2002 8:19:31 PM
4/2/2002 8:19:31 PM
NOR File
C:\...\SI405AAOV1.NOR
C:\...\SI405AAOV1.NOR
C:\...\SI405AAOV1.NOR

Simplified MFIV Actuator Schematic



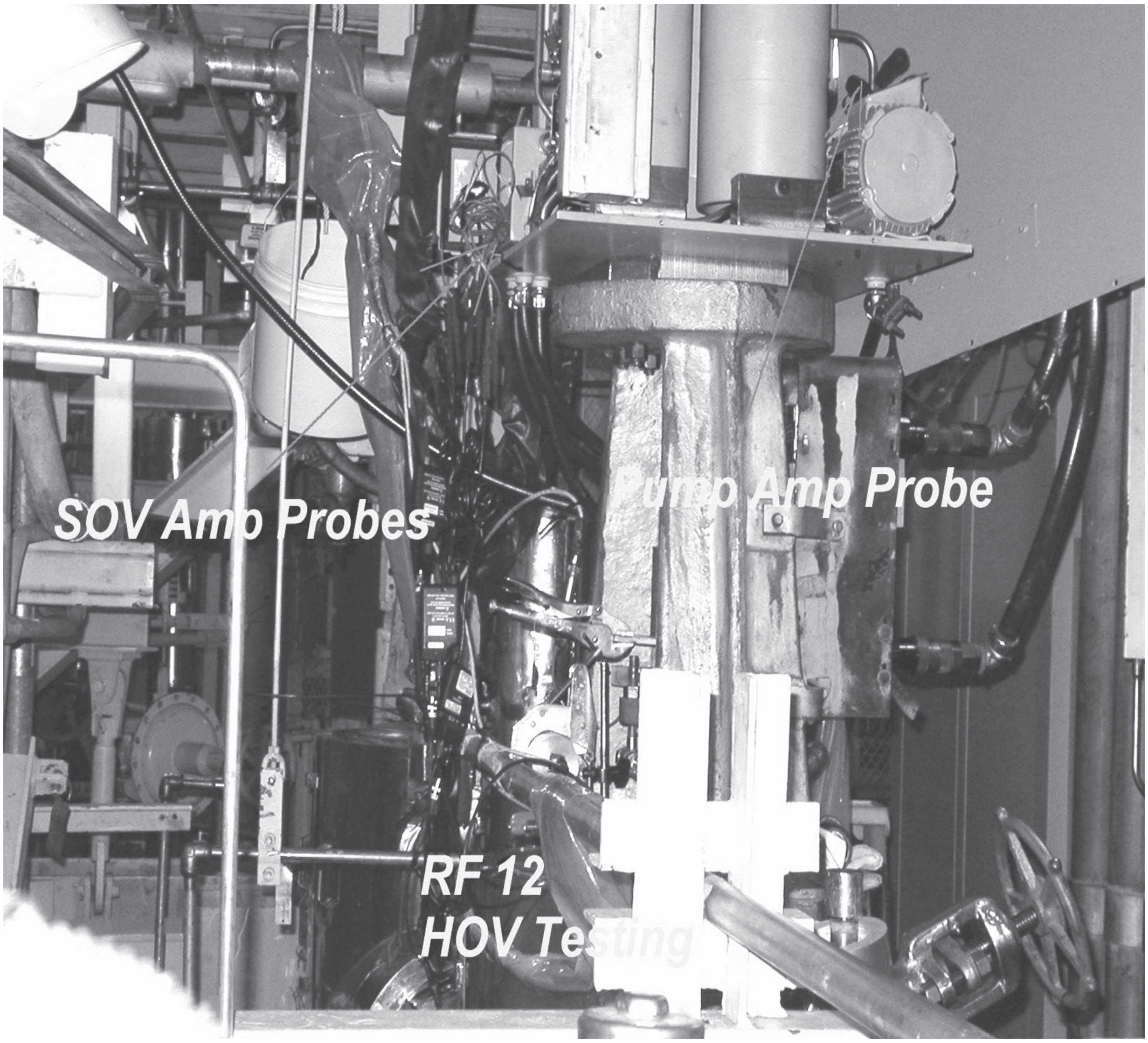

Analysis Print
2/17/2004 11:23:32 AM
Valve ID FW184B
Test Desc. **RF 11 Test with Two Acc
15
10
5
0
Valve began opening
Valve began closing
25000
0
-25000
-50000
-75000
-100000
Stem thrust relaxed after fully closed
No seating force @ opening because of 0.015" orifice
Max Closing Thrust of ~ 106,206 lbs
5000
4750
4500
4250
4000
Accumulator# A Nitrogen Pressure
@ 5087 psig
Accumulator #B Nitrogen Pressure
@ 5098 psig
-300
-250
-200
-150
-100
-50
0
Graph Signal Name
Value at Cursor
Test Title
Test Date
NOR File
1 Position 15.3859 in -147.9988c **RF 11 Test with Two Acc 2002 3:45:01 PMC:\...\FW184B\AOV1.NOR
2 ETT Thrust 470.9769 lbs -147.9988c **RF 11 Test with Two Acc 2002 3:45:01 PMC:\...\FW184B\AOV1.NOR
3 N2 Acc #A 5062.2812 psi -147.9988c **RF 11 Test with Two Acc 2002 3:45:01 PMC:\...\FW184B\AOV1.NOR
4 N2 Acc #B 5093.1572 psi -147.9988c **RF 11 Test with Two Acc 2002 3:45:01 PMC:\...\FW184B\AOV1.NOR
MFIV Before Modification: No trapped hydraulic pressure to maintain closing force



Graph	Signal Name	Value at Cursor			Test Title	Test Date	NOR File
1	Position	15.1499	in	-737.500Sec	**RF12 Test with Two Acc	11/17/2003 3:05:36 PM	C:\...\FW184B\AOV3.NOR
2	ETT Thrust	-283.1003	lbs	-737.500Sec	**RF12 Test with Two Acc	11/17/2003 3:05:36 PM	C:\...\FW184B\AOV3.NOR
3	N2 ACC# A Press	5125.7324	psi	-737.500Sec	**RF12 Test with Two Acc	11/17/2003 3:05:36 PM	C:\...\FW184B\AOV3.NOR
4	N2 Acc# B Press	5122.0703	psi	-737.500Sec	**RF12 Test with Two Acc	11/17/2003 3:05:36 PM	C:\...\FW184B\AOV3.NOR

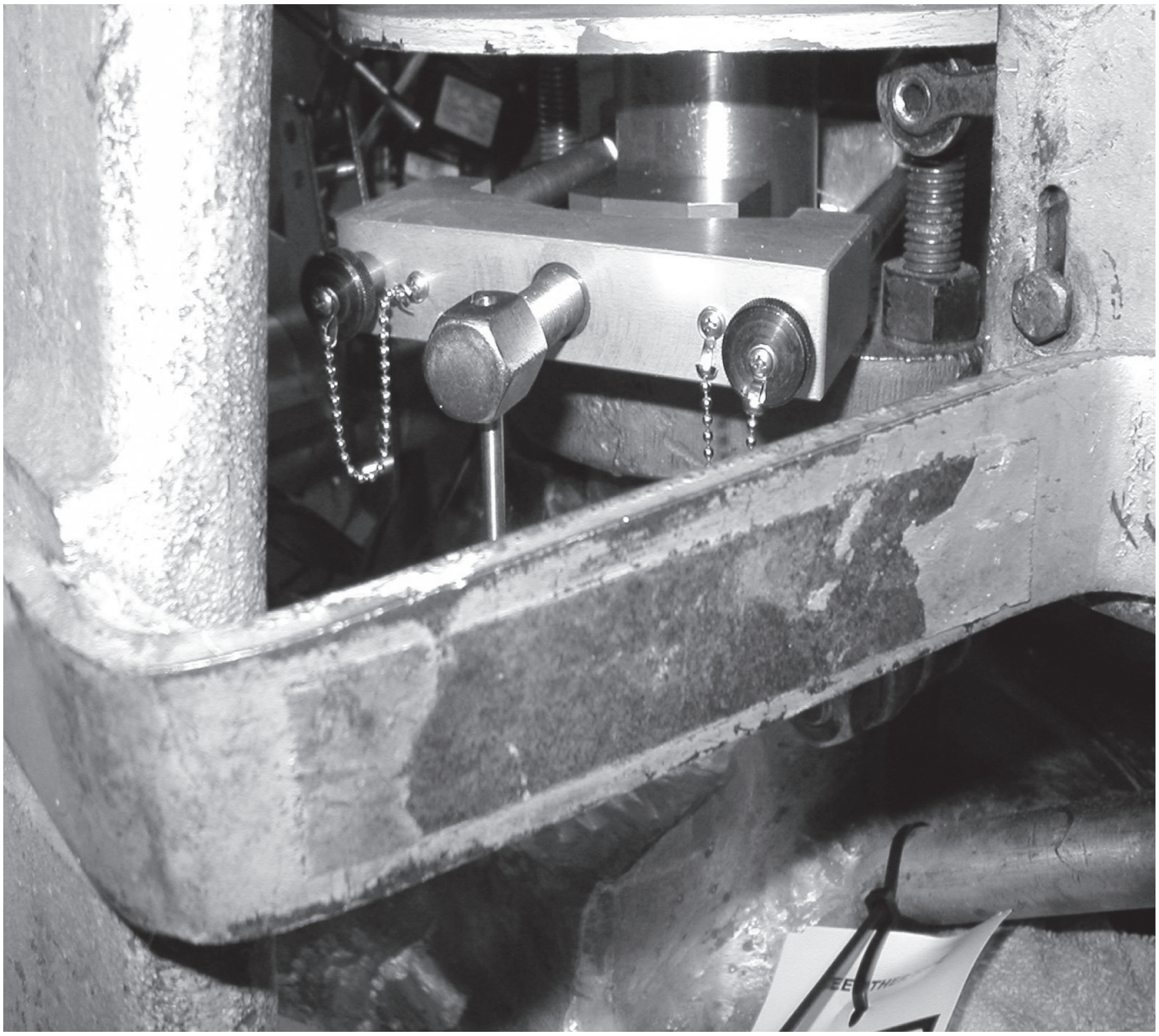
Shut Down Cooling Isolation Valve

Test Sensors



Shut Down Cooling Isolation Valve

Removable ("D" Clamp) Strain Gauge



Main Feed Water Isolation Valve

Permanent Mounted Strain Gauge

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Exelon Nuclear MOV Program Standardization

17 Units, 10 Stations and 1 Best MOV Program

Ted Neckowicz
Steve Gallogly
Exelon Nuclear

The Objective

In November 2002, Exelon Nuclear rolled out its standardized Motor-Operated Valve (MOV) Program to all 10 sites within the Exelon/Amergen fleet. This MOV Program Standardization, which we believe to this day, is the most comprehensive valve program change anywhere in the nuclear industry. The MOV Program changes involved 17 separate MOV procedures and Guidelines (we call them T&RMs) and common centralized software that integrate the procedures and guidelines into one standardized process. Given that the changes involved were complex and had potential significant station impact, a formal project was established with periodic progress and management report outs. A three-man core team provided the foundation of the project with one serving as the Project Manager. The project work was done as level of effort with the project core team fulfilling their normal responsibilities. While the project had several significant challenges and was delayed four months from the schedule originally planned, management sponsorship and focus on the ultimate goal lead to the project success. Now Exelon Nuclear's MOV program is well positioned to reap the benefits of the standardization effort which include effective resource sharing, remote off-site support, reduction of human errors, "state of the art" set-point management /configuration control and improved MOV reliability at a reduced implementation costs. Future program maintenance is also reduced given that only one MOV program rather than 10 site-specific programs exist. Borrowing the famous line, Exelon's MOV Program can now proudly say it's "All for One – One for All".

Who is Exelon Nuclear

Exelon Nuclear is made up of the 5 former ComEd Nuclear Stations including Byron, Braidwood, Dresden, LaSalle and Quad Cities, 2 former PECO Energy Stations including Limerick and Peach Bottom, 2 former GPU stations including Oyster Creek and Three Mile Island, and finally Clinton Station formerly of Illinois Power. These companies were combined to form Exelon in 1999.

The Call to Standardize

At the end of 2000, the call to standardize the Exelon MOV Program was actually part of a much bigger initiative to standardized company wide processes and programs inside and outside of Exelon Nuclear. A Chief Executive Officer (CEO) level corporate commitment to Wall Street proclaimed that Exelon would standardize all business units by the end of 2002. This commitment was the source of the High Level executive sponsorship that became invaluable as various obstacles were encountered. Each engineering program was selected and prioritized by upper management for standardization, with the MOV Program rated as one of the most difficult engineering program given the high level of institutionalization and regulatory oversight. The MOV program was given an original standardization deadline of 6/30/02; one of the last engineering programs. This later changed to 10/31/02 due to project delays. Nonetheless, the project successfully fulfilled the corporate standardization commitment.

The first meeting to conceptually design Exelon's MOV Program Standardization was held during the January 2001 Motor Operated Valve Users Group Meeting in Clearwater. Key participates at that meeting included Ted Neckowicz (former PECO & current Mid Atlantic MOV Engineer), Steve Gallogly (former PECO & current Mid Atlantic Valve Maintenance Specialist), Brian Bunte (former ComEd MOV Engineer) and Bill Cote (current Mid-West MOV Engineer). Each person independently ranked what program attributes they believed would be most beneficial to standardize under the new standardization initiative. Needless to say, this process identified considerable differences in viewpoints between the group members that they were challenged to resolve in order to formulate the initial Standard MOV Program Development Strategy. While initially highly dynamic, this strategy ultimately can be summarized as follows:

- Adopt a best practice approach based on technical merit not on "this is how we do things here at [pick a site…]"

- Design a process that accomplishes the shift from NRC Generic Letter (GL) 89-10 “justify engineering assumptions” to GL 96-05 performance monitoring
- Provide maintenance personnel with simplified criteria that makes MOV diagnostic testing as much like performing a routine surveillance test as possible
- Fully integrate a testing, trending and design into a common process
- Provide procedural guidance to minimize the need for “tribal knowledge” and to achieve consistent test guidance
- Focus on processes and common implementation tools instead of testing hardware and implementation minutiae
- Design fully integrated engineering and maintenance software that is accessible from any computer with access to the Exelon intranet
- Create a simple software interface that is user friendly to less computer savvy maintenance personnel
- Implement common quantitative MOV program performance and health indicators

Quickly this informal program strategy lead to the next step, the development of the formal project plan.

The Project Plan

The Project Plan was written over a period of several days by Ted Neckowicz and Bill Cote who were the principal leads for the engineering initiative, thus the project nick name became “Bill and Ted’s Exelon Adventure”. The Project Plan discussed the following:

1. Program/Process Ownership
2. Project Strategy
3. Interfaces and Control
4. Implementing Procedure Hierarchy
5. Project Phases
6. Budget
7. Baseline Schedule
8. Exceptions to Standardization
9. Site Program Transition
10. Critical Success Factors
11. Management Reporting

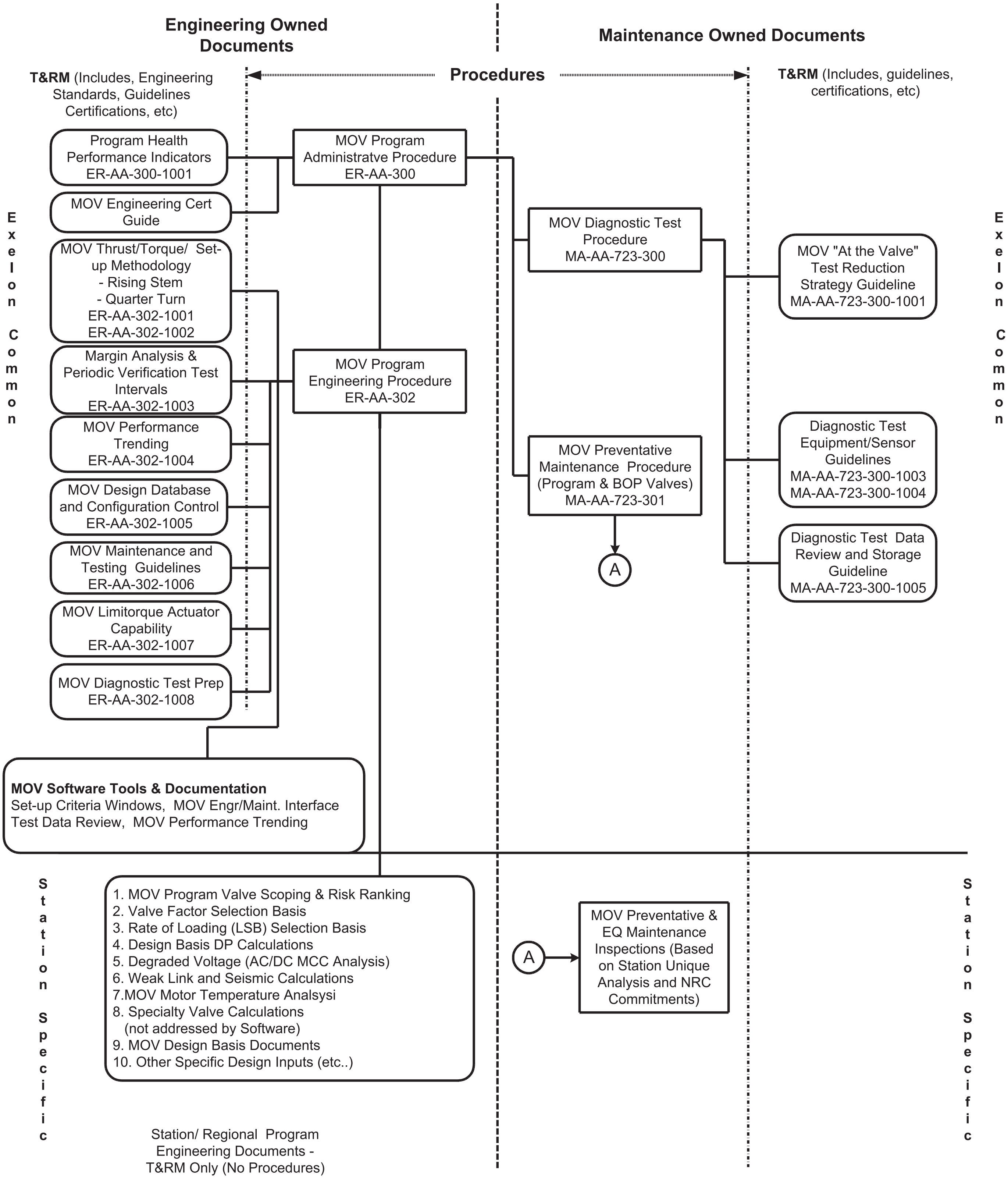
The project plan strategy proposed the following key standardized elements:

- A standardized methodology and calculational software to execute MOV Calculations and manage engineering data.
- A three (3) step MOV Test management process to be facilitated by new software to be developed that includes: Test Preparation, Data Review and Trending.
- A standardized MOV Data Analysis platform to review and store MOV Diagnostic traces. Quiklook for Windows was selected based on ability to process both VOTES and Quiklook data.
- A “Maintenance-owned” testing process where qualified MOV Maintenance Technicians can conduct all routine in-plant MOV diagnostic testing and test acceptance for returning the MOV back to service (operable) without “at the valve” MOV engineer involvement.

Through implementing these standardized elements, the core group believed that Exelon would reap the best long-term MOV Program efficiency gains.

The project plan identified the following (17) new Engineering and Maintenance Procedures and T&RMs for development (See Figure 1).

Figure 1
Exelon MOV Program
MOV Program Procedure / T&RM Heirarchy



Engineering Procedures

1. Motor Operated Valve Program Administrative Procedure
2. Motor Operated Valve Program Engineering Procedure

Engineering Technical & Reference Material (T&RM)

1. Rising Stem Motor Operated Valve Thrust & Torque Sizing and Set-up Window Determination Methodology
2. Quarter-Turn Motor Operated Valve Sizing and Set-up Window Determination Methodology
3. MOV Margin Analysis and Periodic Verification Test Intervals
4. Motor Operated Valve Performance Trending
5. Motor Operated Valve Design Database Control and Design Datasheet Activities
6. Motor Operated Valve Maintenance and Testing Guidelines
7. MOV Limitorque Actuator Capability Determination Methodology
8. MOV Diagnostic Test Preparation Instructions
9. MOV Program Performance Indicators

Maintenance Procedures

1. MOV Diagnostic Test Procedure
2. MOV Preventative Maintenance Procedure

Maintenance Technical & Reference Material (T&RM)

1. MOV "At The Valve" Diagnostic Test Reduction Strategy
2. VOTES Diagnostic Test Equipment / Sensor Guideline
3. QUIKLOOK Diagnostic Test Equipment / Sensor Guideline
4. Review and Evaluation of Motor Operated Valve Test Data

MOV Program attributes that were excluded from MOV Standardization included:

- MOV Diagnostic Test Data Acquisition Equipment – Diagnostic Test data acquisition equipment was not standardized due to the high implementation cost for 10 sites. The Test Analysis Platform was standardized regardless of the diagnostic test acquisition system (i.e. VOTES, QUIKLOOK).
- Valve Factor and Rate of Loading basis – These values are all considered embedded to the site-specific GL 89-10 closure requirements. Very limited program efficiency gain.
- Design Basis Bounding Stem Factor basis – These values are considered embedded to site specific GL 89-10 closure requirements and stem lube type and maintenance practices. Very limited program efficiency gain.
- No Program scope changes were made nor were any MOV design basis reviews revisited as part of MOV Standardization.
- MOV Risk Ranking methodology was standardized using NRC approved methodology. Risk rankings were not immediately revised; however, MOV risk rankings are to be reviewed and adjusted during required periodic site Probabilistic Risk Assessment (PRA) updates.

Project Phases

Project Development – Develop Project Plan (See above).

Procedure Development – The project core team was comprised of Project Manager, Ted Neckowicz (Mid Atlantic – MOV Program Engineer), Bill Cote (Mid-West – MOV Program Engineer) and Steve Gallogly (Corporate Valve Maintenance Specialist). Each Core team member had responsibility for the development of a specific number of draft documents as level of effort activities. Another core team member then reviewed each draft. Following this, each draft went through the following rigorous document review process:

- Site Subject Matter Expert (SME) Review Cycle
- Site Functional Area Manager (SFAM) Review Cycle
- Fatal Flaw Review Cycle
- Corporate Functional Area Manager (CFAM) Review
- Site Approval & Implementation

Each procedure was tracked on a resource-managed schedule. Resources were shifted and all other work except critical support of plant emergent issues was delayed, as necessary, to keep the procedure schedule on track. The MOV Program documents were ready for site approval by the end of June 2002. The procedures were to be implemented in conjunction with the deployment of the MIDAS software later in the fall.

Software Development – New Quality Assured Software was to be developed to implement the new MOV Program process including the standardized sizing methodology. Because of the best practice approach to the software development, all stations had some changes to their existing MOV set-point calculations requiring validation. Additionally, the 3 Step MOV Test Management software process was new to every Exelon station.
Software development started in early 2002 when the 2002 engineering project budget became available. Based on review of existing MOV software products available both internal and external to Exelon, a decision was made to modify the existing PECO MOV software, which was deployed at the PECO plants in 2000. Teledyne Instruments had developed the "MIDAS for Windows" for PECO converting PECO's DOS based MIDAS MOV sizing software to a Windows 2000 GUI based software product. At the time, general consensus of the Exelon MOV subject matter experts was that "MIDAS for Windows" was the most technically advanced and best product available to further modify to support Exelon Standardization.

The MOV program documents provided most of the technical basis for what the new standardized software did and how it did them. Project schedule requirements required several months of overlap between MOV document completion and software development. This posed a significant challenge to Teledyne who was initially developing software based on documents that were frequently changing. This issue was managed only through close coordination and frequent communication between the Exelon Project Manager and Teledyne Instruments. Teledyne Instruments, in particular Michael Richard, played a critical role in making the software development a success through their high level corporate commitment to the project.

Two MOV software products were developed: MIDAS and MIDATEST

MIDAS – MIDAS is the primary MOV engineering tool that provides MOV design/sizing analysis, thrust/torque set-point methodology, margin analysis, PVT-interval analysis and configuration control. MIDAS MOV data are stored in a one record per MOV.

MIDATEST – MIDATEST is the primary MOV engineering and maintenance tool that provides 1) MOV Diagnostic Test Preparation, 2) Diagnostic Test and PM Data review and 3) MOV Data Analysis and Trending. MIDATEST MOV data are stored in a one record per Test/Work Order.

The MIDAS program was essentially complete by the mid-September 2002. Software V&V by Teledyne took nearly one month followed by Exelon acceptance testing.

With the availability of an approved MIDAS, the standard MOV Program rolled out on schedule to the 10 sites and 2 corporate offices on October 31st 2002. This included conversion of all existing MOV data into the new MIDAS format and providing Citrix access to the primary software users in both Engineering and Maintenance at all sites.

Program Implementation and Transition Period
Site-specific implementation dates were established at or after the corporate process rollout on 10/31/02. Stations without near term refueling outages began implementing the process the week of 11/03/02.

Implementation Date: The site specific date after which all new MOV Program activities will be started using the new Exelon standard MOV Program. Activities include MOV set-up window calculations, margin review, MOV test package preparation, diagnostic test review and MOV performance trending.

Transition Period: The period following the implementation date during which MOV testing activities initiated under the former program will be completed (e.g., tested and reviewed) using the same (i.e. former) program. This transition period will be nominally twelve weeks based on the T-12 work planning process.

> ***MOV Program Transition Period Example***
>
> *Scenario* - Limerick implements the new program on 10/31/02 and has an April 7, 2003, outage with on-line MOV work scheduled in November, December 2002 and January 2003.
>
> *Acceptable Limerick Transition Plan* - MOV testing scheduled for 11/02 through 1/03 and previously planned using the existing program before 10/31/02 may be completed using the existing program. All new MOV calculations and test package preparations required for the April 2003 refuel outage and for on-line testing 12 weeks after 10/31/02 shall be prepared using the new MOV Program process. Any new MOV calculations and test package preparations prepared after 10/31/02 shall be done using the new MOV Program process.

Change Management
With a project of this size and affecting 10 stations and 2 corporate offices, a change management plan was required. The change management plan was periodically reviewed by management and rolled out to each of the sites. The change management contained the following:

> Site Implementation dates (based on Fall/Winter Outage conflicts)
>
> Barriers to success – Plans to address

Corporate Actions required to Implement Program (See Example in Table 1)

Site Actions required to Implement – A 2 year implementation period was specified to convert and approve all existing program MOV calculations to the new MIDAS software.

Table 1 (Typical Corporate Implementation Actions)

Task Description	Target Date
Develop and verify MIDAS Software	8/30/02
Complete IT MIDAS software requirements	9/13/02
Develop and verify MIDATEST Software	9/30/02
Complete IT MIDATEST software requirements	10/13/02
Process and Software Training Development	8/15/02
Provide Process Training to MWROG Engineering	9/01/02
Provide Process Training to MWROG Maintenance	9/01/02
Provide Process Training to MAROG Engineering	9/15/02
Provide Process Training to MAROG Maintenance	9/15/02
Quiklook Diagnostic Analysis Training	9/30/02
Quiklook Software IT requirements complete	9/30/02
Assist with Site Data Migration and IT Start-up Support	10/1-31
Supersede or revise corporate level engineering documents	11/30/02
Implement Revised MOV Program Engineering Cert Guide	10/31/02

Training

As indicated above in Table 1, several training sessions were arranged in both the Mid-Atlantic and Mid-West Regions prior to the implementation date. Formal Lesson Plans were developed including practical factor exercises and exams. The training focused primarily on using the new software, which was new to all 10 Exelon sites. Follow-up training is routinely provided after the implementation date using Web training tools such as NetMeeting.

The Keys to Success

Looking back at the project and the barriers encountered, several essential keys to the project's success are noteworthy. They include:

- Senior Management was absolutely committed to successful Standardization implementation. If a specific station or corporate workgroup refused or not adequately support the project, their organization would soon hear from the senior management.
- New procedures and processes were developed by a small core of individuals and presented to the 10 stations for review and comment. "Management by committee" was minimized.
- Once the comment period expired and the comments were dispositioned, only a "Fatal Flaw" identified by a station could prevent approval and implementation. This eliminated the continual cycling of a procedure to incorporate late comments.
- The Citrix server based deployment allowing centralized (single) software installation. This deployment strategy eliminated the need for software installations on every user's personal computer and eliminated the compatibility and software QA problems inherently created. MIDAS has over 120 users throughout Exelon and that list still continues to grow. Without this deployment strategy, the project could not have succeeded.

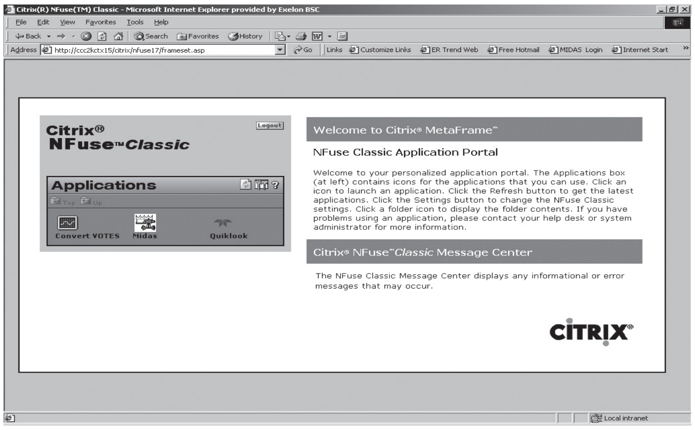
Continual Improvement – Effectiveness reviews

Even with the best of intentions and planning, it was anticipated that some changes or additional enhancements would be necessary to effectively implement the new MOV Program. Consequently, the project had planned and budgeted in 2003 for a program effectiveness review and for additional software improvements. The effectiveness review was conducted during the 2nd quarter of 2003 and the software upgrades rolled out in November 2003.

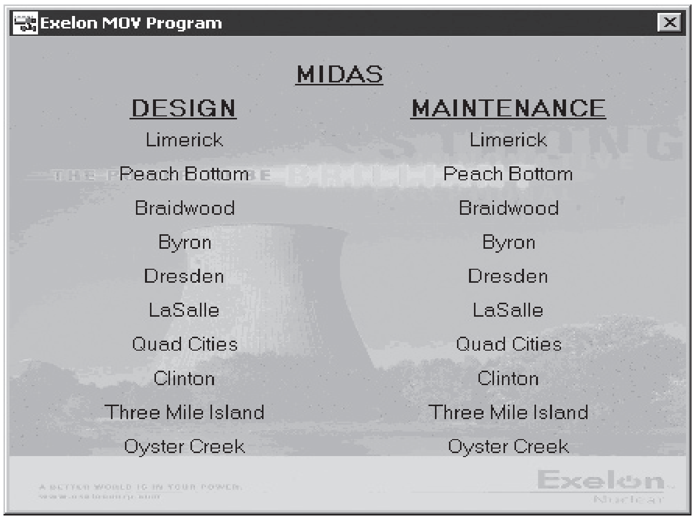
MIDAS & MIDATEST

The Software that makes it all work

The three standardized MOV Program software applications are all accessible via Microsoft Explorer via a Citrix application server and can be accessed from any computer connected to the Exelon intranet.

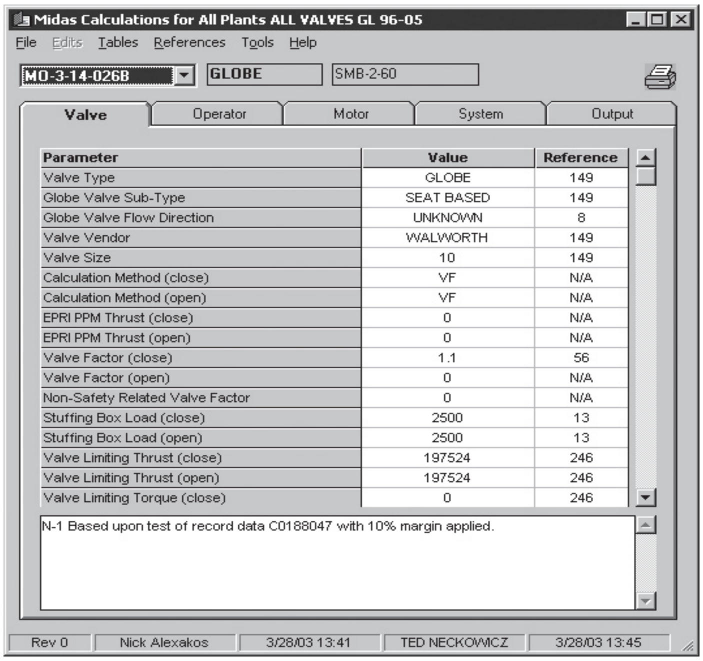


Selecting MIDAS on the Citrix screen runs the MIDAS/ MIDATEST launch pad program. Either MIDAS (Design) and/or MIDATEST (Maintenance) launches when the appropriate site database is selected. Any authorized user can access and view any site database. Different levels of edit privileges can be set for each user.

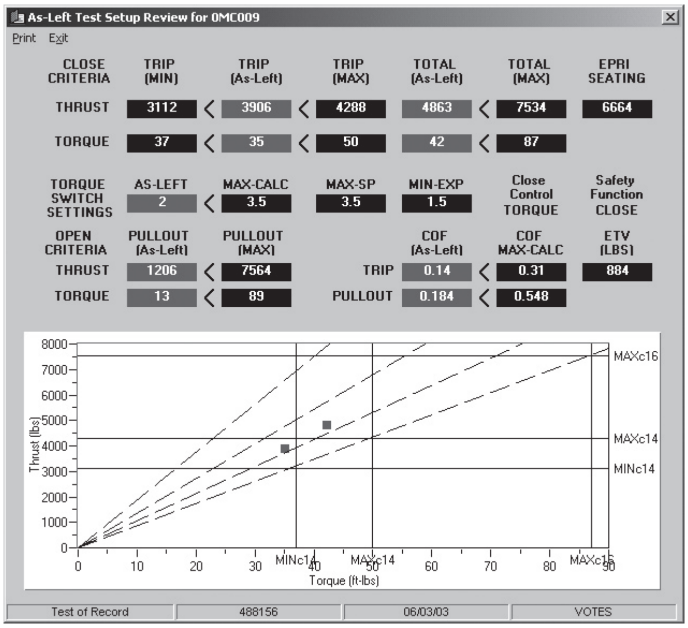


MIDAS

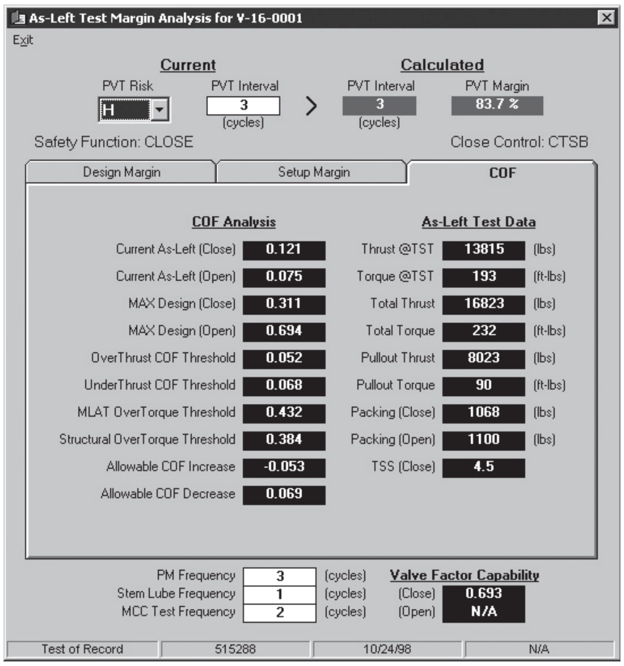
The basic MIDAS interface and main form is shown below. The screen shows an approved Peach Bottom MOV Design Data Record. The revision level, preparer, checker and approval date are shown on the status bar at the bottom.



The screen below shows the resulting set-up window criteria and the current Test of Record Data for a Clinton MOV. MIDAS stores the current Test of Record data in order to perform margin reviews.



The margin tables are displayed below for an Oyster Creek Valve. MIDAS performs set-up margins, design margins and stem COF analysis to assess each valve. Depending of safety function direction, control scheme and valve type, the appropriate margins are combined to determine the PVT margin used to establish the maximum test interval. Additionally, valve factor capability is calculated.



Other MIDAS capabilities include:

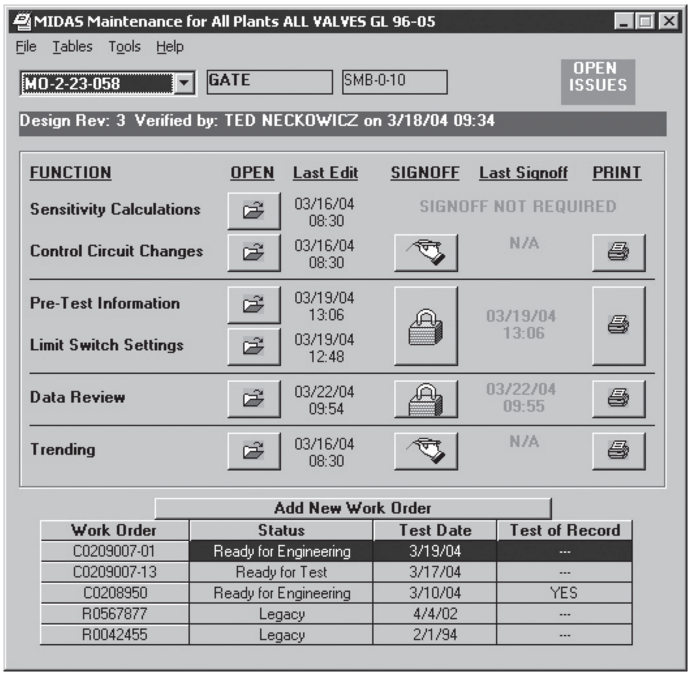
- MOV Voltage drop analysis
- ComEd AC Motor Methodology
- BWROG DC Motor Degraded Stroke Time Analysis
- EPRI Butterfly Torque Methodology
- EPRI Unwedging Analysis
- Powerful Export to Excel Reporting Tool
- Global Parameter Evaluator

MIDATEST

Shown below is the main MIDATEST screen. It shows the available test records in the grid at the bottom of the screen. A new record is created for each new diagnostic testing work order.

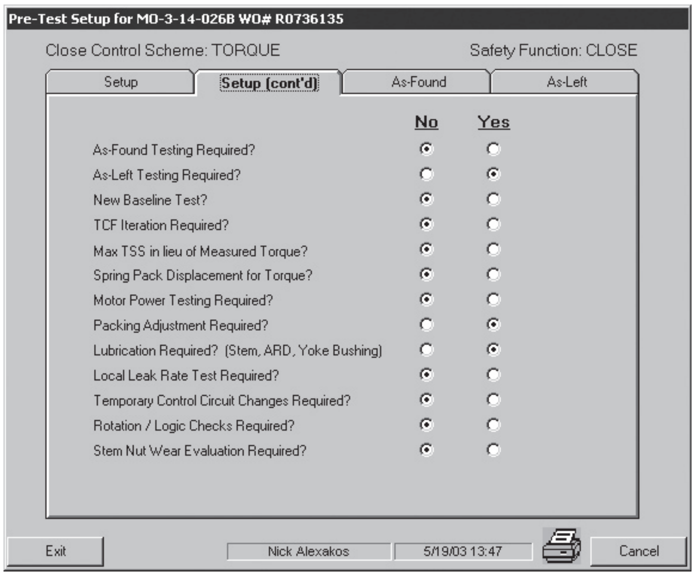
The current MIDAS record status shows up in the status bar. Only approved MIDAS design records are available for use in MIDATEST.

Each module of the MIDATEST software has individual signoffs. Status changes as the valve moves through the testing process from Pre-test to Data Review and then to Trending as each stage is signed off. The current record is shown as complete. Consequently, the Pre-Test, Data Review and Trending are all signed off and locked.



Pre-Test Instructions

Menu Driven Software Guides the Engineer Through the Pre-Test Preparation Process. Each software step in the decision making process is provided with procedure guidance and examples.



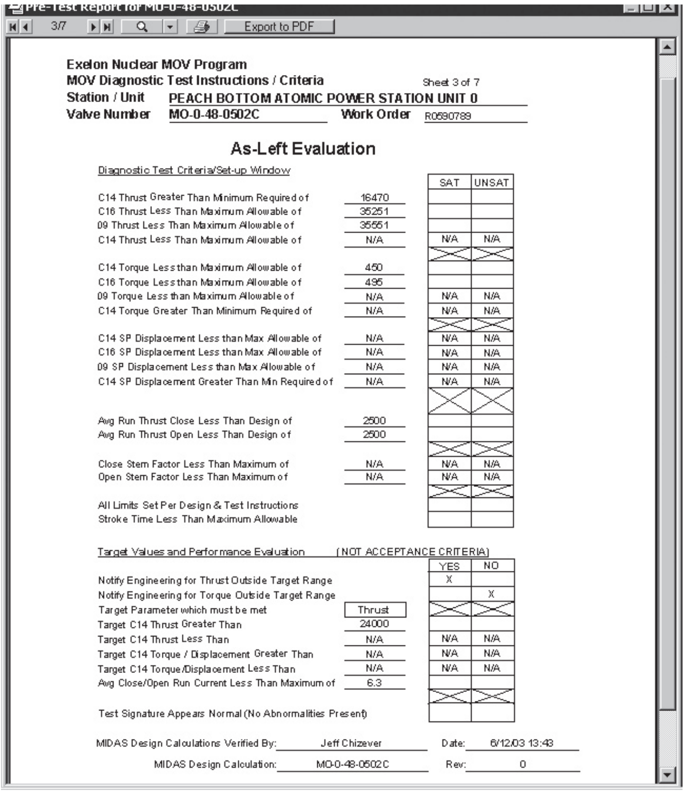
Pre-Test Setup for MO-3-14-026B WO# R0736135

Close Control Scheme: TORQUE   Safety Function: CLOSE

Setup | Setup (cont'd) | As-Found | As-Left

	No	Yes
As-Found Testing Required?	◉	○
As-Left Testing Required?	○	◉
New Baseline Test?	◉	○
TCF Iteration Required?	◉	○
Max TSS in lieu of Measured Torque?	◉	○
Spring Pack Displacement for Torque?	◉	○
Motor Power Testing Required?	◉	○
Packing Adjustment Required?	○	◉
Lubrication Required? (Stem, ARD, Yoke Bushing)	○	◉
Local Leak Rate Test Required?	◉	○
Temporary Control Circuit Changes Required?	◉	○
Rotation / Logic Checks Required?	◉	○
Stem Nut Wear Evaluation Required?	◉	○

Exit   Nick Alexakos   5/19/03 13:47   Cancel



Pre-Test Report for MO-0-48-0502C

3/7   Export to PDF

Exelon Nuclear MOV Program
MOV Diagnostic Test Instructions / Criteria   Sheet 3 of 7
Station / Unit   PEACH BOTTOM ATOMIC POWER STATION UNIT 0
Valve Number   MO-0-48-0502C   Work Order   R0590789

As-Left Evaluation

Diagnostic Test Criteria/Set-up Window

		SAT	UNSAT
C14 Thrust Greater Than Minimum Required of	16470		
C16 Thrust Less Than Maximum Allowable of	35251		
09 Thrust Less Than Maximum Allowable of	35551		
C14 Thrust Less Than Maximum Allowable of	N/A	N/A	N/A
C14 Torque Less than Maximum Allowable of	450		
C16 Torque Less than Maximum Allowable of	495		
09 Torque Less than Maximum Allowable of	N/A	N/A	N/A
C14 Torque Greater Than Minimum Required of	N/A	N/A	N/A
C14 SP Displacement Less than Max Allowable of	N/A	N/A	N/A
C16 SP Displacement Less than Max Allowable of	N/A	N/A	N/A
09 SP Displacement Less than Max Allowable of	N/A	N/A	N/A
C14 SP Displacement Greater Than Min Required of	N/A	N/A	N/A
Avg Run Thrust Close Less Than Design of	2500		
Avg Run Thrust Open Less Than Design of	2500		
Close Stem Factor Less Than Maximum of	N/A	N/A	N/A
Open Stem Factor Less Than Maximum of	N/A	N/A	N/A
All Limits Set Per Design & Test Instructions			
Stroke Time Less Than Maximum Allowable			

Target Values and Performance Evaluation   (NOT ACCEPTANCE CRITERIA)

		YES	NO
Notify Engineering for Thrust Outside Target Range		X	
Notify Engineering for Torque Outside Target Range			X
Target Parameter which must be met	Thrust		
Target C14 Thrust Greater Than	24000		
Target C14 Thrust Less Than	N/A	N/A	N/A
Target C14 Torque / Displacement Greater Than	N/A	N/A	N/A
Target C14 Torque/Displacement Less Than	N/A	N/A	N/A
Avg Close/Open Run Current Less Than Maximum of	6.3		
Test Signature Appears Normal (No Abnormalities Present)			

MIDAS Design Calculations Verified By: Jeff Chizever   Date: 6/12/03 13:43
MIDAS Design Calculation: MO-0-48-0502C   Rev: 0

Maintenance Instructions are formatted to facilitate a Pre-Job Brief.

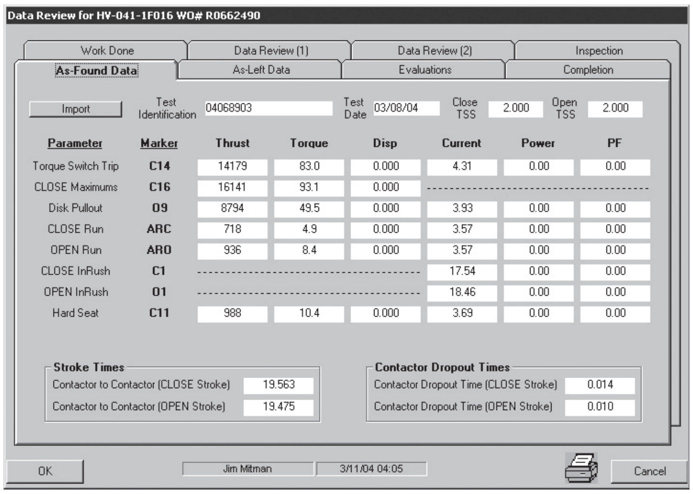
- A simple format is used on the first page of the test instructions to communicate general test requirements.
- **Only required test acceptance criteria are provided to maintenance (e.g., Standard (i.e. Thrust and Torque) or Thrust Only or Torque Only).**
- The Diagnostic Test Criteria/Instructions are structured to minimize the potential errors and confusion during testing (e.g., the software will "N/A" information that is not required in advance of the procedure going to the field). (See sample printout on next page.)

MOV Diagnostic testing is performed with a common procedure utilizing the Pre-Test Instructions

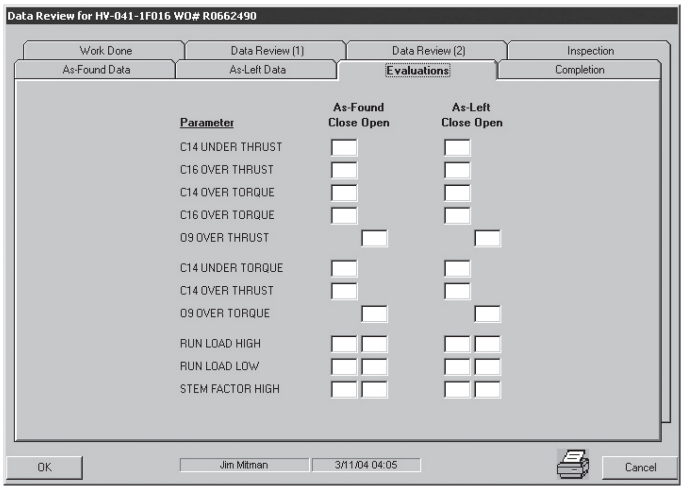
- The test procedure is designed to minimize or eliminate the redundant recording of data.
- The test instructions are included as part of the permanent test record.
- Numerical test results are not required to be transcribed into the procedure.
- As Left test results are independently verified.
- If all Test Acceptance Criteria is satisfactory then the test is acceptable and the valve can be returned to operations at this time without additional review by engineering.

Test Data Documentation / Review - Menu Driven Software Guides Maintenance Through the Data Review Process

- Each software step is provided with procedure guidance and example.
- As-Found and As-Left test data results can be directly imported into the software to eliminate data entry errors. See as-found data entry screen below.



- Results are automatically compared with test criteria and flagged for disposition / errors. Obviously, no flags (shown with an X) are the preferred result.

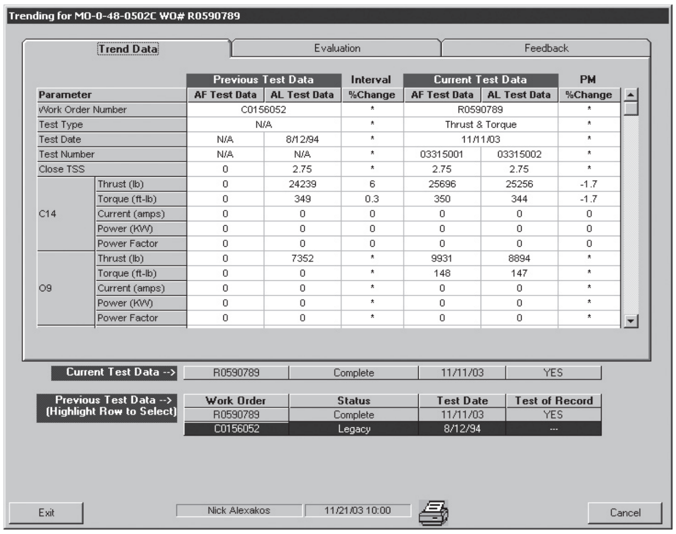


Maintenance Completes the Test Data Review

- Designation of "Test of Record" flags MIDAS that new "Test of Record" data is available for update in MIDAS.
- Once Engineering updates MIDAS with the new "Test of Record" data, all MOV margin evaluations will be based refreshed.

MOV Performance Trending

- Engineering Performs the Trending Review
- As Found test results for the current test are compared to the previous as left test results



- The change form as found to as left performance is also compared
- Quality of the test data for trending is confirmed
- Test performance is evaluated
- Engineering is required to evaluate if adjustments to the PM interval, Test interval or degradation factors in the design calculation prior to closing the trending module
- Engineering Completes the Trending Module and the Testing Process is Complete. Signoff of the Trending Module locks down the file and completes the testing process for the valve under the existing work order

MOV Program Health Reporting and Performance Indicators

Quarterly MOV Program Health Reports are prepared for each station in accordance with Exelon's procedure for management of Engineering Programs. In addition, quantitative Performance Indicators (PIs) are used to monitor the health of the MOV Program. Several of these performance indicators provide evidence of the material condition health and set-up margin. Additional performance indicators monitor the effectiveness of MOV periodic verification, preventative maintenance work activities, and associated recurring task frequencies. Lastly, other performance indicators monitor compliance with applicable GL 96-05 schedule commitments.

Performance Indicator Criteria are developed for the following Program attributes.

MOV Functional Failures (includes maintenance preventable, direct and indirect)

MOV Set-up Non-Conformance Conditions

MOV Margin

MOV Work Planning

MOV Diagnostic Test Proficiency

MOV Data Review

MOV Program Commitments

Emergent Industry/Regulatory Issues

Using the same technique used by the Exelon System Status Health Rating Guide, the following four MOV Program ratings will be established:

Each station is responsible for documenting the station specific MOV PI(s) that will be reported in the quarterly MOV program health reports.

MOV Program Performance Indicator Rating Criteria

White Rating Criteria (Sample)

Acceptable Functional Failure PI.

AND Acceptable Continuing and Singular Program Commitment PIs.

AND No more than two of the following PI(s) with Unacceptable Performance:

MOV NCC   MOV Planning   Test Proficiency

MOV Margin   MOV Data Review

AND White or Green Emergent Industry/Regulatory Issue PI.

A Sample Station MOV Performance Indicators follows:

Rating Color	Performance	Action
Green	Excellent	Requires No Additional Attention at This Time
White	Acceptable	Current Performance and/or Activities are Acceptable
Yellow	Needs Improvement	Needs Additional Attention
Red	Not Acceptable	Risks High and/or Requires Excessive Monitoring/Resources to Maintain

ATOMVILLE

MOV Program Performance Indicators

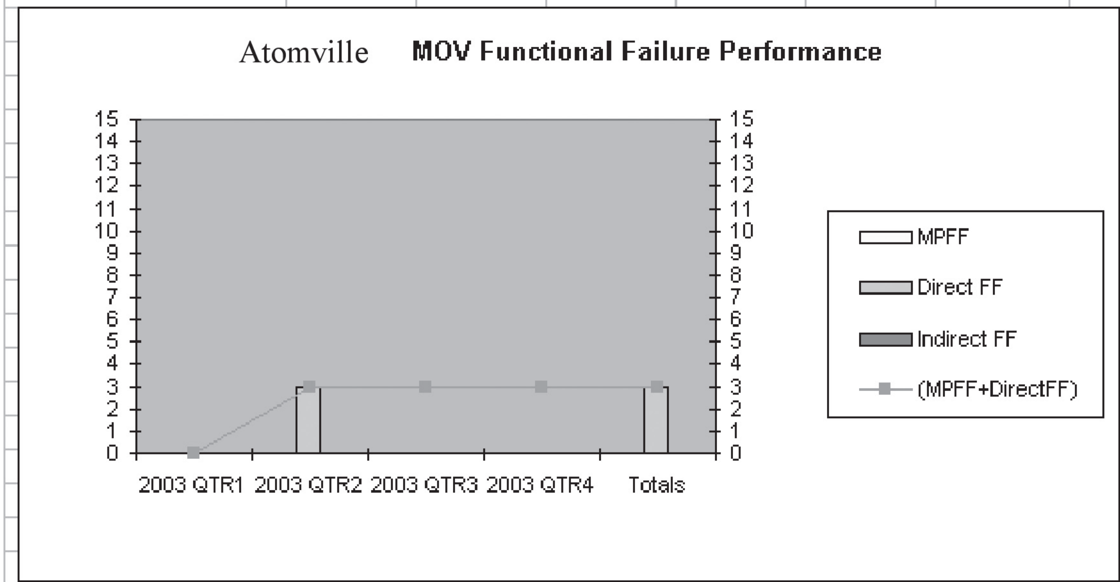
Overall MOV Program Performance - Needs Improvement

MOV Functional Failures	Unacceptable
MOV Non Conforming Conditions	Acceptable
MOV Margin	Unacceptable
MOV Work Planning	Acceptable
Diagnostic Test Proficiency	Acceptable
MOV Data Review	Acceptable
Commitments	Acceptable
Emergent Issues	Unacceptable

MOV Functional Failures - Unacceptable

Criteria: <= 1 MPFF per year/unit, <= 2.42 Direct FF per year (within scope of program control)

Trend Indirect FF (failure cause outside program control)



MOV Functional Failures Last Four Quarters

	2003 QTR1	2003 QTR2	2003 QTR3	2003 QTR4	Totals
MPFF	0	0	0	0	0
Direct FF	0	3	0	0	3
Indirect FF	0	0	0	0	0

Failure Description	When
MO 2-1301-60 found with cracked stem nut	4/11/2003
MO 1-1001-43A found with torque switch roll pin broken	5/20/2003
MO 2-1301-16 found with pressure seal ring leaking	6/25/2003

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Engineering Based Valve Testing and Evaluation

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Abstract

Valve engineering and testing has a long history not only within FANP Germany (former Siemens KWU). The Siemens engineers began to develop and apply diagnosis-measurement equipment for valves as early as the 1980s. Initially, this equipment was designed for valve diagnosis measurement directly at valve locations. Evaluation of the results was based on the experiences of the engineers. We began to systemize the valve diagnosis and to link it to valve engineering in the 1990s. The Valve Performance Concept was developed. It represented the link between valve calculation, design evaluation, valve diagnosis and condition-oriented maintenance. The evaluation criteria of the diagnosis measurements were defined on the basis of the functional model of the valves and the allowable parameters were derived from valve calculation. In order to avoid the costly and time-consuming instrumentation and measurement of the valves in-situ, engineering-based evaluation methods as well as measuring equipment have been developed to determine all necessary diagnosis parameters based on active power measurement from the switch-gear. This idea resulted in our evaluation software ADAM® qualified by the authorities and several types of diagnosis equipment, e.g. SIPLUG®. Due to the active power measurement combined with the quantitative evaluation of the main features, deviations from the design tolerance levels can be identified in the whole chain from the power supply system to instrumentation and control (I & C), actuator and valve. This diagnosis and evaluation methodology is used today in many NPPs, mainly in western and eastern Europe. It is also applicable for testing according to U. S. NRC Generic Letter 96-05. The present FANP diagnosis measurement equipment is the Ultra Check family for measurement at valve locations and the SIPLUG® family for diagnosis based on active power measurement. The measurement equipment can be combined with the evaluation software ADAM®. Existing diagnosis measurement equipment and measurement results can be included as well. It allows the determination of the state of the valves anytime considering statistical evaluation and trending. The reduction of costs for diagnosis measurement and evaluation is possible. The concept of permanent monitoring with SIPLUG® online and ADAM® will be put into effect in the new NPP Olkiluoto 3 in Finland from the start. The results of permanent monitoring, trending and statistical evaluation will be considered for the planning of the scope of maintenance during outages.

Based on this concept, predictive maintenance planning of the outages is possible resulting in high reliability of the nuclear power plants (NPPs).

1. Introduction

Valve engineering and testing has a long history not only within FANP Germany (former Siemens KWU). Our valve engineers have been involved in the definition of requirements for nuclear valves and in the development of such valves since the beginning of nuclear technology in Germany. During the last 25 years, engineering work to a large degree focused on the development of valve diagnosis methods, equipment and evaluation. The application of valve diagnosis is one reason for the high reliability of valves in Siemens NPPs worldwide, represented by the high reliability of these NPPs. Return of investment was possible due to a justified change of maintenance practice from preventive to predictive maintenance. This presentation describes the development of the engineering-based valve diagnosis and evaluation from the beginning up to now considering, for example, valves with electrical actuators.

2. First Steps

The Siemens engineers began to develop and apply diagnosis-measurement equipment for valves as early as the 1980s. The intention was to implement a complete system of motor-operated valve (MOV) diagnosis equipment that allowed the verification of correct operation of the valves and the detection of potential deviations and faults. This system was meant to be applied for diagnosis during outages as well as during commissioning of NPPs. Initially, this equipment was designed for valve diagnosis measurement directly at valve locations. Diagnosis parameters were mechanical parameters like torque, stem thrust and actuator worm gear displacements as well as electrical parameters like switch signals and active power. The evaluation of the results was based on the experience of the engineers. There was no direct link between diagnosis and calculation/engineering although calculation results were considered. The evaluation included, e.g., the correct adjustment of the actuators (switch-off variant and torque switch settings) and checking the start-up torque (especially for globe valves).

3. Engineering based evaluation of diagnosis results

We began to systematize the valve diagnosis and to link it to valve engineering in the 1990s. The Valve Performance Concept was developed. It represented the link between valve calculation, design evaluation, valve diagnosis and condition-oriented maintenance. The evaluation criteria of the diagnosis measurements were defined on the basis of the functional model of the valves and the allowable parameters were derived from valve calculation.

From the beginning, valve calculation included the following steps:

- Verification of the required stem thrust and torque
- Selection of actuator
- Determination of maximum thrust and torque
- Strength analysis of parts in the load path to verify the capability of function
- Analysis of switch-off failure
- Stress and fatigue analysis of pressure retaining parts.

Variable parameters, like friction coefficients or switch-off tolerances, were considered within the verification of the required stem thrust and torque. Allowable ranges of these parameters were defined and covered by safety margins. The calculation methodology as well as the allowable ranges of the parameters and the applicable safety margins have been discussed and agreed with German authorities and are written down in calculation guidelines or German regulations like KTA guidelines. Special computer software is available for calculations according to these guidelines.

In order to avoid the costly and time-consuming instrumentation and measurement of the valves in-situ, engineering-based evaluation methods as well as measuring equipment have been developed to determine all necessary diagnosis parameters based on active power measurement from the switch-gear. This idea was resulted in our evaluation software ADAM® qualified by the authorities and several diagnosis equipment, e.g. SIPLUG®. The evaluation software ADAM® includes project-specific databases with the evaluation criteria for all diagnosis-relevant valves. These evaluation criteria are derived from the valve calculation considering relevant safety margins.

The following parameters (minimum and maximum values) are used as evaluation criteria:

- Start-up torque
- Running torque
- Switch-off torque
- Final torque
- Torque rate (start-up and end position)
- Stroke time
- Switch-off delay
- Friction coefficient

The measurement equipment based on active power measurement allows the recording of the active power and the determination of the following parameters considering the calibration curves of the actuator:

- Start-up torque
- Running torque
- Switch-off torque
- Torque rate (start-up and end position)
- Stroke time
- Tightening time (end position)
- Switch-off delay
- As derived parameter: Friction coefficient

Our evaluation software ADAM® is used to determine the characteristic parameters of the diagnosis measurement (see above). The stem factor is determined based on the in/out-factor and run-time-method. The acceptability of the determined parameters is evaluated by comparison with the allowable values given in the ADAM®-database. The accuracy of the measurement and resulting calculations is taken into account during the comparison. After the evaluation (***Figure 1***), the measurements are displayed in a list (***Figure 2***). Each line in the list shows information regarding one measurement. This list contains the MOV's tag number, date and time of the measurement and an overall assessment ("OK", "uncertain" or "fault detected"). Red colored arrows and frames indicate that a parameter is below or above the given limits. Blue checkmarks indicate correct results. All measurements can be graphically displayed. The measurement results can be used for statistical evaluation and trending. Trending shows long-term changes of relevant parameters displaying them across time. The statistic function displays selected parameters for multiple MOVs. In addition, the reference values and limit values are shown.

The evaluation of the diagnosis measurement based on these data allows the detection of most of the potential faults noted in U.S. NRC Generic Letter 89-10:

- Incorrect torque switch setting
- Spring pack gap or incorrect spring pack preload
- Incorrect stem packing tightness
- Excessive inertia
- Loose or tight stem-nut locknut
- Incorrect limit switch settings
- Stem wear (in the thread)
- Bent or broken stem
- Worn or broken gears
- Grease problems
- Motor insulation or broken rotor rods (2)
- Incorrect wire size or degraded wiring (2)
- Disk/seat binding (including thermal binding)
- Motor undersized (1)
- Mal-adjustment for failure of hand wheel declutch mechanism
- Relay problems
- Worn or broken bearings
- Broken or cracked limit switch and torque switch components
- Missing or modified torque switch limiter plate
- Hydraulic lockup
- Degraded voltage (within design basis)
- Defective motor control logic (1)
- Excessive seating or back-seating force application
- Incorrect reassembly or adjustment after maintenance (1)
- Unauthorized modification or adjustments (1)
- Torque switch or limit switch binding

(1) faults that can be detected under some circumstances but not in all cases

(2) by current measurement and current symmetry

In addition to the potential faults listed above, other common failures can be identified:

- Improper stroke times or improper stroke sequence times
- Excessive torques and stem thrusts
- Overstrain of valve parts in the load path
- Loss of self-locking of the stem nut
- Loss of self-locking of the actuator worm shaft
- Wear or defects on the stem nut bearings
- Improper design or assembling of disc springs for stem nut support
- Increase or decrease of actuator efficiency
- Increase or decrease of stem nut friction coefficient
- Faulty contactors (main contactors)
- Unsteady behavior during valve run (fluctuation of running power)

Due to the active power measurement combined with the quantitative evaluation of the main features, deviations from the design tolerance levels can be identified in the whole chain from the power supply system to I & C, actuator and valve. The evaluation criteria for the databases can be calculated before the start of the first diagnosis and can be used for all steps of diagnosis: Factory Acceptance Tests at the valve manufacturer, commissioning of valves, diagnosis during outages or during operation.

Considerable commercial effects can be achieved with this diagnosis measurement and evaluation by ADAM®. The measurements and evaluations can take place completely self-controlled during plant operation. The condition of the valves can be checked in advance before the outages. Statistic and trending allow extrapolation of the valve conditions into the future. Critical valves can be detected and evaluated in more detail and/or monitored permanently. Valves identified for maintenance and justified by engineering can be taken into account for the outage planning. Thus, the scope and duration of valve inspection/maintenance during outages can be optimized. Unnecessary maintenance activities can be avoided.

Evaluation is used today in many NPPs, mainly in western and eastern Europe. The diagnosis methodology is also applicable for testing according to U.S. NRC Generic Letter 96-05.

4. Present diagnosis equipment

The present FANP diagnosis measurement equipment is the Ultra Check family for measurement at valve locations and the SIPLUG® family for diagnosis based on active power measurement.

As an example the three versions of SIPLUG® are described below:

- Diagnosis sockets with external SIPLUG®
- Pocket SIPLUG®
- SIPLUG® online

Diagnosis sockets with external SIPLUG® (Figure 3)

For measurement of active power, 2 or 3 inductive current transformers and a diagnosis socket are permanently installed in the switch gear. The current transformers can be mounted in the cable outlet area or inside the plug-in unit. The current transformers are easy to install - the power wires of the three phases are fed through the holes of the transformers.

The diagnosis socket can be mounted on the front panel of the plug-in units or in the back doors of the cabinets. For safety reasons, the connections between the diagnosis socket and the power circuit are protected by fuses.

SIPLUG® is a low-cost, battery-powered, miniature data acquisition and storage device.

When the valve is operated, the voltages and currents are measured. The active power is then calculated from these measurements and stored in the SIPLUG®'s internal memory. A total of 400 seconds of data can be stored in the SIPLUG® memory. If the memory is full, the oldest measurements are replaced by the new ones. SIPLUG® measurements can be read directly by the ADAM® software and stored on hard disk. The connection to the computer is made via the standard serial port.

For a measurement, a SIPLUG® is plugged into the diagnosis socket (***Figure 4***). It continuously monitors the control voltages of the interface relay. If a control voltage is detected, data acquisition and storage will occur until the control voltage drops and the motor voltage is zero.

Each diagnosis socket contains a unique code that can be read by the SIPLUG®. From the socket code, the SIPLUG® can determine which MOV is being measured. Furthermore, the user does not need to select an MOV identifier for storing the data - the ADAM® evaluation software automatically performs all data handling via the socket code including the automatic selection of the power range. One SIPLUG® can record data from different MOVs.

Pocket SIPLUG® (Figure 5)

The Pocket SIPLUG® was developed to allow an adequate measurement from switch gears which are not equipped with diagnosis sockets and installed current transformers. The Pocket SIPLUG® is directly adapted to the switch gear by current clamps. The diagnosis functions are similar to the diagnosis socket/external SIPLUG®.

Advantage of this solution: It can also be applied for diagnosis measurement from the valve actuator because the Pocket SIPLUG® can be adapted as well directly to the actuator. The recording and evaluation of data can be completed by mechanical parameters like torque and/or thrust. Existing diagnosis measurement equipment and measurement results can be included as well.

The Pocket SIPLUG® is the simplest start of this diagnosis technology and does not require any modification of the switch gear.

SIPLUG® online (Figures 6 and 7)

The latest development of the valve diagnosis is an online method with automatic engineering-based evaluation, although other applications are still in use.

Small SIPLUG®-online measurement modules are the basis for this variant. They are permanently installed in the switch-gear and allow an automatic active power measurement. These SIPLUG®-online modules are qualified and calibrated measurement equipment. Each valve operation is measured, saved and evaluated for all accordingly equipped valves. The measured data are sent via a data-bus to a central diagnosis server and saved there.

The evaluation software ADAM® is identical for all three SIPLUG® versions. It is also possible to have a combination of the three versions in one plant.

5. Present application of the ADAM®/ SIPLUG® concept

The concept of permanent monitoring will be put into effect in the new NPPs Olkiluoto 3 in Finland and the EPR in France from the start. All safety-related valves will be equipped with the SIPLUG®-online modules. The diagnosis methodology will be used first during the factory acceptance tests at the manufacturer, during commissioning, and later on during operation and outages to reduce preventive maintenance. The results of the permanent monitoring, trending and statistical evaluation will be considered for the planning of the scope of maintenance during outages.

This monitoring concept has influence on the complete valve engineering work:

- The valve specifications contain requirements for valve monitoring up to valve commissioning.
- The valve manufacturer has to present a valve calculation which allows the determination of diagnosis evaluation criteria. The manufacturer has also to specify the variable parameters and their allowable ranges.
- The valve actuators will be calibrated during the Factory Acceptance Tests (FAT).
- The variable parameters (e.g., friction coefficients) will be verified during the FAT of the valves. The measurement will be performed with measurement equipment adequate to the on-site monitoring. The evaluation of the results will consider the specified evaluation criteria. The FAT is the basis measurement for the on-site monitoring.
- The commissioning of the valves in the plant will be used as basic on-site monitoring measurement.

This monitoring concept enables us to improve an item which in the past could not be covered satisfactorily by our engineering concept:

Very low friction coefficients for stem/stem nut were detected in different globe valves with higher stem diameters. These very low friction coefficients <0.05 resulted in the loss of self-locking and self-opening of the valves because of a non self-locking transmission gear of the actuator. In addition, very high stem thrust was induced with high stresses in valve parts.
The stem nut was replaced in case of low friction coefficients in the past to keep the friction coefficient within the allowable range required by the German calculation guidelines.
In the future, we will accept valve calculations with small friction coefficients. The valve manufacturer must define the allowable range and consider it in the calculation. The acceptability of the actual friction coefficient will be checked during FAT and periodically monitored on-site. The loss of self-locking must be avoided by design features, e.g. by using self-locking actuators.

6. Summary

The presentation shows that a simple and permanent monitoring of valves in NPPs is possible with the presently available diagnosis equipment and methodology as well as engineering-based evaluation methods. Existing diagnosis measurement equipment and measurement results can be included as well. The reduction of costs for diagnosis measurement and evaluation is possible (***Figure 8***). It allows anytime the determination of the state of the valves considering statistical evaluation and trending. Based on this concept, a predictive maintenance planning of the outages is possible resulting in high reliability of the NPPs. However, this has to be accompanied with a reliable engineering work based on a qualified performance prediction methodology, e.g., as justified in the U.S. by the Electric Power Research Institute (EPRI). In addition, FANP has also engineering-based diagnosis methods and equipment for pilot operated valves, air operated valves and solenoid operated valves.

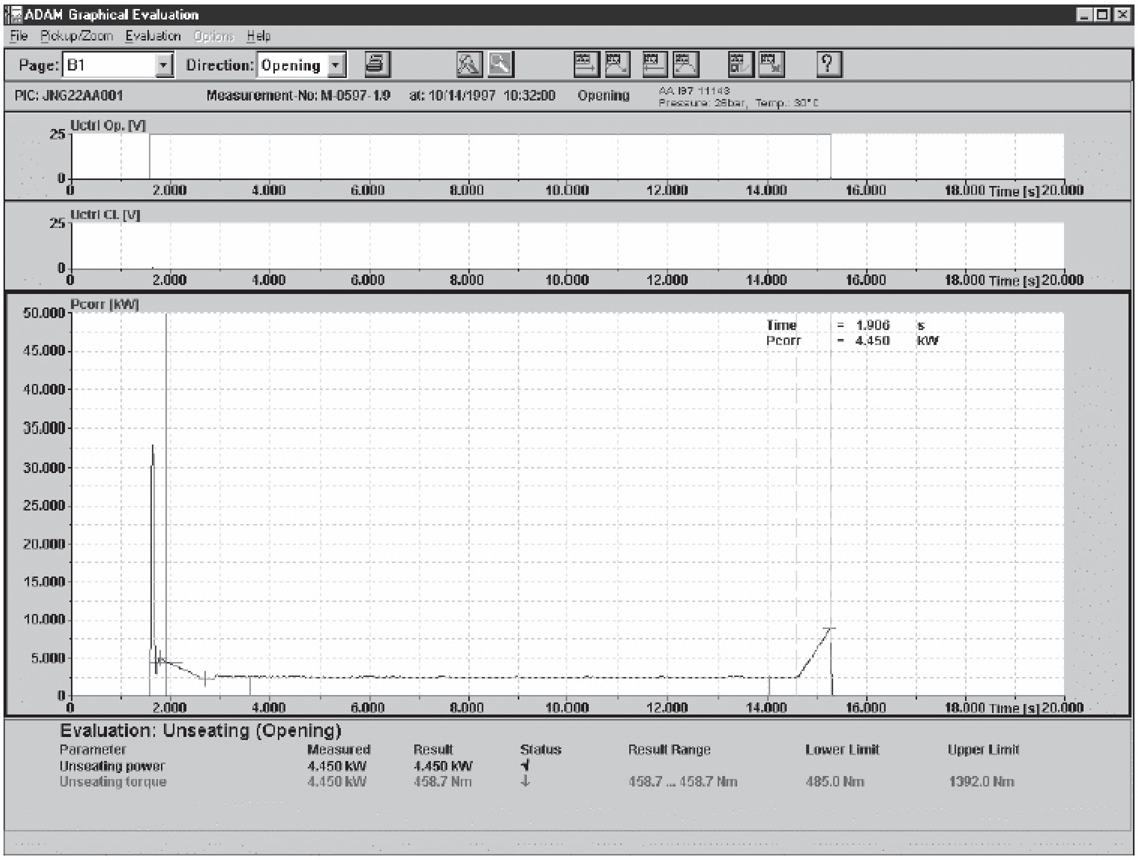


Figure 1: **Diagnosis evaluation with ADAM ® – Active power diagram**

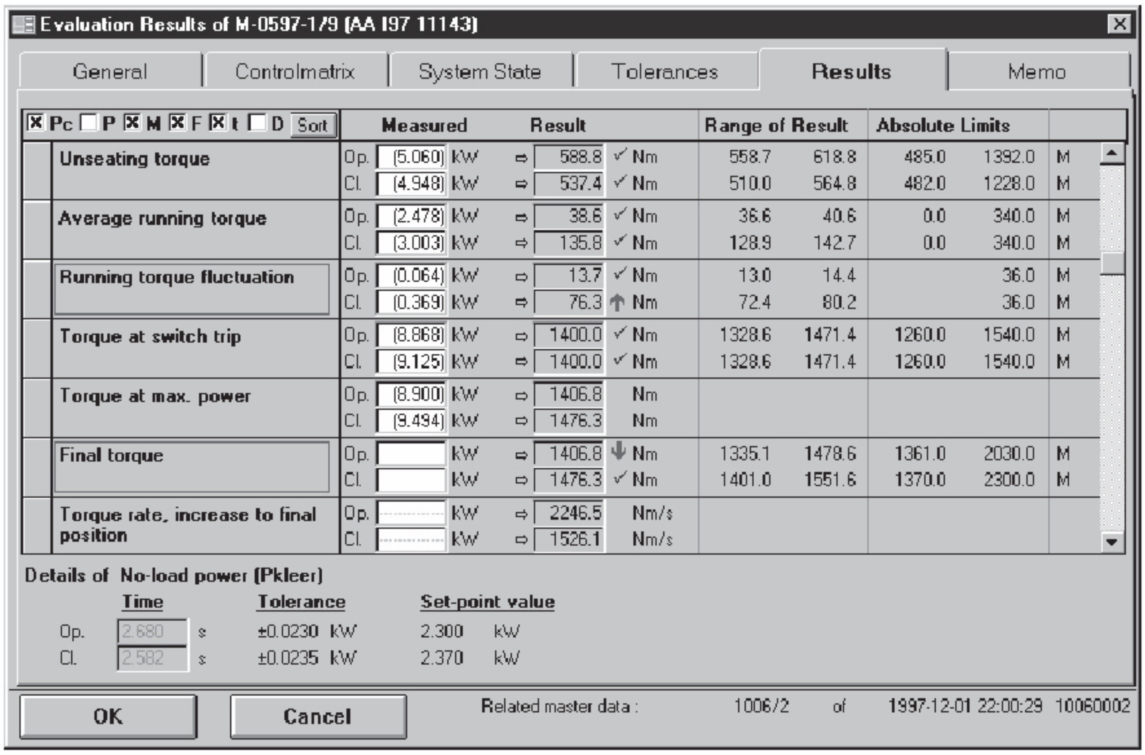


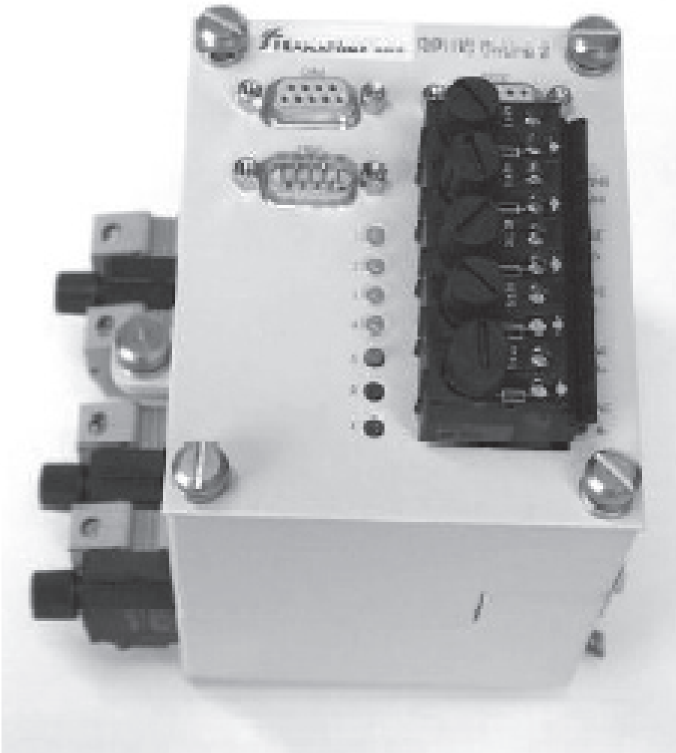
Figure 2: **Diagnosis evaluation with ADAM ® – Result list of evaluation parameters**

***Figure 3*:** **External SIPLUG®**

Figure 4: **Switchgear equipped current transformers inside the plug-in unit and with diagnosis sockets for adaptation of the external SIPLUG®**

Figure 5: Pocket SIPLUG® with current clamps and transportation case

Figure 6: SIPLUG® online 2 module for installation in the cable outlet



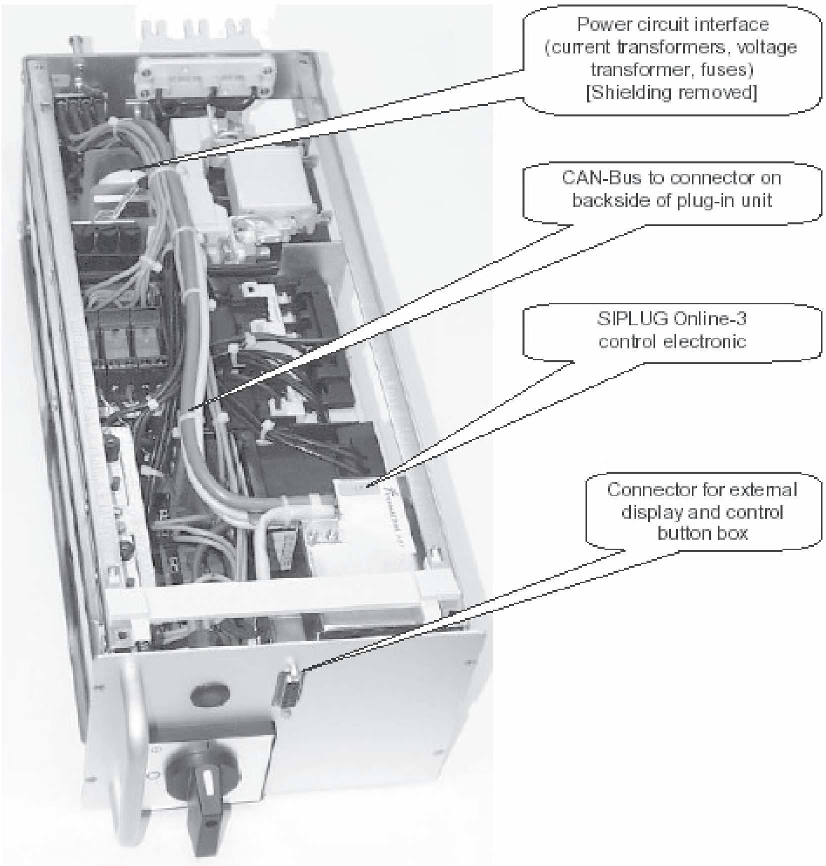


Figure 7: **SIPLUG® online 3 module (integrated in switch gear plug-in module)**

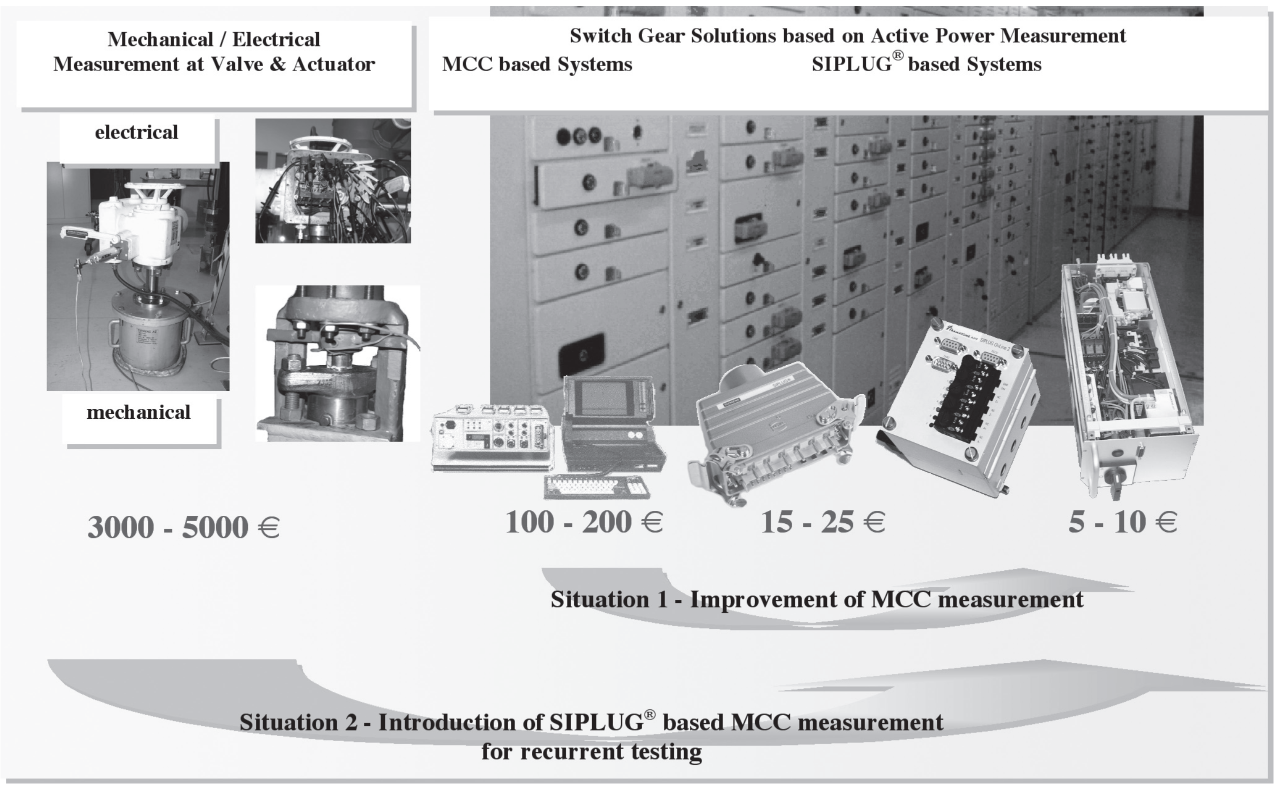


Figure 8: **Recurrent testing and estimated costs**

MOV Periodic Verification Approach from the Joint Owners' Group Program

Tim Chan
TVA

Robert Doyle
Arizona Public Service

Chad Smith
Duke Energy

Glenn Warren
Southern Nuclear Operating Co.

Paul Damerell
Todd Spears
MPR Associates

Abstract

To address long-term motor operated valve (MOV) performance, the Babcock & Wilcox, Boiling Water Reactor and Westinghouse Owners' Groups conducted the Joint Owners' Group MOV Periodic Verification (PV) Program. This program, now complete, had participation by 98 of the 103 operating U.S. reactor units. The program provides a justified approach for periodically testing MOVs. The technical basis is a series of repeat tests on 176 gate, butterfly and globe valves, performed at the participating plants. The PV approach classifies each valve and then specifies a PV test interval based on the MOV's margin and risk significance.

The in-plant repeat testing was performed under conditions with flow and differential pressure (DP) in the pipe. Valves were tested three times, with at least a year between tests. The test results show that there was no age-related degradation, i.e., no increases in required thrust or torque simply due to the passage of time, without DP stroking.

For gate valves, the required thrust did not degrade in service except under certain conditions. Specifically, when the initial valve factor is low due to either valve disassembly or due to limited DP stroking in service, the valve factor tends to increase with DP stroking, up to a stable level. To address this observation, the gate valve PV method includes threshold values above which increases are not observed. Because different valves stabilize at different valve factors, the PV method also provides ways for users to demonstrate from testing that the required thrust is stable.

For butterfly valves, the required torque did not degrade in service, but certain bearing materials and fluid conditions showed variations in bearing friction coefficient, even though there was no increasing or decreasing trend. To address this observation, the butterfly valve PV method includes maximum bearing friction coefficients, as well as test-based methods for users to demonstrate that their friction is less than the maximum value.

For globe valves, no degradation in required thrust was observed, and no limits or test methods are included in the globe valve PV method.

Keywords: periodic verification motor operated valve degradation

Background

US nuclear power plants expended significant efforts in the 1990s to improve MOV reliability and to satisfy US Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-10 (Reference 1). Periodic verification of MOVs is separately covered in NRC GL 96-05 (Reference 2).

To address GL 96-05, the nuclear industry sought to take advantage of the investments each plant made in their GL 89-10 programs and of subsequent testing. The Joint Owners' Group (JOG) MOV Periodic Verification (PV) Program was formed on this basis. Specifically, the Babcock & Wilcox Owners' Group (B&WOG), Boiling Water Reactor Owners' Group (BWROG), Combustion Engineering Owners' Group (CEOG) and Westinghouse Owners' Group (WOG) joined together for the JOG MOV PV Program. During the program, the CEOG merged into the WOG.

The objective of the JOG MOV PV Program is to provide an approach for MOV periodic verification. At the outset of the JOG MOV PV Program (1997), a Program Description Topical Report was prepared (Reference 3). This report described the "design" of the program and the underlying technical basis. This report was submitted to the NRC, who subsequently issued a Safety Evaluation (Reference 4) accepting the proposed program. Individual plants notified the NRC whether they were participants in the JOG MOV PV Program or whether they were implementing their own approach for periodic verification. Ninety-eight (98) of the 103 operating reactor units in the US participated in the JOG MOV PV Program.

This united approach used in the JOG MOV PV Program has key benefits for participating plants and for the regulator. Importantly, it conserves resources. Cost effectiveness is achieved by sharing the burden of valve testing among participating plants. Also, because the program provides a uniform approach for all participating plants, the regulator's burden to individually inspect and approve multiple programs is alleviated. Accordingly, plants can operate under a predictable regulatory expectation with high certainty of acceptance. Finally, because the program has 98 participating units, an extensive set of MOV test data was obtained and evaluated. These data, which are far more extensive than any single plant could expect to obtain, provide the basis for a strong technical justification.

The scope of the JOG MOV PV Program covers the potential degradation in required thrust or torque. The JOG MOV PV program does not cover potential degradation in actuator available thrust or torque. This element of potential degradation is the responsibility of each individual plant, and the JOG MOV PV approach identifies where this degradation should be considered.

In-Plant DP Testing

As mentioned above, a key element of the JOG MOV PV Program is MOV testing at the participating plants. Each participating unit tested two valves under conditions with flow and differential pressure (DP). Each valve was tested three times under nominally identical DP conditions, with at least a one-year separation between tests. The test valves were selected so that, in aggregate, they cover the valve design features and system conditions most commonly encountered in nuclear power plants.

The DP test program includes 176 valves: 134 gate valves, 23 butterfly valves, 12 unbalanced disk globe valves, and 7 balanced disk globe valves. Data were obtained from 3 tests of each valve for 161 of the valves; the remaining 15 valves yielded data for only 2 tests. In total, data from 513 tests were obtained.

To ensure that data obtained from in-plant tests were satisfactory for use in the JOG MOV PV Program, the participating plants were required to adhere to a test specification (included in Reference 3), which includes requirements for:

- Test valve maintenance and material condition, both before and during the tests
- Test conditions
- Test instrumentation
- Test sequence
- Test data evaluation
- Test documentation

The goal of the standard test specification was to ensure that all valves and testing were properly controlled to achieve adequate consistency and quality in the test results obtained from multiple plants. Importantly, the test specification requires that time-history data for stem thrust (or torque for butterfly valves) and DP be obtained. Further, the specification requires analyzing and summarizing the data in a prescribed manner. Finally, the specification requires a test sequence that includes both static and DP test strokes. Although there was not a minimum permissible DP, the specification required that the DP be closely repeated between tests.

Program Completion and Key Conclusions

Four previous papers (References 5, 6, 7 and 8) describe the JOG MOV PV Program and show interim results from in-plant valve tests. The testing is now complete. The purpose of this paper is to summarize the tests results and the insights gained in the program, and to describe the recommended periodic verification approach. A new topical report describing the test results and the PV approach has been prepared and submitted to the NRC (Reference 9). At the time of this paper, the NRC was performing their review.

The key conclusions from the test results are as follows.

- There is no age-related degradation for gate, globe and butterfly valves, i.e., no increase in required DP thrust or torque only due to the passage of time (without DP stroking).
- For gate valves, service-related degradation (increase in required thrust with DP stroking) occurs only with valves that have a low initial valve factor due to disassembly/reassembly or due to limited DP stroking in service. In these cases, the valve factor tends to increase with DP stroking, up to a stable level.
- For butterfly valves, there is no service-related degradation. Butterfly valves with bronze or 300 series stainless steel bearings in untreated water systems without hub seals show variations in bearing friction, with no increasing or decreasing trend. Valves with non-metallic bearings also show small variations.
- For balanced and unbalanced disk globe valves, there is no service-related degradation. Balanced disk globe valves is untreated water systems show thrust variations unrelated to DP thrust. These variations have no increasing or decreasing trend and appear to be related to the effect of particulates.

Overall Periodic Verification Approach

Based on the evaluation of the data, a recommended periodic verification approach has been developed. The JOG MOV periodic verification approach is to classify each applicable valve into one of four classes. The periodic verification requirements are defined for each class based on the valve's risk ranking and margin. Because this PV approach addresses the potential degradation in required thrust or torque, appropriate allowances for actuator degradation need to be included in the calculation of margin. The four classes are summarized below.

Class A

Class A valves are not susceptible to degradation, as supported directly by testing performed in the JOG MOV PV Program. For these valves, static PV testing is only needed to verify proper MOV setup and to quantify margin. For Class A valves with positive margin, the interval between static PV tests is based on the "High Margin" column of Table 1: six years for high risk valves and ten years for medium and low risk valves. The justification is that, because there is no susceptibility to degradation in required thrust, the longest interval is acceptable.

Class B

Class B valves are not susceptible to degradation based on the test results in the JOG MOV PV Program, extended by analysis and engineering judgment to configurations and conditions beyond those tested. For these valves, static PV testing is only needed to verify proper MOV setup and to quantify margin. For Class B valves, the interval for static PV testing is determined from Table 1. The justification is that Class B valves are not susceptible to degradation in required thrust, but the certainty is not as high as for Class A. Therefore, full use of the table, rather than just the high margin column, balances the decreased certainty.

Class C

Class C valves are susceptible to changes in required thrust or torque, as shown by test results in the JOG MOV PV Program. Potential increases in required thrust or torque need to be taken into account in the setup, surveillance and evaluation of these valves. For Class C valves, the PV requirements tend to force changes in the valve or its setup so that it can be reclassified as Class A or B. For gate valves, an allowance needs to be considered in computing the valve's margin. If the margin (including allowance) is positive, static PV testing in accordance with the intervals in Table 7-1 is to be used. For all butterfly valves and for gate valves where the margin (including allowance) is forecast to be less than zero, either (a) the valve is to be DP tested (rather than static tested) at a 2 year interval, with the first DP test to occur at the next available opportunity, not to exceed 2 years, or (b) the MOV or its setup is to be modified such that it covers potential increases or variations in required thrust or torque. Note that globe valves cannot be Class C.

Class D

Valves in Class D are not covered by the JOG MOV PV Program. Individual plants are responsible for justifying the PV approaches for these valves. Valves that are classified as Class D tend to be valves that have a combination of specific, unusual design features in conjunction with certain application conditions. For example, gate vales with self-mated 300 series stainless steel guides that stroke in service above 120ºF are Class D, and globe valves with rising/rotating stems that stroke open against DP are Class D. These specific configurations and applications have potential degradation mechanisms not covered by the JOG MOV PV Program testing.

Periodic Verification of Gate Valves

Figure 1 shows a typical gate valve. The stem moves a wedge-shaped disk into or out of the flow stream to close or open the valve. The required thrust to move the disk needs to overcome packing friction, the effect of pressure pushing the stem out of the valve (stem rejection) and friction of internal valve surfaces sliding against each other. Only the last term is affected by the presence of flow and DP across the valve during its stroke.

The gate valve test data from the JOG MOV PV Program are extensive, and they were analyzed in several ways to evaluate potential degradation in required thrust. These evaluations showed that disk-to-seat friction is the dominant influence on required thrust, and that periodic verification needs to consider circumstances where this friction could increase above the value currently used to justify valve setup and to quantify margin.

Gate valve test data were analyzed to isolate disk-to-seat friction by examining the portions of closing and opening strokes where the disk is sliding across the seat ring. This sliding occurs toward the end of closing strokes (after the disk has covered the seat ring but before it wedges) and at the beginning of opening strokes (after unwedging but before a flow passage opens). The apparent disk-to-seat friction (expressed as either a "valve factor" or a friction coefficient) can be determined from measurements of thrust, line pressure and differential pressure. The results from repeat tests conducted over a span of a few years can then be evaluated to determine the trend. Figure 2 shows typical results. This graph shows the mean and range of disk-to-seat friction (expressed as a valve factor) for a group of 27 valves tested in cold (<120ºF), treated water. These valves have Stellite disk and seat faces and are in service where they stroke against DP 1 to 4 times per year. The results are subdivided into 2 categories – valves that were disassembled and reassembled prior to (within two years of) the first test, and valves that were not disassembled. The disassembled valves exhibit lower initial valve factors that tend to increase in subsequent tests up to a level similar to non-disassembled valves. The DP stroking appears to be responsible for the increase. Figure 3 shows average valve factors for valves (both disassembled and non-disassembled) in 3 categories: valves not typically DP stroked, valves DP stroked 1 to 4 times per year, and valves DP stroked more than 4 times per year. Valves that are DP-stroked more often show a larger, more rapid rise than those that were stroked less frequently.

Another key observation was that different gate valves tend to stabilize at different valve factors; hence, there is a range of potential stable valve factors. If a valve currently has a valve factor in the lower part of the range, it might be susceptible to increase or it might be stable. Valves that had low valve factors and that do not typically DP stroke in service were the most susceptible to increases.

Similar results were observed for gate valves in other fluids (e.g., hot treated water, untreated water, steam) and for valves with other disk-to-seat materials. Figure 4 shows results for a set of eight valves in steam service. These valves all had Stellite disk-to-seat faces. For these valves, the effects of disassembly and stroking appear to be less than in cold treated water. Figure 5 shows results for a set of 4 valves with 400 series stainless steel disk faces and Stellite seat ring faces. The effect of disassembly can be clearly seen on one valve tested in water. Another disassembled valve in water shows minimal effect, because this valve was stroked multiple times between the disassembly and the first test. The steam valve shows minimal effect of disassembly.

Additional evaluations of the gate valve data were performed to evaluate disk guide-to-body guide friction and the friction between the parts of multi-piece disks. These evaluations tended to show stable friction. The effects of disassembly could be seen in the guide friction evaluations, but these effects were less than those for disk-to-seat friction. Figure 6 shows guide friction results for 4 valves with Stellite disk guide faces and carbon steel body guide faces. One of these valves was disassembled, and the friction is stable for all 4 valves. Figure 7 shows results for 10 valves with 300 series stainless steel disk guide faces and either 300 series or 17-4 PH stainless steel body guide faces. Some friction increases can be seen in the valves that were disassembled; overall the results are stable.

The observed results for gate valves suggest that the potential for required thrust to increase depends on the current value of disk-to-seat friction coefficient used for valve setup and margin calculation, and its basis. A valve that has been shown by test to be stable at a specific friction coefficient will not show future increases. A valve that has not been shown by test to have a stable friction coefficient might be susceptible to future increases, depending on the current value. Figure 8 shows a plot of the change in friction coefficient (between consecutive JOG tests separated by at least a year), plotted against the initial friction coefficient. Values at the high end of the range tend be stable, but lower values are susceptible to increase. Based on this result, a periodic verification classification approach that considers the basis for disk-to-seat friction was developed.

First, a screen is used to determine which valve applications are covered by the test data, which are covered by extension and which are not covered. The screen considers: disk style, extent of in-service DP stroking, disk-to-seat and disk guide-to-body guide materials, fluid type, and stroke direction for the valve's design basis function. For valves that are either covered or covered by extension, two questions are evaluated. First, does that valve have a "qualifying basis" of test data that demonstrates that the value of disk-to-seat friction coefficient is stable? Second, does the disk-to-seat friction coefficient exceed the "threshold" value that characterizes a 95% non-exceedence level, as supported by the JOG MOV PV Program test data? A "yes" answer to either of these questions means that the basis for the required thrust for the valve is reliably stable, and the valve is classified as Class A or B, as appropriate. If the answer to both questions is "no", then the valve is susceptible to increases in DP thrust and the valve is classified as Class C. Figure 9 shows a flow chart of the classification process.

Periodic Verification of Butterfly Valves

Figure 10 shows a typical butterfly valve. The stem turns a disk, typically through a 90º stroke. In the closed position, the disk mates with a seat ring on the body inner diameter and blocks the flow. In the open position the disk is parallel to the flow stream, allowing significant open area for flow. The required torque to move the disk needs to overcome packing friction, disk-to-seat friction (only near the fully closed position), stem bearing friction and hydrodynamic loads applied to the disk by the flow. Only the last two terms are affected by the presence of flow and DP across the valve during its stroke. Further, the hydrodynamic load term is not susceptible to degradation. Accordingly, the JOG MOV PV Program examined only the bearing friction term.

Butterfly valve bearing friction was determined from test data by comparing the valve's performance, near the fully closed position, under conditions with and without DP. Because the hydrodynamic torque is negligible in this part of the stroke, the difference in required torque is entirely due to bearing friction. Measurements of stem torque and DP, along with the known diameters of the stem and disk, are sufficient to determine the stem-to-bearing friction coefficient.

Figure 11 shows the bearing friction coefficients for 4 butterfly valves with bronze bearings, in applications with treated water < 100ºF flowing in the pipe. (Values are not shown on the y-axis because they are not needed to understand the observed trend.) Results are shown for the baseline, second and third tests (two strokes per test). There is more than one year of separation between tests. The bearing friction is observed to be stable and there is no increasing trend. One valve showed a significant decrease from the baseline to the second test; a careful review of the data showed that this observation was due to an unusually low unseating torque measured in the baseline static (no DP) test, and that the performance with DP was stable.

Figure 12 shows the bearing friction coefficients for 7 butterfly valves with bronze bearings, in applications with untreated water < 100ºF flowing in the pipe. The results are subdivided into two groups: 3 valves have bearing hub seals and demonstrate low, stable friction; 4 valves do not have bearing hub seals and demonstrate higher friction with considerable variations. The variations do not have an increasing or decreasing trend. Further, the changes are unrelated to the amount of DP stroking that the valve undergoes. Sometimes variations occur between consecutive strokes performed on the same day, in other cases the variations occur between stokes performed years apart. For these conditions (bronze bearing, untreated water, no hub seal), a single measured value of bearing friction cannot reliably be assumed to be stable.

Figure 13 shows results for Teflon-lined bearings in both treated and untreated water. The friction coefficient in untreated water tends to be a little higher, and show a little more variation, than in treated water. Overall, these results are lower than those for bronze bearings, and show less variation than bronze bearings in untreated water.

Figure 14 shows results for 4 valves with 4 other non-metallic bearing materials: Tefzel, polyethylene, Nomex and Nylatron. These results are relatively stable, although the very low friction coefficients for Nylatron in untreated water show some variation.

The observed results for butterfly valves indicate that some bearing materials and fluid conditions have stable bearing friction while other combinations have variations in bearing friction. For those valves that are susceptible to variation, either a set of tests is needed to establish a "qualifying basis" for bearing performance, or an appropriate "threshold" value of bearing friction coefficient (that covers the variations) needs to be used to set up the valve and determine its margin. Based on this result, a periodic verification classification approach was developed that considers bearing material and fluid conditions, the presence or absence of a hub seal, and for those conditions with variations, the basis for bearing friction coefficient.

First, a screen is used to determine which valve applications are covered by the test data, which are covered by extension and which are not covered. The screen considers: bearing and shaft materials, fluid type, and presence or absence of a hub seal. Valves that have bearing materials and fluid conditions not susceptible to variation are identified and classified as Class A. For valves that are susceptible to variation, two questions are evaluated. First, does that valve have a "qualifying basis" of test data that demonstrates that the value of bearing friction coefficient covers the variation? Second, does the bearing friction coefficient exceed the "threshold" value that characterizes a 95% non-exceedence level, as supported by the JOG MOV PV Program test data? A "yes" answer to either of these questions means that the basis for the required torque for the valve is reliable, and that the valve is classified as Class A or B, as appropriate. If the answer to both questions is "no", then the valve is susceptible to increases in DP thrust and the valve is classified as Class C. Figure 15 shows a flow chart of the classification process.

Periodic Verification of Balanced Disk Globe Valves

Figure 16 shows a typical balanced disk globe valve. The stem moves a disk toward or away from a seat to close or open the valve. A balancing port in the disk allows the pressures above and below the disk to be identical. A sliding seal at the end of the disk away from the seat separates the upstream and downstream pressures. Resistance to disk motion comes from packing and sliding seal friction, the effect of pressure pushing the stem out of the valve (stem rejection), area imbalance of the upper and lower sealing diameters on the disk, and friction between the disk and its internal guiding surface. Only the last two terms are affected by the presence of flow and DP across the valve during its stroke, and the area imbalance term is not susceptible to degradation. Accordingly, only a potential increase in disk-to-guide friction could produce a degradation (increase) in required DP thrust.

From the test data, the entire DP thrust (including imbalance and internal friction) was determined and expressed as a valve factor. The first observation from the data is that the DP thrust for these valves is very small, in most cases smaller than the packing friction. Therefore, these valves are inherently insensitive to degradation in required DP thrust. Further, the DP thrust was observed to be stable, i.e., no degradation was observed. Figure 17 shows the results for closing strokes of balanced disk globe valves, and Figure 18 shows the results for opening strokes. (Values are not shown on the y-axis because they are not needed to understand the observed trend.) These test results are from applications in water less than 120ºF and cover a variety of disk-to-guide materials. For both opening and closing, the average result is steady across three tests. Analysis of the data showed that the variations observed for individual valves are within the measurement uncertainty of the tests.

For 3 balanced disk globe valves tested in untreated water, thrust variations unrelated to DP were observed in some tests and not in other tests. These variations appeared as increases in thrust in certain portions of the stroke that had no buildup of DP. These increases were ascribed to the accumulation of particulate matter in the valve, and the plants found that periodically exercising the valve was effective in eliminating this effect.

Because balanced disk globe valves are insensitive to degradation and no degradation was observed, a periodic verification approach of periodic static testing (Class A or B) is appropriate. The periodic verification approach needs only to focus on evaluating which valve design features and fluid conditions are covered by the data, which are covered by extension and which are not covered. Figure 19 shows a flow chart of the classification process. The coverage of compressible flow, elevated temperatures, high flow rates and flashing flow is discussed below under unbalanced disk globe valves.

Periodic Verification of Unbalanced Disk Globe Valves

Figure 20 shows a typical unbalanced disk globe valve. The stem moves a disk toward or away from a seat to close or open the valve. The DP acts across the disk. Resistance to disk motion comes from packing friction, the effect of pressure pushing the stem out of the valve (stem rejection), and the effect of DP acting across the disk area. Only the last term is affected by the presence of flow and DP across the valve during its stroke, but it is not susceptible to degradation. Accordingly, testing in the JOG MOV PV Program was performed to confirm the absence of degradation.

From the test data, the DP thrust was determined and expressed as a valve factor, for those strokes where the DP thrust opposed disk motion (closing strokes for valves with underseat flow and opening strokes for valves with overseat flow). In all cases, the valve factor was observed to be stable. Figure 21 shows the results for eight globe valves in water flow < 120ºF. (In Figures 21 and 22, values are not shown on the y-axis because they are not needed to understand the observed trends.) The average valve factor across three tests is observed to be stable. Although there are minor test-to-test changes for specific valves, these changes are within the measurement uncertainty. Figure 22 shows the results for three valves in steam flow. Two valves, marked UG07 and UG13, show stable results. (In the case of UG07, there are two curves because the valve factor was calculated at two points in the stroke.) One valve, UG14, shows an increase in the closing direction from the first to the third test. The measurement uncertainty is large for these tests because the valve DP was very small when the valve seated. This result occurred because the downstream piping depressurized slowly as the valve closed and was still nearly at full pressure when the valve seated. To address this shortcoming in the test, the valve factor was determined with an alternate method using the opening data (self-actuating stroke), which had the full DP. The result, as shown on Figure 22, is a stable valve factor.

Because no degradation was observed in unbalanced disk globe valves, a periodic verification approach of periodic static testing (Class A or B) is appropriate. The periodic verification approach needs only to focus on evaluating which valve design features and fluid conditions are covered by the data, which are covered by extension and which are not covered. Figure 23 shows a flow chart of the classification process. The unbalanced disk globe valve tests covered incompressible water flow and steam flow; steam results are consistent with water flow. No results were obtained for flashing flow. The maximum flow velocity in the balanced and unbalanced disk globe valve tests (86 ft/sec, based on the seat area) was used to set an applicability limit on the method.

Summary

1. The JOG MOV PV Program is being used by the vast majority of US nuclear power plants to implement MOV periodic verification and to determine the potential degradation in required thrust or torque for gate, globe and butterfly valves.
2. A key component of the JOG PV Program is in-plant valve testing. The testing is now complete and there are repeat test data from 176 valves.
3. For all four valve types tested, there is no age-related degradation (i.e., no increases in required thrust or torque due only to the passage of time without DP stroking).
4. Gate valves are susceptible to service-related degradation only when they have low initial valves factors, either due to disassembly of the valve or due to little or no DP stroking in service. For these valves, valve factor increases tend to occur progressively up to a plateau level as the valve accumulates DP strokes. Valves that are set up using a justified valve factor do not need to consider

increases. Valves that are set up using a valve factor susceptible to increase need to add a margin allowance to cover future increases in required thrust.

5. Butterfly valves have no service-related bearing friction degradation. Bronze bearings have stable friction in treated water and in untreated water when the valve has a bearing hub seal. Bronze or 300 series stainless steel bearings in untreated water without a hub seal show significant friction variations, with no trend. Non-metallic bearings show small friction variations in both treated and untreated water. Valves that are set up using a justified bearing friction coefficient do not need to consider the effect of variations. Valves that are set up using a friction coefficient susceptible to variations need to be justified by DP testing or set up to cover the variations.

6. For balanced disk globe valves and unbalanced disk globe valves, there is no service-related degradation in required thrust. For balanced disk globe valves, the DP thrust component is small and the valve factor is stable. For unbalanced disk globe valves, testing confirmed a stable thrust in both water and steam. In balanced disk globe valves, service in untreated water can lead to thrust variations, not related to DP thrust, that come and go. It appears that these variations are due to particulates interfering with disk motion.

7. A periodic verification approach has been defined and justified, based on the results of the JOG MOV PV Program. The approach classifies valves according to their susceptibility to increases in required thrust or torque. Valves that are set up in a manner that is not susceptible to degradation have periodic static testing at a frequency depending on risk and margin. Valves that are susceptible to increases either have specified margin allowances to be added or need to have periodic DP testing.

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Table 1. Periodic Verification Intervals for the JOG MOV PV Program

Risk Ranking(2)	**PV Test Interval (years) for…**		
	Low Margin(1)	Medium Margin(1)	High Margin(1)
High Risk	2	4	6
Medium Risk	4	8	10
Low Risk	6	10	10

Notes:

1. Criteria for MOV Margin Categories

   Low Margin: JOG MOV PV Margin < 5%

   Medium Margin: 5% ≤ JOG MOV PV Margin < 10%

   High Margin: 10% ≤ JOG MOV PV Margin

2. Criteria for Risk Categories

   High Risk
   Medium Risk
   Low Risk

   } Based on Owners' Group or utility-specific criteria.

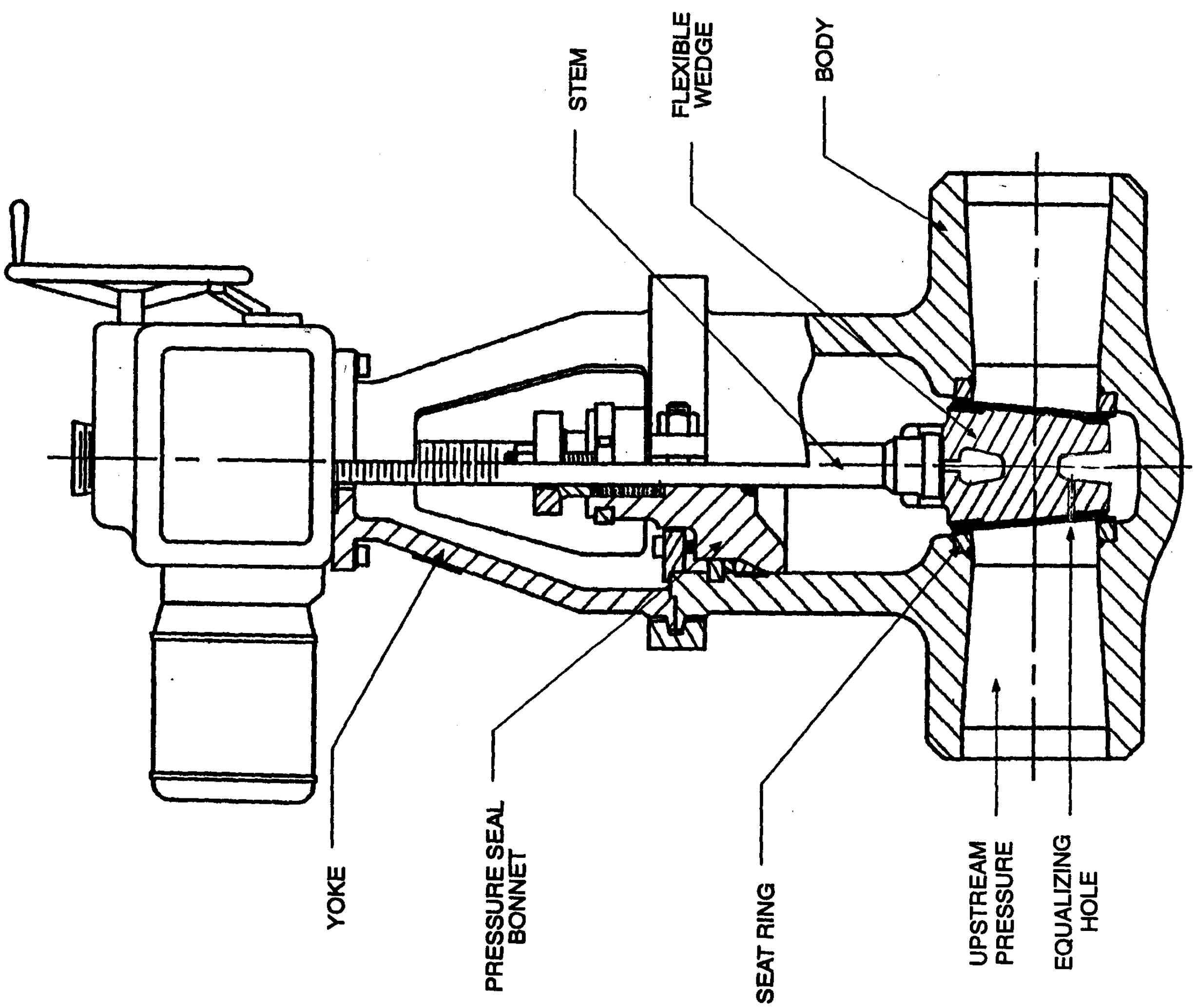
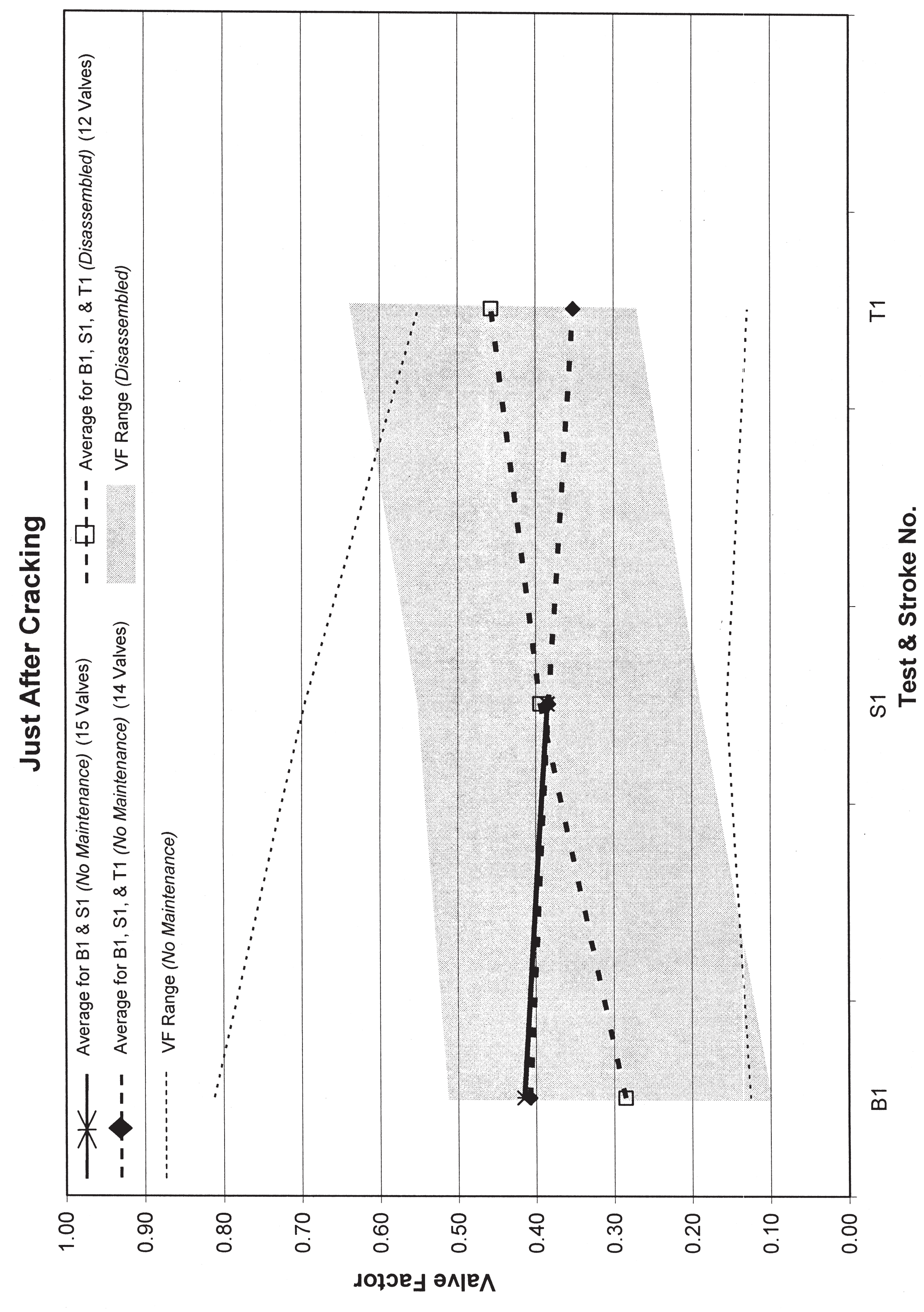


Figure 1. Typical Gate Valve

Figure 2. Opening Valve Factors (Just after Cracking) for Gate Valves with Stellite Seats in Treated Water Systems with 1 to 4 DP Strokes Between Tests



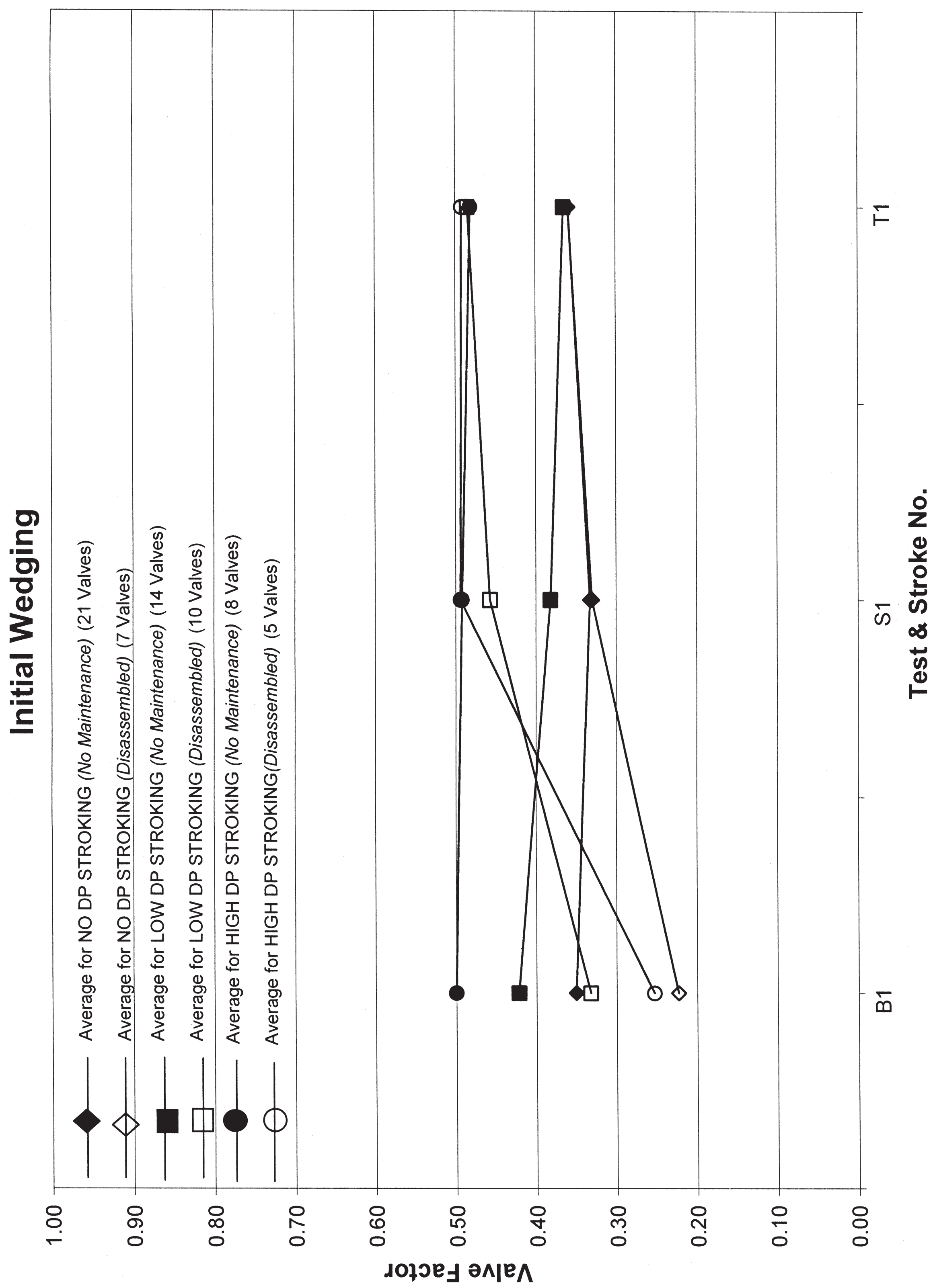
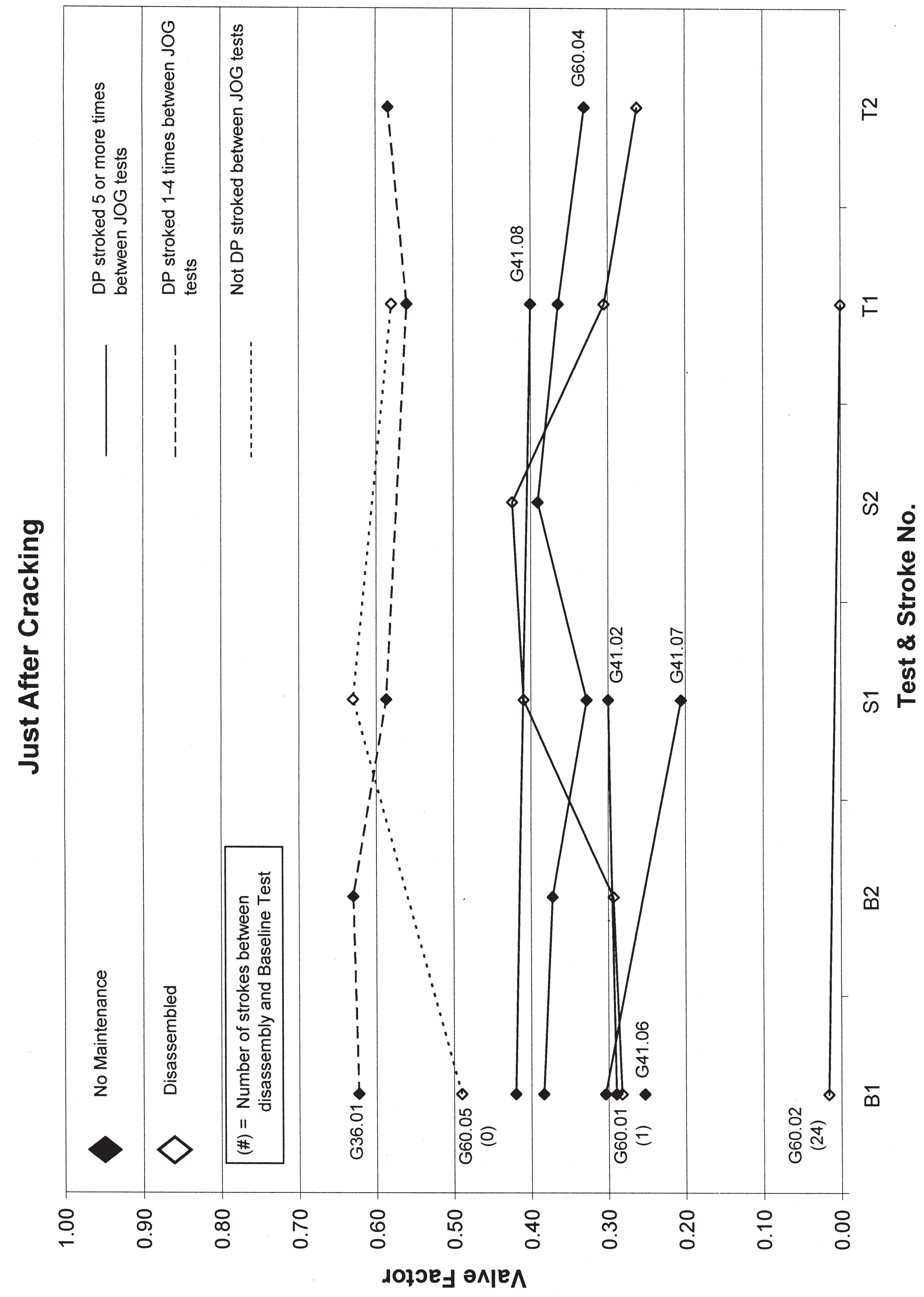


Figure 3. Valve Factors for Disassembled and Non-disassembled Valves with Stellite Seats and Different Amounts of DP Stroking

Figure 4. Opening Valve Factors (Just after Cracking) for Gate Valves with Stellite Disks and Seats in Steam



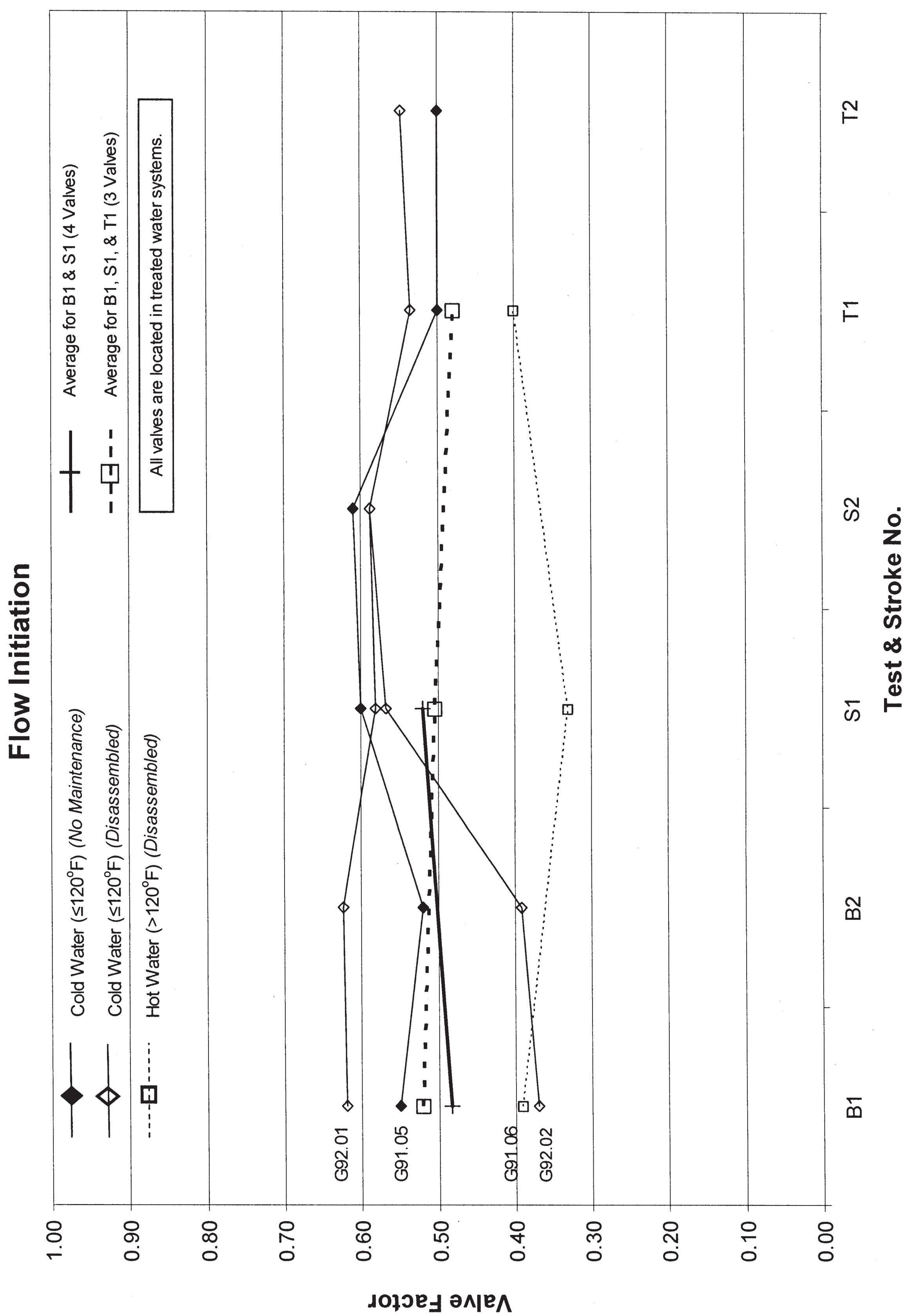
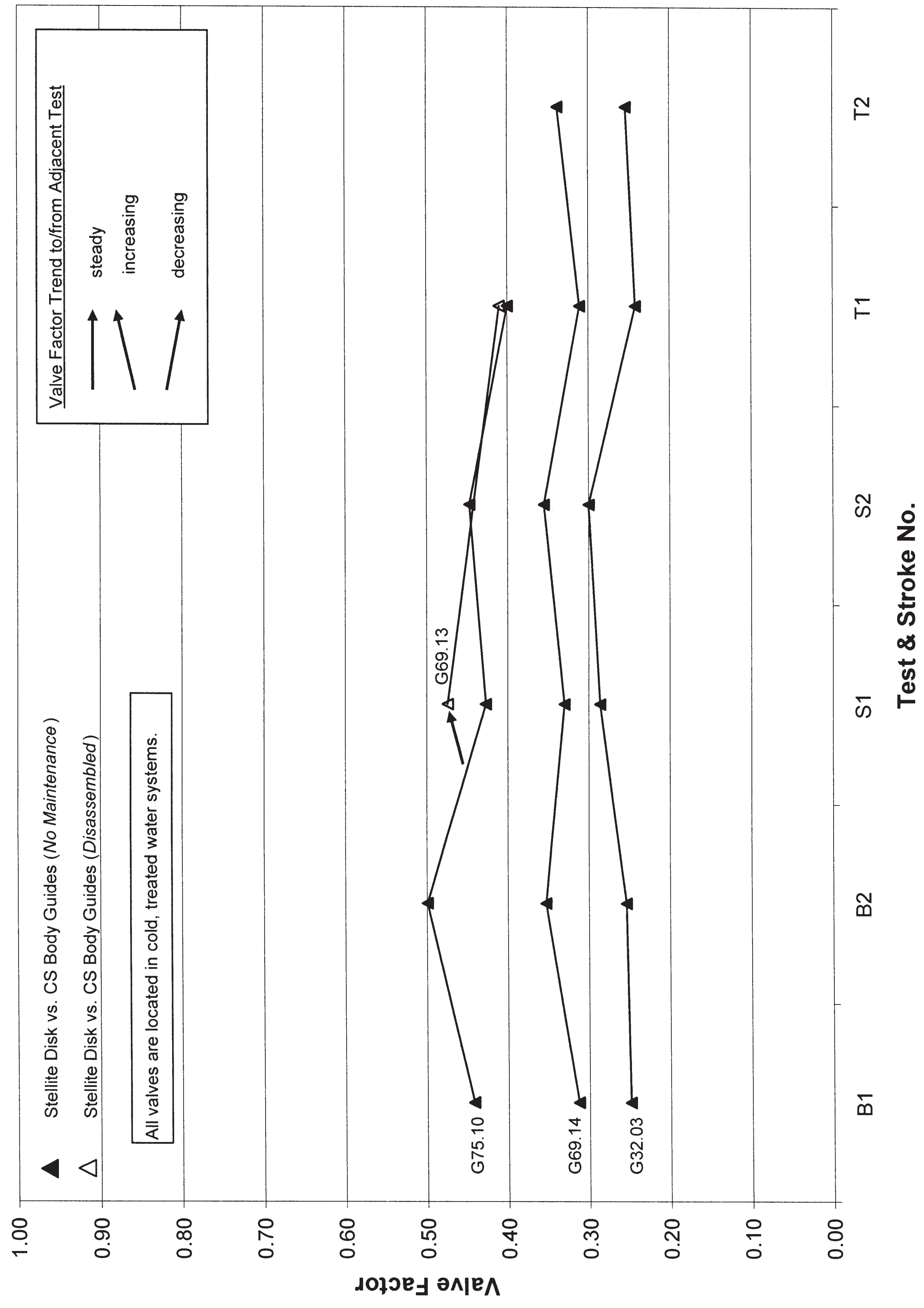


Figure 5. Opening Valve Factors (Flow Initiation) for Gate Valves with 400 Series Stainless Steel Disk and Stellite Seat Ring Faces

Figure 6. Guide Valve Factors for Gate Valves with Stellite Disk Guides and Carbon Steel Body Guides



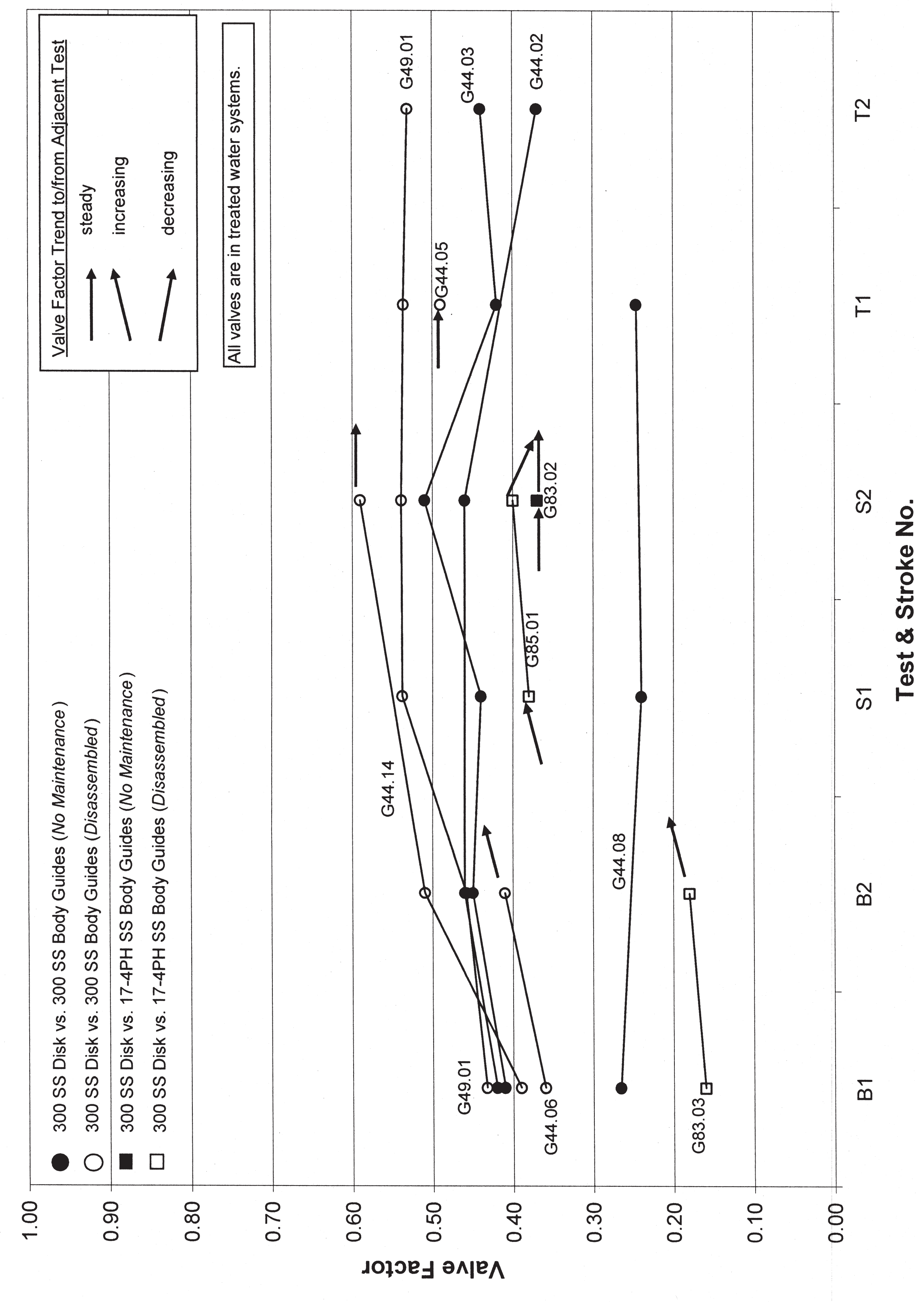
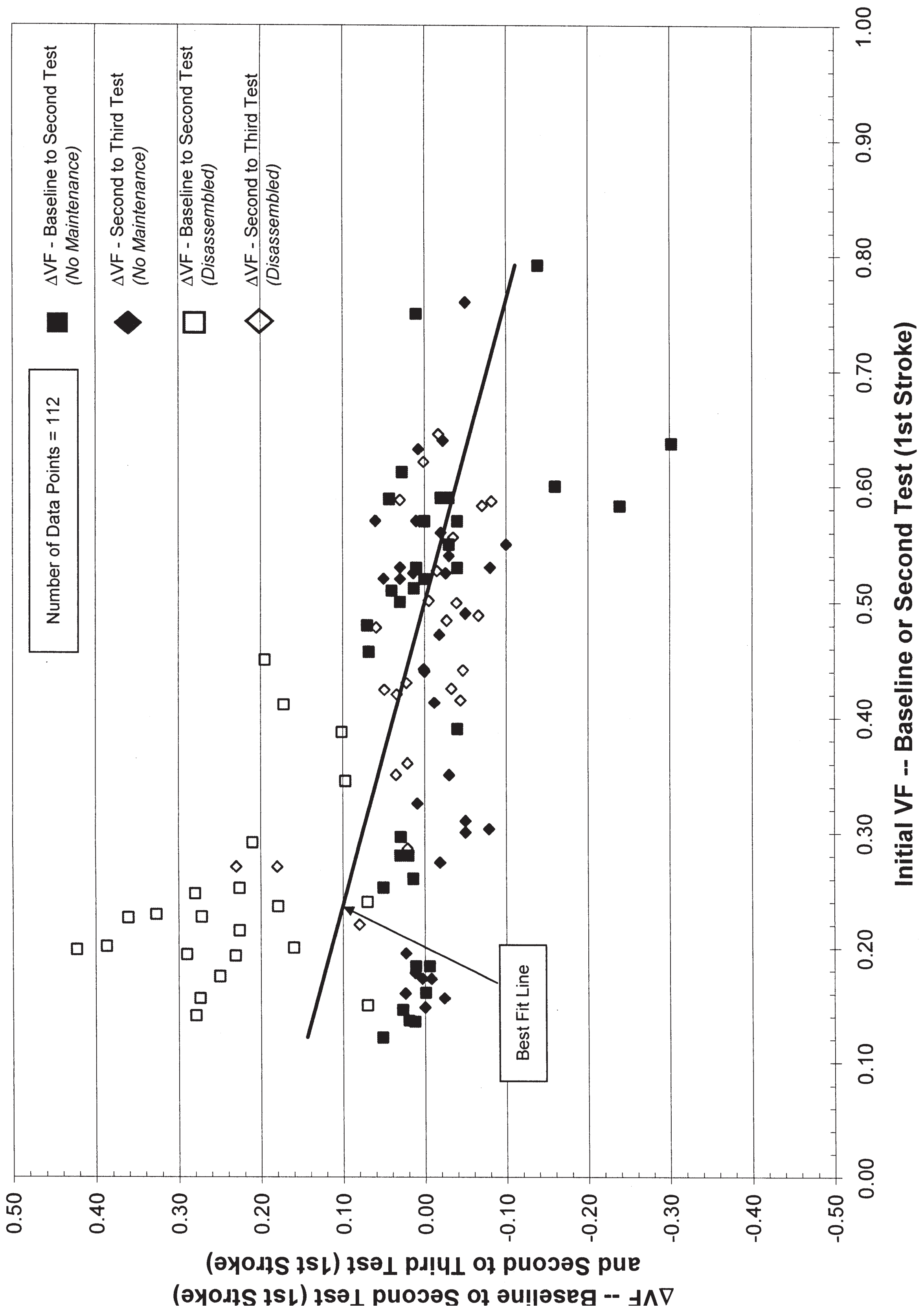
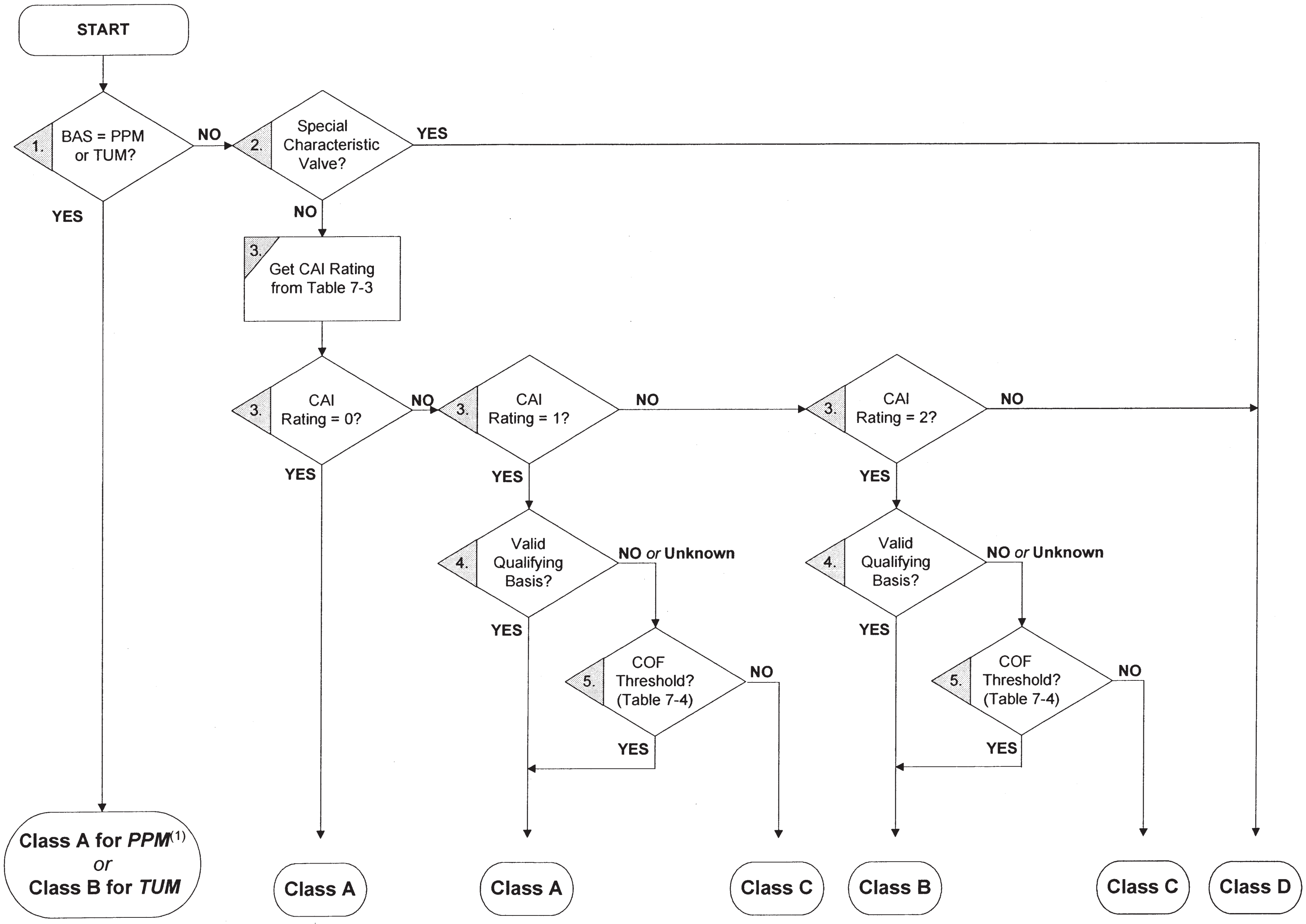


*Figure 7. **Guide Valve Factors for Gate Valves with 300 Series Stainless Steel Disk Guide Faces and Either 300 Series or 17-4 PH Stainless Steel Body Guide Faces***

Figure 8. Change in Disk-to-Seat Friction Coefficient vs. Initial Friction Coefficient for Valves with Self-mated Stellite Seats in Water





Note 1: PPM evaluations beyond the nominal applicability limits (i.e., "best available data") are considered Class B. See Gate Valve Method Step 1 for additional discussion.

Figure 9. Gate Valve Classification Flow Chart

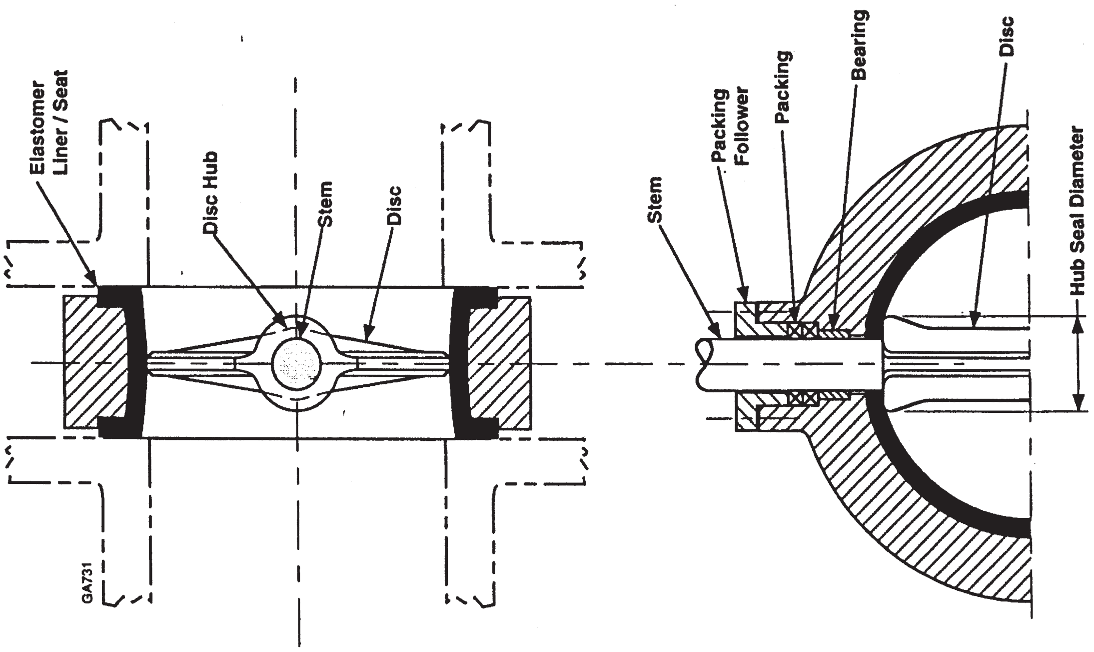


Figure 10. Typical Butterfly Valve (Symmetric Shaft Design)

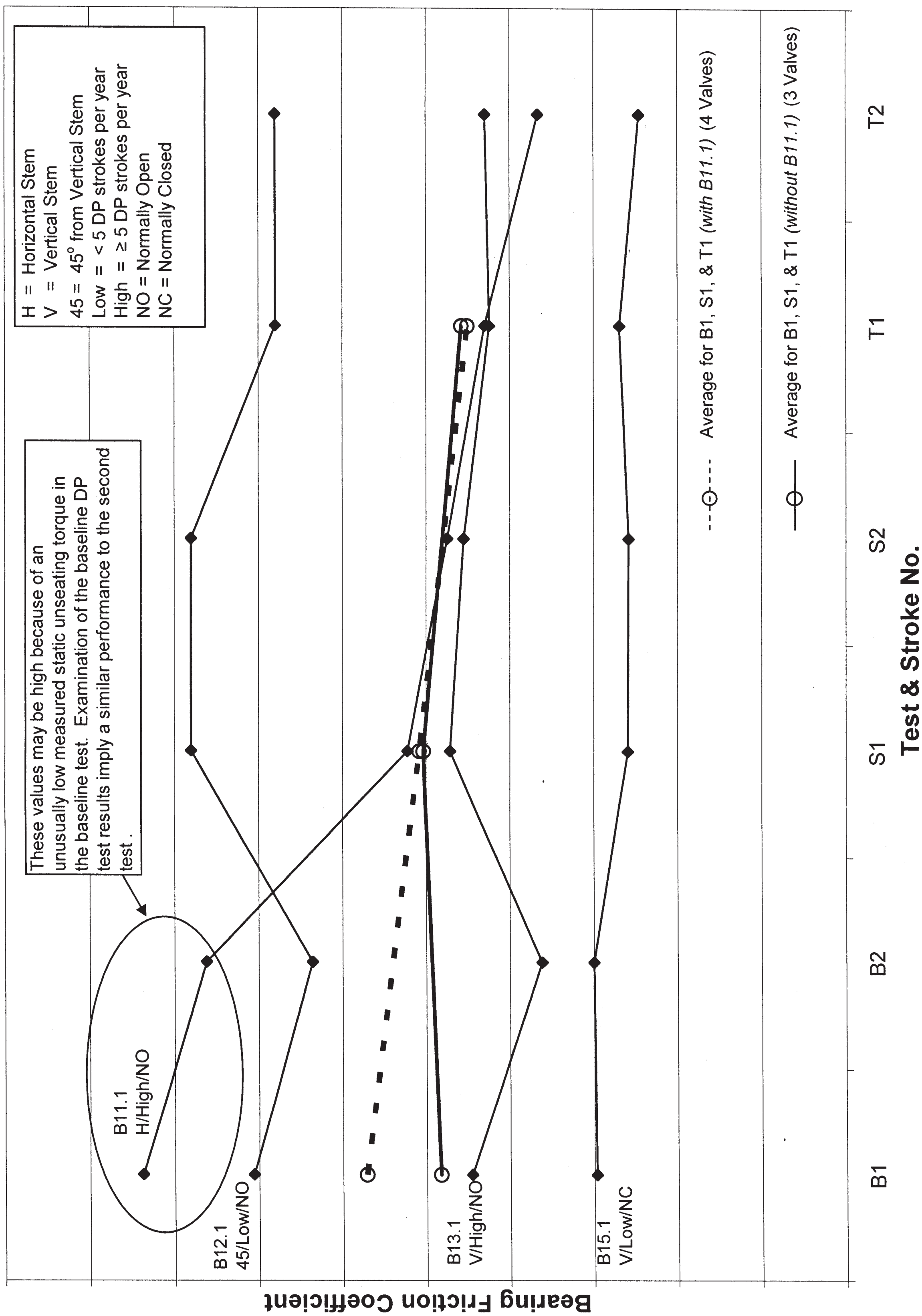
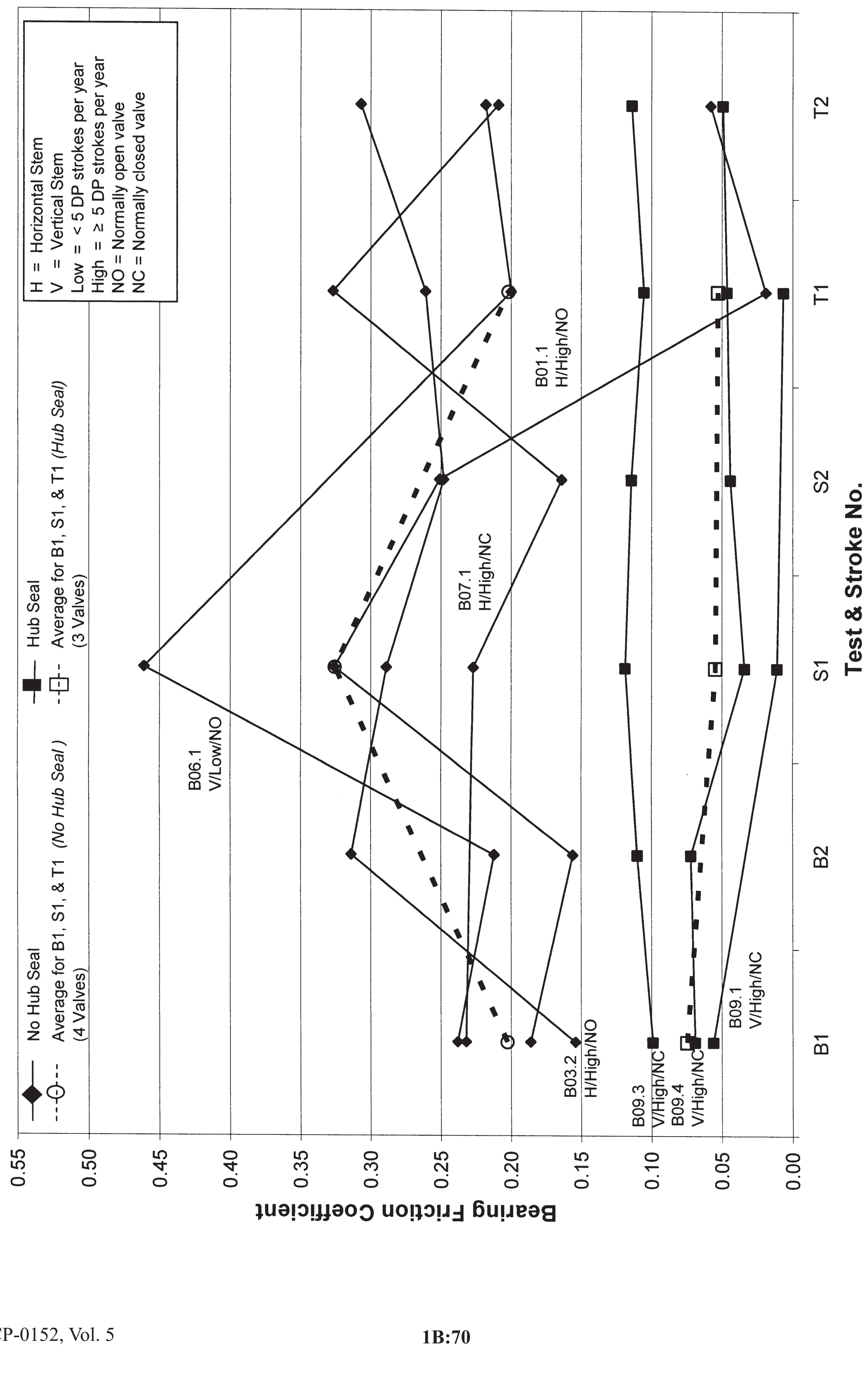


Figure 11. Bearing Friction Coefficient for Bronze Bearings in Treated Water Systems

Figure 12. Bearing Friction Coefficient for Bronze Bearings in Untreated Water Systems



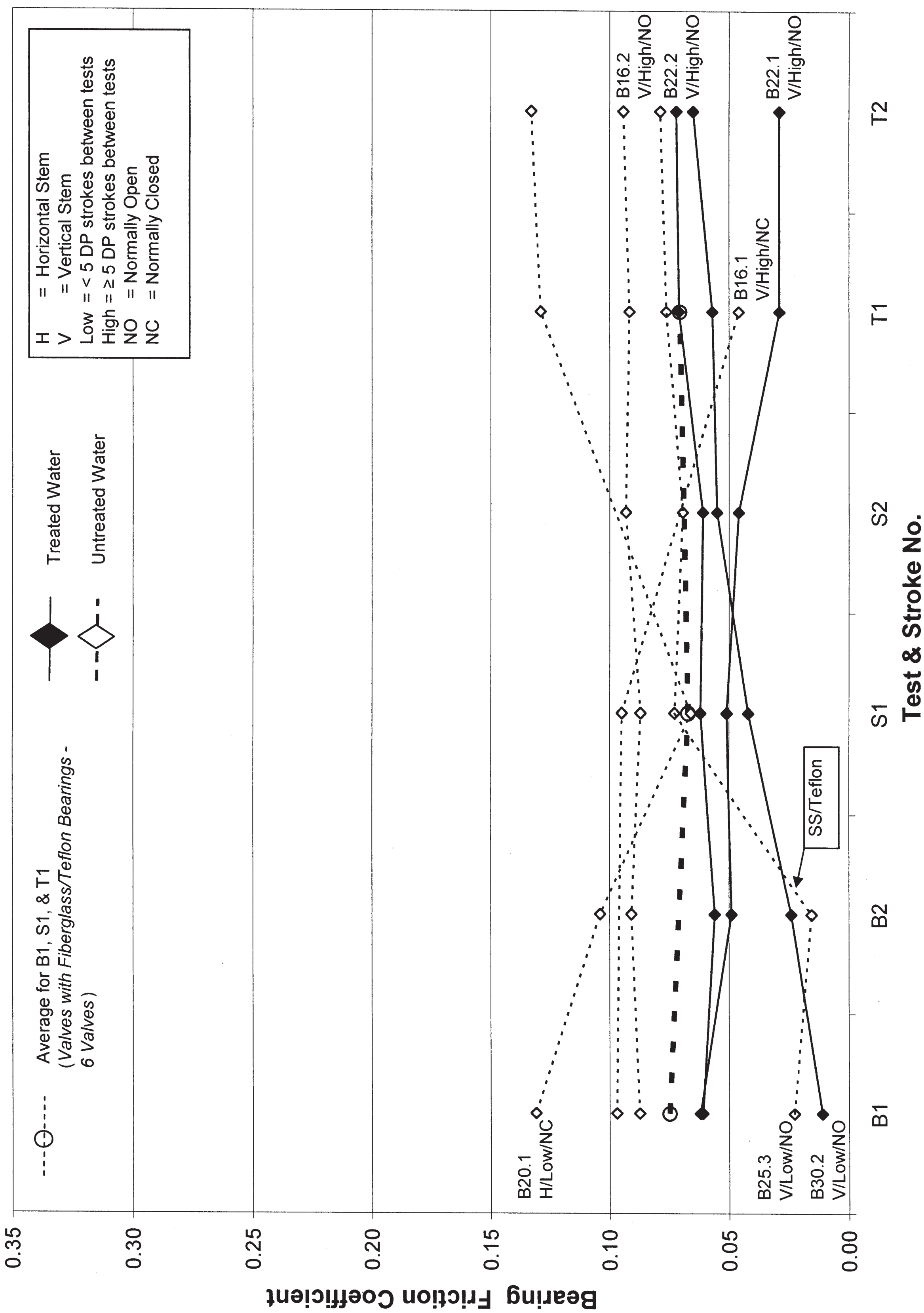
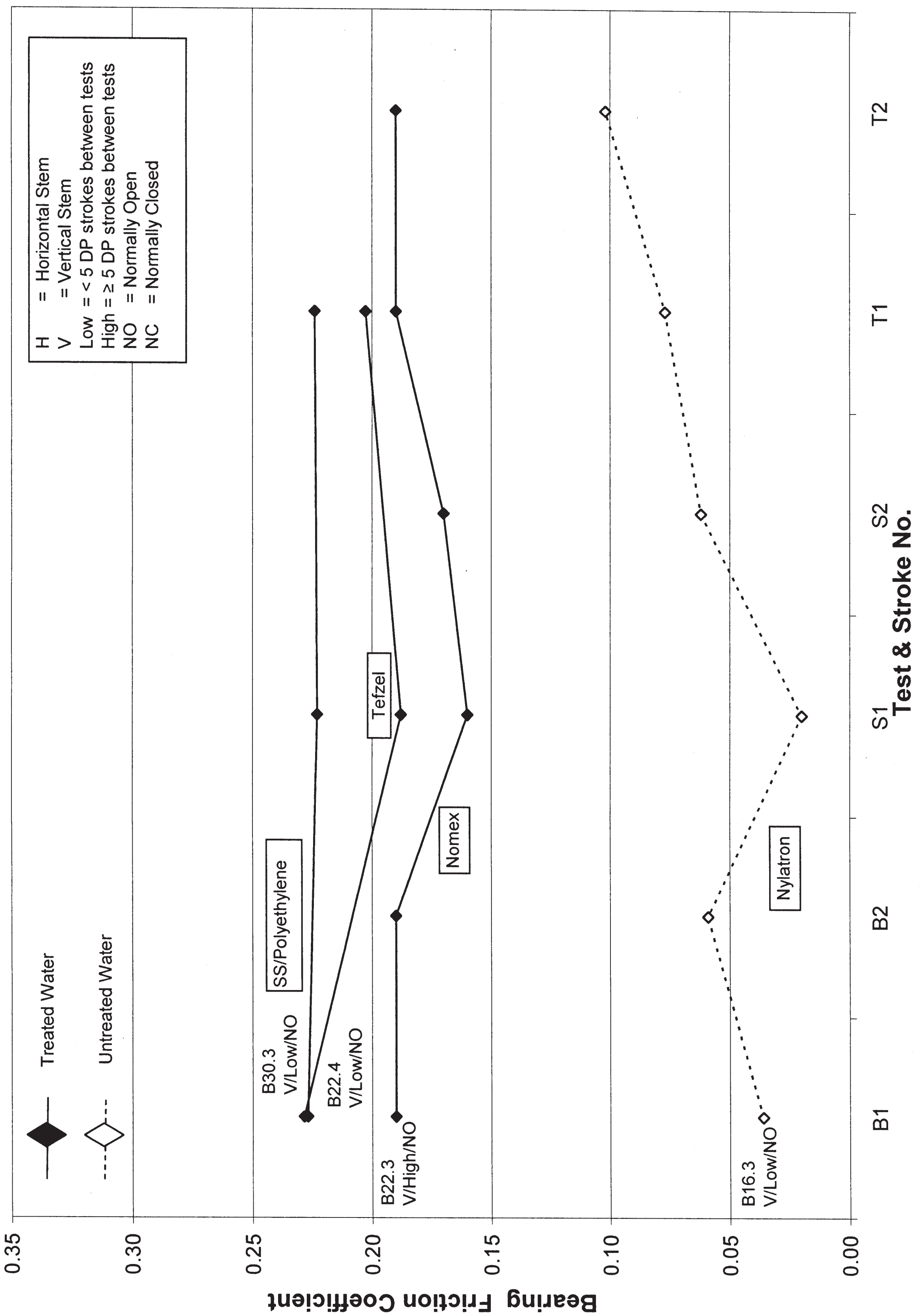
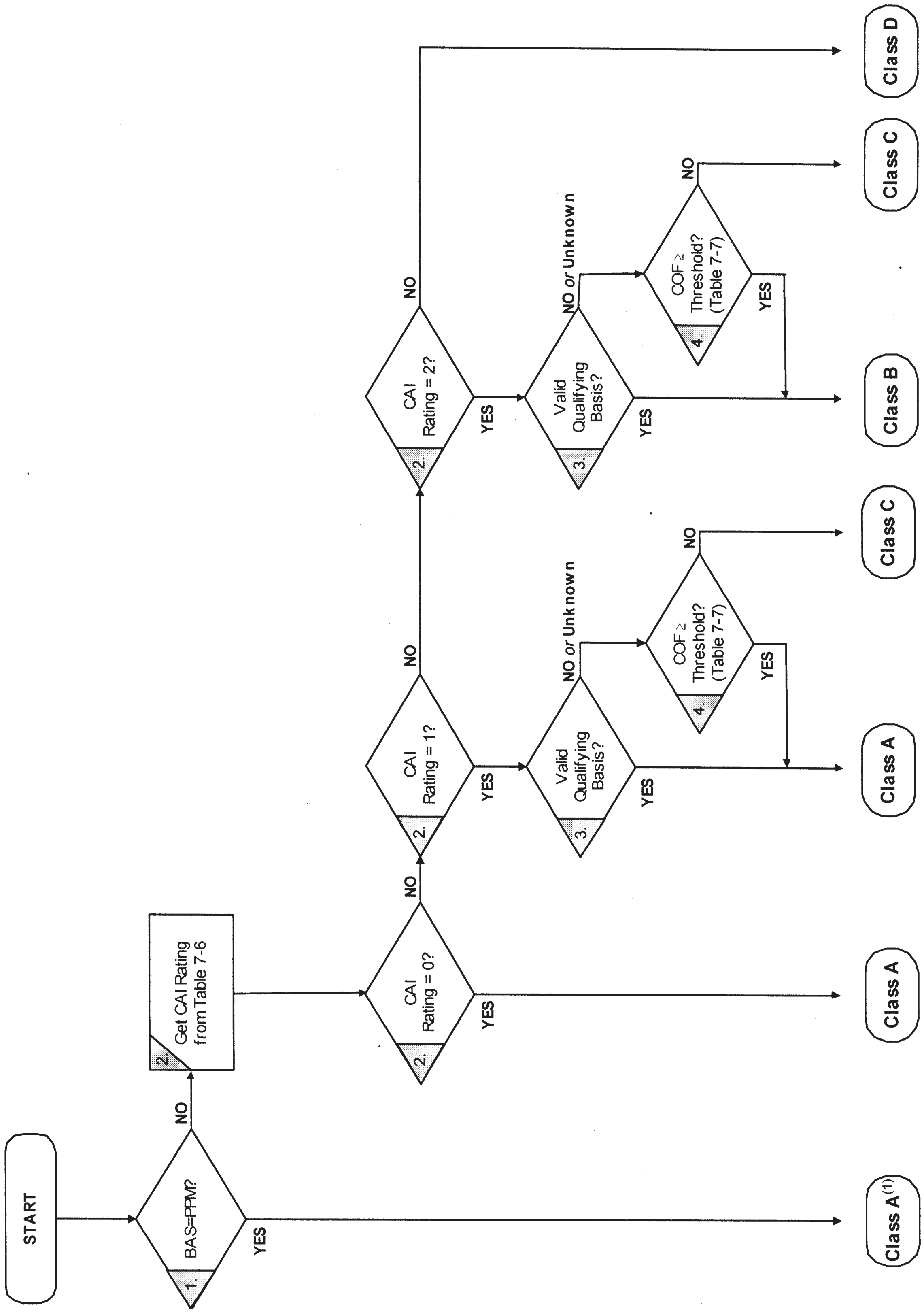


Figure 13. Bearing Friction Coefficient for Teflon-lined Bearings in Water Systems

*Figure 14. **Bearing Friction Coefficient for Non-metallic Bearings (other than Teflon) in Water Systems***





Note 1: PPM evaluations beyond the nominal applicability limits (i.e., "best available data") are considered Class B. See Butterfly Valve Method Step 1 for additional discussion.

Figure 15. Butterfly Valve Classification Flow Chart

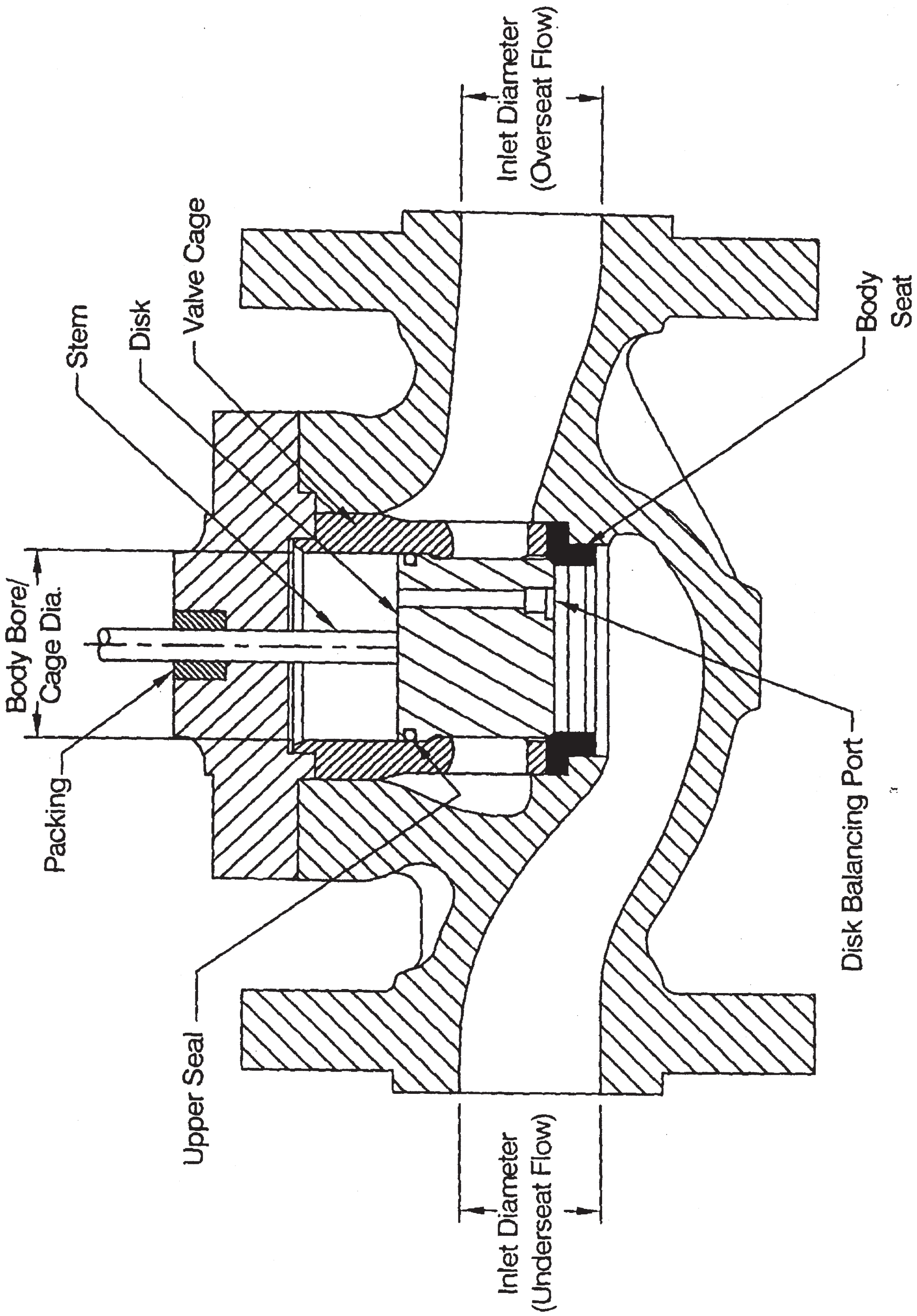


Figure 16. Typical Balanced Disk Globe Valve

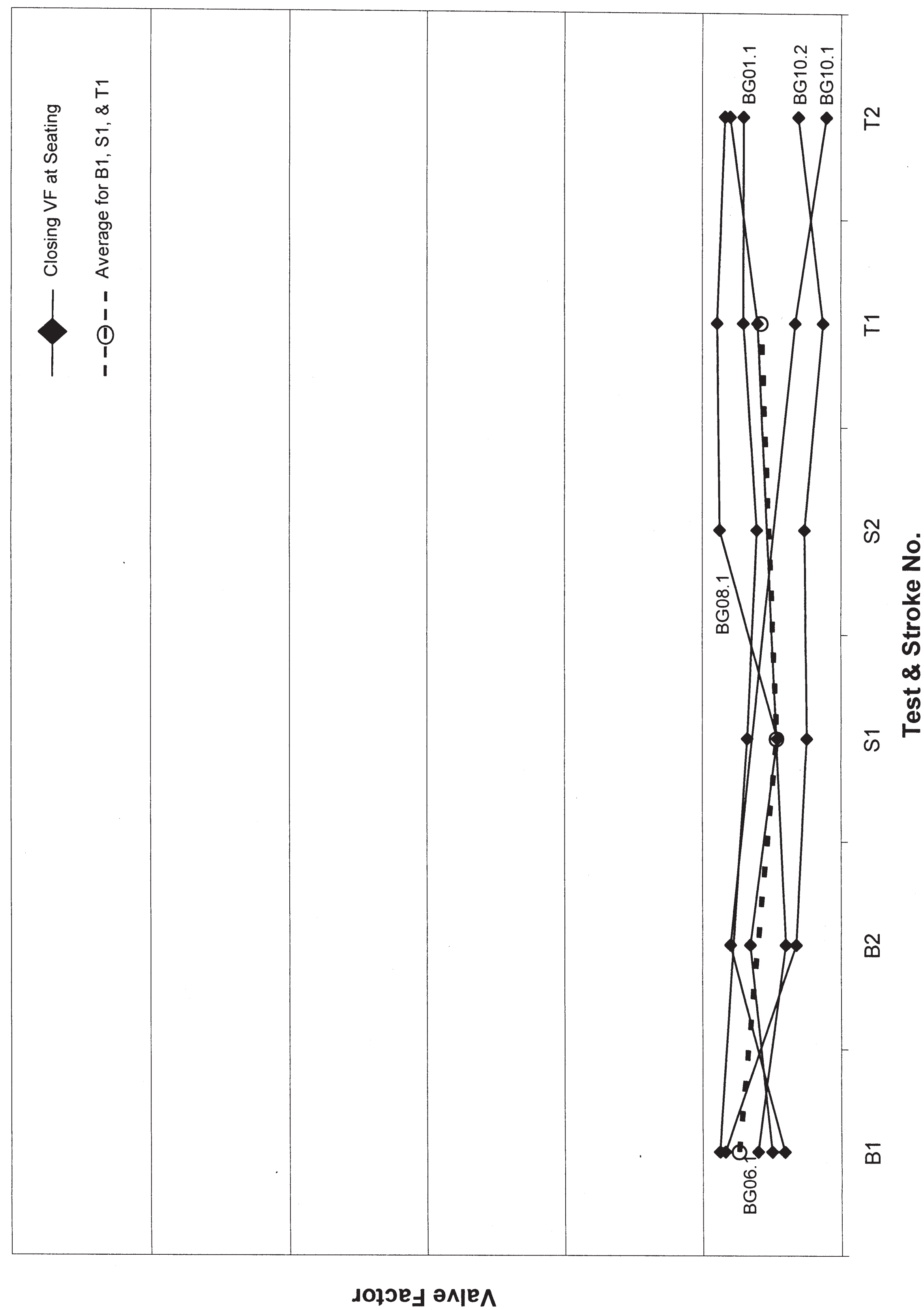
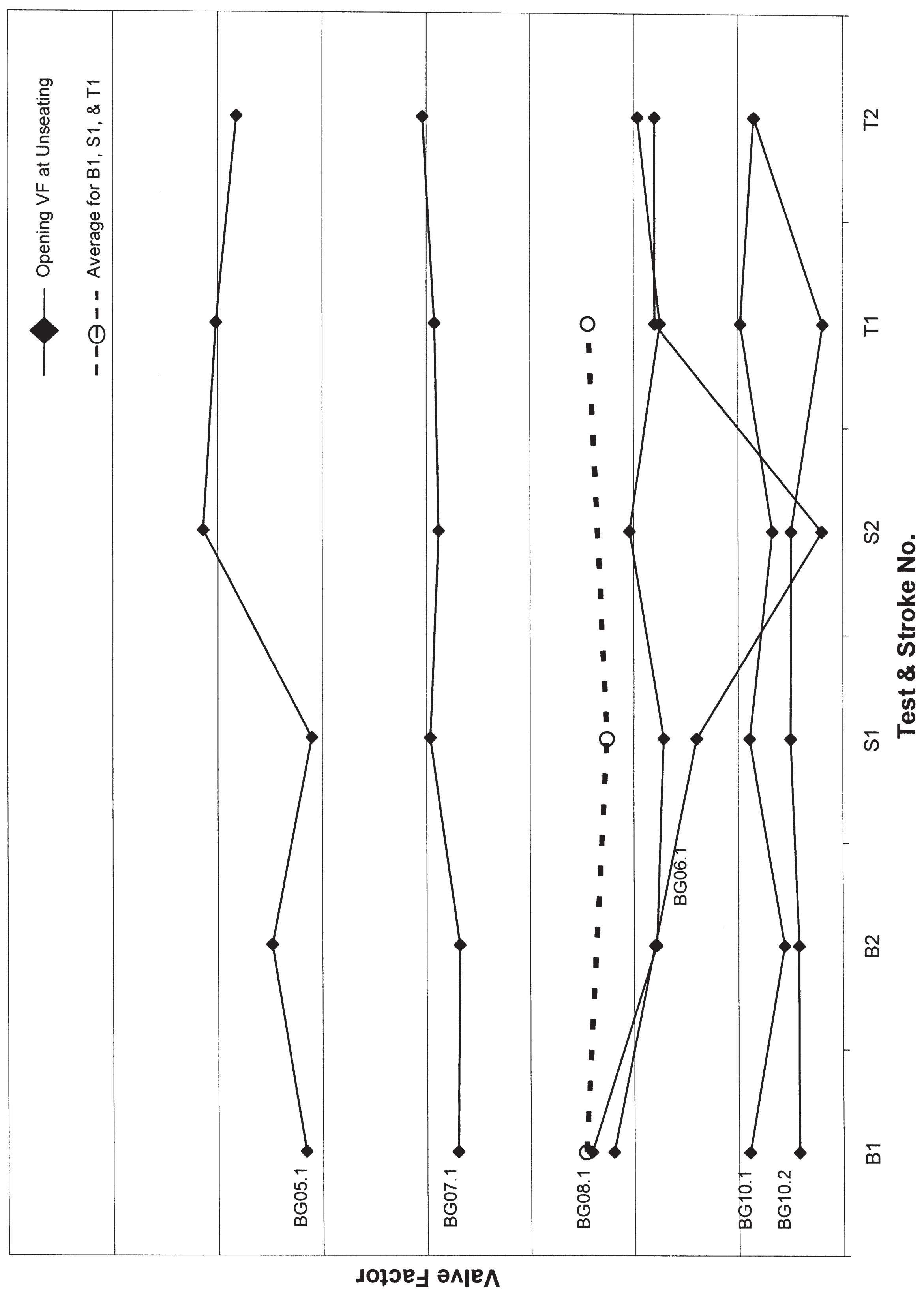
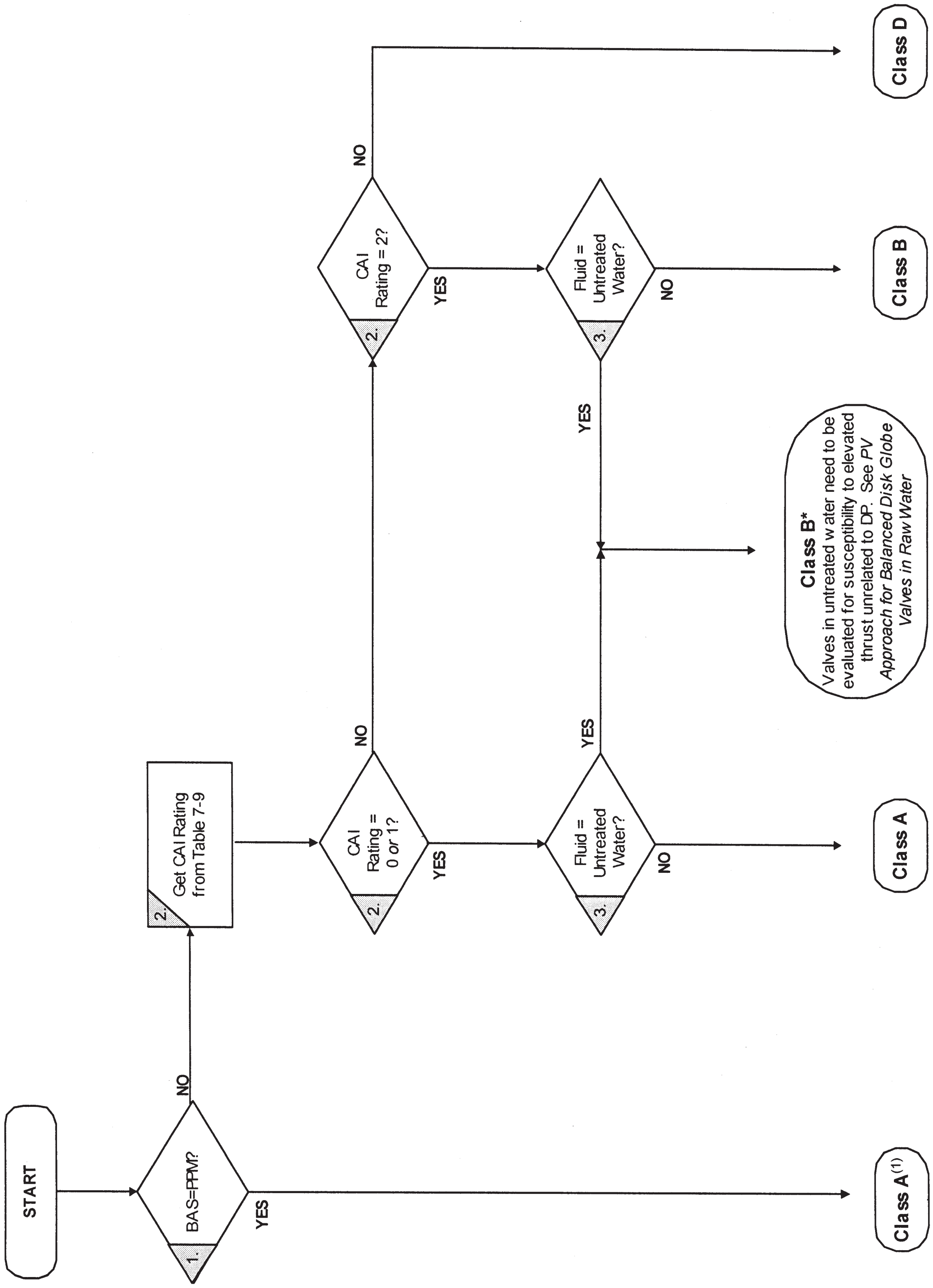


Figure 17. Valve Factors for Closing Strokes of Balanced Disk Globe Valves

Figure 18. Valve Factors for Opening Strokes of Balanced Disk Globe Valves





Note 1: PPM evaluations beyond the nominal applicability limits (i.e., "best available data") are considered Class B. See Balanced Globe Valve Method Step 1 for additional discussion.

Figure 19. Balanced Disk Globe Valve Classification Flow Chart

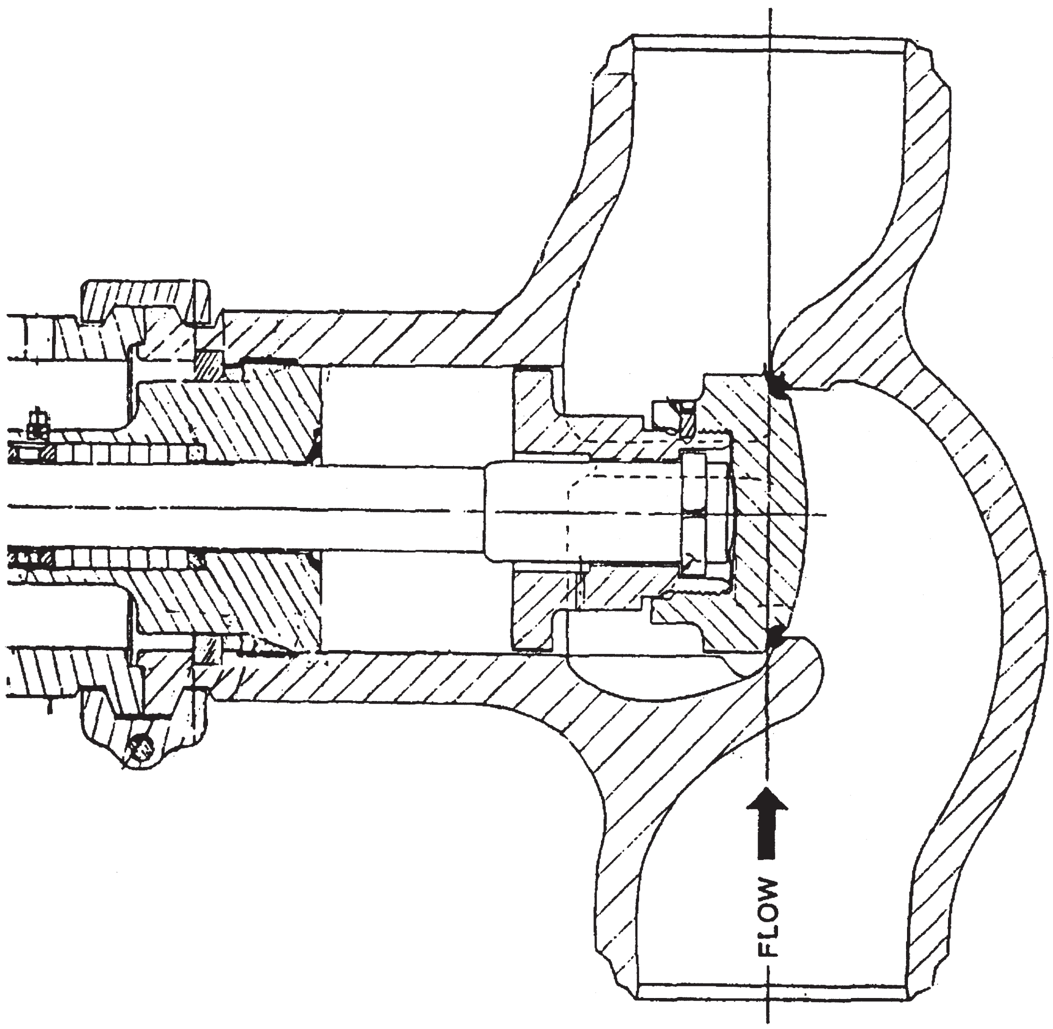


Figure 20. Typical Unbalanced Disk Globe Valve (Underseat Flow)

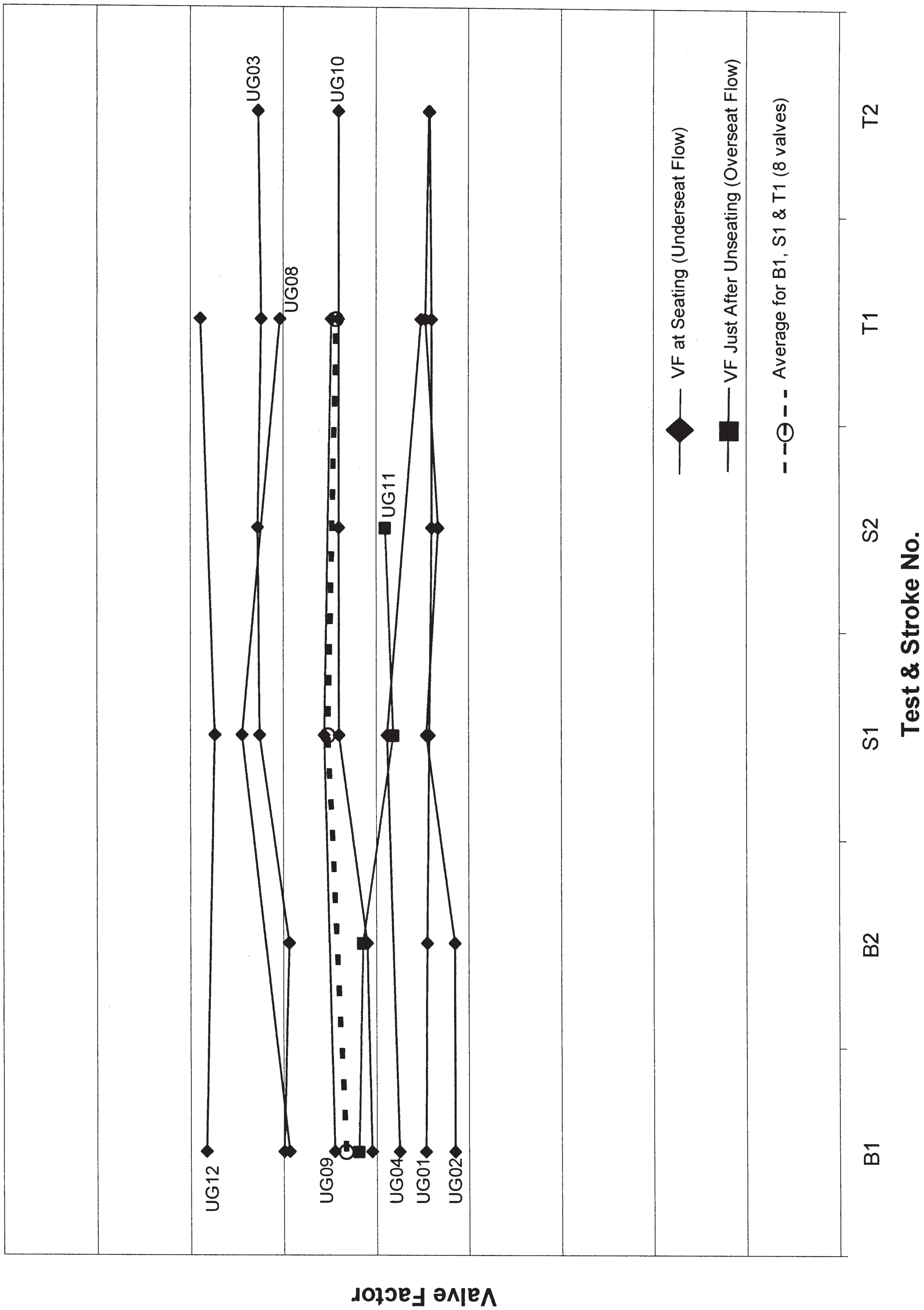
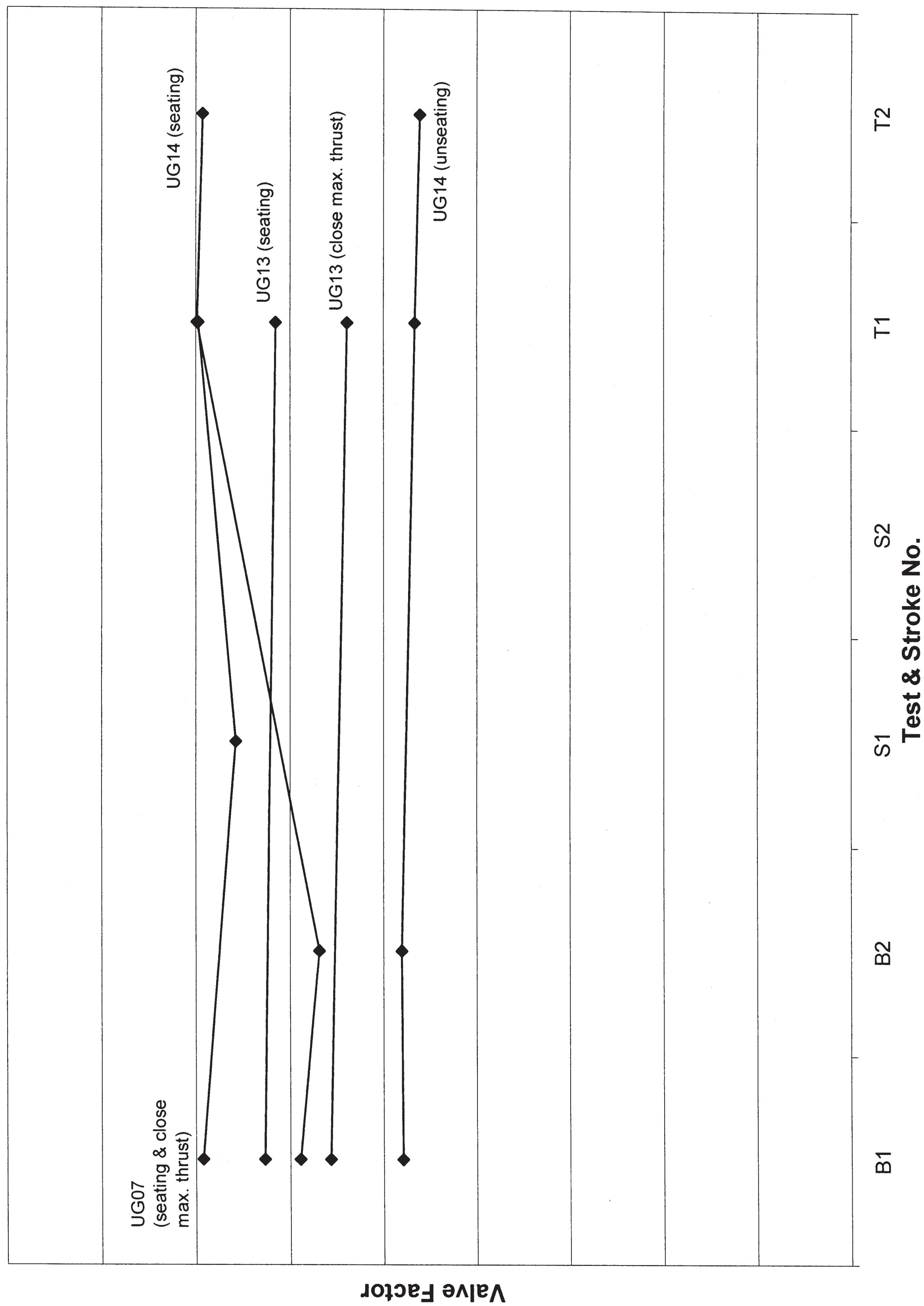
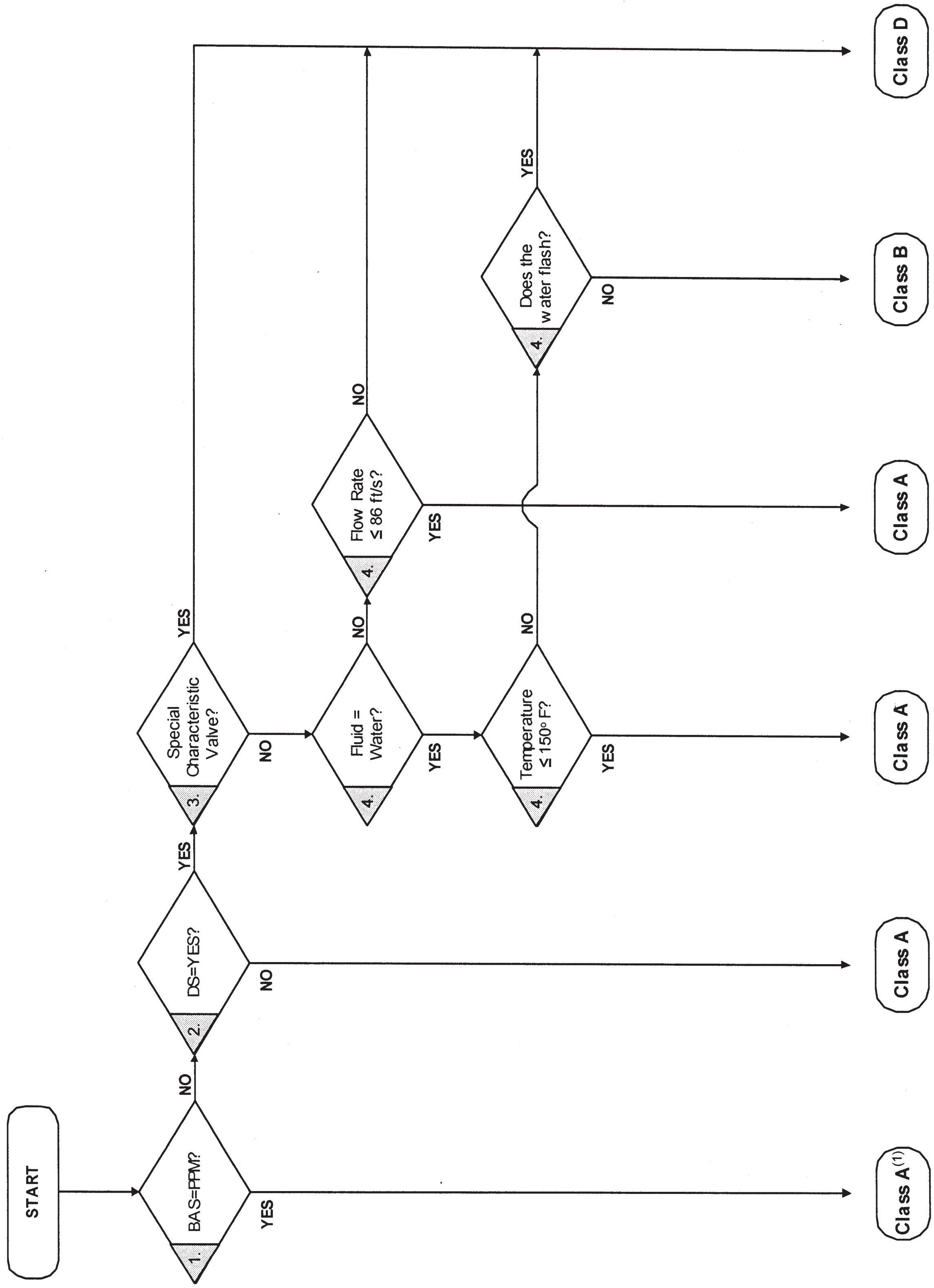


Figure 21. Valve Factors for Unbalanced Disk Globe Valves in Water Flow

Figure 22. Valve Factors for Unbalanced Disk Globe Valves in Steam Flow





Note 1: PPM evaluations beyond the nominal applicability limits (i.e., "best available data") are considered Class B. See Unbalanced Globe Valve Method Step 1 for additional discussion.

Figure 23. Unbalanced Disk Globe Valve Classification Flow Chart

EPRI MOV Stem Lubricant Test Program

Frictional Performance of Exxon Nebula and MOV Long Life in a Stem Lubrication Application

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ABSTRACT

This paper reports initial results of a program to assess the frictional performance of various lubricants in a motor-operated valve (MOV) stem lubrication application. The program will assess the effects of stem loading time-history and temperature on stem friction for a total of ten stem lubricants. Results for the first two lubricants tested (Exxon Nebula and MOV Long Life) are presented herein.

INTRODUCTION

Motor-Actuator Operation

Figure 1 shows the internal components in a typical motor-operated valve actuator. When the motor is activated, a motor pinion gear turns a splined shaft that turns a worm, rotating a worm gear that is keyed to a stem nut resulting in rotation of the nut. The actuator stem is driven up or down by the ACME threaded connection to the stem nut. The torque imparted to the stem by the stem nut is reacted below either by a torque reaction arm built into the valve or by the disk within the valve against the valve seats. As more torque is produced (due to resistance of linear motion occurring in the valve) the worm is driven to the right compressing the spring pack (a series of Belleville washers). When a pre-selected displacement of the spring pack is reached, the torque switch is tripped deactivating the motor. The stem/stem-nut connection converts rotational motion to linear motion or torque to thrust. The friction coefficient at the stem/stem-nut interface is a critical factor in determining the efficiency with which torque is converted to thrust and therefore the thrust that can be produced for a given torque switch setting.

Ambient Temperature Effects

Over the past 14 years, the Electric Power Research Institute (EPRI) and the industry have conducted testing to determine the MOV actuator stem/stem-nut coefficient of friction (COF) and changes in stem friction with loading condition (rate-of-loading) for several stem lubricants and stem/stem-nut configurations. All safety-related MOVs are currently setup based on stem friction coefficients measured in these tests. These data were generally obtained at room temperature conditions. Recent testing sponsored by the U.S. Nuclear Regulatory Commission (NRC) Office of Nuclear Regulatory Research and conducted by the Idaho National Engineering and Environmental Laboratory (INEEL) (References 1 and 2) has shown that for some lubricants, dynamic stem friction coefficients can increase with temperature (20-30% increase in friction with a temperature increase from 21 to 121 degrees C (70 to 250 F). Such an increase in stem friction coefficient would result in a proportionate reduction in the thrust output of MOV actuators (under dynamic loading) at their current control (torque) switch settings.

A review of the INEEL test program completed by EPRI concludes that the testing was conducted using sound testing methods and that the results are accurate for the conditions tested. However, the review also concludes that direct application of the results to industry valves may be difficult for a variety of reasons. Examples include: repeatable performance was not always established prior to varying test parameters, the stem remained in compression at all times unlike many valves that unload (redistributing the grease at the stem/stem-nut interface) during opening strokes, and all tests were conducted under simulated DP loading conditions with no intervening static strokes that would also tend to redistribute the grease. The EPRI review recommends a more comprehensive test program to assess potential temperature effects on stem to stem-nut friction that addresses the issues discussed above.

Stem Loading Effects

In addition, Exxon Nebula grease that is used extensively as a stem-to-stem nut lubricant is no longer being produced. As the current stem friction and rate-of-loading specifications for many plants with this lubricant are based on extensive plant unique tests, moving to a new lubricant may require a reassessment of stem friction and rate-of-loading effects for such plants. A new lubricant (MOV Long Life) has been approved for use as a gearbox grease replacement for Nebula and appears to be an excellent candidate for a replacement for Nebula as a stem lubricant. Data are needed to assist utilities in justifying the switch from Nebula to MOV Long

Life as a stem lubricant without additional plant unique testing to reestablish their stem friction and rate-of-loading specifications.

Rate-of-Loading is defined as the percentage reduction in actuator output thrust at torque switch trip (TST) on a closure stroke, between a static (no differential pressure on valve disk) and a dynamic (flow and differential pressure on valve disk) condition. Research conducted in the mid 1990s determined that the rate-of-loading phenomenon is caused by a squeeze film effect at the stem/stem-nut thread interface. During a dynamic closure stroke, the loading on the valve and resulting thread contact stress increases gradually, and the grease at the stem/stem-nut interface is slowly squeezed out of the threads resulting in most of the stroke occurring with metal-to-metal contact or in a boundary lubrication condition. The resulting friction coefficient is generally in the 0.1 to 0.15 range. In contrast, during a static closure stroke, the threads are relatively lightly loaded for all but the last 100 milliseconds (ms) of the stroke when the valve disk reaches the seat. At this point the load increases very quickly to the point when the torque switch trips. In this very short seating period, the grease has insufficient time to fully squeeze out of the thread interface resulting in a momentary hydrodynamic lubrication condition. This can result in friction coefficients in the 0.03-0.07 range. This reduction in friction coefficient in the static test results in more thrust being produced at torque switch trip (TST) during a static closure stroke than in a dynamic stroke. In addition, during a dynamic stroke, the friction coefficient just prior to seating can be somewhat higher than at torque switch trip. This additional effect is accounted for by the addition of margin in torque switch set-up values.

Utilities utilize diagnostic equipment to measure the thrust output of the actuator at TST. The torque switch is set to obtain the required thrust at TST during a static test (when the stem friction coefficient can be reduced due to rate-of-loading). Many utilities have conducted extensive static and dynamic tests on the same valves to develop a statistical specification that conservatively defines the plant rate-of-loading effect for their valve population. This effect must be accounted for when defining the required thrust at TST.

The magnitude of the rate-of-loading effect can be affected by several factors including stem and stem nut fit up, surface roughness, and geometry and type of lubricant. Current rate-of-loading specifications account for all factors listed above except switching to a new lubricant.

Accordingly, data are needed to establish the effect of temperature on the dynamic (boundary lubrication) stem friction coefficient for stem lubricants currently in use (including MOV Long Life). In addition, data are needed to assess potential differences in room temperature rate-of-loading effects between Exxon Nebula and MOV Long Life.

TEST SYSTEM DESCRIPTION

An actuator test fixture has been designed (see Figures 2 and 3) to allow time-dependent loading of the stem during operation simulating both static and dynamic conditions at a variety of stem/stem-nut grease temperatures. The test fixture is located at EPRI's Charlotte facility. Many components of the test fixture are the same as those used in the rate-of-loading research program conducted on behalf of EPRI by Battelle Columbus in the early 1990s. The test stand includes a new surplus Limitorque actuator (SMB-0, 25 horsepower (HP), 230/460 volts-alternating current (VAC) motor) with MOV LongLife Grade 1 grease in the gearbox and Mobil grease 28 in the limit switch compartment. The actuator gear ratio is chosen to provide a stem speed ranging from 31.75 to 63.5 centimeters per minute (cm/min) (12.5 to 25 inches per minute) depending on the lead of the stem tested. The test stand allows application of a time dependent load history simulating both dynamic and static strokes in both the opening and closing directions, i.e., the stem will go from compression to tension as stroke direction is reversed.

The actuator stem is driven up or down by the rotation of the stem nut within the actuator. The lower end of the stem is threaded and keyed into an adaptor hub. The adapter hub is bolted to an anti-rotation device that has two arms with roller bearings at each end. The stem torque is reacted by machined faced bar stock beams attached to a simulated valve yoke assembly.

Four stop beams are bolted to the bottom of the anti-rotation device. During actuator closure strokes, the lower two beams contact stops bolted to the base plate. Contact with the base plate stops simulates gate or globe valve hard seat contact. After contact with the base plate stops, the thrust load increases rapidly until the torque switch trips deactivating the actuator.

Passive Hydraulic System

The purpose of the hydraulic cylinder is to provide resistance to motion of the actuator stem simulating loading that may occur during valve operation under either static (no flow or differential pressure) or dynamic (flow and differential pressure) conditions. In the original rate-of-loading test program conducted by Battelle, hydraulic pressure to drive the cylinder was provided by a hydraulic pump and associated control system. In the new design, no hydraulic pump will be required. Resistance to motor actuator stem motion will be produced by controlling the flow of fluid from one side of the piston to the other using a rectifier block and a proportional relief valve.

The passive hydraulic system is employed to simulate valve operation. The entire system is pressurized to 1.38 MegaPascals (200 pounds per square inch gage (psig)) to ensure that hydraulic fluid does not cavitate in low-pressure portions of the circuit. Figure 4 shows operation of the hydraulic system simulating valve-closing operation. As the actuator moves the stem, the hydraulic fluid is pushed from the left side of the cylinder into the rectifier block. The check valves within the block direct the fluid upward and out of the block at the top where it passes through a filter and into a proportional relief valve. The relief valve flow is controlled by a signal from the data acquisition computer. The relief valve limits the flow; thereby, building pressure on the left side of the cylinder to resist motion of the actuator. The system can provide constant low loads (simulating packing load) as low as 4448.2 Newtons (1000 lbs) and time-varying loading up to 146,790 Newtons (33,000 lbs). A cylinder by-pass loop with a manual valve is included to allow development of very low packing loads as required. The flow exits the relief valve at a low pressure and enters a water-cooled heat exchanger, and then enters the right side of the cylinder. Experience in use of the system indicates that minimal heating of the hydraulic fluid occurs obviating the need for active cooling.

The system includes high and low pressure side gages, a hydraulic fluid thermometer, and an accumulator to ensure that the system operates at a constant backpressure regardless of fluid temperature increases and/or fluid seepage.

Applying a voltage from 0 to 10 volts DC to the valve's control amplifier can vary the relief pressure of the proportional relief valve. The amplifier then converts the control signal to a pulse width modulated current that drives the solenoid to the desired position. The signal to control the relief valve position is programmed by the operator using the Labview program developed to support the test program.

The system has a pressure capability of 15,569 MegaPascals (3500 psi). In operation, the system pressure does not exceed 8896.4 MegaPascals (2000 psi).

Stem Heating System

A 20.32 cm (8 inch) long cartridge heater is inserted into a hole drilled down each stem centerline and is used to heat the area of the stem nut and grease for the elevated temperature tests. The heater is controlled in closed loop using a type K thermocouple spot welded to each stem just below the bottom of the stem nut when the stem is in the up (retracted) position. The thermocouple provides feedback to a solid-state temperature controller that brings the stem to the programmed temperature without overshoot. Differences in temperature between the thermocouple location and the middle of the stem nut (highest temperature region) are accounted for in setting the target stem temperature. A separate effects test was conducted to establish such temperature differences at each of the temperature levels to be tested. The stem temperature was stabilized to the target temperature to within +/- 2.8 degrees C (5 degrees F) for 15 minutes.

INSTRUMENTATION AND DATA ACQUISITION

The actuator and test system are instrumented to allow measurement of actuator output thrust and torque, cylinder stem position (same as actuator stem position), stem temperature in the area of the stem nut, torque switch activation, and spring pack displacement. All measurements will be recorded using a high-speed data acquisition system except for stem temperature. Stem temperature measurements will be made and recorded manually. Table 1 lists the instrumentation and data acquisition rates for each measurement.

Thrust and Torque

Thrust and torque are measured using a Crane Torque Thrust Cell (TTC). Two Vishay 2311 Signal Conditioning Amplifiers are used to provide excitation voltage and amplify torque and thrust signals. Once amplified, the thrust and torque signals are routed to a BNC Connection box and then cabled to a National Instruments 6036E Multifunction DAQ Card. This card interfaces with the PC and Labview Software. Labview software is used to acquire and analyze the data as well as send the control voltage to the proportional relief valve.

Torque Switch Trip

A key measurement is the time of torque switch trip. This is the reference point for comparing the rate-of-loading characteristics of the stem/stem-nut. Torque switch trip is not the point at which the actuator stops putting out torque and thrust. It is the point (time) at which the current to the switch is lost (indicating that the selected spring pack displacement has been reached and the torque switch has opened) and the relay it holds closed begins to open. Once that relay has opened, additional time passes before the contactors "drop out" de-energizing the motor. Even then, the actuator continues to generate output torque and thrust due the inertia of the motor and gearing within the actuator until the disk finally comes to a stop against the seats (or, in this case, against the stops). This results in a measurable increase in output thrust and torque after the torque switch has opened. Such increases in the thrust/torque need to be considered in evaluating the structural capability of the actuator, valves and, in our case, test system. However, it is not relevant to the rate-of-loading phenomenon that relates only to the thrust and torque output at the moment of torque switch trip. Accordingly, a method is needed to precisely determine the moment when the torque switch actually opens.

A custom torque switch trip circuit was designed by Battelle in the original test program and is being implemented in this program as well. The circuit generates a TTL signal (Transistor-Transistor Logic step change in voltage) at the initiation of the opening of the torque switch contacts. The circuit generates and latches (holds) the signal when the frequency of the electric motor-starter holding coil current changes from 60 hertz (Hz). The input to the circuit is from a current probe hooked around a loop of 10 coils of wire connected to the torque switch close terminal.

TEST MATRIX

Data are recorded only during closure strokes. In addition, data are recorded on static closure strokes only under room temperature conditions. The opening strokes are conducted only for the purpose of repositioning the stem to the open position and redistributing the grease at the stem/stem-nut interface. Opening strokes do not involve torque switch trip (the actuator is limit controlled in the opening direction) and, therefore, provide no meaningful quantitative information with regard to the rate-of-loading (ROL) phenomenon. Further, data need not be collected for elevated temperature static closure tests as all in-plant diagnostic testing used to set torque switches is conducted at room temperature.

Each stem-lubricant combination undergoes a test sequence involving 99 total strokes. Data are recorded for 30 closure strokes, and 25 dynamic and 5 static strokes. Each test sequence includes confirmation of stability in the thrust at torque switch trip followed by a set of 5 static and 5 dynamic closure strokes conducted at room temperature to assess rate-of-loading effects. These tests are followed by 5 dynamic closure strokes at nominal temperatures of 130, 190, 250 and 70 degrees F. Low load static strokes are conducted between dynamic strokes to reposition the stem and redistribute the lubricant. Each lubricant is tested on three stems (A, G and I) as detailed in Table 2.

RESULTS

Rate-of-loading

Figure 5 compares the observed rate-of-loading performance of each stem for each lubricant tested. Each column shown in Figure 5 represents the average rate-of-loading for the 5 sets of static and dynamic tests conducted on each stem-lubricant combination. All data shown are for room temperature conditions.

The rate-of-loading percentages shown are computed using the following equation:

ROL % = (Thrust at TST Static –Thrust at TST Dynamic) X 100 / Thrust at TST Dynamic

Stem A and Stem I exhibited significant ROL, while Stem I showed minimal ROL.

With the exception of the data labeled Nebula *, no significant differences in rate-of-loading performance were observed between MOV Long Life and Nebula. The first test series conducted on Stem A using Nebula resulted in the data represented by the column labeled Nebula *. As these data were not consistent with the data obtained from the other two stems, this series was repeated. The data from the repeat series was consistent with the performance observed on the other stems.

Effect of Stem Temperature

Each lubricant (Nebula and MOV Long Life) was tested on three stems (A, G and I) at four nominal temperature levels (70, 130, 190 and 250 degrees F). Five dynamic tests were performed at each temperature level with intervening static strokes conducted between dynamic strokes. The stem coefficient of friction was calculated for each stroke using the corrected thrust and torque and appropriate stem dimensional information in the following equation:

$$\text{Stem COF} = (0.96815 * d * (24 * 3.14 * SF - L)) / (24 * SF * L + 3.14 * d^2)$$

Where:

d = Pitch Diameter = Stem O. D. – ½ * Pitch (inches)

SF = Absolute value of the Stem Factor = Corrected Torque (Ft-lbs)/Corrected Thrust (lbs)

L = Stem Thread Lead (inches)

The grease on the stem in the area of the stem nut was heated using a cartridge heater inserted into a hole drilled down the stem centerline to a point coincident with the stem nut location when the stem is in the up (retracted) position. All heating is conducted with the stem in this retracted position.

The test system was capable of heating Stems A and G to 121 C (250 F) but was only able to reach a peak stem temperature of 113 C (235 F) for Stem I. This still allowed adequate definition of the effect of grease temperature on stem coefficient of friction.

Figure 6 shows the effect of stem temperature on dynamic friction for Nebula for each of the three stems tested. Each data point represents the average of the 5 COF values obtained in the 5 tests conducted at each temperature. Each COF value is the maximum recorded during the last second prior to hard seat contact during dynamic closure strokes. The stem thread pressure during this portion of the stroke is approximately 110 MegaPascals (16,000) psi. Stem thread pressure is calculated assuming that the entire thrust is being applied to a single thread.

As shown in Figure 6, minimal change (of the order of 5 %) in stem COF is evident for Stems I and G. Stem A shows a more significant increase (of the order of 20 %) in COF from 21 to 121 degrees C (70 to 250 degrees F).

Figure 7 shows the effect of temperature on stem coefficient of friction for MOV Long Life on each of the three stems tested. Increasing the stem temperature from 21 to 121 degrees C (70 to 250 degrees F) resulted in increases in stem COF ranging from 13 to 26 % depending on the stem tested.

Figures 8 through 10 compare temperature effects for Nebula and MOV Long Life exhibited on stems A, G and I, respectively. The most significant temperature effects were for Stem A and Stem I. Stem G consistently exhibited lower temperature effects for both lubricants. The effect of temperature on stem friction is slightly greater for MOV Long Life compared to that for Nebula for the stems tested.

The stem coefficient of friction returned close to, and in many cases lower than, its original room temperature value after the stem was cooled back to room temperature.

On two tests, the torque switch tripped prior to the stem reaching the hard stop. These were tests on Stem I, MOV Long Life at temperatures of 88 and 113 degrees C (190 and 235 degrees F), respectively. Stem I exhibited consistently high COFs for both lubricants tested.

CONCLUSIONS

The objectives of this phase of the project are to:

1. Compare the rate-of-loading performance of Nebula EP-1 and MOV Long Life, and
2. Assess the effect of temperature on the dynamic coefficient of friction at the stem/stem-nut interface for Nebula and MOV Long Life.

With regard to the first objective, these tests show no significant difference in rate-of-loading performance between Nebula and MOV Long Life.

With regard to the second objective, the results for these tests indicate some increase in stem friction coefficient for both Nebula and MOV Long life with MOV Long life exhibiting a somewhat greater effect than Nebula. Previous testing by INEEL (References 1 and 2) on different stems showed minimal effects of temperature on stem friction for these lubricants. It is concluded that temperature effects on stem friction can occur for these lubricants and that the magnitude of such effects is stem dependent.

REFERENCES

1. K.G. DeWall, et al, “Performance of MOV Stem Lubricants at Elevated Temperature,” NUREG/CR-6750, October 2001.

2. K.G. DeWall, et al, “MOV Stem Lubricant Aging Research,” NUREG/CR 6806, March 2003.

Table 1

Test System Instrumentation

Measurement	Transducer Selected	Full Scale Calibrated Range	Transducer Accuracy	Data Acquisition Rate
Stem Torque	Crane TTC RC	+/- 1170 ft-lbs	+/- (2% of Reading + 0.5% Full Scale)	1000 samples/sec
Stem Thrust	Crane TTC RC	+/- 40,000 lbs	+/- (1% of Reading + 0.5% FS)	1000 samples/sec
Stem Temperature	Fluke Model 52 Thermometer	-328 to +2501 Deg F	+/- 0.05% of Reading + 0.5 Deg F	N/A-Manual recording
Stem Position	MTS Temposonics APM	0-6 inches	+/- 0.05% FS	1000 samples/sec
Torque Switch Current	Fluke Clamp-on Probe	N/A - Used for timing only.	N/A	1000 samples/sec
Limit Switch Current	Fluke Clamp-on Probe	N/A - Used for timing only.	N/A	1000 samples/sec
Torque Switch activation	Fluke Current Sensor/ TST Circuit	N/A - Used for timing only.	N/A	1000 samples/sec

Table 2

Stems and Stem-Nuts Tested

Stem	Stem Geometry (inches)	Stem Material	Stem Nut Threaded Length (inches)	Stem Velocity (inches/min)	Rate of load increase after hard seat contact (lbs/sec)
A	2 x ¼ x ½	17-4 Ph	3.88	25.0	185,000
G	2 x ¼ x ½	410 SS	3.25	25.0	185,000
I	1.75 x ¼ x ¼	17-4 PH	6.00	12.5	108,800

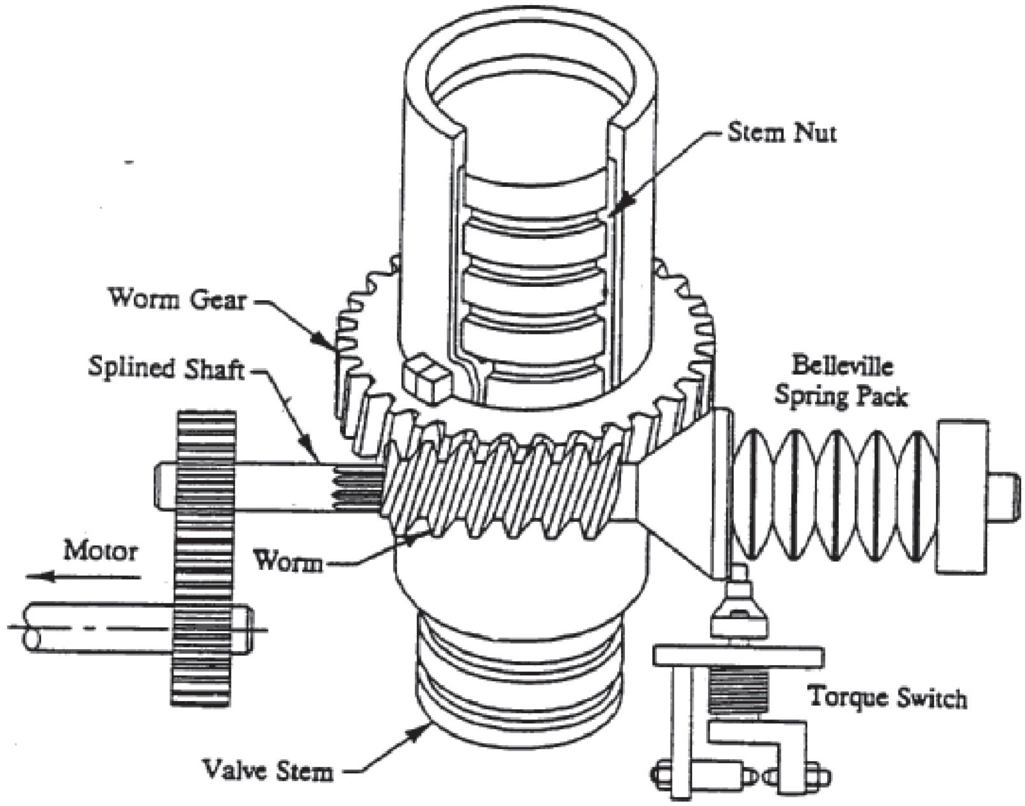

Figure 1 Motor-Actuator Drive Train

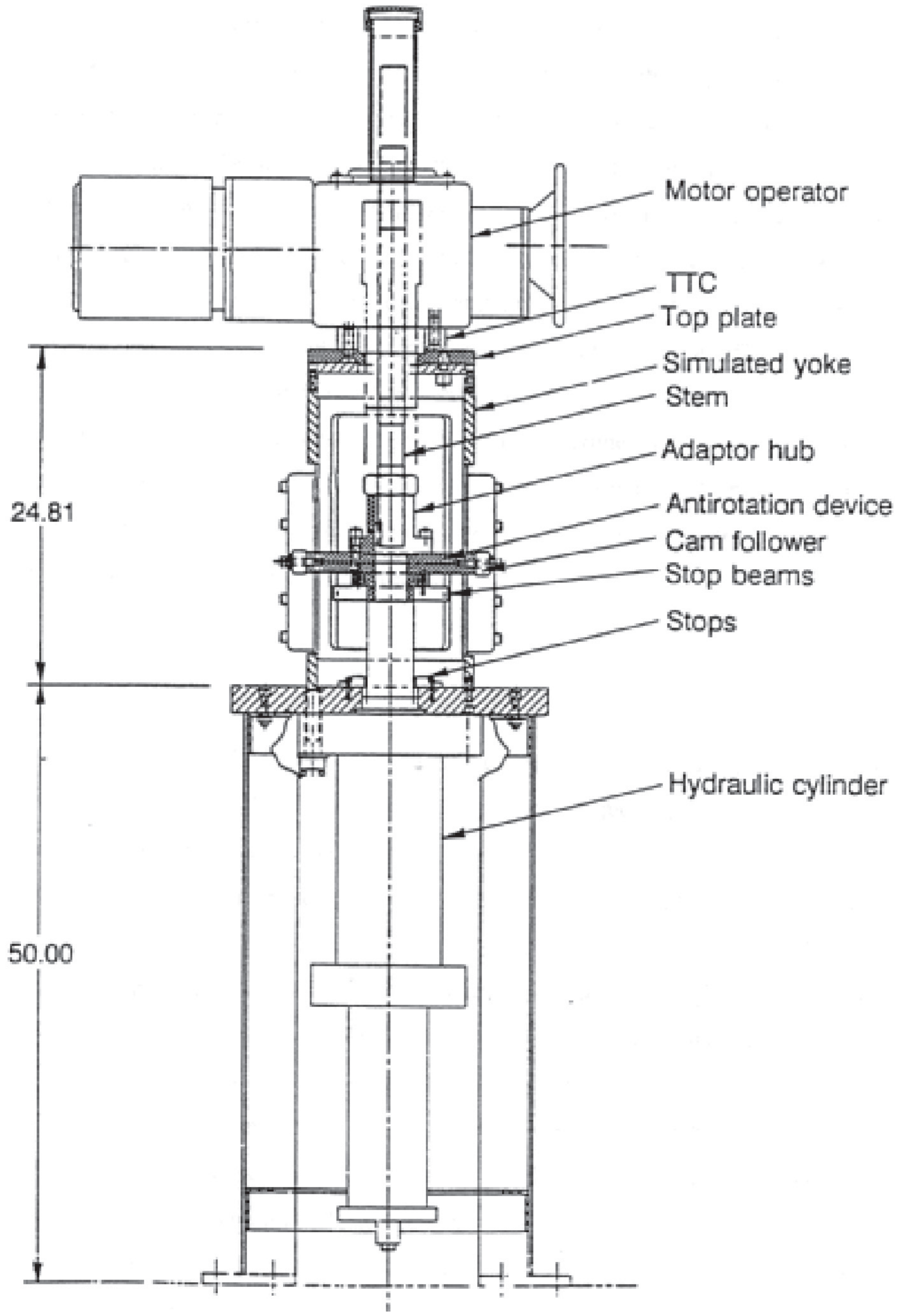

Figure 2 Actuator Test Fixture Components

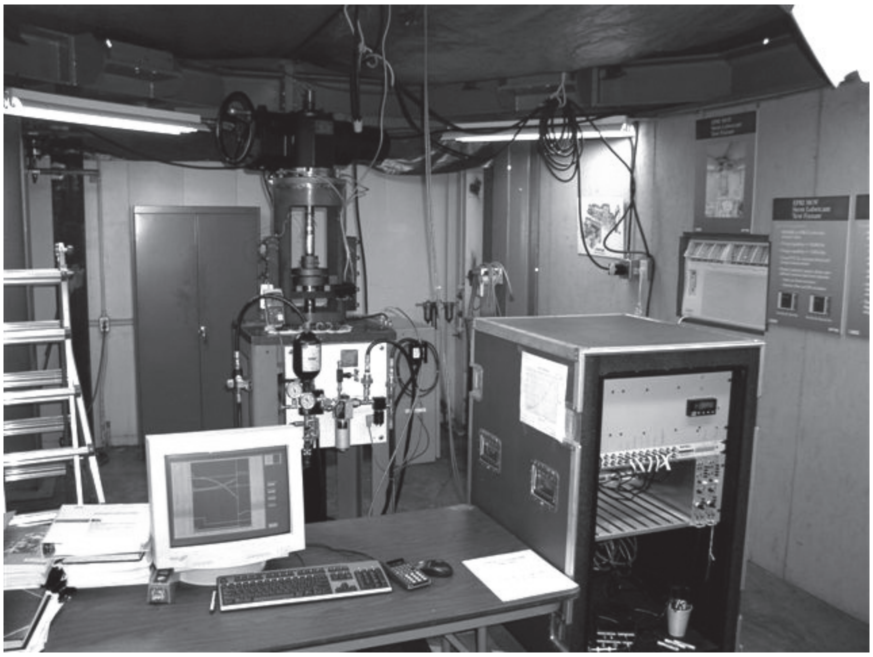

Figure 3 Actuator Test Fixture and Associated Equipment

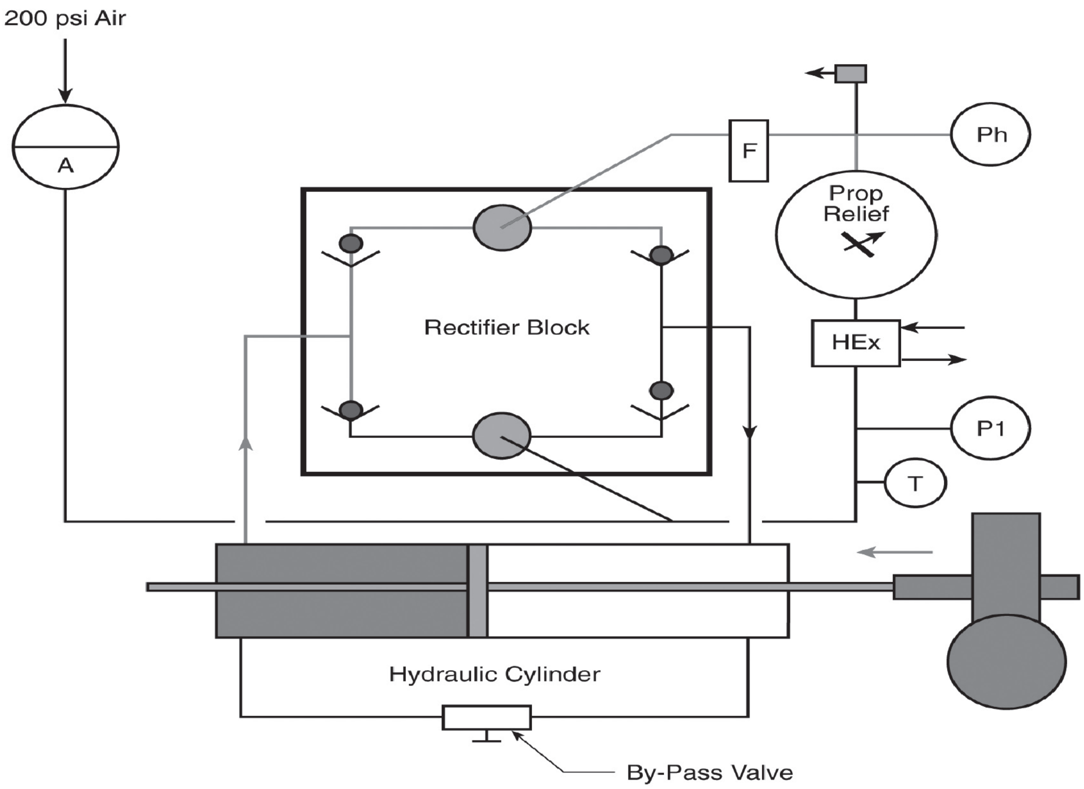

Figure 4 Passive Hydraulic System Simulating Valve Closing Operation

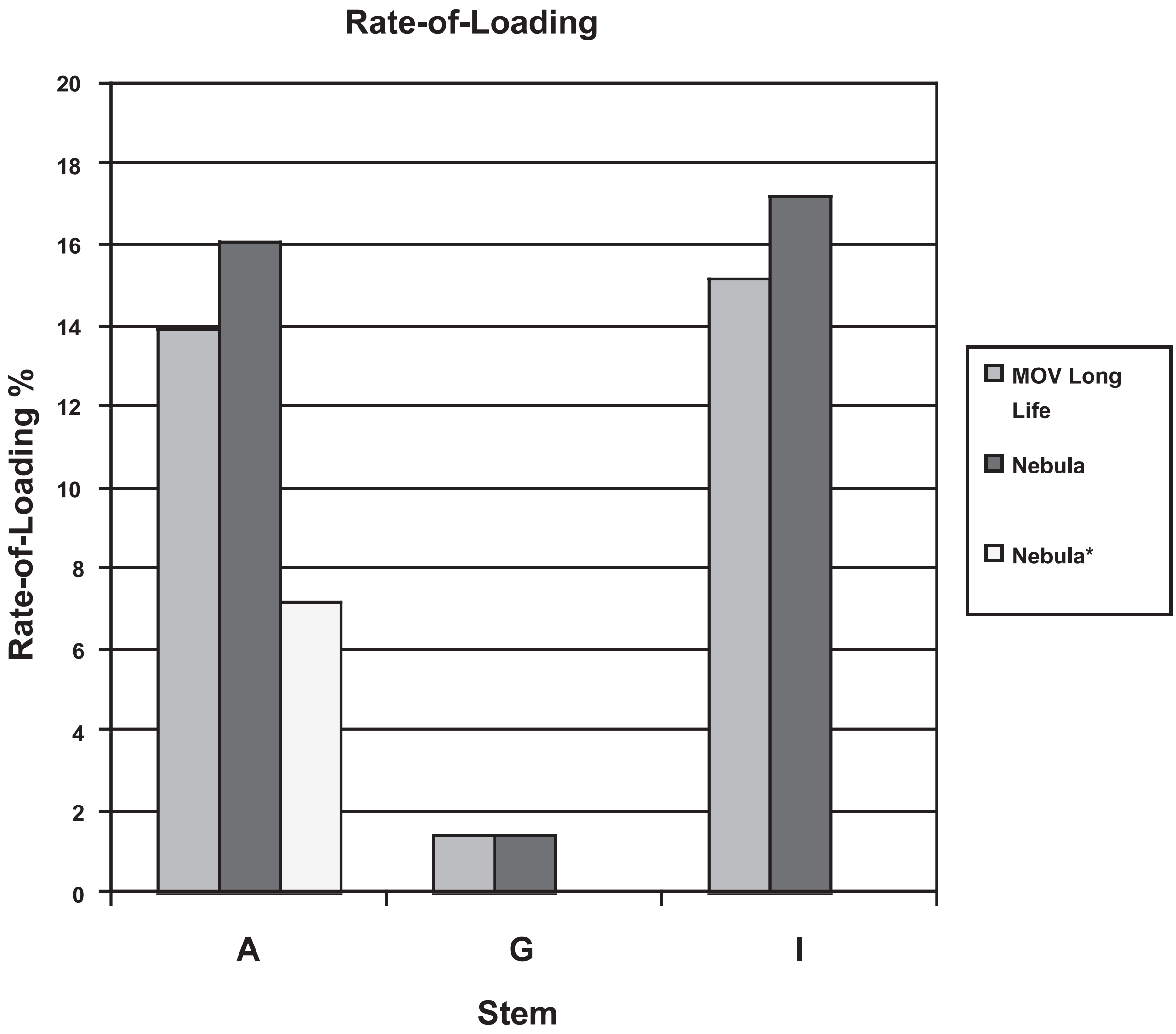

Figure 5 Rate-of-Loading Comparison

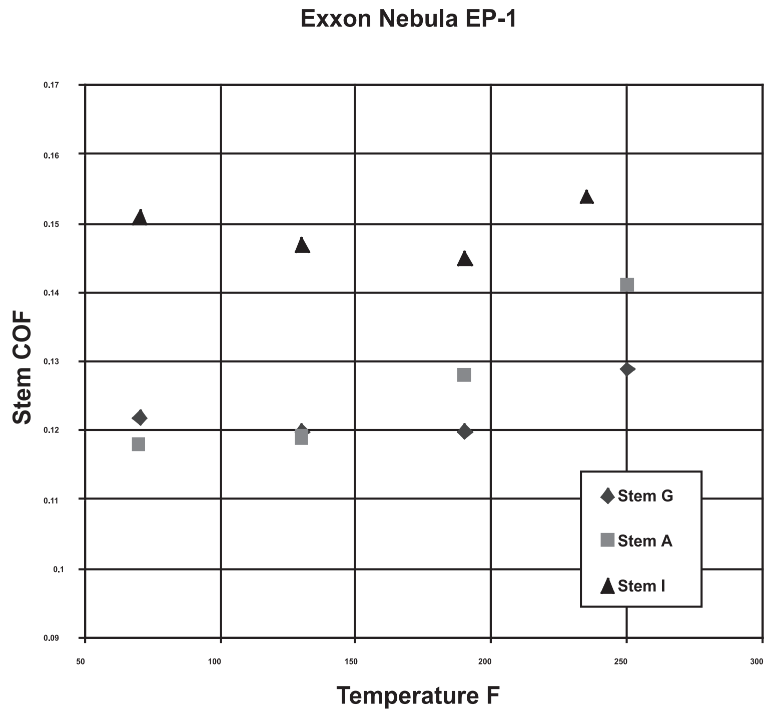

Figure 6 Effect of Temperature on Stem COF – Exxon Nebula EP-1

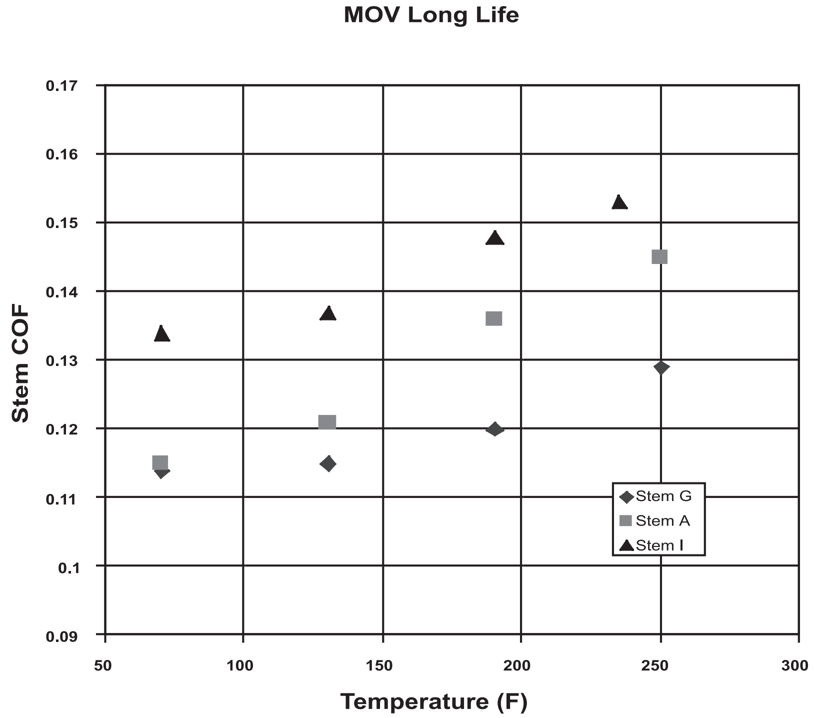

Figure 7 Effect of Temperature on Stem COF – MOV Long Life

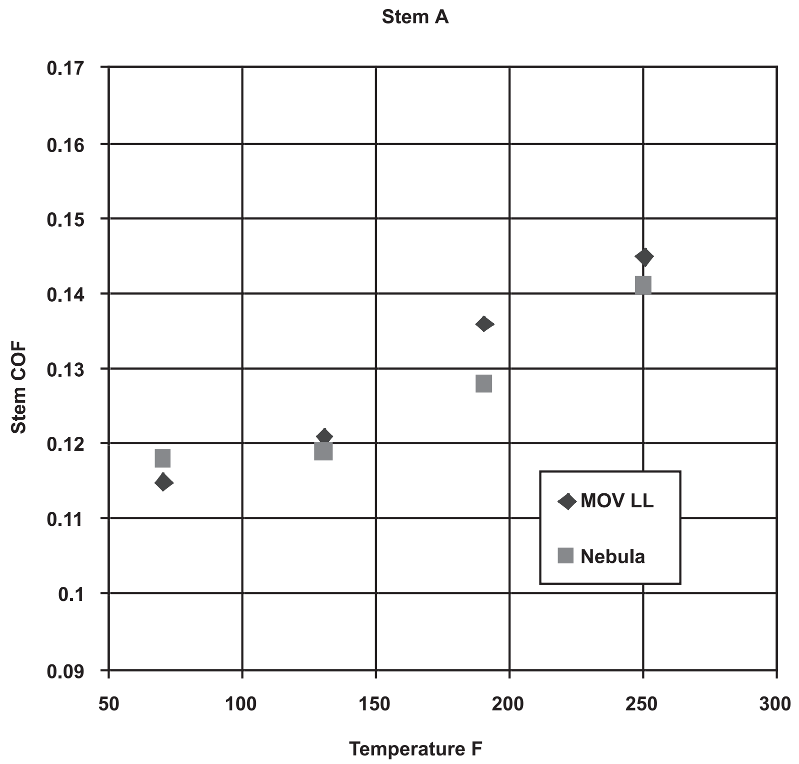

Figure 8 Effect of Temperature on Stem COF – Stem A

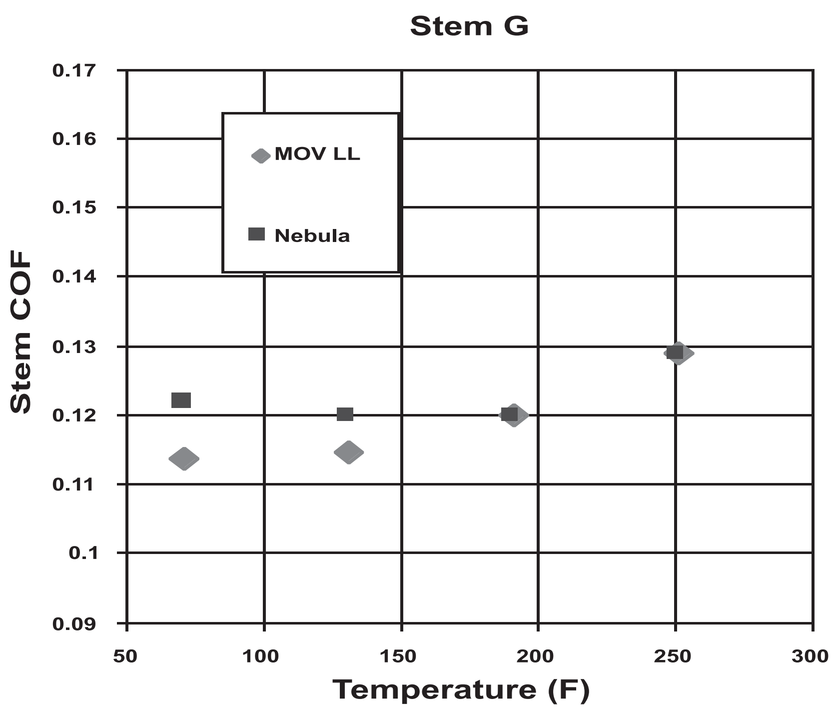

Figure 9 Effect of Temperature on Stem COF – Stem G

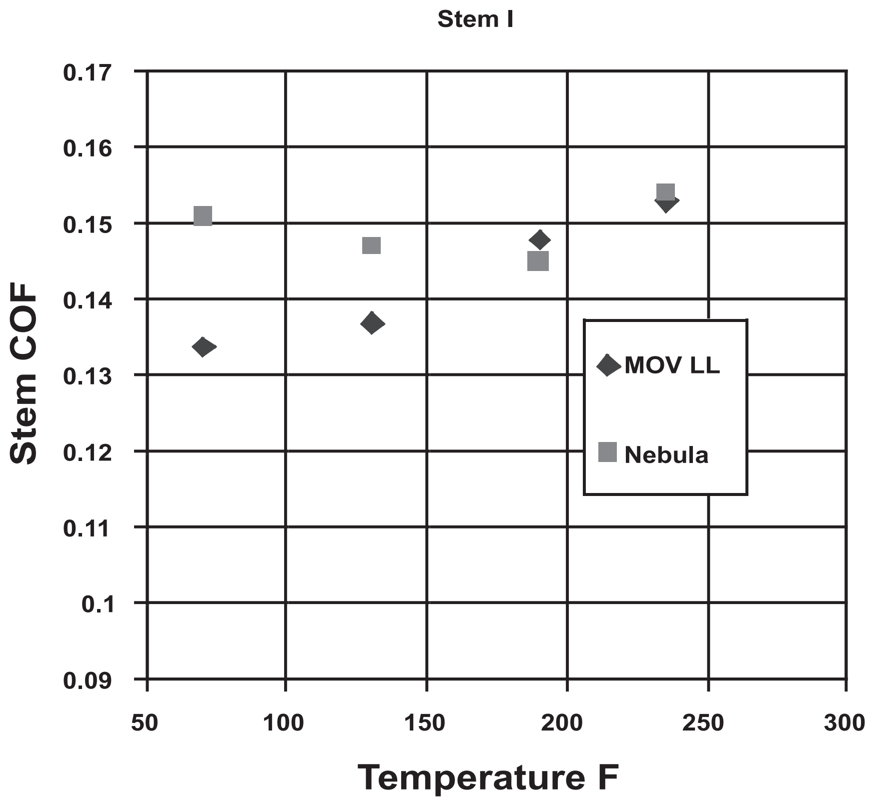

Figure 10 Effect of Temperature on Stem COF – Stem I

Session 2(a): Risk-Informed Inservice Testing of Valves & Pumps

Session Chair

Craig D. Sellers

Alion Science and Technology

EXPERIENCES GAINED IN IMPLEMENTING A BROAD-BASED RISK-INFORMED APPLICATION AFFECTING PUMP AND VALVE TESTING

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ABSTRACT

The South Texas Project was granted a first-of-kind exemption from special treatment requirements contained in 10CFR Parts 21, 50, and 100 in August 2001. Since that time, South Texas has pursued a cautious, deliberate approach to implement these risk-informed exemption allowances. Over the past two years, South Texas has gained a unique insight into the challenges and benefits that exist in pursuing a broad-based risk-informed application. The American nuclear industry is currently pursuing similar capabilities through proposed rule 10CFR 50.69* which is scheduled for NRC final review and approval in the July, 2004 timeframe. This proposed rule closely resembles the approach taken by South Texas in the exemption process and the allowances granted. For nuclear utilities that wish to pursue a similar broadbased risk-informed application, a well-conceived strategic approach is needed to prioritize the implementation activities as well as engage stakeholders in the implementation process. Cultural and communication challenges exist which must be addressed and effectively overcome.

The goal of this paper is to communicate these challenges to the attendees, inform attendees of the safety and economic benefits to be recognized through this risk-informed approach, and to provide insight into continuing application opportunities that were not readily apparent when the broad-based exemption was originally conceived. This paper and presentation will be beneficial for both domestic and international attendees, as well as for personnel with utility or regulatory backgrounds.

* Editor's Note: The NRC had not completed the development of 10 CFR 50.69 at the time of the preparation of this paper. Therefore, the discussion of the provisions of 10 CFR 50.69 in this paper should not be considered to represent the NRC final position on the rule.

INTRODUCTION

The South Texas Project (STP) is a two-unit Westinghouse four-loop PWR rated at 1270 MWe output. Unit 1 was placed in commercial operation in 1988, and Unit 2 was placed in commercial operation in 1989. The Station is owned by four separate entities, and managed by the South Texas Project Nuclear Operating Company (STPNOC). The Station is located about 85 miles southwest of Houston, Texas near the Texas Gulf Coast. Cooling water for the Station is drawn from an above-ground reservoir supplied by water from the nearby Colorado River. The design of the South Texas Project incorporates three safety trains; however, the Station is licensed such that all three safety trains must be available.

This paper discusses the blending of the STP Probabilistic Risk Assessment (PRA) Model with deterministic insights resulting in a variety of risk-informed applications. The application with broadest influence is the Exemption from Special Treatment Requirements, which was submitted as an Exemption Request to the Nuclear Regulatory Commission (NRC) in July 1999, and ultimately approved in August 2001. Since that time, STP has begun a cautious and deliberate implementation approach of these various Exemption allowances. This paper provides insights into the benefits and challenges noted in implementing a broad-based risk-informed application, with specific focus on pump and valve testing.

NOMENCLATURE

Probabilistic Risk Assessment Model – an engineering tool used for decision-making that models certain components within the plant design which influence the protection of the reactor core and the health and safety of the public. Risk-Informed Safety Classifications (RISC) – the segregation of categorized components into specific groupings. The four groupings identified in 10CFR 50.69 include:

- RISC-1 – safety-related, safety significant
- RISC-2 – non-safety related, safety significant
- RISC-3 – safety related, low safety significant
- RISC-4 – non-safety related, low safety significant

Special Treatment Requirements – the additional controls placed on safety-related equipment which exceed the normal controls placed on non-safety related equipment.

BACKGROUND

The South Texas Project (STP) has been actively involved with industry risk-informed applications since the 1980s. This involvement lead to the development of a robust Level 1 and Level 2 Probabilistic Risk Assessment (PRA) Model which has been foundational in the decision-making processes at STP. In November 1997, STP was granted a Graded Quality Assurance (GQA) Safety Evaluation Report, which permitted reduced assurances to be applied to components determined to be of low safety significance. During the initial implementation phases of this GQA allowance, it was determined that the regulatory Special Treatment Requirements contained within 10CFR Parts 21, 50, and 100 constrained STP to continue applying robust treatments to components determined to be low safety significant. This recognition resulted in a series of interactions with the Nuclear Regulatory Commission (NRC) to discuss potential approaches to address this regulatory constraint. In July 1999, STP submitted to the NRC a broad-based Exemption to exclude certain requirements of 10CFR Parts 21, 50, and 100 from those components determined to be Low Safety Significant or Non-Risk Significant. This Exemption approach was an industry first in that the request sought relief from broad process requirements rather than specific aspects of a specific rule.

In August 2001, following extensive discussions and interactions with the NRC, the *Exemption from Certain Special Treatment Requirements of 10CFR Parts 21, 50, and 100* was granted. This broad-based first-of-kind Exemption offered reductions in certain Special Treatment Requirements for the following regulations:

- 10CFR Part 21.3 – Reporting Requirements
- 10CFR 50.49(b) – Environmental Qualifications
- 10CFR 50.59 – Change Control
- 10CFR 50.55a(f), (g), (h)(2) – ISI/IST, ASME
- 10CFR 50.65 – Maintenance Rule
- Appendix B – Quality Controls
- Appendix J – Containment Leak Tightness
- 10CFR Part 100 – Seismic Requirements

The NRC viewed the South Texas Exemption as a proof-of-concept to permit other industry licensees to pursue similar reductions in special treatment requirements. Since the South Texas efforts preceded an industry approach, the STP effort was also viewed as a proto-type pilot for how the industry might proceed.

INDUSTRY'S APPROACH

In December 1998, the NRC issued SECY-98-0300, which identified three options that could be pursued in advancing broad risk-informed approaches. The three options offered were:

Option 1 – continue to allow licensees, on a case-by-case basis, to pursue individual risk-informed exemptions to existing rules. Under this option, there would be no broad industry-wide effort to either adjust the scope of the existing rules, or to risk-inform the rules themselves.

Option 2 – alter the *scope* to which the existing rules apply. For components determined to be low safety significant, these components could generally be removed from the scope of special treatment requirements and be subjected to normal commercial controls. Components determined to be safety significant would continue to be subjected to existing special treatment requirements. However, under this option, the existing rule language would not be changed.

Option 3 – revise the existing rule language to incorporate risk insights into the rules. This option was considered to be the final goal of a risk-informed environment, however, it was also recognized as being the most difficult to achieve in the short term.

Considering these three options, the NRC determined that an approach which combined Options 2 and 3 should be pursued. It was recommended that an Option 2 approach be pursued in the short-term, and in parallel, Option 3 should be pursued on certain specific rules.

The South Texas approach was deemed to be a prototype pilot for the Option 2 approach. To codify a more generic industry approach which could be used by any domestic licensee, draft rule 10CFR 50.69 *'Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors'* was generated and submitted for public review and comment in May 2003. The comment period closed in August 2003, and the NRC staff is currently working to resolve the received comments. The goal is to forward the draft rule to the NRC Commissioners in July 2004 for final review and action.

SCOPE OF DRAFT 50.69

The current scope of draft rule 10CFR 50.69 closely mirrors the South Texas Exemption scope. The rules to be addressed within 50.69 include the following:

- 10CFR Part 21
- 10CFR 50.49
- 10CFR 50.55a(f), (g), (h)
- 10CFR 50.55(e)
- 10CFR 50.65
- 10CFR 50.72
- 10CFR 50.73
- Appendix B
- Appendix J
- Appendix A to 10CFR Part 100

Draft 10CFR 50.69 is a voluntary rule which provides high level insights into the categorization and treatment approaches. To offer more detailed insight into the categorization and treatment implementation, the Nuclear Energy Institute (NEI) has drafted NEI-00-04 '*10CFR 50.69 SSC Categorization Guideline'*. In addition, the Electric Power Research Institute (EPRI) is drafting industry guidance for treatment of low safety significant components in the areas of environmental and seismic qualifications.

IT ALL BEGINS WITH CATEGORIZATION

Implementation of either the South Texas Exemption or the 10CFR 50.69 allowances require the categorization of components on a system-by-system basis. The categorization scheme created by STP, and generally mirrored by the 10CFR 50.69 approach, was reviewed and approved by the NRC. The STP approach relied upon probabilistic insights from STP's PRA Model blended with deterministic insights from a working-level Integrated Working Group (IWG). The Working Group consists of experts in the areas of PRA, Operations (a senior reactor operator), Licensing, Engineering, Quality, Operating Experience, Maintenance, and the associated System Engineer. The Working Group begins each system review by identifying all functions performed by the associated system. These functions are then categorized by asking a set of consistent questions which look at the influence of a specific function on initiating events, accident mitigation, the ability to fail other risk-significant systems, emergency operations, or mode changes/plant shutdown. The response to each of these questions is then weighted and summed to determine the final functional importance. Once completed, all components within the system are mapped to the functions that they support (a certain component may support a single function, or may support multiple functions). The Working Group then deliberates on the final component categorization considering the PRA categorization (if the component is modeled), component redundancy and diversity, operational history, and the knowledge/experience of the group. Using consensus decision-making criteria, a final categorization for each component is determined, the technical basis for the categorization documented, and the draft categorizations forwarded to a separate Expert Panel for review and approval.

The Expert Panel is made up of senior-level managers who are expert in the areas of PRA, Engineering, Licensing, Operations, and Maintenance. This Panel independently reviews the draft categorization input developed by the Working Group and deliberates on the satisfaction of the final results and the adequacy of the technical basis. If the Expert Panel concurs with the proposed categorization, the data is entered into the Station's electronic Master Equipment Database and becomes available for use by site personnel.

Only components that have been categorized are subject to the control adjustments stated in the Exemption. If a component has not yet been categorized, the treatments that were in place prior to the grant of the Exemption will remain in force.

STATUS OF THE STP CATEGORIZATION

As of March 18, 2004, South Texas had completed categorizations on 68 different system designators constituting over 70,000 individual components. The systems completed to date include those which would generally be considered as most crucial to safe reactor power operations. The categorized systems include:

- Reactor Coolant
- Safety Injection
- Auxiliary Feedwater
- Charging and Volume Control
- Emergency Diesel Generators
- Essential Cooling Water
- Main Steam
- Main Feedwater
- Component Cooling Water

Insight from the STP categorization effort to date identifies the following:

- Approximately 90% of all components categorized to date have been determined to be low safety significant (either RISC-3 or RISC-4 under the 10CFR 50.69 categorization approach)
- For safety-related components only, approximately 25% of these components are determined to be safety significant (RISC-1) while the remaining 75% are determined to be low safety significant (RISC-3)
- Less than 1% of the components have been determined to be non-safety related yet safety significant (RISC-2)

STP performs a periodic review to assess the continued acceptability of component categorizations on a once-per-18- month basis. The most recent periodic review was just completed in the first quarter of 2004. To date, STP has not identified any potential adverse performance trends as a result of applying reduced special treatment requirements.

CATEGORIZATION LESSONS LEARNED

The STP categorization process is proceduralized to ensure consistency in application. Beneficial insights, which have been identified to date, include the following:

1. *Be aware of potential critical changes* – changes to the PRA Model or possible performance declines in RISC-3 components can lead to a component crossing the threshold between low safety significant (RISC-3) into the safety significant area (RISC-1). Preventions must be put in place to anticipate these potential categorization changes, and a process must exist to quickly respond when an RISC-3 to RISC-1 transition occurs.
2. *Categorization changes are primarily driven by PRA Model changes* – to date, STP has not identified an adverse performance trend that has been due to the application of reduced treatments to RISC-3 components. However, due to the living nature of the PRA Model, when model revisions occur, an assessment of the model changes must be completed timely to understand the potential impacts onto the component categorization results.
3. *Creation of a 'buffer zone' is beneficial* – to heighten the awareness of borderline components that reside at the upper threshold of the RISC-3 box (however, are not significant enough to initially be placed in the RISC-1 box), STP created a buffer zone to assess these components during the initial categorization process and during follow-up reviews. This buffer zone (RAW between 1.8 and 2.0; Fussel-Vesely between 0.004 and 0.005) has been proceduralized to proactively consider potential categorization changes.
4. *Evaluate PRA-Modeled RISC-2 components early* – for safety significant, non-safety related components (RISC- 2) that are modeled in the PRA, however, have yet to undergo the component categorization process, these components should be evaluated for possible enhanced special treatment controls even before the final categorization is completed.
5. *Categorization guidance for electrical components and cabinets must be clear* – electrical component categorization requires unique guidance on breakers due to the potential impact on upstream safety significant components if the breaker fails to perform its function. In addition, instrumentation cabinets generally include many sub-components (i.e., fuses, relays, etc.) that may not be uniquely tagged as are pumps and valves. The

categorization of cabinets must factor in the functions performed by the sub-components contained within the cabinet.

6. *Excellent categorization stability has been noted* – using the South Texas approach to component categorization, very few categorization changes have been necessitated due to performance changes in components, PRA Model updates, or reassessment by Working Group members.

The above stated preventions have been note-worthy in achieving this stability.

7. *Consensus decision-making has worked well* – few dissenting opinions have been generated from the STP categorization process. When a dissenting opinion is noted, a process is in place to raise this issue to the Expert Panel for resolution.

8. *Application-specific categorizations can be used to better focus on component importance* – in addition to the broad- based categorizations performed by STP, application specific categorizations (e.g., for Risk-Informed In-Service Testing) can be developed and implemented. These specific categorizations focus on the application need (e.g., active testable functions performed by the component versus considering passive functions into the final importance determination). The hierarchy of the categorizations must be maintained with the application-specific categorizations remaining as a subset of the broad-based categorization approach. The application-specific categorization process is outside the scope of the STP Exemption or the approach to 10CFR 50.69.

9. *General Notes have aided the documentation basis* – each system generally consists of a number of support components (i.e., vent valves, drain valves, handswitches, etc.) which generally do not impact the ability of the major function to be satisfied. To aid in documenting the categorization bases for these support components, STP developed a series of General Notes which are consistently used from one system to another. The General Notes permit a short-hand means to document the categorization basis without repeating the same wording numerous times.

The categorization process has evolved, and continues to evolve, with the experiences gained at South Texas. Effective documentation of the categorization decisions and the bases that supports the categorization is of the utmost importance for future evaluation and validation of the adequacy of the existing component category.

IMPLEMENTING THE REDUCED TREATMENT ALLOWANCES

A sound and robust categorization process is necessary for effective implementation of the reduced treatment allowances provided by either the STP Exemption process or the industry's 10CFR 50.69 process. If the categorization process does not result in extreme high confidence that components have been properly 'bucketed' into one of the RISC-1, RISC-2, RISC-3, or RISC-4 boxes, then the confidence level in implementing the reduced treatment allowances will remain low and the implementation effort effectiveness will be hampered.

It is important to note again that only components which have gone through a categorization process are subjected to potential treatment changes. Any component, which has yet to be categorized, will remain under the current treatment requirements that are in force at the Station. For categorized components under either the STP

Exemption approach or the 10CFR 50.69 approach, the general treatment allowances are as follows:

RISC-1 Components – these are safety-related, safety significant components. The special treatment requirements currently imposed by regulatory requirements will remain, and no additional special treatments are necessary.

RISC-2 Components – these are non-safety related, safety significant components. These components generally are not under current regulatory special treatment requirements. The current performance of these components must be assessed to determine if additional controls should be applied. If the current performance does not meet expectations, then additional controls should be considered.

RISC-3 Components – these are safety-related, low safety significant components. These components are currently subjected to the same regulatory special treatment requirements imposed on RISC-1 components. RISC-3 components are candidates for reductions in special treatment controls per the allowances of 10CFR 50.69.

RISC-4 Components – these are non-safety related, low safety significant components. These components are generally not under current regulatory special treatment requirements, and do not require any additional controls to be applied. These components generally receive industrial-type controls.

STATUS OF THE STP IMPLEMENTATION ACTIVITIES

STP pursued a cautious, deliberate approach in implementing the treatment reduction allowances for RISC-3 components as provided in the STP Exemption.

Implementation of the Exemption allowances formally began in January 2002, and is continuing today. STP chose to focus on a limited number of programs that would provide both safety and economic benefit to the Station. The programs chosen, and the benefits noted, are generally as follows:

1. *Local Leak-rate Testing (LLRTs)* – RISC-3 components have been removed from the scope of LLRT testing based on being low safety significant and satisfying one or more of the following criteria:
   - The valve is open with mass flow during accident scenarios
   - The valve is closed in a closed water-filled system and is not required to change state in response to the accident
   - The valve is in a closed piping system which has a crush pressure greater than that of Containment
   - The valve is 1” in size or less

The LLRT Program and procedures have been modified to reflect the change in scope, and training provided to technicians and operators. The implementation has resulted in a 57% reduction in valves scoped for Type C Local Leak-rate Testing. It should be noted that the STP Exemption requested relief for Type C LLRT testing only, whereas the 10CFR 50.69 approach is seeking relief for both Type B and Type C LLRT testing.

2. *Maintenance Rule* – in cases where an entire system has been determined to be RISC-3 through the categorization process, the system can be removed from the scope of Maintenance Rule tracking and actions. To date, STP has removed 16 systems from the scope of the Maintenance Rule (the systems which previously caused the greatest number of Maintenance Rule actions were the Radiation Monitoring system and the Emergency DC Lighting system. Both of these systems were determined to be low safety significant, and have been removed from the scope of the Maintenance Rule through this process.). In addition, the other categorized systems have had their Maintenance Rule actions reduced since only safety significant components are required to be addressed. When systems/components are removed from the Maintenance Rule scope, STP relies on the Condition Reporting process to track and correct identified issues.

3. *Inservice Testing (IST)* – inservice testing of pumps and valves involves surveillance testing to provide periodic assurance that the component’s functional capabilities are validated. For RISC-3 components, these assurances do not require the same degree of rigor. STP has focused on extending the frequencies of RISC-3 components factoring in the component’s low safety significance and the performance history. Due to the large number of procedures impacted by removing the RISC-3 components from the IST Program, many of these components remain within the IST Program scope with extended test frequencies. The reasonable assurance basis used to justify the frequency extensions was documented and retained.

To date, STP has identified no increased failures due to the test frequency changes. Generally, the scope of valve stroke time testing has been reduced by about 25% due to the program changes.

In addition, STP is currently pursuing a Risk-Informed IST program request with the NRC to address those components remaining within the scope of IST (RISC-1 components). If the RI-IST Program is approved, an additional 178 valves and 7 pumps will be available for possible test frequency extensions. It is important to note that additional benefits are available to Stations that wish to pursue a RI-IST or RI-ISI program in addition to a 10CFR 50.69 approach only.

4. *Parts Procurement* – the STP procurement organization and spare parts engineering organization evaluate RISC-3 parts purchases on a case-by-case basis for potential usage of available industrial parts. In order to utilize an industrial part in an RISC-3 application, an engineering evaluation must be performed to document a basis for reasonable assurance that the industrial part will satisfy the safety-related functional requirements under design basis conditions. If the evaluation is satisfactory and the purchase of the industrial part is economically beneficial, then an industrial part can be procured. If the evaluation cannot successfully document a reasonable assurance basis, or there is little economic benefit in procuring an industrial part, then a safety-related, qualified part will be procured and installed. Generally, the price differential between a qualified part and an industrial part is a factor of three to five times higher. STP has identified certain instances where the price differential was greater than a factor of forty times higher to buy a qualified part versus an industrial part.

Examples of areas where industrial parts have been procured for RISC-3 applications include:

- Radiation monitor sample pumps
- Spent Fuel Pool Heat Exchanger discharge valve flow guides
- 1" vent and drain valves
- HVAC analog-to-digital flow controller changeouts
- Capacitors on computer card rebuilds

To date, STP is achieving approximately $250,000 per year in hard savings in the procurement area. Some areas which have hampered further procurement benefits have been associated with determining the proper level of reasonable assurance required for environmentally and/or seismically qualified parts. STP is working with EPRI to develop industry standards which can be utilized. In addition, the available safety-related, qualified stock in the warehouse must be depleted before additional possible industrial purchases are pursued. Also, in some cases, manufacturers are reluctant to sell industrial parts to their nuclear customers.

5. *Tool-Pouch Maintenance* – Tool-Pouch Maintenance (TPM) is a streamlined maintenance strategy that desires to utilize the skill-of-craft knowledge existing among the craft labor force, while reducing the burdensome documentation that generally accompanies task performance and completion. This approach generally results in no planned work instructions to complete a straight-forward task that the craftsman is skilled at performing (i.e., valve packing adjustments, flange leak tightening, etc.). Documentation of the task completion is maintained at a minimal level (computer based), and no paperwork is generated for long-term document retention. Document retention is accomplished by retaining the computer record only. Due to Appendix B requirements, the Tool-Pouch

Maintenance allowances were allowed only on non-safety related equipment prior to the grant of the STP Exemption. Upon approval of the Exemption, the TPM Guideline was revised to permit performance on safety-related RISC-3 components. Since that time, TPM performance has been tracking approximately 30% higher than historical performance. TPM performance permits a more timely correction of identified deficiencies, reduces the administrative burden on the low safety significant components, and permits more time to be focused on safety significant material deficiencies.

6. *Preventive Maintenance* – the scope and frequency of Preventive Maintenance (PM) activities have been altered by considering the safety significance of the associated component. In cases where the component is determined to be safety significant (RISC-1 or RISC-2), the PM activities have been evaluated for potential increases in scope or reductions in the periodicity between PM performances. In cases where the component is determined to be low safety significant (RISC-3), the scope may be reduced, but more likely, the PM frequency will be optimized considering the component performance history. Through the PM evaluation process, STP has identified averted cost savings of approximately $300,000 per year in labor, and approximately $60,000 per year in parts. These savings are realized each year for the remaining life of the Station.

STP's implementation activities have been hampered by several significant equipment issues during the initial two year effort (i.e., Steam Generator replacement in Unit 2 in October 2002, Unit 2 Main Turbine thrown blade in December 2002, Unit 1 Bottom-Mounted Instrument boron leak in April 2003, Unit 2 Emergency Diesel Generator thrown piston in December 2003). None of these equipment issues were a result of the Exemption implementation; however, each of these equipment issues has drawn both focus and resources away from the implementation efforts. However, the implementation activities continue to move forward deliberately and safely.

IMPLEMENTATION LESSONS LEARNED

The STP implementation process officially began in January 2002. Beneficial insights, which have been identified to date, include the following:

1. *Involve management early* – by nature of the Exemption process, STP had extensive management involvement early in the process due to this first-of-kind effort. It is imperative to initiate the implementation activities from a top-down approach. With management cognizant and supportive of the implementation requirements, the needed resources can be made available to support programmatic changes, and management can help influence the needed cultural changes within the organization. If management is not on board with the broad-based, risk-informed application, the rest of the organization will likely not follow, and the individual tasked with the implementation effort will be fighting a losing battle.

2. *Begin with a strong safety culture at the Station* – the first and foremost purpose of a broad-based risk-informed application is to enhance nuclear safety. If a sound safety culture does not currently exist at the Station, it would not be recommended for that Station to pursue broad risk-informed applications. A strong safety culture will help control the pace and quality of both the categorization and implementation efforts, and establish the parameters on how far the organization is comfortable and willing to move on the reasonable assurance scale. A strong safety culture will effectively push-back on efforts to move the implementation efforts too far, too fast.

3. *Using an Expert Panel helps pave the implementation pathway* – the currently proposed 10CFR 50.69 utilizes an Integrated Decision-making Panel (IDP) to perform the categorization of system functions and components. This IDP equates to the Working Group currently in place at STP. However, the 50.69 process does not require an independent, senior review panel to validate the categorization results and to provide management guidance to the IDP. STP has found the Expert Panel (made up of senior managers who are separate and distinct from the Working Group) to be an invaluable part of the categorization and implementation process. The Expert Panel provides a management backstop to the Working Group decisions by validating the soundness of the proposed categorizations. The Expert Panel addresses any dissenting opinions which arise during Working Group deliberations, and offer a management perspective on thepriorities and strategies for the Station to best pursue effective implementation. In addition, the Expert Panel serves as a springboard to communicate the capabilities of the Exemption allowances into the Station's organizations, and has the ability to hold their own resources accountable to accomplish the implementation tasks.

If an Expert Panel (or similar management structure) is not in place at a particular Station during the categorization process and during the implementation activities, it is likely that the IDP will be paralyzed by the lack of direct management support. In addition, a Station which undertakes a broad-based risk-informed application is pursuing a significant investment in resources with an anticipation of safety and economic returns. It is unlikely that any Station organization will turn this significant responsibility over to working level experts and expect them to solely determine the scope of plant components that will be subject to Special Treatment Requirements in the future.

4. *Have a plan* – implementing the allowances of a broadbased risk-informed application is not a quick undertaking. There are cultural issues to deal with, and as you probe into the depths of existing Station programs, there will be surprises found that must be addressed. All of these issues highlight one of the fundamental premises of change management: *have a plan*.

The developed plan must focus on the short-term milestones while maintaining a vision on the long-term objectives. The plan needs the involvement and concurrence of the various stakeholders that will be implementing the plan, as well as the review and approval of the management team that will be funding the plan's activities. The developed plan should be viewed as a living document, and should be periodically reviewed and updated with new statuses or newly recognized insights. The implementation plan developed by STP focused on those programmatic areas that were pursued in the short-term. A management sponsor of the implementation activities was identified and was periodically briefed by the stakeholders on the status of implementation actions. A stakeholder team was formed to discuss implementation challenges and to look for new opportunities.

5. *Maintain a cautious, deliberate approach* – the details of a 10CFR 50.69 implementation approach are complex and require that a sound bases for reasonable assurance be developed prior to reducing associated treatments. Personnel at the Station often don't realize or understand the criteria surrounding the approval of a 50.69 approach, and, without a plan, may attempt to pursue treatment reductions without the needed reasonable assurance or programmatic controls being in place. It is imperative that the developed plan be followed, and that this plan pursues a cautious, deliberate approach.

The developed plan must control the pace and quality of the implementation activities, and should offer opportunities for clear and critical feedback to be provided and factored into future actions and direction. A 50.69 implementation approach must focus on the long-term safe and reliable operation of the Station. The reason for pursuing 50.69 must not be to achieve some short-term economic fixes.

6. *Focus on areas that have both safety and economic benefits* – as the implementation plan is being developed, focus on opportunities that will enhance nuclear safety while at the same time offer economic benefits to the Station. While it may be desirable to focus initially on hard-dollar benefits in parts procurement and labor reductions, generally these savings will occur if the focus is shifted first toward programmatic nuclear safety enhancements. Nuclear safety enhancements are realized by shifting the focus of attention from the RISC-3 components and placing more focus on the RISC-1 components. The RISC-3 components are still expected to perform their design basis functions under accident conditions, howbeit at a lesser degree of

assurance. This lesser degree of assurance can be noted through reductions in testing requirements, reductions in inspection requirements, etc. As the burden demands are lessened in some of these programmatic areas, additional focus can then be placed on RISC-1 components and programmatic controls.

7. *Not all stakeholders will view this as a beneficial change* – up to this point in the history of commercial nuclear power, the operation of domestic reactors and safety systems have largely been controlled by deterministic regulations and programmatic controls. Even Station's with strong safety cultures and strong support for a 50.69 approach will have team members who are adverse to accepting the premise of risk-informed approaches and would prefer to maintain the deterministic bases that currently exist. If this deterministic individual is the programmatic owner of a process that you wish to risk inform, it is not suggested that this program would be your first choice to implement the 50.69 allowances.

Successful implementation comes in a series of small victories. Choose programmatic areas where the stakeholders are anxious to implement the 50.69 allowances, and are willing to expend the effort necessary to establish needed reasonable assurance bases and to modify programs and procedures. As small victories are claimed and burdens are reduced, others who were initially skeptical tend to become more accepting of the risk-informed environment.

8. *Understand your commitments* – STP added a new section to the Updated Final Safety Analysis Report (UFSAR) which captured the commitments for the approved Exemption. Since other domestic Stations will likely not pursue exemptions from the deterministic rules, but rather will pursue a license amendment under the 10CFR 50.69 approach, it is still important for the commitments to be clearly understood and captured prior to beginning your implementation activities. This process will require involvement of the Licensing personnel at the Station. In certain cases, if the approved 10CFR 50.69 wording is vague, the documentation of interpretations is important to establish a common basis of understanding. This may at times require the involvement of NRC personnel who supported the approval process.

When implementing a 50.69 approach, the vision must always be on the future and the defensibility of the actions being taken today. At some point in time, others will become responsible for the 50.69 implementation, and a clear paper trail should exist which documents the basis for actions previously taken.

9. *Implementation is not a one-year effort. It becomes part of your Station's long-term strategic plan* – when a Station pursues a broad-based risk-informed application, the Station is committing its long-term strategic plan to include the sound and deliberate implementation of the 50.69 allowances. This activity is a multi-year implementation effort, and will be a life-of-plant management responsibility. The Station decides on how quickly or slowly it wishes to pursue the implementation activities, but the license has been altered to factor in the 50.69 allowances. Therefore, the long-term vision must be clear when 10CFR 50.69 is chosen to be pursued.

CONCLUSION

As the industry's proto-type pilot for the 10CFR 50.69 activities, South Texas has gained a wealth of insights and experience in both the categorization activities and in the implementation activities. These insights point to the soundness of the risk-informed environment and its benefits in the decision-making processes at the Station. South Texas will continue to cautiously and deliberately pursue the full implementation of the Exemption allowances, and will be supportive of furthering industry's capabilities to pursue similar approaches.

RISK-INFORMING THE SPECIAL TREATMENT REQUIREMENTS OF THE NRC REGULATIONS

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Abstract

In Title 10 of the Code of Federal Regulations, the U.S. Nuclear Regulatory Commission (NRC) has established special treatment requirements for structures, systems, and components (SSCs) that perform safety functions at U.S. commercial nuclear power plants. These requirements address such aspects of SSC functional capability as environmental and seismic qualification, quality assurance, and inservice inspection and testing, and are based principally on deterministic considerations. The NRC is developing an alternative regulatory framework (proposed 10 CFR 50.69) that will allow the application of risk insights to determine appropriate treatment for plant SSCs in lieu of the current special treatment requirements. Implementation of this framework will provide flexibility in plant operation and design which can result in burden reduction without compromising safety.

I. INTRODUCTION

The regulations of the U.S. Nuclear Regulatory Commission (NRC) in Parts 21, 50, and 100 of Title 10 of the Code of Federal Regulations (10 CFR) contain special treatment requirements that impose controls to ensure the quality of SSCs that are within the scope of the regulations. Special treatment requirements are defined as those requirements that exceed normal commercial and industrial practices to provide a greater degree of confidence in the capability of SSCs to perform their safety functions under design-basis conditions throughout their service life. Special treatment requirements encompass such aspects as quality assurance, environmental and seismic qualification, inspection and testing, and performance monitoring.

The NRC has established an initiative to risk-inform the regulatory requirements for the treatment of SSCs used in nuclear power plants in the United States. As discussed in several Commission papers prepared by the NRC staff (e.g., SECY-99-256 and SECY-00-0194), Option 2 of this initiative involves categorizing plant SSCs based on their safety significance, and specifying the treatment that would provide an appropriate level of confidence in the capability of those SSCs to perform their design functions in accordance with their risk categorization. Under Option 2 of the NRC's risk-informed regulation initiative, RISC (risk-informed safety class)-1 SSCs are safety-related SSCs that perform safety-significant functions. RISC-2 SSCs are nonsafety-related SSCs that perform safety-significant functions.

RISC-3 SSCs are safety-related SSCs that perform low safety-significant functions on an individual basis. RISC-4 SSCs are nonsafety-related SSCs that perform low safety-significant functions. As described in SECY-98-300, the NRC staff expects there to be confidence that safety-related SSCs categorized as low risk-significant remain functional under design-basis conditions. Similarly, in SECY-00-194, the staff stated that nuclear power plant licensees will be required to maintain the functional capability of safety-related SSCs using existing or new programs.

II. PROOF-OF-CONCEPT EFFORT

On July 13, 1999, STP Nuclear Operating Company (STPNOC), licensee of the South Texas Project Units 1 and 2 nuclear power station, submitted a request under 10 CFR 50.12 for exemptions from the special treatment requirements of 10 CFR Parts 21, 50, and 100 for SSCs categorized at STP as low safety-significant (LSS) or non-risk significant (NRS) that are within the scope of these regulations. The NRC staff conducted the review of the STPNOC exemption request as a proof-of-concept effort for Option 2 of the risk-informed regulation initiative. In its submittal, the licensee requested approval of the exemptions primarily based on its categorization process that would allow the treatment of SSCs at STP according to their risk significance. Although relying heavily on STPNOC's categorization process in reaching the conclusions regarding the individual exemption requests, the staff recognized that

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. NRC has neither approved nor disapproved the technical content.

the functionality of SSCs must be maintained consistent with the Option 2 approach, and to support the implicit assumption in the categorization process that SSCs will remain capable of performing their safety functions under design-basis conditions. The staff did not consider it necessary to maintain the same level of confidence in the functionality of low-risk SSCs as provided by the special treatment requirements. In assessing functionality, the staff's review focused on whether the programmatic elements of the licensee's treatment processes, if effectively implemented, could be sufficient for the exempted SSCs to remain capable of performing their safety functions under design-basis conditions. The staff determined that it was not necessary to assess the details regarding how the licensee will implement its treatment processes for safety-related LSS and NRS SSCs. On August 3, 2001, the staff granted STPNOC's request for exemptions from many of the special treatment requirements in the NRC regulations for safety-related LSS and NRS SSCs in consideration of the categorization and treatment processes to be applied at STP.

III. PROPOSED 10 CFR 50.69

Background

In SECY-02-176, the NRC staff presented proposed 10 CFR 50.69 to the Commission for risk informing the special treatment requirements in the NRC regulations. The Commission approved issuance of proposed 10 CFR 50.69 for public comment in a staff requirements memorandum (SRM) dated March 28, 2003. Proposed 10 CFR 50.69 was published for public comment in the Federal Register on May 16, 2003 (68 FR 26511).

In the Federal Register notice for the proposed rule, the Commission stated that it is important to note that this rulemaking effort, while intended to ensure that the scope of special treatment requirements imposed on SSCs is risk-informed, is not intended to allow for the elimination of SSC functional requirements, or to allow equipment that is required by the deterministic design basis to be removed from the facility (i.e., changes to the design of the facility must continue to meet the current requirements governing design change, most notably 10 CFR 50.59). Instead, the rulemaking should enable licensees and the NRC to focus their resources on SSCs that make a significant contribution to plant safety by restructuring the regulations to allow an alternative risk-informed approach to special treatment. Conversely, for SSCs that do not significantly contribute to plant safety, this approach should allow an acceptable, though reduced, level of assurance that these SSCs will satisfy functional requirements.

The Commission also stated that it was proposing to establish 10 CFR 50.69 as an alternative set of requirements whereby a licensee may undertake categorization of its SSCs using risk insights and adjust treatment requirements based upon their resulting significance. Under this approach, a licensee would be allowed to reduce special treatment requirements for SSCs that are determined to be of low safety significance and would revise requirements for treatment of other SSCs that are found to be safety significant. The proposed requirements would establish a process by which a licensee would categorize SSCs using a risk-informed process, adjust treatment requirements consistent with the relative significance of the SSC, and manage the process over the lifetime of the plant.

To implement these requirements, a risk-informed categorization process would be employed to determine the safety significance of SSCs and place the SSCs into one of four risk-informed safety class (RISC) categories. It is important that this categorization process be robust to enable the NRC to remove requirements for SSCs determined to be of low safety significance. The determination of safety significance would be performed by an integrated decision-making process which uses both risk insights and traditional engineering insights. The safety functions would include both the design basis functions (derived from the "safety-related" definition, which includes external events), as well as functions credited for severe accidents (including external events). Treatment requirements for the SSCs are applied as necessary to maintain functionality and reliability, and are a function of the category into which the SSC is categorized. Finally, assessment activities would be conducted to make adjustments to the categorization and treatment processes as needed so that SSCs continue to meet applicable requirements. The proposed rule also contained requirements for obtaining NRC approval of the categorization process and for maintaining plant records and reports.

Proposed Rule Requirements

§ 50.69 Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors

(a) Definitions.

"Risk-Informed Safety Class (RISC)-1 structures, systems, and components (SSCs)" means safety-related SSCs that perform safety-significant functions.

"Risk-Informed Safety Class (RISC)-2 structures, systems and components (SSCs)" means nonsafety-related SSCs that perform safety-significant functions.

"Risk-Informed Safety Class (RISC)-3 structures, systems and components (SSCs)" means safety-related SSCs that perform low safety-significant functions.

"Risk-Informed Safety Class (RISC)-4 structures, systems and components (SSCs)" means nonsafety-related SSCs that perform low safety-significant functions.

"Safety-significant function" means a function whose degradation or loss could result in a significant adverse effect on defense-in-depth, safety margin, or risk.

(b) Applicability and scope of risk-informed treatment of SSCs and submittal/approval process.

(1) A holder of a license to operate a light water reactor (LWR) nuclear power plant under §§ 50.21(b) or 50.22, a holder of a renewed LWR license under Part 54 of this chapter; a person seeking a design certification under Part 52 of this chapter, or an applicant for a LWR license under § 50.22 or under Part 52, may voluntarily comply with the requirements in this section as an alternative to compliance with the following requirements for RISC-3 and RISC-4 SSCs:

(i) 10 CFR Part 21.

(ii) 10 CFR 50.49.

(iii) 10 CFR 50.55(e).

(iv) The inservice testing requirements in 10 CFR 50.55a(f); the inservice inspection, and repair and replacement, requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g); and the electrical component quality and qualification requirements in section 4.3 and 4.4 of IEEE 279, and sections 5.3 and 5.4 of IEEE 603-1991, as incorporated by reference in 10 CFR 50.55a(h).

(v) 10 CFR 50.65, except for paragraph (a)(4).

(vi) 10 CFR 50.72.

(vii) 10 CFR 50.73.

(viii) Appendix B to 10 CFR Part 50.

(ix) The Type B and Type C leakage testing requirements in both Options A and B of Appendix J to 10 CFR Part 50, for penetrations and valves meeting the following criteria:

(A) Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.

(B) Containment isolation valves that meet one or more of the following criteria:

(1) The valve is required to be open under accident conditions to prevent or mitigate core damage events;

(2) The valve is normally closed and in a physically closed, water-filled system;

(3) The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and that is not connected to the reactor coolant pressure boundary; or

(4) The valve is 1-inch nominal size or less.

(x) Appendix A to Part 100, sections VI(a)(1) and VI(a)(2), to the extent that these regulations require qualification testing and specific engineering methods to demonstrate that SSCs are designed to withstand the Safe Shutdown Earthquake and Operating Basis Earthquake.

(2) A licensee voluntarily choosing to implement this section shall submit an application for license amendment pursuant to § 50.90 that contains the following information:

(i) A description of the process for categorization of RISC-1, RISC-2, RISC-3 and RISC-4 SSCs.

(ii) A description of the measures taken to assure that the quality and level of detail of the systematic processes that evaluate the plant for internal and external events during normal operation, low power, and shutdown (including the plant-specific probabilistic risk assessment (PRA), margins-type approaches, or other systematic evaluation techniques used to evaluate severe accident vulnerabilities) are adequate for the categorization of SSCs.

(iii) Results of the PRA review process conducted to meet § 50.69 (c)(1)(i).

(iv) A description of, and basis for acceptability of, the evaluations to be conducted to satisfy § 50.69(c)(1)(iv). The evaluations shall include the effects of common cause interaction susceptibility, and the potential impacts from known degradation mechanisms for both active and passive functions, and address internally and externally initiated events and plant operating modes (e.g., full power and shutdown conditions).

(3) The Commission will approve a licensee's implementation of this section if it determines that the process for categorization of RISC-1, RISC-2, RISC-3, and RISC-4 SSCs satisfies the requirements of § 50.69(c) by issuing a license amendment approving the licensee's use of this section.

(4) An applicant for a license voluntarily choosing to implement this section shall include the information in § 50.69 (b)(2) as part of application for a license. The Commission will approve an applicant's implementation of

this section if it determines that the process for categorization of RISC-1, RISC-2, RISC-3, and RISC-4 SSCs satisfies the requirements of § 50.69(c).

(c) SSC Categorization Process.
(1) SSCs must be categorized as RISC-1, RISC-2, RISC-3, or RISC-4 SSCs using a categorization process that determines whether an SSC performs one or more safety-significant functions and identifies those functions. The process must:

(i) Consider results and insights from the plant-specific PRA. This PRA must at a minimum model severe accident scenarios resulting from internal initiating events occurring at full power operation. The PRA must be of sufficient quality and level of detail to support the categorization process, and must be subjected to a peer review process assessed against a standard or set of acceptance criteria that is endorsed by the NRC.

(ii) Determine SSC functional importance using an integrated, systematic process for addressing initiating events (internal and external), SSCs, and plant operating modes, including those not modeled in the plant-specific PRA. The functions to be identified and considered include design bases functions and functions credited for mitigation and prevention of severe accidents. All aspects of the integrated, systematic process used to characterize SSC importance must reasonably reflect the current plant configuration and operating practices, and applicable plant and industry operational experience.

(iii) Maintain the defense-in-depth philosophy.

(iv) Include evaluations that provide reasonable confidence that for SSCs categorized as RISC-3, sufficient safety margins are maintained and that any potential increases in core damage frequency (CDF) and large early release frequency (LERF) resulting from changes in treatment permitted by implementation of § 50.69(b)(1) and § 50.69(d)(2) are small.

(v) Be performed for entire systems and structures, not for selected components within a system or structure.

(2) The SSCs must be categorized by an Integrated Decision-making Panel (IDP) staffed with expert, plant-knowledgeable members whose expertise includes, at a minimum, PRA, safety analysis, plant operation, design engineering, and system engineering.

(d) Alternative treatment requirements.
(1) RISC-1 and RISC 2 SSCs. The licensee or applicant shall ensure that RISC-1 and RISC-2 SSCs perform their functions consistent with the categorization process assumptions by evaluating treatment being applied to these SSCs to ensure that it supports the key assumptions in the categorization process that relate to their assumed performance.

(2) RISC-3 SSCs. The licensee or applicant shall develop and implement processes to control the design; procurement; inspection, maintenance, testing, and surveillance; and corrective action for RISC-3 SSCs to provide reasonable confidence in the capability of RISC-3 SSCs to perform their safety-related functions under design basis conditions throughout their service life. The processes must meet the following requirements, as applicable:

(i) Design control. Design functional requirements and bases for RISC-3 SSCs must be maintained and controlled. RISC-3 SSCs must be capable of performing their safety-related functions including design requirements for environmental conditions (i.e., temperature and pressure, humidity, chemical effects, radiation and submergence) and effects (i.e., aging and synergism); and seismic conditions (design load combinations of normal and accident conditions with earthquake motions);

(ii) Procurement. Procured RISC-3 SSCs must satisfy their design requirements;

(iii) Maintenance, Inspection, Testing, and Surveillance. Periodic maintenance, inspection, testing, and surveillance activities must be established and conducted using prescribed acceptance criteria, and their results evaluated to determine that RISC-3 SSCs will remain capable of performing their safety-related functions under design basis conditions until the next scheduled activity; and

(iv) Corrective Action. Conditions that could prevent a RISC-3 SSC from performing its safety-related functions under design basis conditions must be identified, documented, and corrected in a timely manner.

(e) Feedback and process adjustment.
(1) RISC-1, RISC-2, RISC-3 and RISC-4 SSCs. In a timely manner but no longer than every 36 months, the licensee shall review changes to the plant, operational practices, applicable industry operational experience, and, as appropriate, update the PRA and SSC categorization.

(2) RISC-1 and RISC-2 SSCs. The licensee shall monitor the performance of RISC-1 and RISC-2 SSCs. The licensee shall make adjustments as necessary to either the categorization or treatment processes so that the categorization process and results are maintained valid.

(3) RISC-3 SSCs. The licensee shall consider data collected in § 50.69(d)(2)(iii) for RISC-3 SSCs to determine whether there are any adverse changes in performance such that the SSC unreliability values approach or exceed the values used

in the evaluations conducted to satisfy § 50.69 (c)(1)(iv). The licensee shall make adjustments as necessary to either the categorization or treatment processes so that the categorization process and results are maintained valid.

(f) Program documentation, change control and records.
(1) The licensee or applicant shall document the basis for its categorization of any SSC under paragraph (c) of this section before removing any requirements under § 50.69(b)(1) for those SSCs.

(2) Following implementation of this section, licensees and applicants shall update their final safety analysis report (FSAR) to reflect which systems have been categorized in accordance with § 50.71(e).

(3) When a licensee first implements this section for a SSC, changes to the FSAR for the implementation of the changes in accordance with § 50.69(d) need not include a supporting § 50.59 evaluation of the changes directly related to implementation. Thereafter, changes to the programs and procedures for implementation of § 50.69(d), as described in the FSAR, may be made if the requirements of this section and § 50.59 continue to be met.

(4) When a licensee first implements this section for a SSC, changes to the quality assurance plan for the implementation of the changes in accordance with § 50.69(d) need not include a supporting § 50.54(a) review of the changes directly related to implementation. Thereafter, changes to the programs and procedures for implementation of § 50.69(d), as described in the quality assurance plan may be made if the requirements of this section and § 50.54(a) continue to be met.

(g) Reporting. The licensee shall submit a licensee event report under § 50.73(b) for any event or condition that would have prevented RISC-1 or RISC-2 SSCs from performing a safety-significant function.

Public Comments

The NRC received 26 comment letters on the proposed rule. In addition, the NRC received feedback in response to several specific issues discussed in the proposed rule notice. A summary of the most significant of over 200 public comments on the proposed rule and feedback on specific issues is provided below:

1. Consideration of More Detailed Language for RISC-3 SSC Treatment Requirements.

   As discussed in the proposed rule notice, the Commission invited comment on whether more detailed rule language for RISC-3 treatment was necessary to provide reasonable confidence in RISC-3 design basis capability. For the most part, industry commenters asserted that there was no need for more detailed treatment requirements for RISC-3 SSCs in the rule. Comments from State organizations and public interest groups considered the proposed rule language to be inadequate to provide reasonable confidence in the capability of RISC-3 SSCs to perform their safety-related functions under design basis conditions. The public comments revealed a significant divergence in the interpretation of the proposed rule language by industry commenters from the expectations described in the SOC for the proposed rule.

2. PRA Requirements

   The Commission requested stakeholder comment on whether the NRC should amend the requirements in paragraph 10 CFR 50.69(c) to require a level 2 internal and external initiating events, all-mode, peer-reviewed PRA that must be submitted to, and reviewed by, the NRC. Stakeholder comments ranged from those supporting more extensive PRA requirements to those who conclude that the current PRA requirements in 10 CFR 50.69(c) are sufficient. The industry commenters stated that additional PRA requirements were not necessary. State organizations and public interest groups supported increased PRA requirements.

3. Review and Approval of RISC-3 Treatment

   The Commission requested stakeholder comment on whether the NRC should review and approve the RISC-3 treatment processes being developed by the licensee or applicant prior to implementation in addition to reviewing the categorization process. Public interest groups and comments from State organizations generally stressed the need for the NRC to review and approve RISC-3 treatment processes in advance of implementation to confirm appropriate treatment will be applied to RISC-3 SSCs given that these SSCs are safety-related. On the other hand, industry commenters did not consider prior review and approval of RISC-3 treatment to be necessary in light of the low safety significance of individual RISC-3 SSCs, other requirements that help maintain safety, and the availability of inspection and enforcement by the NRC.

4. Inspection and Enforcement

The Commission requested stakeholder comment on whether or not changes are needed in the NRC's reactor oversight process, including the inspection and enforcement program, to enable NRC to exercise the appropriate degree of regulatory oversight of these aspects of facility operation with regard to 10 CFR 50.69. The public comments on the proposed rule indicated general support for providing regulatory oversight of the implementation of processes established under 10 CFR 50.69 through the NRC's inspection and enforcement process. Some stakeholders considered the current inspection and enforcement process to be sufficient without adjustment. Other stakeholders recommended that the NRC consider additional training and guidance to inspectors to support implementation of 10 CFR 50.69.

5. Operating Experience

The Commission requested stakeholder feedback regarding the role that relevant operational experience could play in reducing the uncertainty associated with the effects of treatment on performance and specifically sought public comment as to what information might be available and how it could be used to support implementation of this rulemaking. Some stakeholders commented that relevant operating experience argues against the removal of special treatment requirements and that regulatory attention should be increased for this equipment. Other stakeholders suggested that there is a large amount of data that demonstrates that commercial and safety-related SSCs have comparable failure rates with the implication that special treatment requirements can be removed with little impact. Other stakeholders commented that there are already opportunities for industry to share experience data with existing industry and regulatory programs implying that a new program is not necessary.

6. SOC Guidance

Numerous comments were received from the industry regarding the nature of the information in the proposed rule's SOC supporting both 10 CFR 50.69(c) and (d)(2). Several industry commenters stated that the discussion in the SOC was inconsistent with the rule requirements. For example, some commenters suggested that, contrary to the SOC discussion, the treatment requirements for RISC-3 SSCs in 10 CFR 50.69(d)(2) would allow exercising of pumps and valves as a means of providing reasonable confidence in the design basis capability of those components. Another commenter claimed that, contrary to the SOC discussion, 10 CFR 50.69 would allow the leakage tests required by 10 CFR Part 50, Appendix J, for containment isolation valves to be eliminated without considering the capability of those valves to close under design basis conditions. Other commenters asserted that the corrective action process alone would be sufficient to satisfy the high-level requirements for feedback and monitoring of RISC-3 SSCs in 10 CFR 50.69.

7. RISC-3 Treatment Requirements

Numerous stakeholder comments were received concerning the 10 CFR 50.69(d)(2) requirements for RISC-3 SSCs. Some public stakeholders provided their view that the RISC-3 treatment requirements were inadequate in light of previous industry experience (e.g., regarding the use of substandard parts) and that more detailed RISC-3 requirements are needed to address common cause failures, significant degradation, and in general to avoid an increase in risk to the health and safety of the public. Industry stakeholders tended to view the RISC-3 requirements as too prescriptive and beyond what is necessary to maintain reasonable confidence of RISC-3 SSC design basis capability. Some of the industry comments revealed that the rule requirements might not be implemented consistent with the NRC's expectations discussed in the SOC.

8. Seismic Experience Data

Several industry commenters stated that the SOC for the proposed rule might create additional burden on plants licensed prior to implementation of Appendix A to 10 CFR Part 100. Industry commenters also raised concerns regarding the SOC discussion on use of seismic experience data. Some commenters implied that it would be acceptable to use "experience data" alone to have reasonable confidence that an SSC is capable of functioning during an earthquake even if there is no actual "experience data" for the SSC.

9. Feedback

Several industry commenters requested adjustments to the feedback requirements in 10 CFR 50.69(e)(1) to provide more efficient implementation of the rule. For example, one commenter suggested that the maximum time interval for updating the categorization and treatment processes be modified from 36 months to two refueling outages.

10. Basis for RISC-3 SSC Reliability

A number of comments were received regarding the technical basis for the RISC-3 SSC reliability (failure rates) to be used in the risk sensitivity study performed under 10 CFR 50.69(c)(1)(iv) to demonstrate reasonable confidence that any potential risk increase from implementation of the rule is maintained acceptably small. Some commenters suggested that licensees or applicants that voluntarily implement the rule should be required to characterize and reasonably bound the specific effects of eliminating treatment on SSC reliability under design basis and severe accident conditions. Other commenters suggested that there is evidence that reductions in treatment (using industry practices) have no impact on SSC reliability.

11. Crediting SSCs

    A number of industry commenters indicated that statements in the SOC specifically obligated a licensee implementing 10 CFR 50.69 to evaluate treatment applied to all safety significant SSCs to ensure adequacy of treatment and cited this as an added burden that is neither necessary nor appropriate because RISC-1 SSCs are already subjected to full regulatory requirements. Another commenter stated that the additional performance conditions (beyond what is assumed in the design basis) to address PRA performance assumptions should not be subject to 10 CFR 50, Appendix B, requirements that remain for RISC-1 SSCs and indicated that the design control documentation necessary to capture the assumptions made in the categorization process will place a large implementation cost on plants. Another commenter recognized that, while RISC-1 SSCs performing beyond design basis functions and RISC-2 SSCs may require additional special treatment requirements to be applied, they interpreted the NRC intent in the SOC as requiring all safety significant SSCs (RISC-1 and RISC-2) to be subjected to enhanced regulatory control.

12. Adequate Protection

    The staff received several comments indicating that the proposed regulation would not maintain adequate protection of public health and safety. The public comments on proposed 50.69 revealed divergent interpretations of the high-level requirements for the treatment of RISC-3 SSCs in 10 CFR 50.69.

13. License Amendment

    Some stakeholders commented that the proposed requirement to prepare, submit, and then receive approval of a license amendment in order to implement 10 CFR 50.69 is a disincentive to its use. It was commented that, in light of the desire to move to a more performance-based regulatory regime, voluntary implementation of 10 CFR 50.69 should be developed by licensees using the requirements in the rule and any attendant regulatory guidance, with routine NRC inspection serving to verify acceptable compliance.

Review of Public Comments

At the time of preparing this paper, the NRC staff was reviewing public comments on proposed 10 CFR 50.69 for resolution. The schedule provides a goal of completing the review of public comments and preparing a final rule later in 2004.

IV. CONCLUSIONS

The NRC regulations specify special treatment requirements for SSCs that perform safety functions at U.S. commercial nuclear power plants. These requirements address such aspects of SSC functional capability as environmental and seismic qualification, quality assurance, and inservice inspection and testing, and are based principally on deterministic considerations. The NRC prepared proposed 10 CFR 50.69 that would allow the application of risk insights to determine appropriate treatment for plant SSCs in lieu of the current special treatment requirements. The NRC staff is reviewing public comments on proposed 10 CFR 50.69 with publication of the rule anticipated later in 2004. If implemented effectively, the rule will allow NRC and licensee to focus their resources for the treatment of SSCs commensurate with their importance to health and safety. It will provide flexibility in plant operation and design which can result in burden reduction without compromising safety. The risk-informed regulation initiative and the STP exemption review reflect the NRC's ongoing efforts to incorporate risk insights into the regulation of nuclear power plants.

V. REFERENCES

Federal Register, 68 FR 26511, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," May 16, 2003.

Letter dated August 3, 2001, to William T. Cottle, STPNOC, from John A. Zwolinski, NRC, regarding South Texas Project, Units 1 and 2 - Safety Evaluation on Exemption Requests from Special Treatment Requirements of 10 CFR Parts 21, 50, and 100.

SECY-98-300 (December 23, 1998), "Options for Risk-Informed Revisions to 10 CFR Part 50 - Domestic Licensing of Production and Utilization Facilities."

SECY-99-256 (October 29, 1999), "Rulemaking Plan for Risk-Informing Special Treatment Requirements."

SECY-00-0194 (September 7, 2000), "Risk-Informing Special Treatment Requirements."

SECY-02-176 (September 30, 2002), "Proposed Rulemaking to Add New Section 10 CFR 50.69, 'Risk-Informed Categorization and Treatment of Structures, Systems, and Components.'"

Increased Component Reliability Utilizing Risk Insight and Refined Maintenance Optimization (RMO) Approaches

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Abstract

Equipment reliability is – "The assurance that the function of structures, systems, trains and components will perform upon demand and sustain their function for their intended design mission time." Reliability included in the original plant design is sustained over the plant life by the integration of Preventive Maintenance (PM) and Predictive Maintenance (PdM) strategies with appropriate inspection and test technologies.

The Sargent & Lundy (S&L) Refined Maintenance Optimization (RMO) process focuses on the criticality of components using a risk insight approach and a more refined optimization of maintenance requirements. The Refined Maintenance Optimization is aimed at improving plant component reliability and reducing overall maintenance costs. The RMO process is a more focused and detailed approach that is the next step beyond the industry template driven approaches. It is not a "cookie cutter" approach and it requires more detailed and analytical engineering evaluations using an integrated multi-talented team and extensive repository of testing data. The RMO approach complements and adds considerable value to plant maintenance optimization (MO) programs.

The RMO process utilizes innovative techniques to cost effectively optimize maintenance tasks and frequencies. By utilizing "Refined Maintenance Optimization" approach, the plant owner is able to:

- Reduce overall maintenance costs while improving equipment reliability.
- Show quick payback on RMO investment.
- Achieve significant economies of scale for similar component types in other plant systems through leveraging RMO project results.
- Potentially reduce dose.

Background

Over the past several years, a number of industry initiatives have been implemented to formulate acceptable approaches for determining criticality of components. In this regard, the American Society of Mechanical Engineers (ASME), Electric Power Research Institute (EPRI), Institute of Nuclear Power Operations (INPO), and various industry users groups have published papers and guidelines to provide users with the necessary guidance to properly categorize and determine criticality of components. Most of these approaches utilize risk insight approaches. The primary reasons for this effort can be summarized as follows:

- Identification of critical components will ensure that, from a safety and reliability perspective, engineering, maintenance, and operation resources can be focused on the right components to maintain reliable plant operation.
- Effective maintenance strategies can be formulated and implemented for critical components based on the degree of component criticality. In other words, maintenance strategies for critical components would differ from those components that are categorized as non-critical components.

Once the criticality of components has been determined, the next step is to develop the most effective maintenance strategies for critical and non-critical components. The maintenance strategies will depend on many factors including the criticality of components. A number of plants use the techniques published by EPRI, INPO, and various users groups, while others have developed their own techniques to support maintenance optimization effort. The common thread in these approaches is the use of varying criteria, some risk and other non-risk based, to first determine the criticality of components and then move forward with maintenance optimization.

This paper presents an acceptable approach and proven technique to determine the criticality of components using a risk insight approach. It also introduces a unique process to optimize current maintenance requirements and frequencies. This unique maintenance optimization approach is known as Refined Maintenance Optimization.

Methodology for Risk Informed Categorization

Nuclear power plants have developed plant specific Probability Risk Assessment (PRA) models that incorporate several major components. However, these PRA models usually do not address all components subject to risk. Because of this, the industry has developed various techniques to identify critical components based on risk. Several plants have reviewed the application of various risk-based component categorization techniques and found them to be expansive in scope and not economically feasible. The method documented in this paper provides a cost-effective approach for categorizing valves. This approach can be easily expanded, modified, and streamlined to determine criticality of other components in the plant.

Figure 1 provides an overview of risk-based approach to categorize valves. The determination of valve category will employ system's risk significance data as documented in the station's Maintenance Rule (MRule) program. Utilizing MRule data will ensure consistency between the valve and MRule programs as it pertains to risk informed ranking of structures, systems, and components (SSCs). The approach presented in Figure 1 provides a structured and systematic method for categorizing valves which will achieve the following:

- Determination of critical valves based on safety classification, functional requirements, MRule risk significance, and economics.
- Focusing of resources for performance of valve design bases, testing, and maintenance activities as defined by the station valve programs.
- Identification of scope of valves for maintenance optimization effort.

Refined Maintenance Optimization (RMO) Approach

The objective of current industry and regulatory initiatives is to ensure safe plant performance (i.e., improve plant performance and reliability) and reduce/control operating and maintenance costs to remain competitive. To achieve these objectives, systematic techniques and cost effective methods are needed to:

- Identify critical systems and components.
- Focus engineering, maintenance, and financial resources on the right systems and components.
- Develop and implement cost-effective maintenance strategies.
- Prioritize engineering and maintenance activities by implementing maintenance strategies on the right components.
- Migrate from unplanned maintenance to planned maintenance.
- Establish measurable performance indicators.

Although several industry initiatives have produced a number of documents to perform risk informed categorization of components, not much has been published in the past several years for maintenance optimization. Most utilities have some type of a maintenance optimization program in place. Typically, these maintenance optimization programs were developed based on guidelines established by the industry and utility users group. It is our experience that the results achieved through implementation of these industry guidelines result in conservative preventive maintenance (PM) and predictive maintenance (PdM) requirements and frequencies resulting in:

- Many maintenance tasks and additional maintenance burden (i.e., costs).
- Deferral of PMs with limited bases and minimal justification.
- Increase in maintenance backlog.

The Refined Maintenance Optimization (RMO) process goes beyond the current industry template driven maintenance optimization approach and reduces maintenance costs while improving equipment reliability. RMO is built around a unique set of processes, technologies, and people; and each of these attributes are briefly summarized as follows:

The Process

A unique process and implementing procedure is developed that improves work efficiency and ensures a consistent level of quality that meets or exceeds industry and plant specific requirements. The RMO process is aimed at improving plant equipment reliability and reducing overall maintenance costs. Several plants have realized favorable results using this approach. Figures 2 and 3 show the overall RMO process.

The Technologies

Existing industry and plant-specific component test data is leveraged to support the RMO process and obtain meaningful results. The repository of this data acquired over the past two decades is used to quickly produce quantifiable results with sound technical bases.

The People

Effective execution of RMO projects requires a focused, integrated, and multi-talented team of individuals with system, component, maintenance, and aging management experience. Use of an integrated team allows the process to be effective by leveraging and utilizing the project team's core competencies. This integrated team will also bring multi-industry best practices to the table.

The following case studies are presented that demonstrate the success and significant benefits from employing the RMO approach:

Case Study 1: Diaphragm Valve Project (Categorization & RMO)

RESULT OF RISK BASED VALVE CATEGORIZATION	
Category 1: High Safety Significant	59
Category 2: Low Safety Significant	86
Category 3: Economically Significant	187
Category 4: Others	726
Total	**1058**

PLANNED MAINTENANCE COST					
Frequency	Number of PMs	X	Total Number of PMs	Average* Cost/PM	Total Cost
4 Years	59**	5	295	$5,700	$1,681,500
				Current Planned Level of Effort:	**$ 1,681,500**

* Maintenance labor/parts cost. Does not include work planning and associated costs.

** Scope of project was for 59 category 1 valves.

RMO PROJECT INVESTMENT	
Actual cost of performing the RMO project	**$60,000**

REVISED PLANNED MAINTENANCE COST WITH TECHNICAL BASES					
Frequency	Number of PMs	X	Total Number of PMs	Average Cost/PM	Total Cost
3 Years	1	6	6	$5,700	$34,200
10 Years	5	2	10		$57,000
20 Years	38	1	38		$216,600
30 Years	15	1	15		$85,500
				Revised Planned Level of Effort:	**$ 393,300**

CUMULATIVE COST AND SAVINGS	
Current Planned Level of Effort	$1,681,500
RMO Project Investment	($60,000)
Revised Planned Maintenance Cost Using S&L Refined Approach	($393,300)
SAVINGS	**$1,228,200**

SIMPLE PAYBACK ANALYSIS			
PLANNED		REVISED PLANNED	
Cumulative:	$1,681,500	Cumulative:	$393,300
Annual:	$84,075	Annual:	$19,665
Savings/Year		$64,400	
Required Investment		$60,000	
Payback		**< 1 Year**	

Case Study 2: Air Operated Valve (AOV) Project (Categorization)

RESULT OF RISK BASED VALVE CATEGORIZATION	
Category 1: High Safety Significant	66
Category 2: Low Safety Significant	609
Category 3: Economically Significant	113
Category 4: Others	624
Total	**1412**

Case Study 3: Air Operated Valve (AOV) Project (RMO)

System: Bleed Steam				Total Number of AOVs: 169	
CURRENT PLANNED MAINTENANCE COST					
Frequency	Number of PMs	X	Total Number of PMs	Average Cost/PM	Total Cost
Planned Valve Assembly Overhauls:					
6 Years	29	4	116	$6,900	$800,400
12 Years	140	2	280	$6,900	$1,932,000
Planned Actuator Assembly Overhauls:					
6 Years	168-29=139	2	278	$4,100	$1,139,800
				Current Planned Level of Effort:	**$3,872,200**
* Maintenance labor/parts cost. Does not include work planning and associated costs.					

RMO PROJECT INVESTMENT	
Cost of performing the RMO project	**$75,000**

PROJECTED PLANNED MAINTENANCE COST	
Diagnostic Testing	$245,000
Valve Assembly Overhauls	$62,000
Actuator Assembly Overhauls	$177,000
Total	**$484,000**

CUMULATIVE COSTS AND SAVINGS	
Current Planned Level of Effort	$3,872,000
MO Project Implementation Cost (Investment)	($75,000)
Projected Planned Maintenance Cost Using S&L Refined Approach	($484,000)
SAVINGS	**$3,313,000**

SIMPLE PAYBACK ANALYSIS			
CURRENT PLANNED		PROJECTED PLANNED	
Cumulative:	$3,872,000	Cumulative:	$484,000
Annual:	$161,000	Annual:	$20,200
Savings/Year		$140,800	
Required Investment		$75,000	
Payback		**≅ 6 Months**	

Conclusion

Significant benefits can be realized from utilizing risk insight and RMO approaches. As the case studies demonstrate, RMO projects can successfully reduce the plant's overall maintenance costs and improve component reliability. It is expected that the following benefits will be realized from implementing an RMO project:

Quantitative

- Reduced Overall Maintenance Cost
- Reduced Maintenance Labor Burden
- Material/Parts Procurement Cost Reduction
- Potential Dose Reduction
- Potential Reduction of Outage Tasks

Qualitative

- Documented Bases
- Increased Reliability (INPO AP-913)
- Reduced Scheduling & Planning
- Reduced Likelihood of Error
- Proper Identification of all PM Tasks and Intervals.

Figure 1
Risk Insight Categorization Flowchart

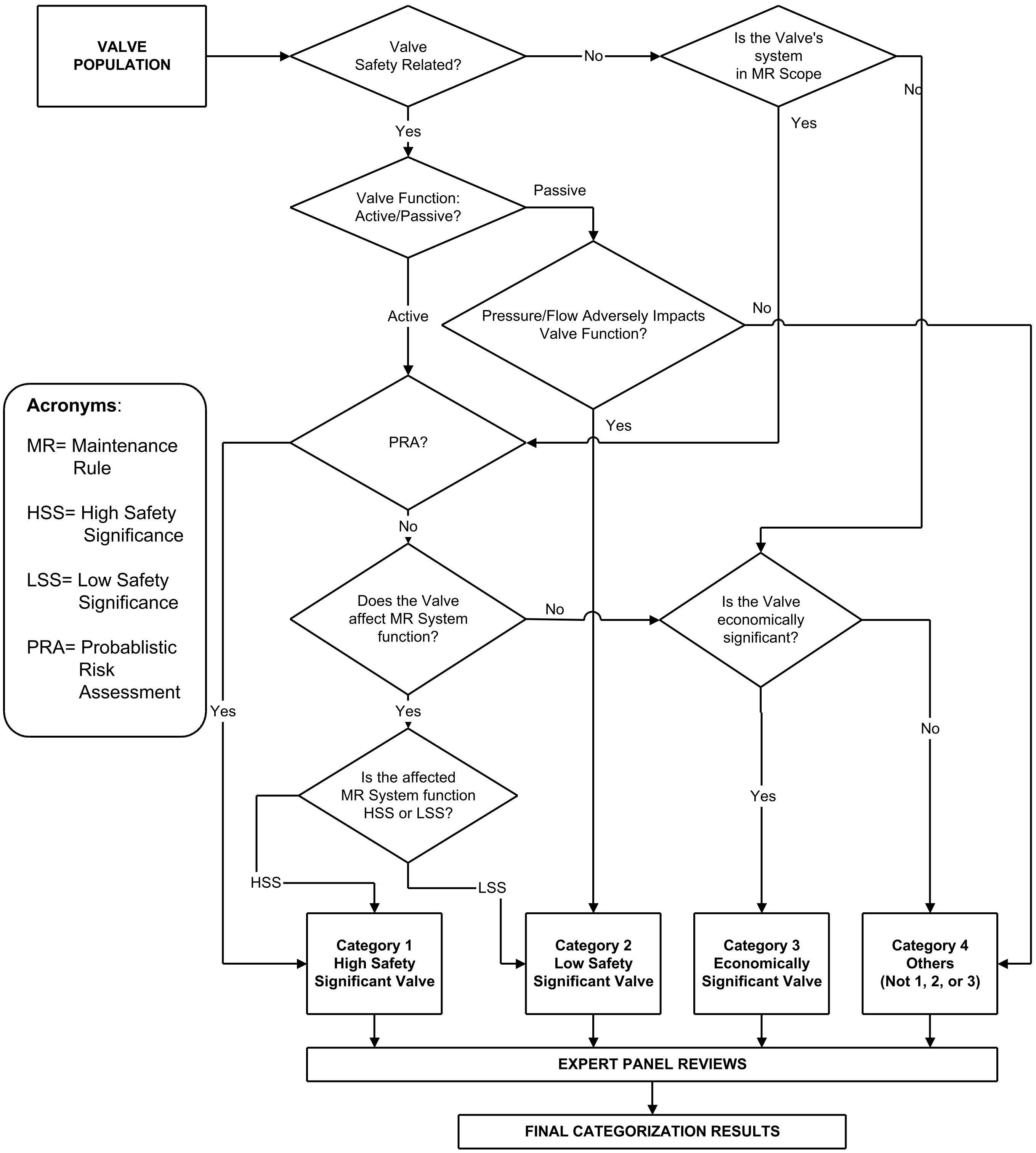


Figure 2
Refined Maintenance Optimization
Bubble Chart

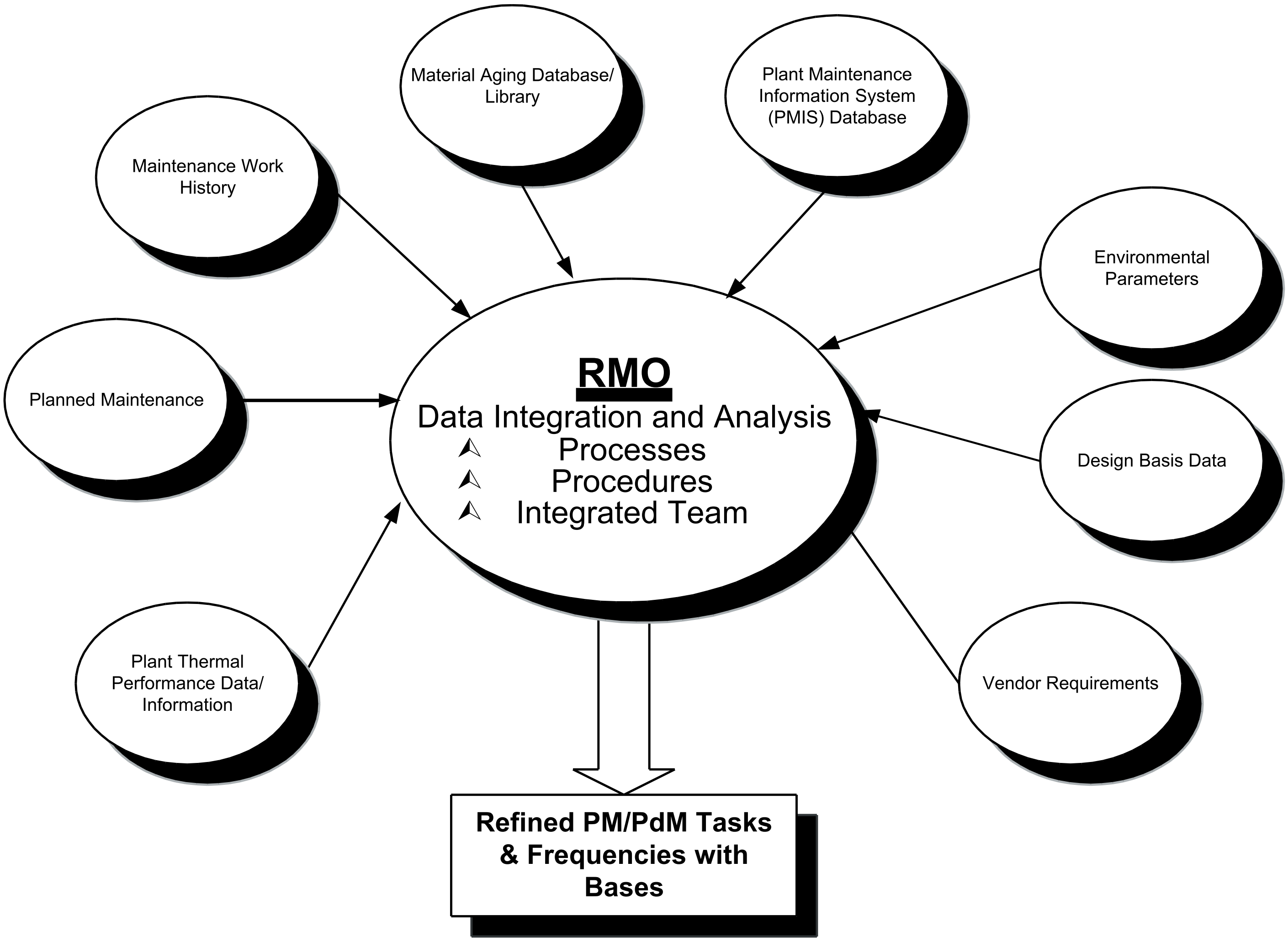
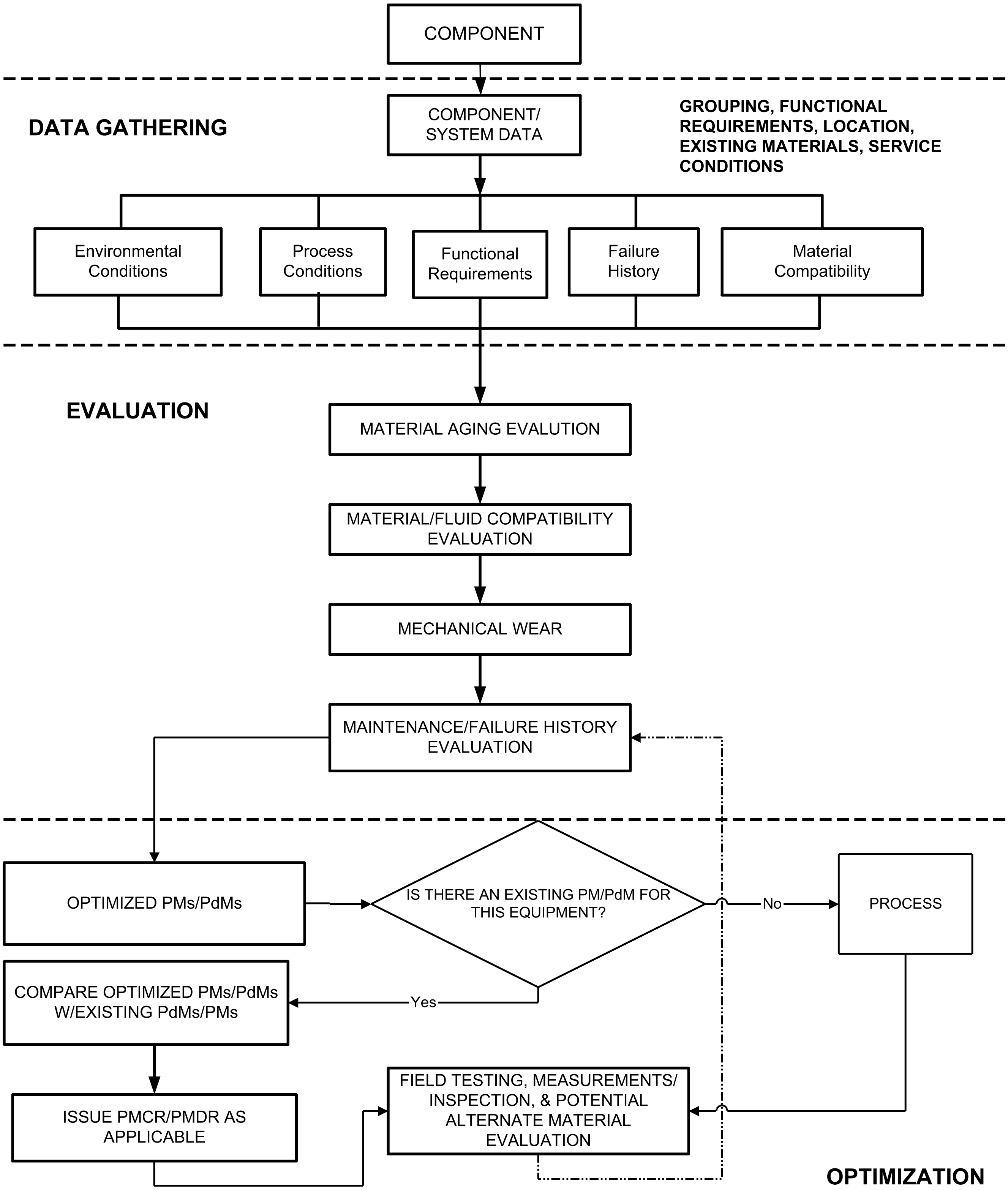


Figure 3
RMO Process Flowchart



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Proposed ASME OM Code Subsection ISTE – A Presentation of the Concepts of Component Testing

Craig D. Sellers

Alion Science and Technology

Abstract

Proposed Subsection ISTE of the American Society of Mechanical Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code) provides mandatory requirements for owners who voluntarily elect to implement a risk-informed inservice testing (IST) Program. The proposed Subsection was prepared by combining the component categorization requirements and methodology from Code Case OMN-3 with high-level inservice test requirements for components developed on philosophies from Code Case OMN-1 (performance-based testing for motor-operated valves) and OM Code Appendix II (check valve condition monitoring).

The proposed test strategies for High Safety Significant Component (HSSC) Pumps and Power-Operated Valves are derived the performance-based testing philosophy of Code Case OMN-1 (performance-based testing for motor-operated valves). The performance-based test philosophy of OMN-1 is presented in a non-prescriptive fashion providing flexibility allowing the owner to determine appropriate parameters for monitoring and trending on a component, or component group basis. The proposed test strategy for Low Safety Significant Component (LSSC) components is specified as non-diagnostic exercising on a frequent basis supplemented by performance monitoring, diagnostic examination to verify design basis capability on an infrequent basis, and a requirement to maintain component reliability.

This paper presents the concept of Code Case OMN-1 performance-based testing for motor-operated valves (MOVs) and its application to other HSSC power-operated components. It also describes the expansion of OM Code Condition Monitoring requirements beyond check valves and presents the basis for LSSC test requirements.

1.0 INTRODUCTION

Proposed Subsection ISTE provides mandatory requirements for owners who voluntarily elect to implement a risk-informed inservice testing (IST) Program. The proposed Subsection was prepared by combining the component categorization requirements and methodology from Code Case OMN-3, *Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants*,[1] with high-level inservice test requirements for components developed on philosophies from Code Case OMN-1, *Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants OM Code-1995, Subsection ISTC*,[2] and OM Code Appendix II, *Check Valve Condition Monitoring Program*.[3]

A basic tenant of risk-informed inservice testing is to focus activities and resources on High Safety Significant Components (HSSCs) while reducing efforts on Low Safety Significant Components (LSSCs). Baseline IST requirements are those of the current OM Code. Applying this risk-informed tenant to IST requirements, one would increase OM Code test requirements for HSSCs and decrease OM Code test requirements for LSSCs. The proposed Code Case was developed on this basis.

The proposed test strategies for HSSC pumps and power-operated valves are derived the performance-based testing philosophy of Code Case OMN-1.[2] The performance-based test philosophy of OMN-1, in which test frequency is based on the margin between observed performance and required performance, is capable of identifying and trending degradation that could lead to component failure. This is consistent with the requirements of Code Case OMN-3,[1] and represents increased test requirements to those in the current OM Code.

The proposed test strategy for HSSC self-actuated valves is to place the valves in a condition monitoring program consistent with OM Code Appendix II, *Check Valve Condition Monitoring Program*.[3] Condition monitoring programs implement inservice activities capable of identifying and trending degradation that could lead to component failure which is also consistent with the requirements of Code Case OMN-3,[1] and represents increased test requirements to those in the current OM Code.

The proposed test strategy for LSSC components is specified as non-diagnostic exercising on a frequent basis supplemented by performance monitoring, diagnostic examination to verify design basis capability of power-operated components on an infrequent basis, and a requirement to maintain component reliability. These inservice test activities combined provide confidence in component operational readiness and represent a decrease in test requirements to those in the current OM Code.

2.0 HSSC Test Requirements

The proposed test strategy for HSSC self-actuated valves is to place the valves in a condition monitoring program consistent with OM Code Appendix II.(3) The requirements from OM Code Appendix II were placed verbatim into the proposed ISTE except that the term "check valve" was replace with "valve" to expand applicability to additional self-actuated valves such as relief valves. Additionally, the Appendix II requirements on grouping and documentation were incorporated into those specific sections of ISTE.

The proposed test strategies for HSSC pumps and power-operated valves are derived the performance-based testing philosophy of Code Case OMN-1.(2) OMN-1 describes a methodology for performance-based testing of electric motor-operated valves in which the available valve stem torque is compared to the required stem torque and the functional margin determined. (Valve performance parameters other than stem torque, such as stem thrust, are allowed.) The required test interval is determined based on analysis of time-related changes in functional margin. An example determination of test interval is shown in ***Figure 1***.

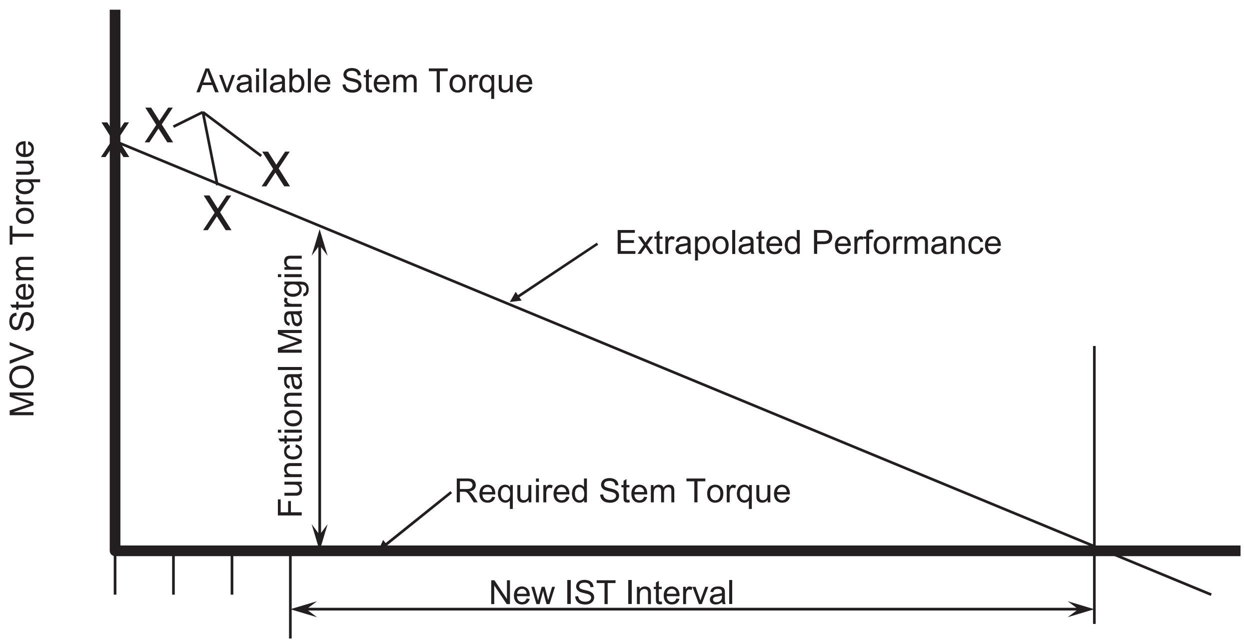
Code Case OMN-1 describes multiple methods for determining required and available stem torque including analytical means if justified.

Proposed ISTE takes this general methodology for determining test interval based on functional margin, expands it to include the concept of limit margin, and applies it to all pumps and power-operated valves. Rather than specifying specific parameters to use in assessing performance margins, proposed ISTE requires the owner to specify and justify the selected parameters.

1.1 High-Level Requirements

Two options were considered for applying OMN-1 requirements to components other than MOVs. One option was to add prescriptive requirements for the additional components and the other was to remove prescriptive MOV requirements.

Figure 1
Example Determination of Test Interval



The option chosen was to remove the prescriptive requirements applicable to MOVs and develop high-level requirements that can be applied to all power-actuated components. The basis for this choice was two-fold. First, owners implementing risk-informed programs will be making major changes to the way they do business and having to develop new programs for structure, system, and component treatment. Imposing prescriptive requirements would hinder this process. Second, adding prescriptive requirements would fail to address new component designs, possibly fail to address all current components, and significantly expand the volume of the subsection.

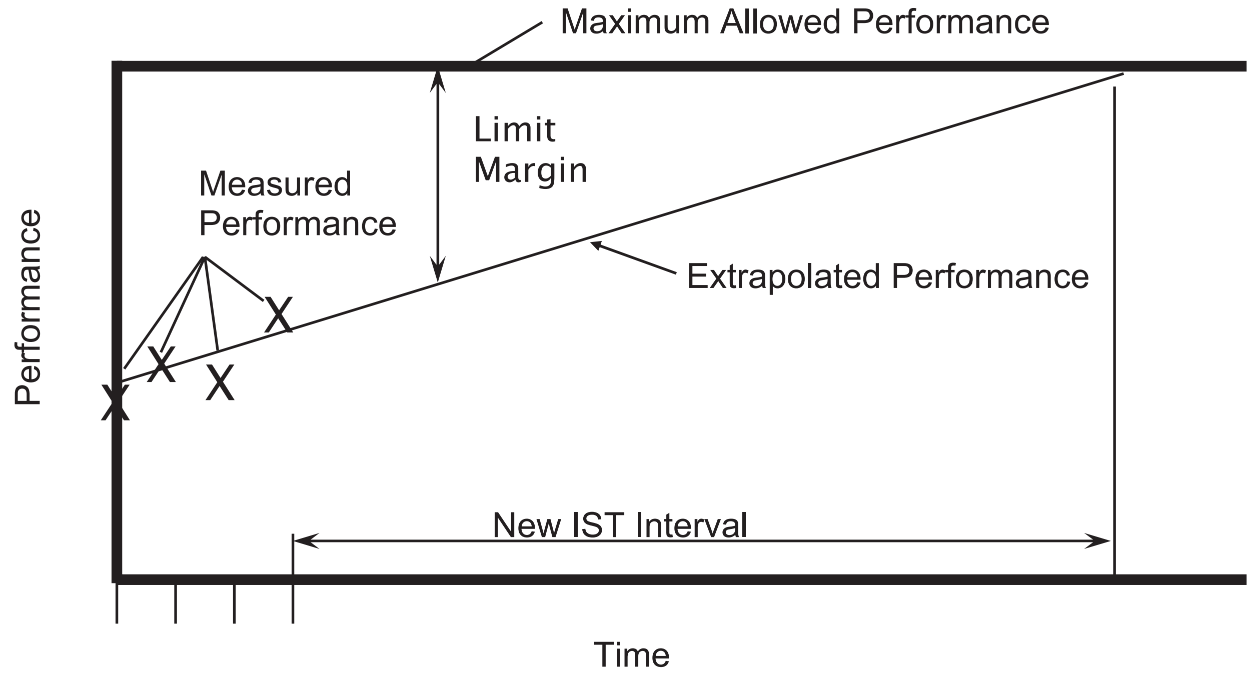
Additionally, while OMN-1 specifies prescriptive requirements for determining required and available MOV stem torque based on testing at design basis conditions, it also allows the use of alternative analytical methods with justification. Prescriptive requirements for these analytical methods and justification of the methods are not provided. In developing the proposed ISTE, the decision was made to exclude prescriptive requirements for determining required and available performance parameters in lieu of specific requirements for the owner to select and justify appropriate parameters.

1.2 Limit Margin

The concept of limit margin is introduced in the proposed ISTE and has been the subject of many comments. Functional margin is defined as the increment by which a component's available capability exceeds the capability required to operate under design basis conditions. This definition is derived from the Code Case OMN-1 definition of MOV functional margin. Proposed ISTE defines limit margin as the increment by which a component's maximum allowable performance exceeds the observed performance.

Limit margin is very similar to functional margin; the difference being functional margin compares observed performance to required performance while limit margin compares observed performance to allowable performance. Functional margin typically assesses performance parameters where reduction in performance is of primary concern, such as stem torque, stroke time, pump flow, and pump developed head. Limit margin assesses performance parameters where increase in performance is of primary concern, such as stem thrust, bearing vibration, and lubricant contamination. An example determination of test interval based on limit margin is shown in ***Figure 2***.

Figure 2
Example Determination of Test Interval Based on Limit Margin



1.3 Acceptance Criteria

Proposed ISTE specifies the use of acceptance criteria where ISTB and ISTC use reference values. The acceptance criteria required by ISTE are identical to reference values in ISTB and ISTC except that individual parameters are not specified.

Example performance parameters for use as acceptance criteria in the determination of functional and limit margins include:

Component	Functional Parameter	Limit Parameter
MOVs:	Required Stem Thrust Required Stem Torque	Allowable Stem Thrust Allowable Stem Torque Allowable Motor Torque
Air-Operated Valves (AOVs):	Required Stem Thrust Required Spring Force	Allowable Stem Thrust Allowable Packing Load Allowable Spring Relaxation
Hydraulic-Operated Valves (HOVs):	Required Stem Thrust Required Spring Force	Allowable Stem Thrust Allowable Packing Load
Solenoid-Operated Valves (SOVs):	Required Stem Time Required Coil Saturation Time	Allowable Coil Current
Pumps:	Discharge Pressure Required Flow Rate	Allowable Vibration Allowable Lube Contamination

3.0 LSSC Inservice Test Requirements

The proposed test requirements for LSSC pumps and power-operated valves are exercising on a refueling interval and design basis capability verification on a 10-year interval. Proposed test requirements for LSSC self-actuated valves are exercising on a refueling interval for check valves and either exercising or replacement on a 10-year interval for relief valves. All LSSC testing is supplemented with performance monitoring and a requirement to maintain component reliability. Consistent with the intent of risk-informed initiatives, this represents a relaxation in testing requirements from the current OM Code.

The basis for this reduced level of testing and examination is the low safety-significance of the components. The process and requirements for categorizing components as low safety-significant verifies that plant safety is maintained even when a LSSC fails. The exercising and performance monitoring on LSSCs, and the requirement to maintain component reliability, continually assesses the performance of the LSSCs from a population and common-mode failure perspective and provides the owner confidence in operational readiness.

4.0 References

1. Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants, ASME OM Code Case OMN-1.
2. Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor-Operated Valve Assemblies in Light-Water Reactor Plants OM Code-1995, Subsection ISTC, ASME OM Code Case OMN-1.
3. Check Valve Condition Monitoring Program, ASME OM Code Appendix II.

Session 2(b): Valves II

Session Chair

Steven M. Unikewicz

U.S. NRC

Effect of Butterfly Valve Disc Shape Variations on Torque Requirements for Power Plant Applications

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ABSTRACT

Tests sponsored by the U.S. Nuclear Regulatory Commission (NRC) at the Idaho National Engineering and Environmental Laboratory (INEEL) under the "Containment Purge and Vent Valve Test Program" in 1985 showed that manufacturers' methods for predicting torque requirements had serious limitations. Under design basis conditions, torque requirements in single-offset valves with shaft downstream were found to be self-opening, instead of self-closing as predicted by valve manufacturers. It was also found that variations in butterfly disc shapes are quite large and the influence of disc shape, upstream piping configuration, ΔP (differential pressure) and unchoked vs. choked flow conditions on torque requirements in compressible and incompressible flows had not been adequately addressed by the industry. The Electric Power Research Institute (EPRI), under its Motor-Operated Valve (MOV) Performance Prediction Program (1990-1994), developed analytical models and conducted tests to address some of these shortcomings. However, the models were based on simple analytical approaches with large conservatism to cover known uncertainties, and testing was limited to incompressible flow with only symmetrical and single-offset disc geometries. Furthermore, the EPRI methodology was developed for MOVs, which have a constant actuator output torque capability and, therefore, did require position dependent accuracy in torque predictions for margin evaluation. Torque prediction methodologies for Air-Operated Valves (AOVs) need to have position dependent accuracy because AOV actuator output varies with stroke. Consequently, the MOV methodologies are generally not suitable for accurate assessment of AOV margins.

This paper presents highlights of a comprehensive and advanced butterfly valve model development program that overcomes above limitations. Incompressible and compressible flow test programs have been described in earlier papers. The focus of this paper is to present the key results from analytical research and testing that overcome limitations that were identified in earlier programs. The disc shape and certain key geometric features that influence the valve performance are discussed. This paper also provides examples of the advanced models and the benefits derived from the efficient use of the massive database of flow and torque coefficients by software to address design basis evaluations for both incompressible and compressible flow plant applications

INTRODUCTION

To meet an important industry need for evaluating the capability of safety-related Air-Operated Valves (AOVs) to operate under design basis conditions, Kalsi Engineering, Inc., initiated a comprehensive program to develop validated models for quarter-turn valves. The program included development of first principle models, extensive computational fluid dynamics (CFD) analyses, and flow loop tests (incompressible and compressible flows) on all common types of AOV quarter-turn valves. The test program included systematic evaluation of a wide matrix of disc shapes, elbow orientations and proximities, and pressure drop ratios/flow rates on the required torque. The program was conducted under a quality assurance (QA) program that meets the Appendix B requirements in Part 50 to Title 10 of the *Code of Federal Regulations* (10CFR50). Earlier papers [1, 2]* provide and overview of the incompressible and compressible flow test programs. The products of this program are advanced, validated models and software (KVAP™) for AOV/MOV design basis sizing and margin calculations [13].

The new models and KVAP software have significantly advanced the state-of-the-art and provide the most comprehensive database in the industry for accurately predicting performance of all common types of quarter-turn and linear valves. This paper presents an overview of the previous industry developments relevant to this program, provides a discussion of key results/insights, and summarizes plant experience and the benefits achieved by the utilities from application of these new models at many nuclear power plants.

LIMITATIONS OF EARLIER BUTTERFLY VALVE PROGRAMS

NRC/INEL Containment Purge and Vent Valve Test Program

A survey performed by NRC/INEL [5] showed that valve manufacturers did not have validated methodologies for reliable torque predictions of butterfly valves that appropriately take into account the variations in disc geometry as a function of valve size, pressure class, and model; fluid media (compressible or incompressible); and pressure drop ratios and flow rates from fully choked to unchoked/low ΔP conditions. Many manufacturers had performed tests on a few small valves (usually 8" or smaller) and developed sizing predictions for their entire product line without considering the geometric deviations with valve size/pressure class and validating the predictions against large valve tests. Compressible flow tests were generally performed under low flow/low ΔP unchoked conditions across the valve; and the performance under choked flow conditions had not been properly addressed. The effect of different elbow configurations and their proximities on torque requirements had also not been evaluated by most manufacturers.

Under the "Containment Purge and Vent Valve Test Program," U.S. NRC/INEL performed tests on three butterfly valves (two 8" and one 24" valves from two manufacturers) with gaseous nitrogen under blowdown conditions [4, 5]. Testing was limited to single-offset disc design (Figure 1), because the NRC survey showed that this design had the dominant population in the U.S. nuclear power plants. The program included testing with upstream elbows at valve inlet with four different configurations.

One of the most surprising test results found by NRC/INEL was that under design basis conditions, the valve performance with shaft downstream orientation was totally opposite of manufacturers' predictions (self-opening throughout the stroke instead of self-closing over majority of the stroke).

The program did not include symmetric disc, double- and triple-offset disc designs, even though the population of double-offset disc designs in containment purge applications is relatively significant. Furthermore, tests on two valves in series (typical installation in containment purge applications) were not included. Most of the tests were performed under choked flow conditions, and only a few of tests under low ΔP, unchoked, flow conditions were performed. NRC/INEL provided recommendations to the industry for further testing to overcome these limitations.

EPRI MOV Performance Prediction Program (PPP)

EPRI MOV PPP was a comprehensive program to develop performance prediction models for gate, globe and butterfly valves. The program included incompressible flow testing on symmetric and single-offset disc designs of different aspect ratios [6, 7, 8]. The EPRI program objective was to develop a methodology for MOV applications. For MOV evaluations, only a *single value* for the *peak required torque* is needed, regardless of where the peak occurs (Figure 4A). Therefore, the analytical model development of the EPRI MOV Performance Prediction Methodology (PPM) did not require position-dependent accuracy in torque predictions. The analytical models that form the basis of EPRI MOV PPM symmetric and single-offset butterfly valve methodology were based on simplified, thin disc 2D (two dimensional) streamline analysis approximations. Adjustments to torque coefficients to take into account disc thickness (aspect ratio) and shape were based upon simple hydraulic resistance calculations, available industry data and engineering judgment. Relatively large margins had to be included in these approximate models to cover uncertainties, simplifying assumptions and the limitations of the then-available test data [6, 7].

Validation of the EPRI MOV PPM models against flow loop and in-situ test data showed that even though the *Required Torque* predictions bounded the EPRI test data [7, 8], the dynamic torque signature predictions lacked position dependent accuracy required for AOVs as shown in Figure 4B. The total required dynamic torque predictions as a function of disc position (also referred to as *Torque Signature Predictions)* were in some cases overly conservative, and in other cases nonconservative over large portions of the stroke, e.g., as shown in Figures 2 and 3. EPRI issued information notices, error notices and industry guidance to address potential known nonconservatism of EPRI MOV PPM predictions while evaluating AOVs [10, 11, 12].

Kalsi Engineering, Inc.'s Advanced Model

Development Program for AOVs/MOVs

To develop validated models with position-dependent accuracy for all common types of quarter-turn valves in nuclear power plants, and to overcome the limitations of the NRC/INEL "Containment Purge and Vent Program" and the EPRI MOV PPM discussed above, Kalsi Engineering conducted a comprehensive development program that included advanced analytical modeling, compressible and incompressible flow testing, The program spanned over three years and was conducted in two phases: Phase I focused on incompressible flow applications including analytical model development, flow loop testing, and validation. Under Phase II, advanced compressible flow models were developed based upon Computational Fluid Dynamics (CFD) analyses and compressible flow testing covering a wide range of pressure drop ratios from highly choked to unchoked conditions. The disc shape test matrix and highlights of the program results are presented below.

Matrix of Disc Shape Geometries

Surveys by NRC/INEL and EPRI Nuclear Maintenance Application Center (NMAC) show that the following basic butterfly valve disc types are commonly used in the industry:

- Symmetric Disc Butterfly
- Single-Offset Butterfly
- Double-Offset Butterfly
- Triple-Offset Butterfly

In addition to butterfly valves, Kalsi Engineering's recent survey from twenty nuclear plants showed that the following types of quarter-turn valves are also common in AOV applications:

- Spherical Ball
- Segmented (V-Notch) Ball
- Eccentric Plug
- Cylindrical/Tapered Plug

The advanced model development program performed by Kalsi Engineering covered both butterfly and other types of quarter-turn valves. Figures 5-9 show the geometry, relative proportions and key features for various types of butterfly valves that were tested. To adequately cover the variations in disc geometries common in nuclear power plant applications, a total of 25 disc shapes were included in the test matrix. In addition to systematically covering variations in the disc aspect ratio, the matrix also included scale models of disc geometries having exact geometrical similarities to the 18", 36", 42" and 48" valves used in safety-related nuclear plant applications. The scale model testing approach was used because this approach was validated against 42" full-scale valve test data under the EPRI MOV PPP.

The butterfly valve disc shape variations included in the test program are described below:

Basic disc types:	Symmetric & non-symmetric (single-offset, double-offset and triple-offset designs).
Disc aspect ratio:	0.15 to 0.31 for symmetric disc designs 0.09 to 0.47 for non-symmetric designs
Disc front face geometry:	Flat or recessed. The recess can be flat or concave (Figures 6, 7). The non-flat, recessed front face geometries are common in cast designs.
Disc shaft side geometry:	Prismatic, conical or radiused. This disc face can be relatively smooth (e.g., prismatic shapes typically fabricated from plate/machined components) or have bosses/projections and recesses (which are common in cast designs). Another variation in the shaft side disc faces included stub shaft hub design. Figures 6 and 7 show these geometric variations.

It should be noted that all tests on single-offset butterfly valves performed by NRC/INEL and EPRI MOV PPP used disc geometries, which had flat front faces as shown in Figure 1. The non-flat face geometries can have higher torque requirements than flat face geometries as will be discussed under Key Results.

Matrix of Incompressible & Compressible Flow Tests

Both incompressible and compressible flow tests were performed with baseline configuration (no upstream elbows within 20 pipe diameters) and with various elbow configurations and proximities (from 0 to 8D) as described in References 1 & 2. The test sequence for each valve installation/configuration typically consisted of 17 static/dynamic strokes for incompressible flow testing, and up to 24 strokes for compressible flow testing. This resulted in a total matrix of 1,272 tests for incompressible flow and 1,116 tests for compressible flow. The flow loop testing provided a massive database of nondimensional hydrodynamic torque/flow coefficients (for incompressible flow) and aerodynamic torque coefficients (for compressible flow) for various valve geometries over a range of wide flow conditions.

KVAP SOFTWARE*:* *The tool for efficient and user-friendly application of advanced models and massive database for complete AOV/MOV evaluations*.

The calculations necessary to predict torque requirements for quarter-turn valves are very extensive, time consuming and potentially error prone because they require a detailed knowledge of the methodologies, and a large number of parameters, which are application specific. This dictated the need for development of a software to help utility engineers perform calculations efficiently without being burdened with extensive interpolations required to account for:
(a) application specific torque/flow coefficients which depend upon valve geometry (disc shape, aspect ratio),
(b) installation parameters (disc orientation, elbow configuration/proximity), and (c) operating conditions (pressure, $\Delta P/P_{up}$ ratios, fluid media and flow rate). The advanced validated models as well as the massive database of torque and flow coefficients from the test program were incorporated into a PC based software called KVAP (Kalsi Valve and Actuator Program). The software was developed with emphasis on very intuitive and user-friendly graphical features. Table 1 provides a comparison of validated models that were developed under this program and incorporated in KVAP software against the previously available industry methodologies/software.

In addition to addressing quarter-turn valves, KVAP software includes all linear valves (gate, globe and diaphragm) as well as all commonly used AOV and MOV actuators. In summary, KVAP is designed to provide complete design basis evaluations and margins for all AOVs and MOVs in power plants [13].

QUALITY ASSURANCE

All testing, model development, and KVAP software development activities were conducted in accordance with our quality assurance program, which satisfies 10CFR50, Appendix B requirements.

DISCUSSION OF KEY RESULTS FROM ANALYSES & TESTING

Key Results From CFD Analyses

CFD analytical results (including pressure and velocity contours; shock wave location, strength and movement; and interaction between two valves in series) provided insights that were significant in understanding the behavior of butterfly valves in compressible flow. Figure 10 shows a comparison of the Mach number, pressure and velocity distribution for a symmetric disc butterfly valve operating under unchoked, relatively low $\Delta P/P_{up}$ conditions (left picture) against fully choked, high $\Delta P/P_{up}$ conditions (right picture). Under low $\Delta P/P_{up}$ operation, the flow becomes sonic just downstream of the leading edge, and it remains separated from the downstream disc face. However, under choked flow conditions, the flow shock front reattaches itself to the downstream disc face, as shown in Figure 10. The reattachment of the shock front to the disc downstream face causes a jump in the pressure distribution, which in turn dramatically affects the magnitude as well as the direction of the resultant aerodynamic torque on the disc. Furthermore, the reattached shock front changes its location on the downstream disc face as the $\Delta P/P_{up}$ ratio is changed. This explains the non-linear changes in aerodynamic torque as $\Delta P/P_{up}$ ratio is increased from low (nearly incompressible, unchoked conditions) to high (fully choked conditions).

The phenomenon described here is equally applicable to single- and double-offset disc designs with shaft downstream orientations, and it explains why the manufacturers' predictions (based upon unchoked, low ΔP tests) were contradictory to the NRC/INEL test under high ΔP, choked flow conditions. This is further discussed under "Key Results from Incompressible and Compressible Flow Testing" section in this paper.

The CFD analyses also showed that the presence of a downstream butterfly valve (Figure 11) can dramatically alter the pressure distribution and aerodynamic torque experienced by the upstream valve. This is due to the fact that the reduction in the flow area at the downstream valve location causes the flow to accelerate, which can cause the shock front to move from the upstream valve to the downstream valve location.

The significant insights obtained from the CFD analyses research provided excellent guidance for the key parameters to be varied in the test matrix for compressible flow testing. The test program covers a wide range of $\Delta P/P_{up}$ ratios from nearly incompressible, low ΔP conditions to highly choked flow conditions. The effect of various upstream and downstream resistances was also systematically evaluated to determine their effect on torque coefficients, as discussed in Reference 2.

Key Results from Incompressible and Compressible Flow Testing

Some of the key results for the incompressible and compressible flow testing that are discussed in this section are shown in Figures 12 to 15.

Validated Model for Double-Offset Disc Designs
Tests revealed that variations in hydrodynamic torque for double-offset valves (which were not included in the EPRI MOV PPP) can be significant based upon the combination of the first and second offset magnitude, as well as critical disc geometry features, e.g., a concave or recessed disc face instead of a flat face (Figure 12). The sensitivity of the torque coefficients and flow coefficients to streamlining the disc faces as shown in Figure 8 was also evaluated to provide bounding coefficients for the advanced models and KVAP software.

Aerodynamic Torque can Change From Self-Closing to Self-Opening with Changes in $\Delta P/P_{up}$ Ratio
Figure 13 shows that incompressible-flow torque coefficients are independent of pressure drop. Therefore, the hydrodynamic torque magnitude is linearly proportional to ΔP, and torque behavior at a given stroke position does not change (e.g., from self-closing to self-opening).

A comparison against the torque coefficients from compressible flow (Figure 14) shows that under low $\Delta P/P_{up}$ ratios, the behavior of the butterfly valve is basically the same as that under incompressible flow testing. Figure 14 also shows that aerodynamic torque for a single-offset disc, with shaft downstream, changes from *self-closing* (under low $\Delta P/P_{up}$, unchoked, nearly incompressible conditions) to *self-opening* as $\Delta P/P_{up}$ is increased to fully choked conditions. This is caused by the reattachment and movement of the shock front on the downstream disc face as discussed above under Key Results from CFD.

Geometry of Downstream Resistance can Provide Significant Relief in Aerodynamic Torque
Figure 15 shows that the geometry of the downstream resistance can have a profound effect on the torque requirements of butterfly valves. The comparison shows that the presence of a fully open downstream butterfly valve significantly lowers the aerodynamic torque of the upstream butterfly valve. An equivalent length of downstream pipe that has the same flow resistance as that of a fully open butterfly valve has a much smaller influence on the aerodynamic torque requirement of the upstream valve. Therefore, for appropriate application, a significant improvement in margin can be achieved by taking credit for this phenomenon. This is particularly important for containment purge valves that are installed in series (typically one valve inside and one valve outside the containment).

Advanced Models Account for Inaccuracies in Torque vs. Position Caused by Upstream Elbows
The presence of upstream flow disturbance (e.g., an elbow) near the inlet of butterfly valves (which is common practice in power plant applications) affects both the magnitude and distribution of the hydrodynamic torque, Thyd. A simple multiplier (like the one provided by the Upstream Elbow Model in EPRI's MPV PPM) cannot account for the shift in Thyd. Advanced modeling is necessary to maintain position dependent accuracy with the presence of upstream elbows.

For example, in a symmetric disc installation without upstream elbow, the hydrodynamic torque component at the fully open position is nearly zero because the flow around the disc is balanced. Upstream elbow installation near the valve inlet skews the flow velocity and pressure distribution around the disc even in the fully open position. This skew in flow velocity and pressure caused by the elbow results in a net positive or negative hydrodynamic torque in the fully open position. The magnitude and direction of the net Thyd depend on the relative orientation and proximity of the elbow with respect to the valve disc. The necessary development and validation for both compressible and incompressible flows have been incorporated in KVAP.

Recessed Faced Discs Exhibit Higher Torque than Flat Faced Discs

Testing with shaft downstream valve orientations showed that discs with recessed flat faces (Figure 7) exhibit higher Thyd than discs with true flat faces without a recess or a depression on the flat face (Figures 1 and 6) especially at the large disc opening angles. The increase in the magnitude of Thyd depends on the depth and extent of these flat face depressions. The advanced methodologies in KVAP account for the effects of typical depressions on torque requirements.

These tests results may show that earlier methodologies are not as conservative as they were considered prior to this test program. The reason is that flow loop testing (prior to KEI testing) was limited to discs with purely flat faces.

APPLICATION EXAMPLES, PLANT EXPERIENCE AND BENEFITS

Since the first release of the KVAP program in November of 2000, the software has been used for AOV and MOV evaluations at a large number of nuclear power plants. In many plants, substantial cost savings (often in excess of $500,000 at each plant) have been realized by the utilities by avoiding the need for modifications due to “apparent” negative margins predicted by other methodologies/software. The following examples show typical improvement in margins based upon the use of the more accurate models in KVAP for incompressible and compressible flow applications. In many instances, modifications of AOV groups containing multiple valves (up to eight in several cases) were proven unnecessary and successfully avoided. Such unnecessary modifications to increase the actuator output torque capability would also require re-evaluation of the AOV weak link and seismic re-qualification of the valve/actuator assembly.

Another significant cost benefit provided by the validated models incorporated in KVAP is that they provide an alternative to dynamic ΔP testing to evaluate the AOV/MOV capability to operate under design basis conditions.

Plant Example 1: Margin evaluation of AOV application highlights misconception. Figure 16 shows a typical input screen and the margin plot from KVAP analysis of an AOV from an actual plant evaluation of a symmetric disc butterfly valve with a Scotch Yoke actuator used in an incompressible flow application. In this application, the minimum AOV margin is dictated by the dynamic torque at around the 25-degree location and not by the unseating torque (at closed position), which is significantly higher. The unseating torque would govern the margin for an MOV where actuator output is constant throughout the stroke. This example shows the importance of position-dependent accuracy in torque prediction models.

An important *general* observation from this plant example is that even though seating/unseating torque may be the highest torque throughout the stroke, this may not dictate the minimum margin in an AOV (unlike in an MOV).

Plant Example 2: Identification of “apparent” negative margin eliminates need for unnecessary modifications. This plant had performed design basis calculations for the six service water butterfly valves operated by piston actuators with lever-and-link mechanism for quarter-turn operation. These AOVs had a maximum disc-opening angle of 60°. Based upon earlier industry methodologies, it was concluded that this AOV had a negative margin under design basis calculations (Figure 17). Modifications were planned to change the actuators to provide higher torque outputs to meet the requirements indicated by the previous analysis. Re-evaluation (using the more accurate validated models described in this paper) showed a positive margin was actually available throughout the stroke. This eliminated the need for changing actuators, resulting in significant cost savings without compromising safety/reliability of valve operation.

Plant Example 3: KVAP application improves margin in containment purge application. Figure 18 shows the comparison of required torque predictions for an 18” double-offset disc containment purge valve (with shaft downstream orientation) to close under design basis Loss of Coolant Accident (LOCA) conditions. The AOV actuator was a Scotch-Yoke type with spring return to fail close the valve. The minimum actuator output available from the actuator at various stroke positions had been provided by the manufacturer and verified by the plant engineers. EPRI MOV PPM software indicated a large negative margin throughout the stroke. The use of KVAP software, along with the use of torque/flow coefficients database based upon the appropriate $\Delta P/P_{up}$ ratio for this application, resulted in a significant reduction in torque requirements, and a positive margin throughout the stroke. This eliminated the need for plant modifications that were being planned for 8 valves in this group of Category 1 AOVs.

CONCLUSION

The advanced, validated models and KVAP software successfully fulfill the industry need for reliable position-dependent torque predictions for AOVs. The benefits in margin improvement from KVAP are also applicable to MOV applications. Validated models provide an alternative to ΔP testing. Plant experience has shown significant cost savings by avoiding equipment modifications in many applications. KVAP margin improvements may be used to ease plant equipment modification and maintenance burdens by enlarging AOV and MOV actuator field set-up windows, extend periodic verification inspection and test intervals, and improve power uprate and life extension decisions. KVAP software is an efficient, intuitive, and user friendly software developed under our 10CFR50 Appendix B QA program to provide reliable predictions for safety-related applications.

ACKNOWLEDGEMENTS

Kalsi Engineering and the authors acknowledge contributions made by the valve manufacturers, NRC/INEL, EPRI/NMAC, and power plant engineers over the years which led to improved understanding and development of advanced models described in this paper.

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	Valve Types Prevalent in AOV Population	NRC/INEL Cont. Purge	EPRI MOV PPM (Note 1)	Ace, AirBase, Others (Note 2)	KVAP Software
1	Symmetric Butterfly	None	√*	None	√
2	Single-Offset Butterfly	√**	√	None	√
3	Double-Offset Butterfly	None	None	None	√
4	Segmented V-Ball	None	None	None	√
5	Spherical Ball	None	None	None	√
6	Eccentric Plug	None	None	None	√
7	Tapered/Cylinder Plug	None	None	None	√

*** Incompressible Flow Only**
**** Compressible Flow Only**

General Note: NRC/INEL and EPRI MOV PPP methodologies for single-offset discs were based upon tests performed on discs having flat front faces (no recesses) that may not bound data for recessed designs. Recessed faces are common in cast disc designs.

Note 1: EPRI MOV PPM models provide bounding predictions for MOVs. EPRI Torque Signature predictions can be nonconservative over portions of the stroke. See EPRI MOV PPP Software Information and Error Notices [10, 11, 12].

Note 2: ACE, AirBase, and other software, e.g., Excel spreadsheet, do not have built-in validated torque/ flow coefficients. Predictions based on the use of EPRI MOV PPM coefficients in these softwares can be nonconservative over portions of the stroke. See EPRI MOV PPP Software Information and Error Notices [10, 11, 12].

Table 1

Comparison of Validated Methodologies Available in KVAP Against Other Methodologies/Software

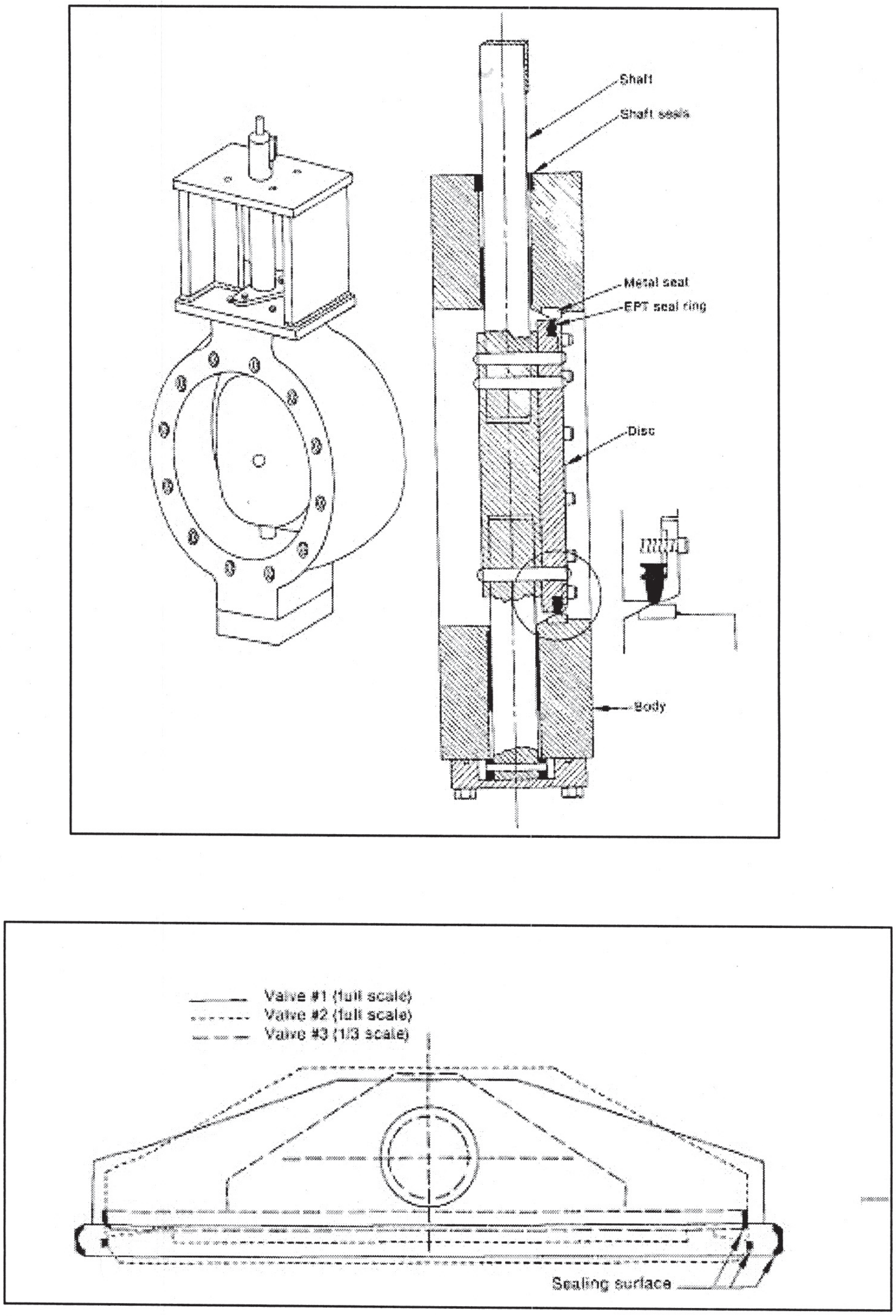


Figure 1: Details of a single-offset butterfly valve (top) and a composite drawing (bottom) showing geometric comparison of disc cross-sections of 3 different disc shapes from 2 manufacturers tested by NRC/INEL [4, 5].

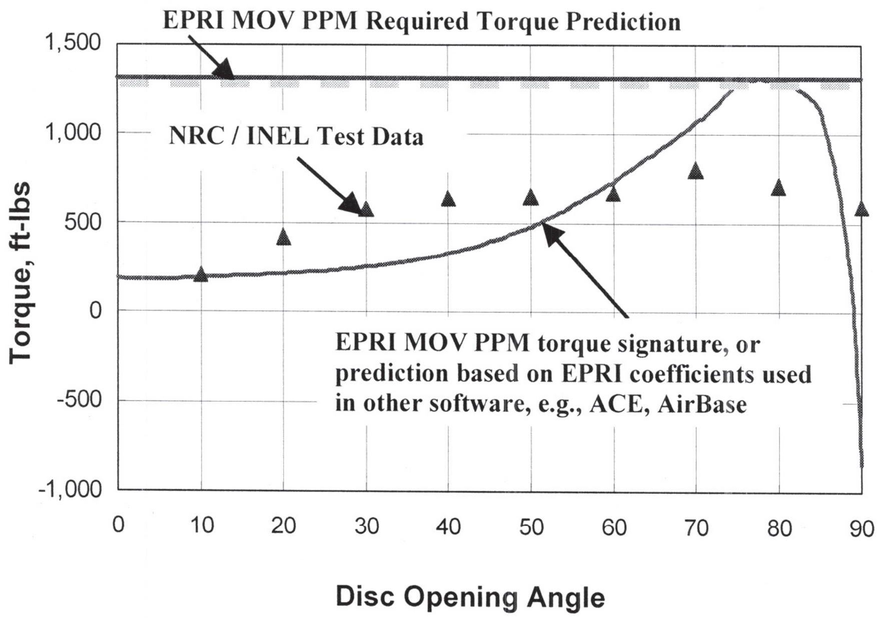
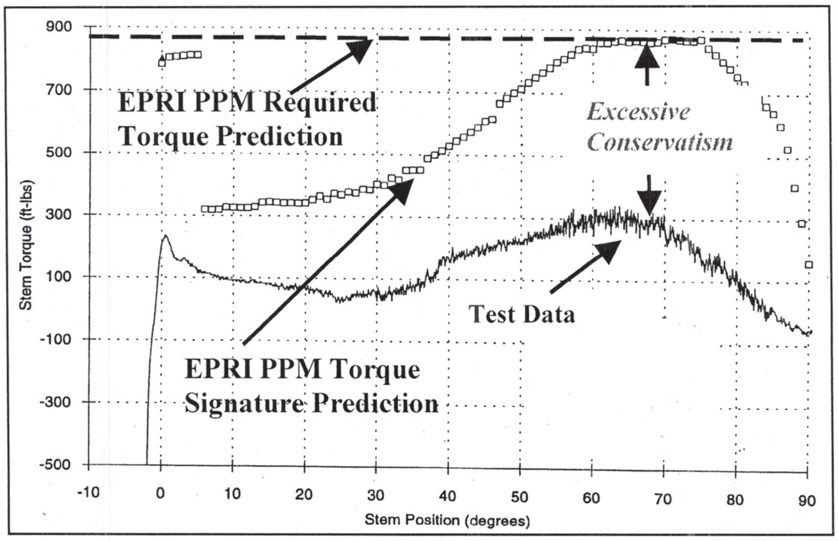
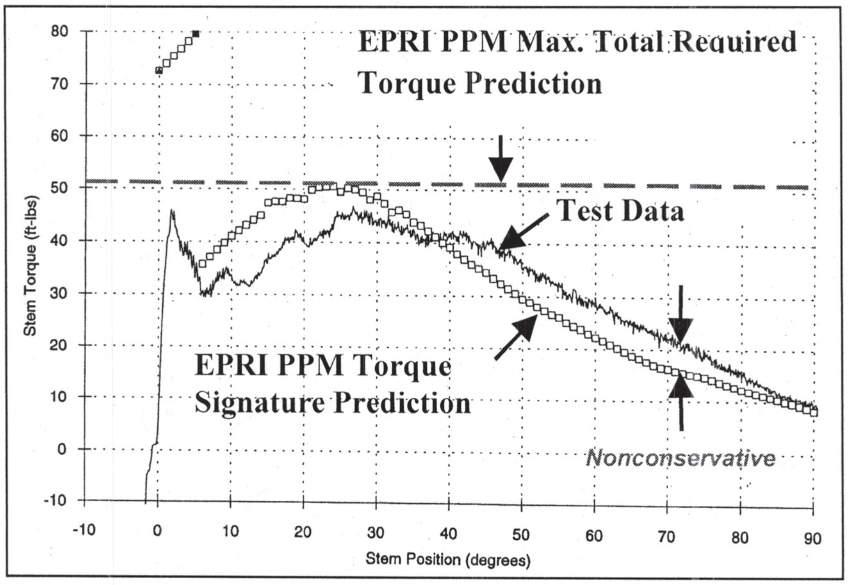


Figure 2: EPRI MOV PPM Required Torque bounds NRC/INEL compressible flow test data, but Dynamic Torque predictions (also called Torque Signature predictions) are nonconservative over a large portion of the stroke.



EPRI Valve Test No. F-55



EPRI Valve Test No. I-27

Figure 3: The Total Dynamic Torque predictions (Torque Signature) from EPRI MOV PPM for incompressible flow applications can be overly conservative (e.g., top figure) or nonconservative (e.g., bottom figure) depending upon valve type and application.

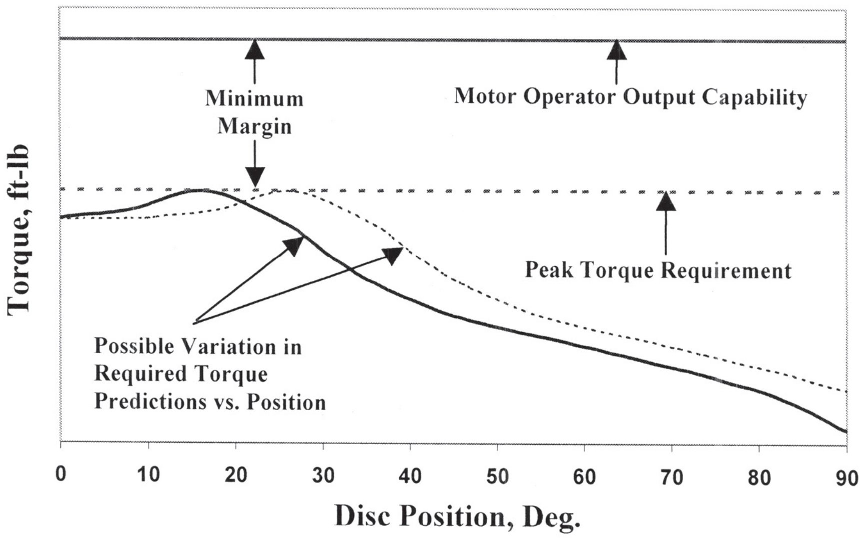


Figure 4A: Typical MOV actuator output is constant throughout the stroke; only peak torque magnitude (regardless of stroke position) dictates the minimum margin.

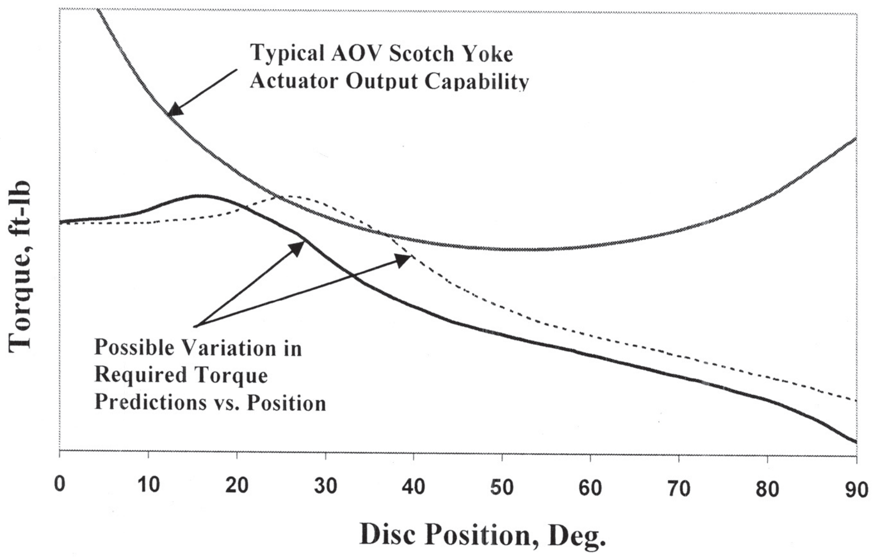


Figure 4B: Typical AOV actuator output varies with position; valve torque requirements must be accurately determined at each stroke position to calculate minimum margin throughout the stroke.

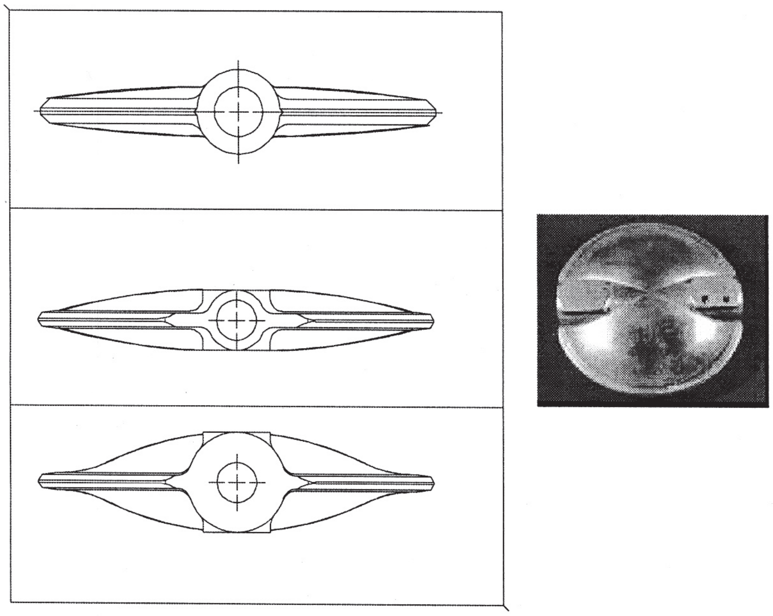


Figure 5: Symmetric discs with different aspect ratios.

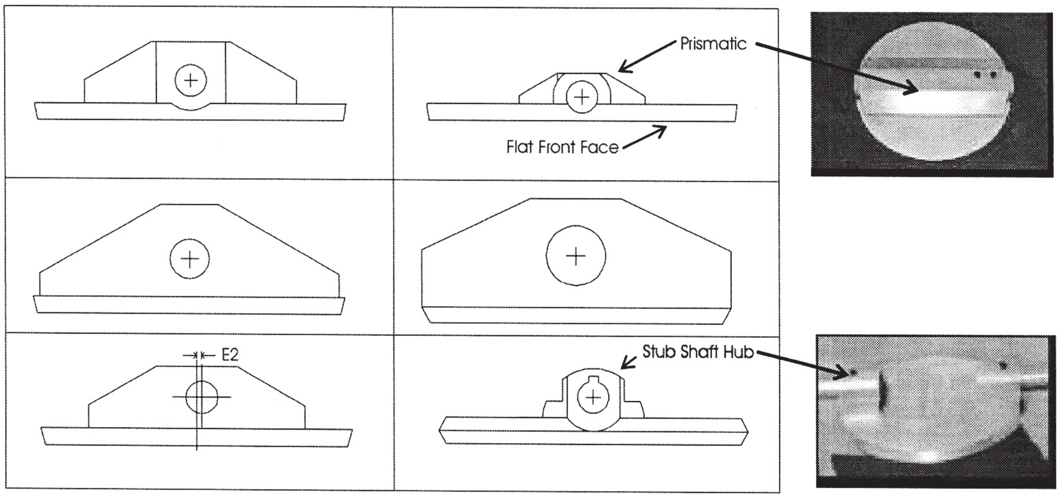


Figure 6: Flat front faced single- and double-offset discs of various aspect ratios and geometries.

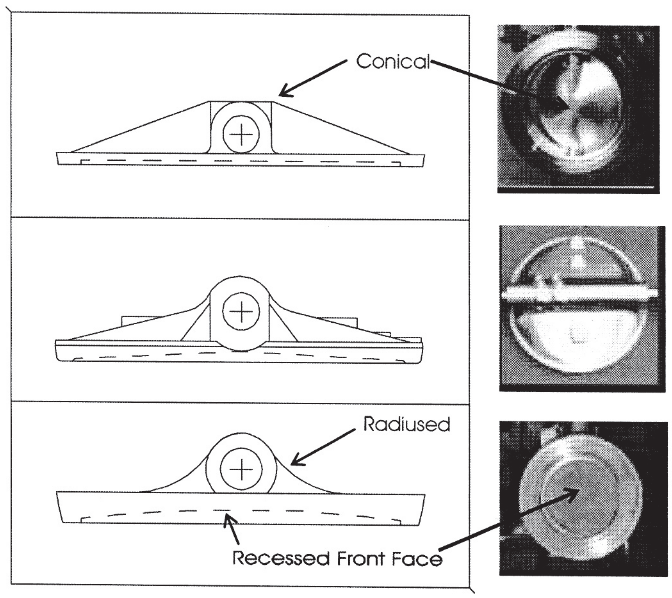
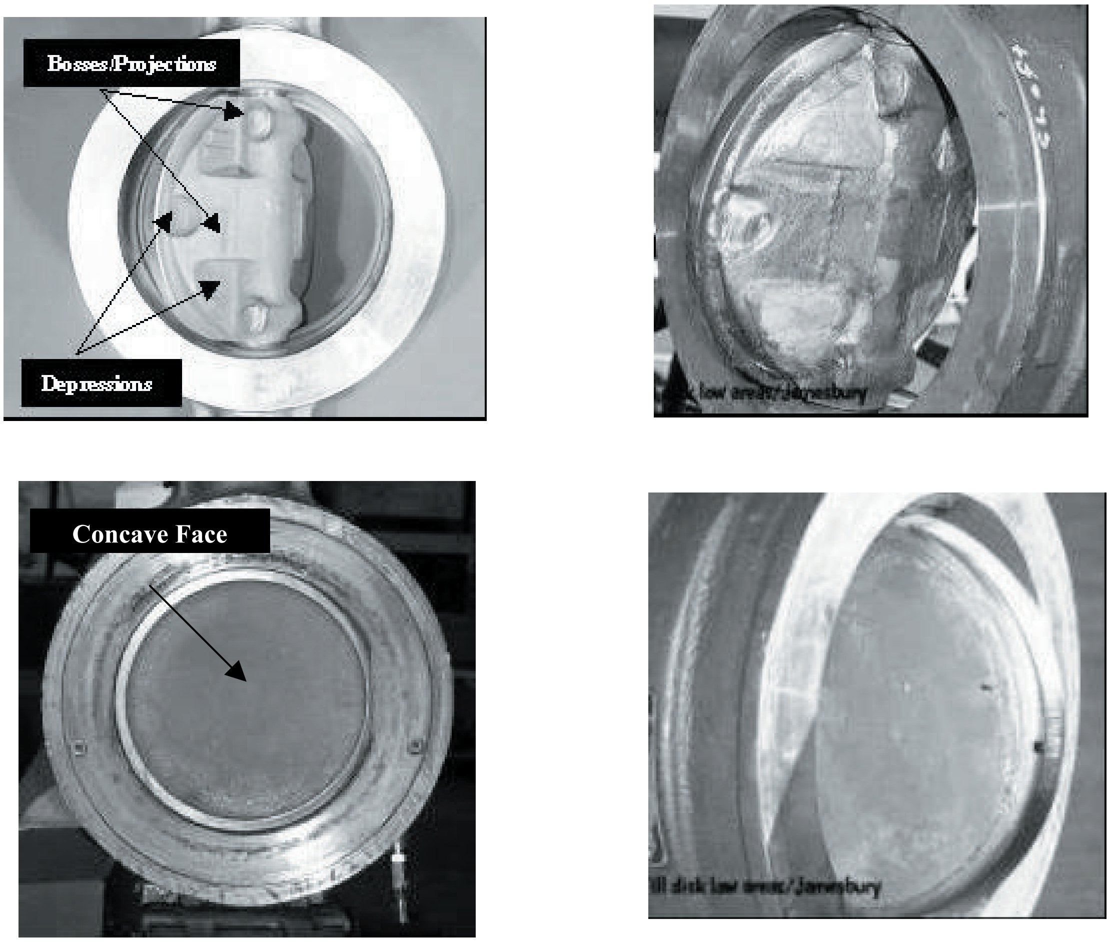


Figure 7: Recessed front faced single- and double-offset disc geometries.



Original Disc from Manufacturer **Disc Faces Streamlined with Filler**

Figure 8: Test matrix included sensitivity evaluation of streamlining both the upstream and downstream disc faces on hydrodynamic torque.

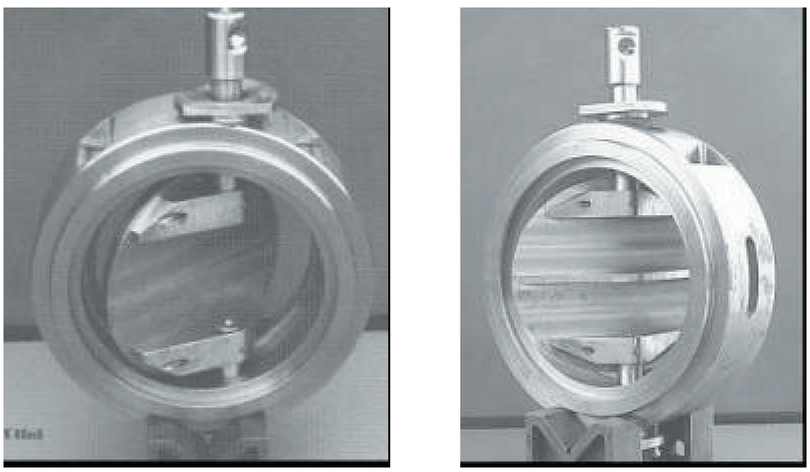


Figure 9: Triple-offset discs with large second offset were included in the test matrix.

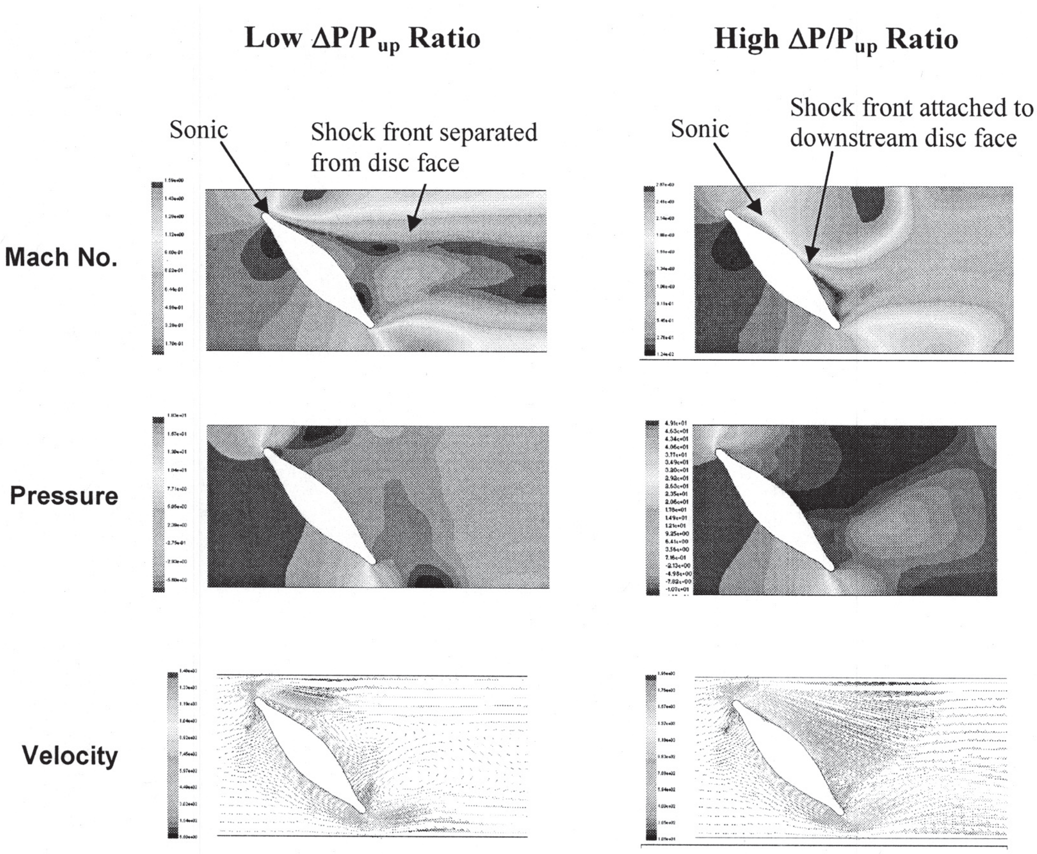


Figure 10: Compressible flow CFD analyses under low and high DP/Pup conditions show that shock front reattachment/location on the downstream disc face causes significant changes in pressure distributions, which dictate aerodynamic torque.

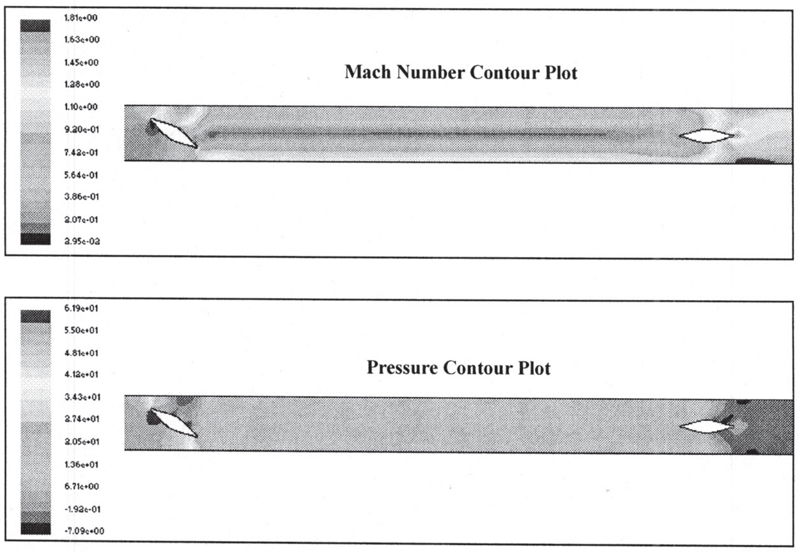
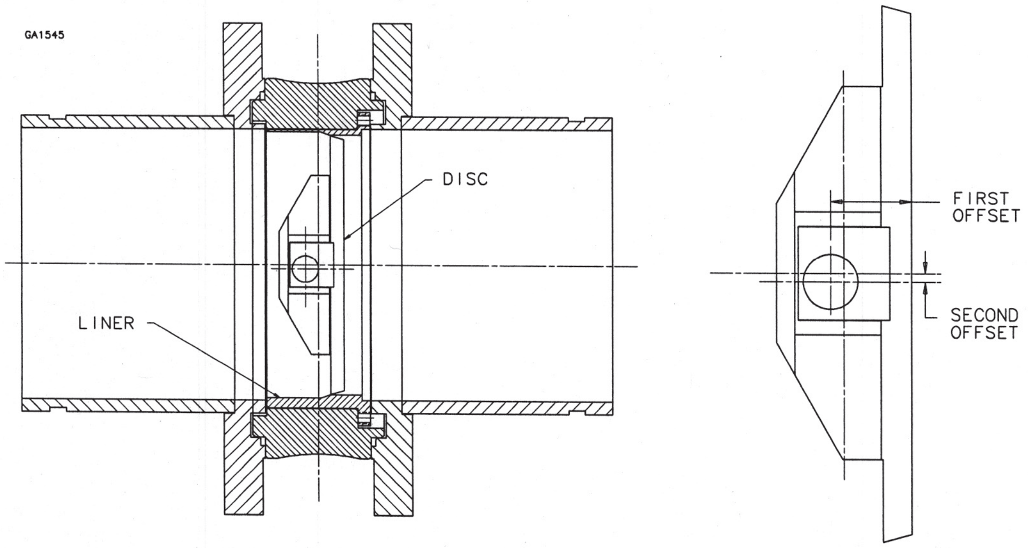
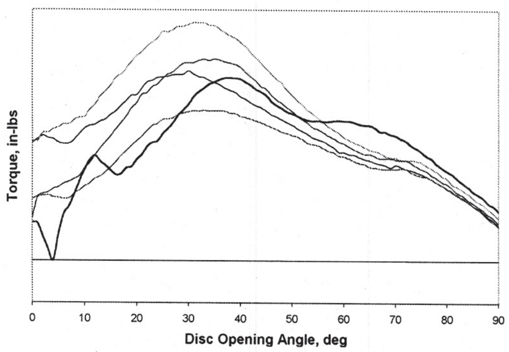
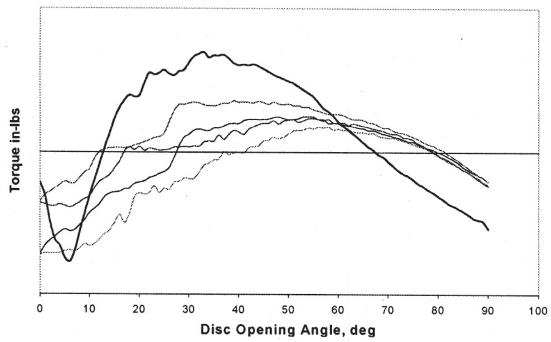


Figure 11: The presence of a downstream valve significantly alters the DP/Pup ratio across the upstream valve by causing changes in pressure distribution on its downstream disc face, which dictates the aerodynamic torque.





Shaft Upstream



Shaft Downstream

Figure 12: Combinations of the first and second offset magnitudes were systematically varied to evaluate their effect on the hydrodynamic torque for double-offset disc valves.

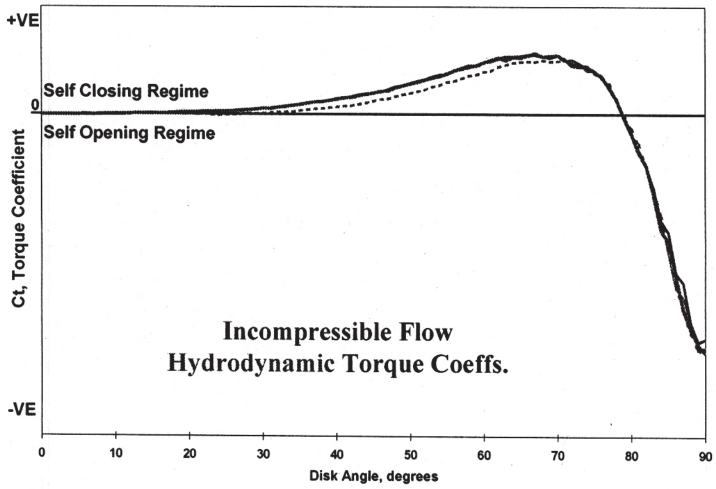


Figure 13: For incompressible flow, torque coefficients are independent of pressure drop, therefore torque magnitude is proportional to DP, and torque behavior remains the same between low and high DP conditions.

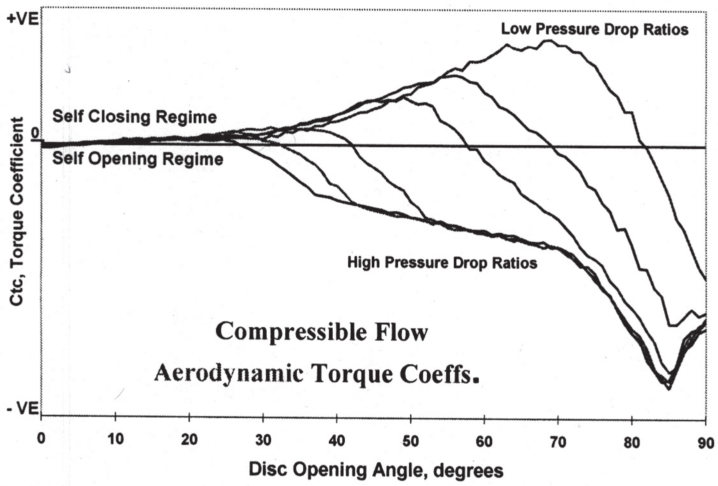


Figure 14: For compressible flow, torque coefficients change from self–closing regime to self-opening regime as the DP/Pup ratio is increased.

Note: *This explains why NRC/INEL [4,5] tests under containment purge conditions (high DP/Pup ratios) exhibited self-opening torque whereas manufacturers predicted self-closing torque (based upon their low DP/Pup ratio tests).*

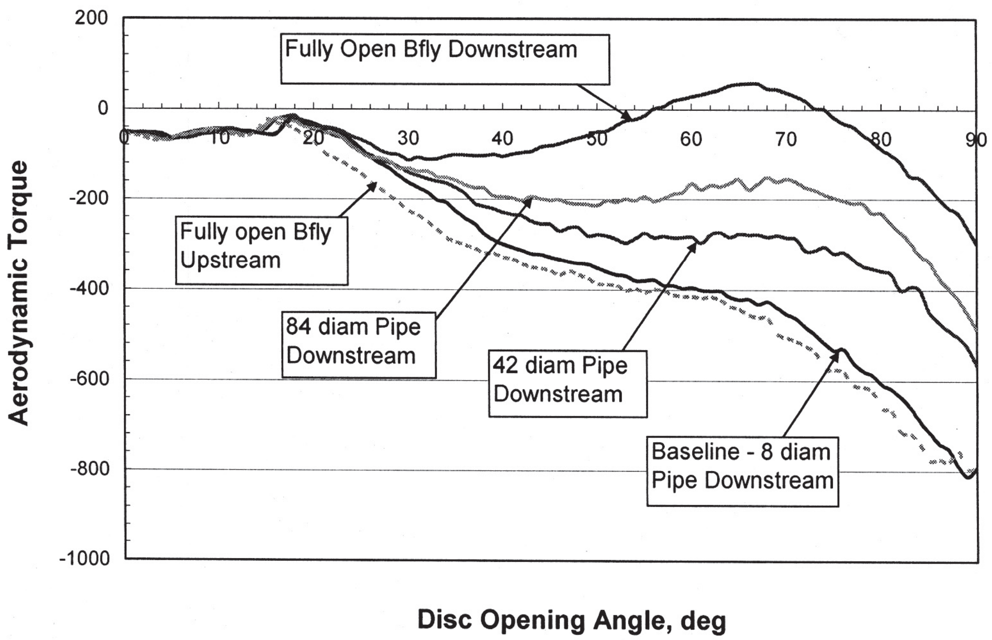


Figure 15: Geometry of downstream flow resistance (e.g., a butterfly valve instead of an equivalent length of pipe) has a profound effect on the aerodynamic torque.

Note: *In this comparison, a fully open downstream butterfly valve significantly lowers aerodynamic torque on upstream butterfly valve, as compared to an equivalent resistance length of downstream pipe (42 diam.). This can increase margin, eliminate unnecessary modifications and allow operation under plant modes previously not permitted.*

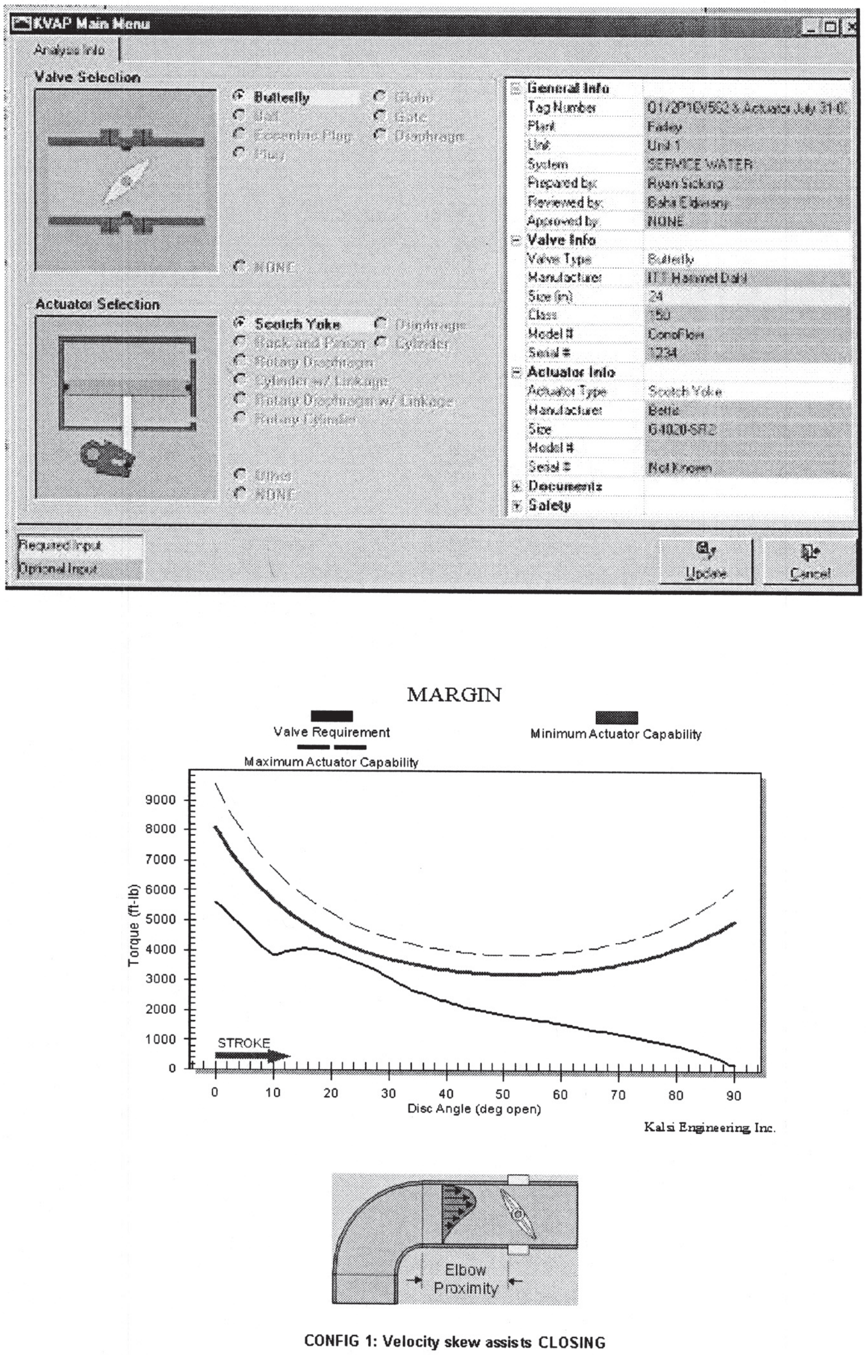


Figure 16: Graphically oriented and intuitive user-friendly features of KVAP for input and output screens eliminate the potential for error, and permit efficient calculations by interpolating flow and torque coefficients from the extensive built-in database for the application-specific attributes (e.g., disc geometry, aspect ratio, DP/Pup ratio, upstream elbow configuration and proximity).

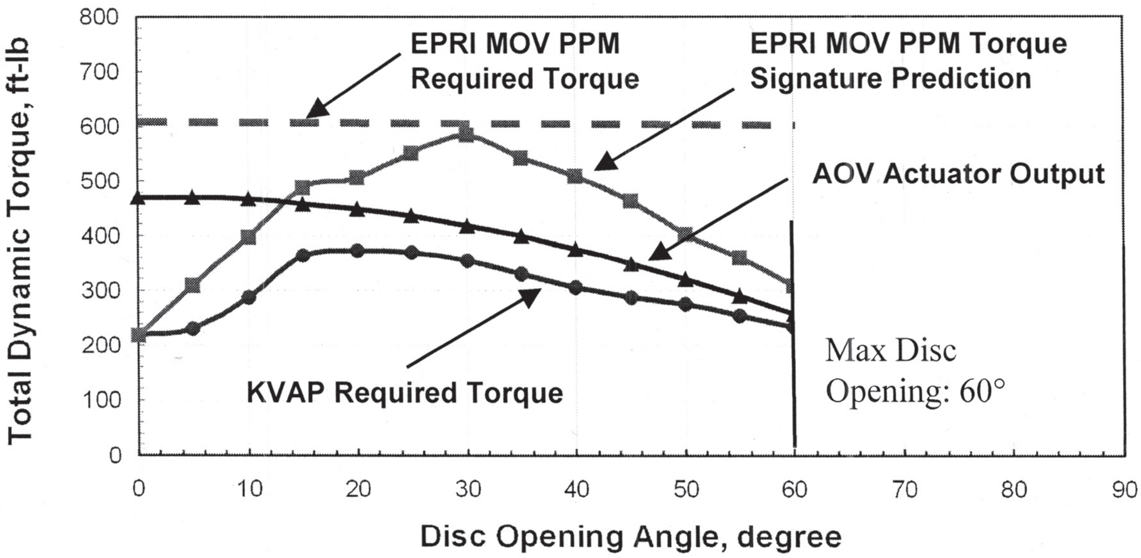


Figure 17: KVAP Margin improvements for 16" butterfly valves in a service water application eliminated the need for modifications indicated by EPRI MOV PPM.

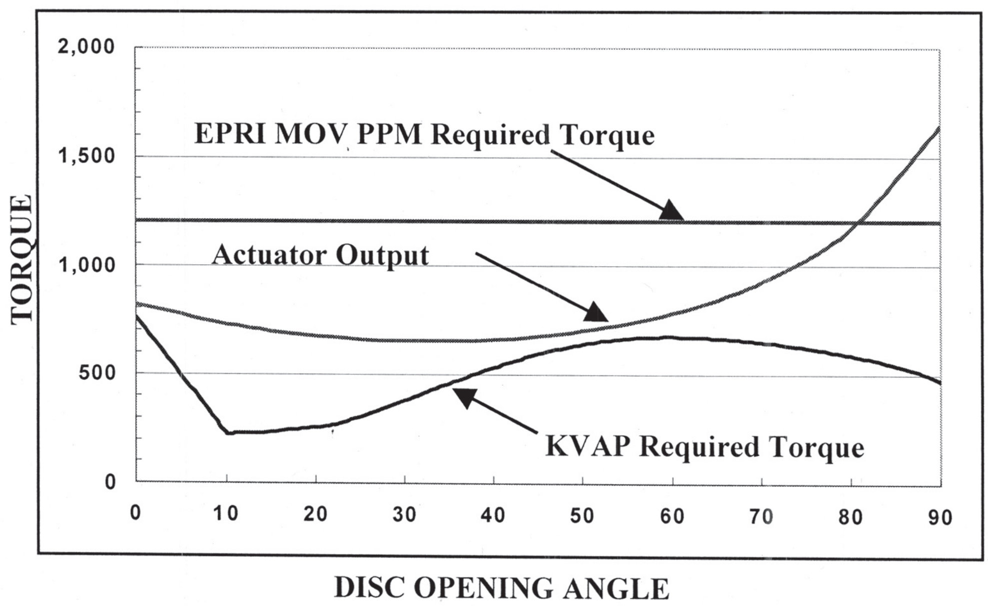


Figure 18: KVAP Margin improvement achieved for 18" butterfly valves in containment isolation application eliminated the need for modifications indicated by EPRI MOV PPM.

Actuator Capability and Rating Evaluation for Non-Limitorque Actuators in Korea NPPs

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Abstract

The safety assessment for MOVs (motor-operated valves) in Korea NPPs (nuclear power plants) has been performed to implement US NRC Generic Letter 89-10 (GL 89-10: Safety-Related Motor-Operated Valve Testing and Surveillance). This safety assessment consisted of a design basis review and a diagnostic test. Since the information on non-Limitorque actuators is not enough, a TTS (torque test stand) has been introduced in the safety assessment program to support the actuator capability evaluation of non-Limitorque actuators. In order to evaluate the TTS test results, a direct and indirect method as an engineering scheme and eTTS program as a software tool have been developed. The results indicate that the real actuator output torques for Joucomatic actuator models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58) are 20%~100% greater than those of design basis review. For the EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

In addition, the actuator rating analyses are performed for Joucomatic actuators because the actuator ratings for the actuators are not found from documents. For Limitorque actuators, the three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators. The actuator ratings calculated are highly conservative but useful for implementing GL 89-10.

1. Introduction

The safety assessment for MOVs (motor-operated valves) in Korea NPPs (nuclear power plants) has been performed to implement the US NRC GL 89-10. This safety assessment mainly consists of a design basis review and a diagnostic test. The design basis review includes a system analysis, a required stem torque/thrust analysis, a weak-link analysis, a voltage degradation analysis, an actuator capability analysis, and margin analysis. The diagnostic tests are divided into a static test and a dynamic test.

The population of safety class actuators in Korea NPPs is shown in Table 1. Limitorque is a major contributor providing 73.4% of total safety class actuators, followed by Rotork (15.3%), and Joucomatic (6.8%). It was noticed that Joucomatic, Hopkinsons and EIM actuators are only found in Ulchin 1&2, Kori 1&2 and Wolsong 1, respectively.

Limitorque and Rotork provide sufficient information to assess an actuator capability relatively whereas other vendors do not provide an actuator efficiency, a rated torque, etc, which makes actuator capability calculations difficult. Therefore, the TTS (torque test stand) has been introduced in the safety assessment program to support the actuator capability evaluation of non-Limitorque actuators. The TTS consists of a power cabinet, a control panel and sensor, and a main body which has a pneumatic break system, a hydraulic thrust system, an adapter and a sleeve connector, and dynamometer. In order to evaluate the TTS test results, a direct/indirect method as an engineering scheme and eTTS program as an analyzing software tool have been developed. This paper describes test experience for the non-Limitorque actuators in Korea NPPs with the aid of TTS equipment.

In addition, the actuator rating analyses are performed for Joucomatic actuators because the actuator ratings for the actuators are also not found from documents. For Limitorque actuators, it is the worm and worm shaft that are known to have the greatest probability of failure during operation. The three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm for Limitorque actuators. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators. Minor's rule was used to obtain the fatigue stress for the worm tooth. The material S-N curves are given by the "Criteria of the ASME Boiler and Pressure Vessel Code" including American Society of Mechanical Engineers (ASME) material properties. The actuator ratings calculated are highly conservative but useful for implementing GL 89-10.

2. Actuator Capability Evaluation

Design Basis Review of Actuator Capability

The actuator capability can be typically obtained by analyzing voltage drop, actuator efficiency, environmental temperature, etc. For an AC motor and a DC motor, the motor starting torque at a reduced voltage condition is proportional to the square of the voltage, whereas it varies proportionally with change in available voltage for a DC motor. The motor starting torque at reduced voltage condition can be obtained as follows:

$$MT_{DV} = MST \times DVF \quad (1)$$

$$DVF = (VT/VR)^N \quad (2)$$

where

MST = motor starting torque

DVF = degraded voltage factor

VT = motor terminal voltage

VR = motor rated voltage

N = 2 for AC motor and 1 for DC motor

The actuator torque also varies proportionally with motor starting torque, motor input voltage, actuator efficiency, overall gear ratio and environmental temperature condition. The actuator torque is generally given as follows:

$$TQ_{DV} = MT_{DV} \times OVR \times PULL_{eff} \times AF \times TDF \quad (3)$$

for gate and globe valves and

$$TQ_{DV} = MT_{DV} \times OVR \times PULL_{eff} \times AF \times TDF \times QGR \times QGR_{eff} \quad (4)$$

for butterfly valves,

where

TQ_{DV} = actuator output torque under degraded voltage condition

OVR = overall gear ratio

$PULL_{eff}$ = pull-out efficiency

AF = application factor

TDF = temperature degradation factor

QGR = quarter turn gear ratio

QGR_{eff} = quarter turn gear efficiency.

TTS and eTTS Program

The real actuator capability was measured with the aid of the TTS. The TTS, shown in Figure 1, was designed and engineered by Kalsi Engineering, Incorporated (KEI). It is designed to provide a torque resistance ranging from 12.5 foot-pound force (ft-lbf) to 3,600 ft-lbf. This is less than the 20 ft-lbf rated torque of the smallest Rotork 7A actuator up to the stall torque of the Rotork 90 series actuator. It consists of a power cabinet, a control panel and sensor, and a main body. The main body has a pneumatic break system, a hydraulic thrust system, an adapter and a sleeve connector, and a dynamometer. Also, it is equipped with a manually operated hydraulic system, which provides up to 75,000 lbf of upward or downward thrust load on the actuator. This simulates the stem thrust of the valve, and provides a realistic load on the thrust bearings of the actuator.

Since the raw signal from the TTS includes a lot of noise, the eTTS program was developed by KOPEC and Monitoring and Diagnosis (M&D) to remove the noise and manage test signals effectively. The eTTS program in Fig.2 consists of a filter module, an analysis module that extracts the voltage drop ratio and the actuator efficiency, a database module, and a complete graphic module. The raw signal was generally filtered by RTA (run time averaging) method, which is incorporated in the eTTS program.

Actuator Capability Evaluation through TTS Test

The actuator capability was analyzed with a direct method and an indirect method. A brief description for both methods is given below.

Direct Method. The actuator torque is directly taken from the TTS test. This method is generally applied to the valves with negative margin to obtain real actuator capability. Because it is difficult to evaluate the temperature degradation factor and set a test voltage for an exact design voltage with the TTS, some engineering process is required. After testing several times at a specified voltage condition, a voltage drop ratio is extracted. The actuator capability is then recalculated through Eqs. (1)~(4). The direct method was applied to EIM actuators.

Indirect Method. This method is similar to a grouping concept to evaluate the valve factor. The capability of the same group of actuators was assessed from testing actuator specimens that are easily taken in the plant or the same spare actuators. In addition, the Joucomatic actuator capability was calculated through an interpolation or extrapolation on the certified torque, which is provided by the vendor. The indirect method for Joucomatic actuator was accomplished by comparing the test result with the certified torque.

The Autotork actuator capability was verified by a statistical method as follows (one of the indirect method). For several test voltages, the 2nd order curve fitting of actuator torque is obtained by the least square method as follows:

$$Tq = aVR^2 + bVR + c \tag{5}$$

where a, b and c are the coefficients of the curve fitting equation. The actuator torque at each testing voltage, Tq_i, is recalculated with Eq. (5), which is $Tq_{cal,i}$. The deviation of actuator torque is easily obtained by:

$$\sigma_{Tq} = [\sum_{i=1}^{N}[Tq_i - Tq_{cal,i}]/(N-2)]^2 \tag{6}$$

where N represents the number of tests at each test voltage. The presumed actuator torque at the design basis voltage condition, Tq_{DB}, is then calculated with Eq. (5). Finally, the applied actuator torque at the design basis voltage condition, $Tq_{DB,a}$, is calculated as follows:

$$Tq_{DB,a} = (Tq_{DB} - t_{95} \times \sigma_{Tq}) \times TDF / U_{eff} \tag{7}$$

where U_{eff} and t_{95} represent an uncertainty and a statistical distribution according to testing, respectively.

TTS Test Results

TTS tests had been carried out for non-Limitorque actuators to obtain an appropriate actuator capability. Table 2 shows the matrix of test actuators. The matrix includes several actuator models from different actuator vendors. The method in Table 2 means the evaluation methodology of TTS test results as mentioned above. Most of the Joucomatic actuators were spares, whereas others are operating ones.

The results of design basis review for the non-Limitorque actuators are shown in Table 3. The design basis review was conducted through Eq. (1) ~Eq. (4) by assuming the actuator efficiency and the temperature degradation factor from the Limitorque test information. It is seen that, as the voltage condition goes higher, the actuator output becomes stronger in Table 3.

The actuator output torque from the TTS test is shown in Table 4. For Joucomatic models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58), the real actuator output capability is 20%~100% greater than those of the design basis review. Therefore, it can be estimated that the actuator capability from the design basis review for Joucomatic was very conservative. For Autotork NQ-60 model, the real actuator output was less than that of the design basis review. Because the Autotork NQ60 model was the smallest one in the test models and the actuator output torque was at the bottom sensitivity limit of the TTS equipment, it is difficult to obtain an accurate result. Since the Autotork NQ60 has sufficient margin, the test was terminated after obtaining an acceptable actuator torque. Also, for EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

3. Actuator Rating Evaluation

The actuator rating analyses were performed for Joucomatic actuators because actuator ratings for the actuators are not provided from the vendor. The general configurations of DR and L types Joucomatic actuators are shown in Figure 3 in a cutaway view showing the major mechanical components of the system. The vertical translational motion of the actuator valve stem is generated by the worm/worm gear set. The worm machined on the worm shaft is directly driven by an electric motor for the DR type actuator. However, for the L type actuator, the worm, which is also machined on the worm shaft, is driven by an electric motor through a helical gear set. The worm in turn drives the worm gear that is directly coupled to a stem nut. The stem nut rotation creates the linear motion of the valve stem.

For Limitorque actuators, it is known that the worm and worm shaft have the greatest possibility of failure during operation. The three consistent failure points are the worm tooth at the worm/worm gear contact, the worm shaft at the worm/worm shaft contact point, and the root of the limit switch worm for Limitorque actuators [6]. However, the only failure point is the worm tooth at the worm/worm gear contact for Joucomatic actuators because the limit switch worm is not on the driving shaft and there is no worm/worm shaft contact point.

Analysis Method

The cumulative damage integral (CDI) for a ramp is given by Kalsi as:

$$\mathrm{CDI} = \int_{S_e}^{S_{ao}} \frac{\left(\frac{N_o}{S_{ao}}\right) dS_a}{\frac{1}{(9.25EC_f)^{1/b}}\left\{\frac{S_a}{\left[1-(S_{mo}/S_u)^y\right]^{1/x}} - B\right\}^{1/b}} \quad (8)$$

where

$$C_f = \ln\left(\frac{1}{1-A}\right)$$

$$A = F_A RA$$

$$b = -F_b RA$$

$$B = F_B S_e$$

$$S_f = S_u + 50{,}000\,psi$$

and where S_{ao} is the maximum stress reached in the ramp, N_o is the total number of shaft revolutions in the load ramp, S_e is the endurance of the worm material, E is the modulus of the elasticity, RA is the fractional reduction of area, S_a is the alternating stress, S_{mo} is the maximum mean stress reached in the ramp, S_u is the ultimate tensile strength of the material, and x and y are the exponents to represent mean stress effects on fatigue. F_A, F_B and F_b are the empirical factors to facilitate a better correlation with the equation of S-N curves. We did not use the empirical factors because we had not performed the testing for the actuator. Therefore, we used $F_A = 1$, $F_B = 1$ and $F_b = 0.5$. And we use the Modified Goodman criteria for accounting of mean stress effects on fatigue life, that is, x = 1 and y = 1.

The most important factors affecting the operating life of the actuators are the load profile of the applied torque, and the gear ratios of the actuator torsional components. The typical load curve for a Joucomatic actuator valve under static condition is shown in Figure 4. The wedging and unwedging load ramps are linear and have very short durations. These steep ramps require relatively few revolutions from the worm to perform the actuation resulting in fewer stress cycles that contribute to fatigue damage. However, it is known that the road ramps under dynamic conditions are of longer duration with only a piece-wise linear profile. Therefore, a higher number of worm revolutions are required for actuation in comparison to the static condition; and the magnitude of closing torque is much larger than that of the opening torque. The actual damage depends on load magnitude and the required number of worm revolutions. We have used static test data with the maximum static stress and 1.5 times the duration of operating time for conservatism.

The analysis model used for the worm shaft configuration for the DR type actuators is shown in Figure 5. For the L type actuators, helical driving gear set is included to the DR type actuator model. The dimensional data for the calculation are obtained from drawings and by direct measurement. The worm shaft is directly connected to a motor for DR type actuators. The model shows forces and dimensions for the worm shaft. The external forces applied on the worm are designated F_w, and on the driving gear are designated F_d. The bearing reaction forces are designated B_1 and B_2 for the shaft.

The external forces and the bearing reaction forces resulting from the valve stem torque and thrust are calculated for both loading and unloading conditions. The worm stresses and the worm body stresses are also calculated. Mean and alternating von Mises stresses are computed for the critical location and are applied to the equation (8). The theoretical stress concentration factors, such as stress concentration factor, size effect, surface finish factor, and fatigue notch factor, are applied to the only alternating von Mises stress.

The thrust rating analysis was not performed. It is addressed in the weak link analysis in part, and the actuator bearing thrust was compared with the maximum thrust.

Rating Analysis Results

The results of the rating analysis of Joucomatic actuators are shown on Table 5. The certified torques and the performance margins shown on Table 1 are the capability of the actuators at 15% under-voltage and at 0 voltage drop from the vendor maintenance manual [7]. The actuator types 80L 111 and 80L 20 have the same configuration and dimension except worm tooth profile. Therefore, the calculated ratings are nearly same. The actuator types DR 5 and DR 10 and the actuator types DR 20 and DR 40 also have the same configuration and dimension except worm tooth profile. It is considered that the worm tooth profiles show a higher effect on the fatigue life because the DR type actuators are smaller than the L type actuators. The actuator ratings should be designed higher than the certified torques and performance margins. However, some ratings calculated are not higher than the certified torques and performance margins. It is considered that the calculated actuator ratings are highly conservative. In spite of the high conservatism, the actuator rating calculation is useful for implementing GL 89-10.

4. Conclusion

The TTS test experience for non-Limitorque actuator has been described in this paper. The actuator capability was assessed with the direct and indirect method. The results indicate that the real actuator output torques for Joucomatic actuator models (80L111, 80L20, DR10.35, DR10.58, DR40.72, and DR5.58) are 20%~100% greater than those of design basis review. For EIM-30 model, the real actuator torques are very close to the design basis actuator torque.

The calculated rating torques are different from the certified torques and the performance margins. Testing for the actuators is required to demonstrate higher rating torques.

In spite of the high conservatism, the actuator rating calculation is useful for implementing GL 89-10.

As a conclusion, we could improve and confirm some non-Limitorque actuator capabilities by introducing the TTS and the actuator rating analysis.

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5. EPRI TR-100449, Motor-Operated Valve Margin Improvement Guide, Topical Report, EPRI, 1992.
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7. Equipment Maintenance and Operation Manual, Joucomatic Electric Actuator Valves.

Table 1. Actuator manufactures in Korea NPPs

Unit \ Manufactures		LI*	JO*	EIM	HO*	RO*	AO*
Kori 1&2		117			18		
Kori 3&4		218				4	
Youngkwang 1&2		218				4	
Youngkwang 3&4		200				37	
Ulchin 1&2			88				
Ulchin 3&4		57				55	9
Wolsong 1		47		19			
Wolsong 2,3,4		96				99	12
Total	Quantity	953	88	19	18	199	21
	(%)	73.4	6.8	1.5	1.4	15.3	1.6

*LI: Limitorque, HO: Hopkinsons, RO: Rotork, AO: Autotork, JO: Joucomatic

Table 2. Actuator models tested with TTS

Unit	Manufacture	Model	Method
Ulchin 1&2	JO	80.L.111	indirect
		80.L.20	
		DR.10.35	
		DR.10.58	
		DR.40.72	
		DR.5.58	
Ulchin 3&4	AO	NQ60	indirect
Wolsong 1	EIM	EB-30	direct

Table 3. Actuator output torque (ft-lbf) with design basis review

Actuator model		Voltage condition		
		80%	90%	100%
JO	80.L.111	227.8	242.0	255.7
	80.L.20	457.4	561.3	670.4
	DR.10.35	73.8	73.8	73.8
	DR.10.58	161.9	191.7	223.0
	DR.40.72	22.8	28.9	35.7
	DR.5.58	46.4	58.5	72.0
AO	NQ60	-	44.7@ 97.8%	-
EIM	EB-30	-	142.5@97.8%	-

Table 4. Actuator output torque (ft-lbf) with TTS test

Actuator model		Voltage condition		
		80%	90%	100%
JO	80.L.111	455.2	-	-
	80.L.20	860.6	864.1	-
	DR.10.35	131.2	142.3	164.6
	DR.10.58	240.1	237.3	246.8
	DR.40.72	-	39.2	46.0
	DR.5.58	-	95.0	100.0
AO	NQ60	-	26.17@95.6%	-
EIM	EB-30	-	147.5@98.2%	-

Table 5. Actuator rating analysis results

Actuator Model	Maximum Torque (ft-lbf)	Certified Torque (ft-lbf)	Performance Margins (ft-lbf)	Calculated Torque Rating (ft-lbf)
DR 5.35	51.0	36.6	50.5	160.0
DR 5.58	25.0	25.6	-	100.0
DR 10.35	60.2	73.2	150.0	160.0
DR 10.43	41.0	73.2	116.3	160.0
DR 10.58	81.1	58.5	95.8	100.0
DR 20.35	204.1	146.3	338.0	300.0
DR 20.43	138.6	146.3	261.9	270.0
DR 20.72	102.4	87.8	150.7	310.0
DR 20.88	80.9	73.2	120.7	220.0
DR 40.35	35.4	292.6	663.5	350.0
DR 40.72	187.3	175.6	299.9	260.0
80L 20	496.7	512.1	848.5	750.0
80L 111	563.0	234.1	417.0	740.0
100L 89	1052.8	438.9	899.7	1450.0
125LS 19	1514.4	2231.1	3686.8	2250.0
125L 47	1978.6	1389.9	2787.0	2300.0

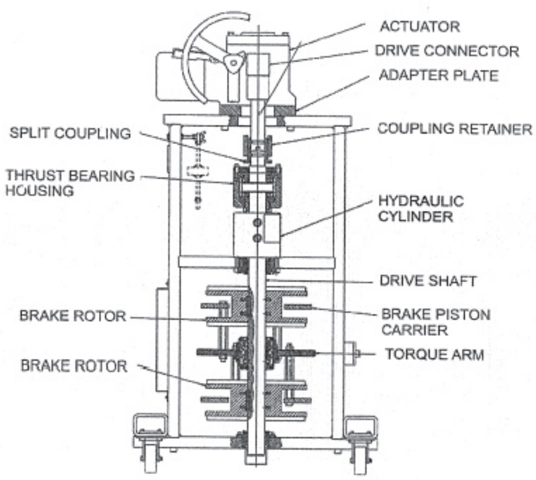


Figure 1. Outline of TTS equipment

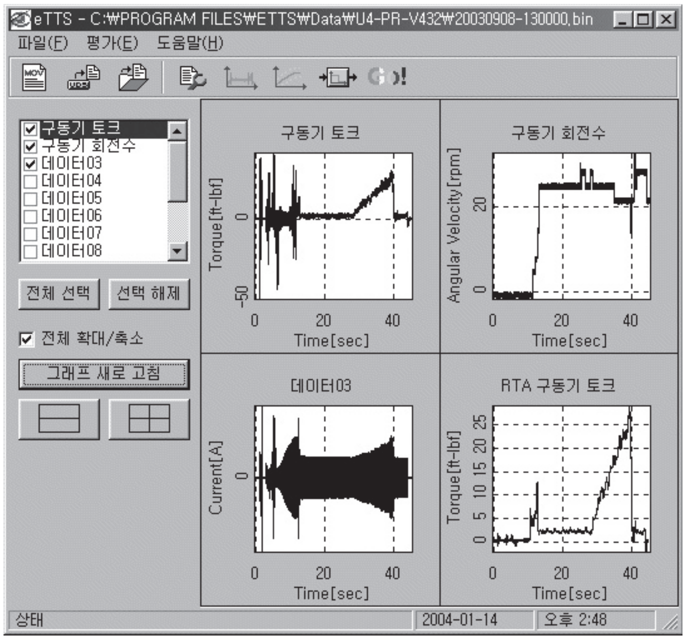
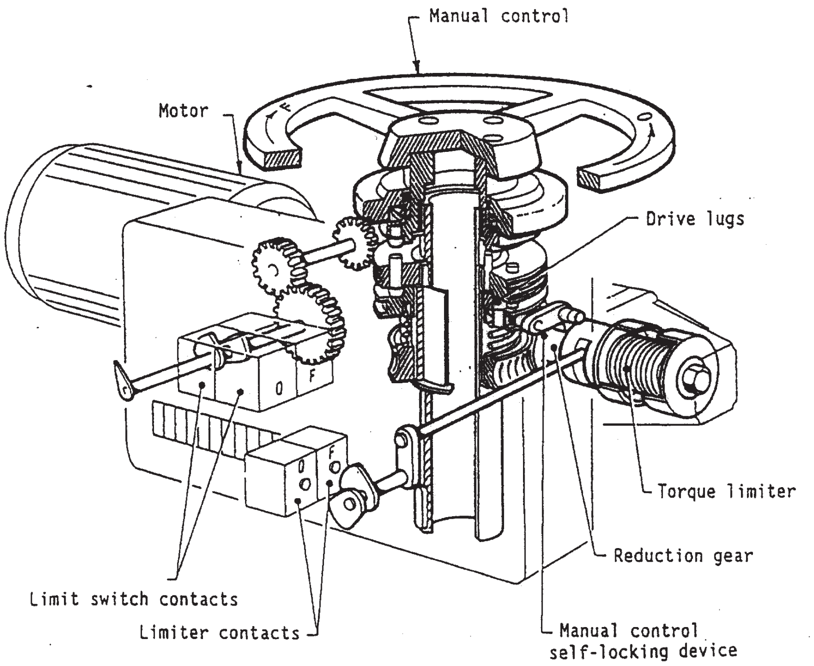
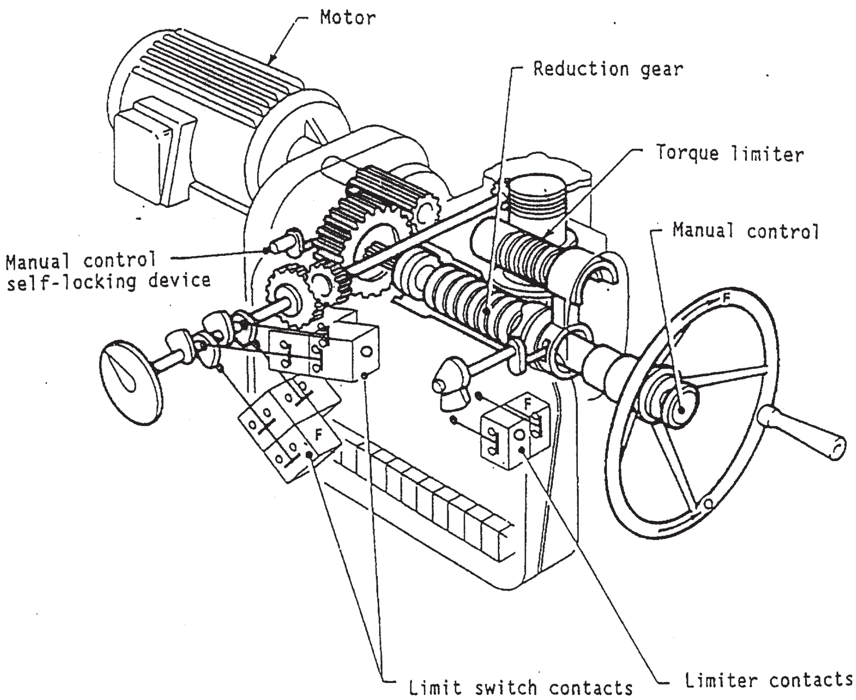


Figure 2. Outline of eTTS program

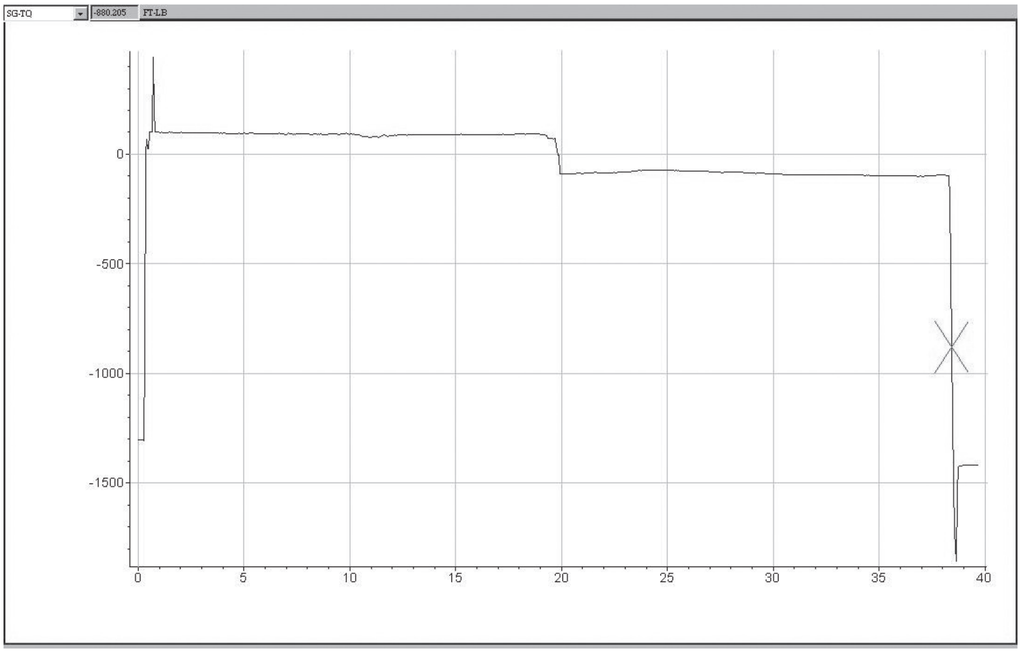


(a) DR type Joucomatic actuator

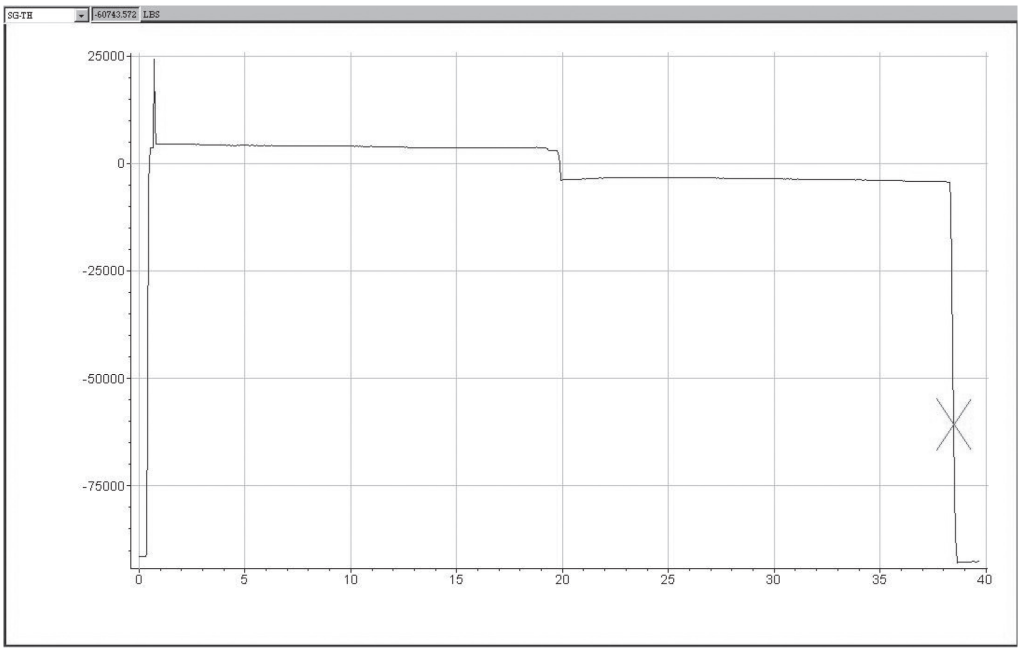


(b) L Type Joucomatic actuator

Figure 3. Joucomatic actuators



(a) A typical torque ramp for Joucomatic actuator



(b) A typical thrust ramp for Joucomatic actuator

Figure 4. Typical valve torque curve for static test

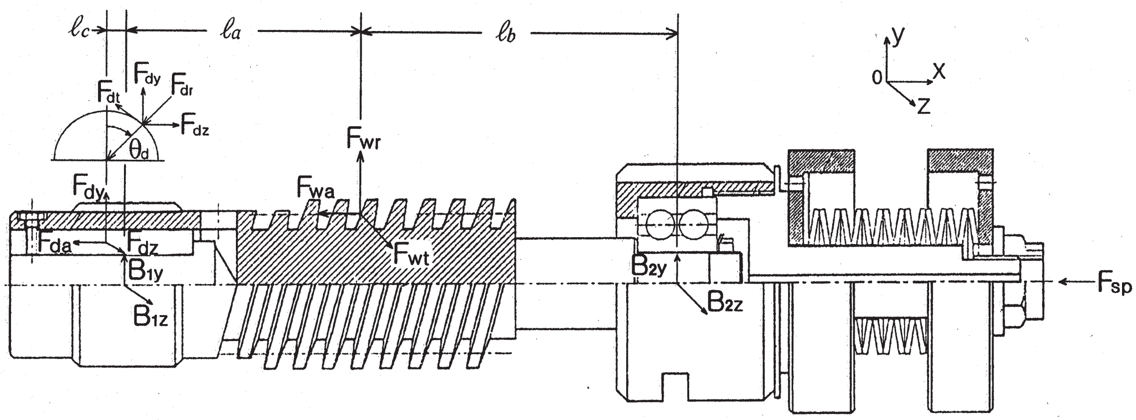


Figure 5. Analysis model for the actuator shaft with worm

Upgrading to Digital Positioners on Feedwater Regulating Valves

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Abstract:

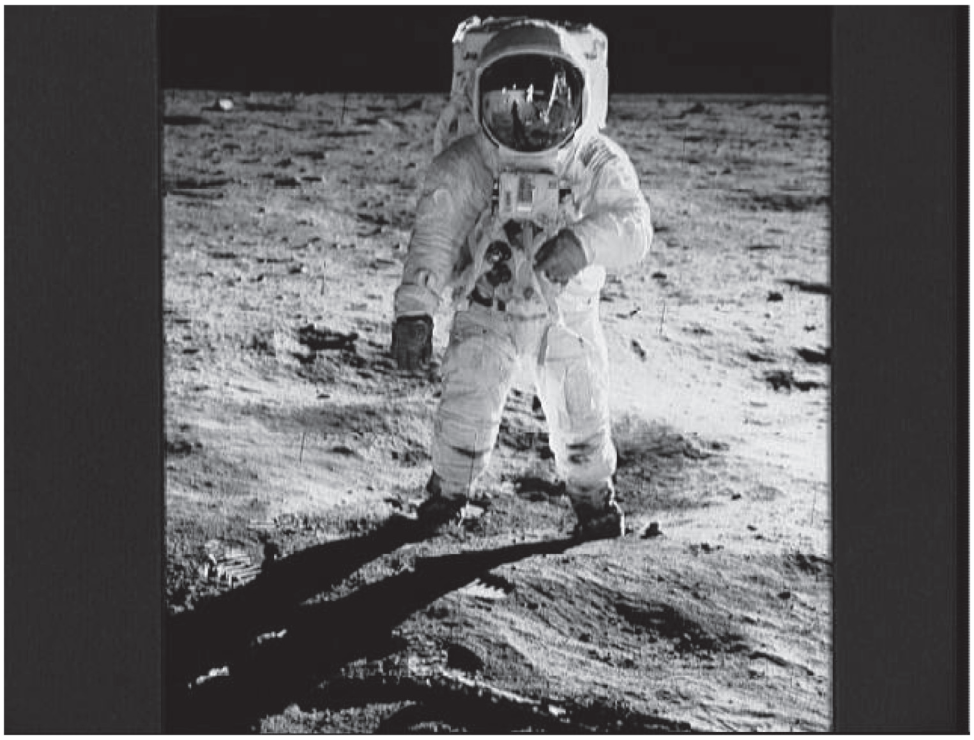
Fort Calhoun Station experienced reliability problems with the Feedwater Regulating Valves.

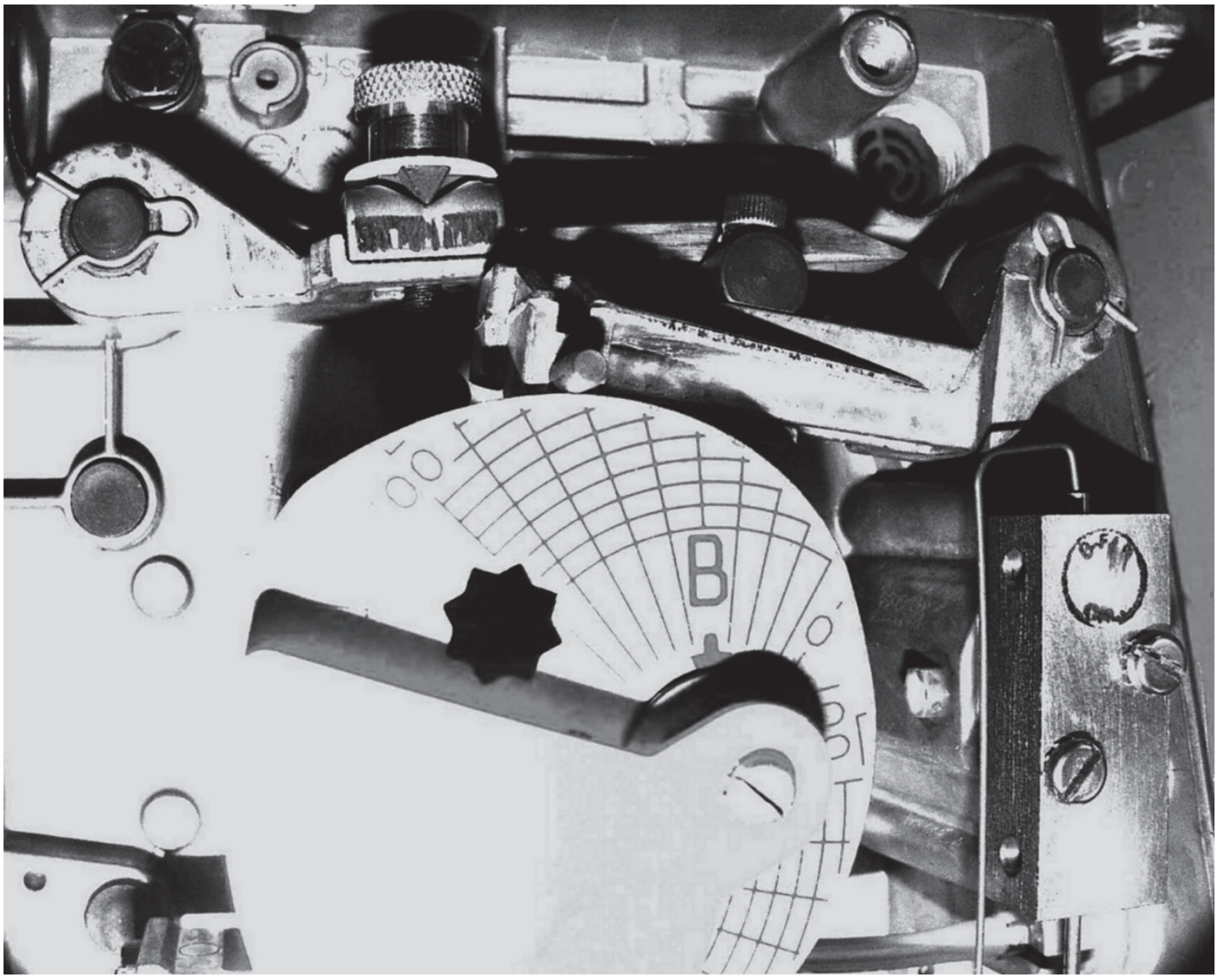
The Steam Generator Level Control System provides a 10 to 50 milliamp (ma) signal to a Fisher Model 546 positioner. The single pneumatic output of the Fisher positioner feeds into a Bailey Model AV1 positioner to provide a dual output to a Fisher Type 472, Size 80 piston actuator. Similar designs are used in the nuclear industry.

The lever arm in the positioner has a ball bearing mounted on a shaft which rides as a wheel on the positioner cam. The retaining clip which holds the ball bearing in place vibrated off allowing the ball bearing to fall off causing the shaft to ride directly on the cam. A plant shutdown would be necessary to fix the problem.

Positioner problems such as spool valve fretting, feedback arms and linkages have been

an ongoing issue in the Nuclear Industry. The decision was made to look at new technology in an attempt to eliminate the problem(s). The option of a digital positioner was selected for the upgrade. Several features such as remote mounting capability, on board diagnostics capability and allow integration to a future Digital Process Control System modification at Fort Calhoun Station. Based on the experiences at Fort Calhoun Station and discussions with plants installing digital positioners on Feedwater Regulating valves many of the challenges were similar. This presentation is important because some of the issues were technical in nature but many revolved around cultural paradigms and work practices. To gain the full advantage of equipment upgrades such as this one, one must be ready to address culture and to change work practices.





Background:

On January 23, 2001, a reactor operator at Fort Calhoun Station received a RC-2A S/G High Level Alarm. The reactor operator notified his supervisor that the automatic control mode of the flow control loop was not functioning properly. The flow control loop was taken from automatic to manual mode and a plan to troubleshoot the problem was formulated. A 22 percent step change in valve position was observed on the Feedwater Regulating Valve (FRV) after trouble shooting. The FRV was returned to automatic mode after the positioner problem was better understood until the next refueling outage. During the refueling outage the positioner cover was removed and it was determined that the retaining clip came loose and the cam roller was found lying in the cover.

On August 26, 2003, a reactor operator received a RC-2A S/G LOW LEVEL ALARM. It appeared the FRV was not responding in automatic mode. The operator restored level control by shifting FRV control from automatic to manual mode. While restoring steam generator level the plant experienced a slight ***reactor power transient***. This was a second occurrence at Fort Calhoun Station.

After generically looking at common industry operating experience problems with positioners such as age degradation, air leaks, linkage and positioner problems, the decision was made to evaluate upgrading the positioners to enhance reliability. Upgrading a positioner sounds like an easy task on the surface but it is not; this experience provided many interesting challenges which are shared in this paper. The importance of this paper is to acknowledge changes in process control technology that may impact utilities wishing to upgrade to digital controllers in the future.

Positioner Failure

The picture above illustrates typical technology used by many manufacturers in the process control industry over the past several decades. A lever arm has a ball bearing (not shown) mounted on a shaft which rides as a wheel on the positioner cam. In this case a retaining clip most likely vibrated loose allowing the ball bearing to fall off causing the shaft to ride directly on the cam. This causes a shift in the feedback within the device which makes the positioner think that the valve is in a different position and results in a corrective action from the positioner. At Fort Calhoun Station this caused the level in the steam generator to shift followed by a slight system transient.

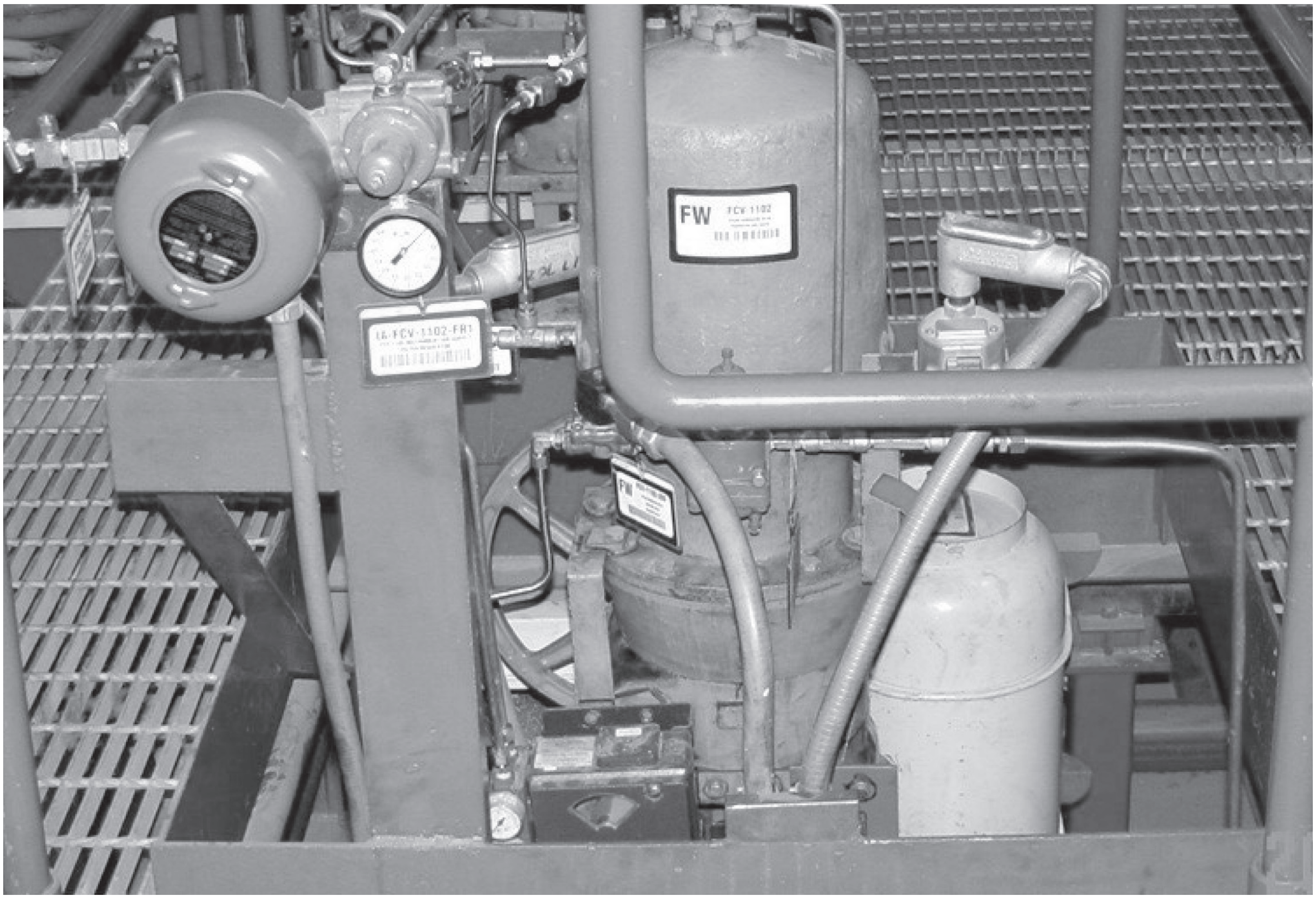
Original Air Operated Valve Configuration:

Actuator: Fisher Type 472-1 Size 80,
Piston without Spring

Valve: Fisher Model EHD
Size 8 inch with travel limited to 3.5 inches.

Positioner: Fisher Model 546/Bailey Model AV1
10 – 50 ma input
3 – 27 psi output

The pneumatic output signal was fed into a Bailey positioner to convert the single output to a double output for a piston actuator.



Reliability Issue:

FCS experienced valve positioner problems impacting plant reliability. The positioner was subjected to vibration which created continuous problems such as maintaining calibration and cam follower roller bearing failure. Discussion with other plants in the industry also identified positioner linkage and fretting problems in the sliding spool control valve assembly within the positioner potentially resulting in degraded valve control performance or a possible plant trip.

Bailey Positioner

Choosing a new positioner for the Upgrade:

The decision was made to investigate use of new technology available to increase plant reliability. Challenges for upgrading the positioners existed in many areas so we looked from the inside of the box to the outside.

- **Cultural Change**s (Engineering, Craft and Operations)
  - ❑ Site engineering experience with digital technology was very limited and plant procedures were not in-place to evaluate digital modifications.
  - ❑ Craft and Operations personal had no experience with the digital positioners or the associated software
  - ❑ Training and experience would be needed for everyone. Experienced on-site staff did have the appropriate level of knowledge for digital positioners.
  - ❑ Culturally there was concern about the **"Digital Scare"** problems heard in the industry over many years and the possibility of malfunctions during the installation of the modification and post maintenance during plant startup & operations.

Advantages

- The digital positioners selected have the capability to perform advanced diagnostics which almost eliminated the need for conventional diagnostic test equipment.
- Historical data could be retrieved after the installation of a Digital Process
- Control System from a remote location.
- The issue of man machine interface when performing calibration is addressed. The results will be the same as long as the same data is used.
- Local and Remote mounting capability eliminates leakage adjustment which could affect calibration.
- Maintenance time required for calibration, and maintenance was significantly reduced. In addition, removal for a remote mounted digital positioner for valve and actuator overhauls takes only a few minutes.

Modification Process:

Evaluation of Digital positioners

- Evaluation Procedures – Outside assistance was obtained to develop procedures to document and evaluate digital process controls that utilize microprocessors, associated software/firmware to perform its intended design function. This process was based on available industry information from EPRI Report TR-102348, "Guideline on Licensing Digital Upgrades."
- Learning new technology – Several digital positioners were considered. The following features were looked at to make a final decision
  - ❑ Robust construction and a product that was easy to maintain
  - ❑ Positioners with on-board diagnostics capabilities and characteristics that were similar to diagnostic test equipment currently used in the nuclear industry
  - ❑ Vendor Support for Training with minimal costs to the station
  - ❑ Positioners that would be compatible with new digital plant architectures in the future and that had a significant installed base within the process control industry.
  - ❑ Ease of installation, testing and calibration
  - ❑ Capable of being remotely mounted to avoid harsh environments during maintenance, normal operation and accident conditions.

Modification Issues

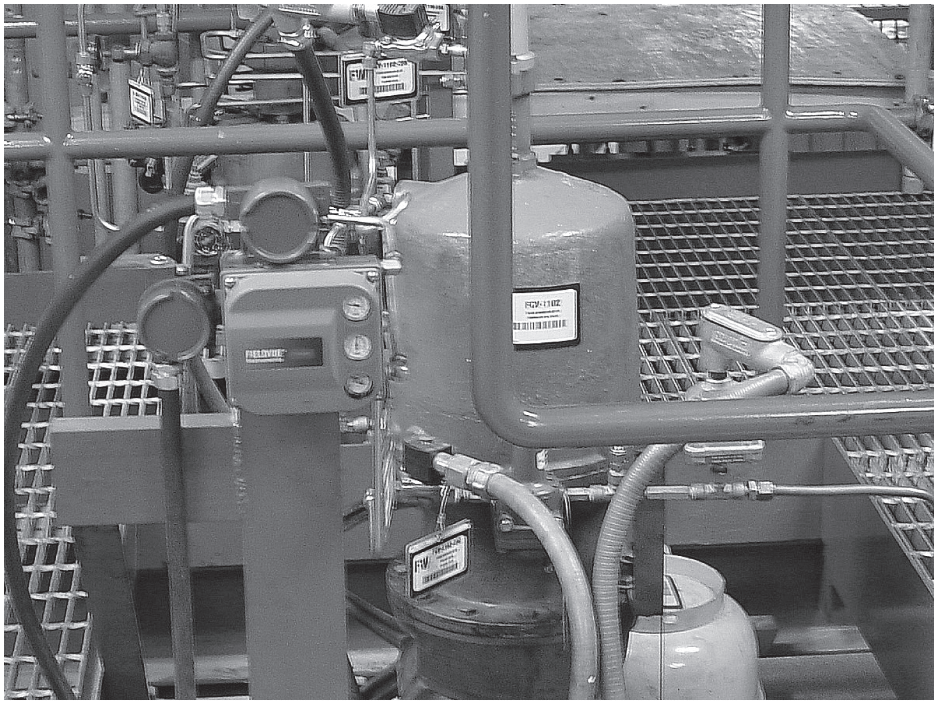
- Converting the process control signal from 10 – 50 ma to 4-20 ma.
  - ❑ A signal conditioner was installed in remote panels to convert the signal to 4-20 ma.
- Testing
  - ❑ Testing requirements had to be established.
  - ❑ Portable diagnostic Test Equipment was used to validate On-Board diagnostic dynamic and ramp test capability of the digital positioner.
  - ❑ Plant calibration procedures were revised.
- Training and Experience
  - ❑ I&C Technicians and Training Department personnel familiar with air operated valve diagnostics were trained by the vendor on digital positioners and associated software.
  - ❑ Vendor experience was used during the installation and validation testing. This included pre-outage walkdowns and checking out the positioner in the I&C shop to ensure itoperated correctly and to familiarize plant personal with test equipment and software.

- Component Testing and Design Engineers benchmarked similar modifications at a site and participated with the installation of digital positioners with the vendor. This provided engineering knowledge and experience required for preparation, procurement and installation of the digital positioners. In addition, experience was obtained for initial setup and calibration to develop changes to plant procedures and the modification package.

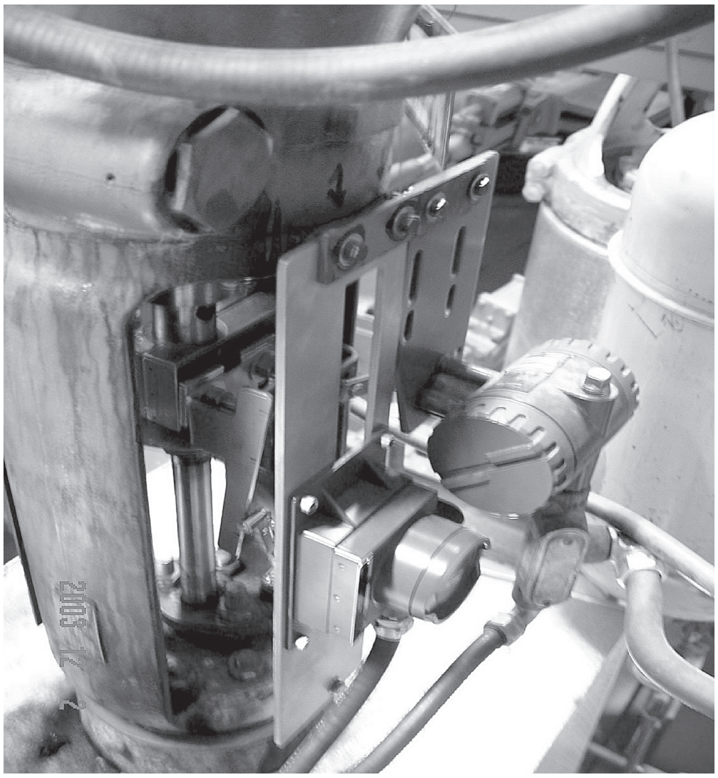
Diagnostic Testing with On-Board Diagnostics and AOV Diagnostic Test Equipment.

- The Feedwater Regulating System utilizes a three element control loop with inputs from feedwater flow, steam flow, and steam generator Level. It controls the FRVs at 70% open (Equivalent to 100% Power) to maintain the steam generator programmed level at 65%.
- In the event of a turbine trip, a ramp signal will close the both FRVs from 70% open (100% Power) to 8% (5% Power) open in 20 seconds.
- Fisher ValveLink Software was used to setup the digital positioner on the Air Operated Valve. In addition the Hart communicators were used to ensure that the positioner would perform similar tasks, as part of an equipment check.
- Diagnostic tests were compared using Fisher Flowscanner 5000 diagnostic test equipment to validate the signatures from the AMS ValveLink Software.
- The Loop Calibration Procedures were used as a final check for Post Maintenance Testing and returning the loop to operation.
- Diagnostic Testing was performed to verify AOV setup parameters such as:
  - Valve stroke length
  - Tuning Setup
    - Proportional & Integral gain settings
    - Dynamic error and linearity
    - Zero and Span at full range of travel
  - Packing friction
  - Overall dynamic valve signature comparison between Fisher Flowscanner and AMS ValveLink Software.

Installation of the Digital Positioner



Installation of the Mounting Bracket and Travel Potentiometer for the Digital Positioner

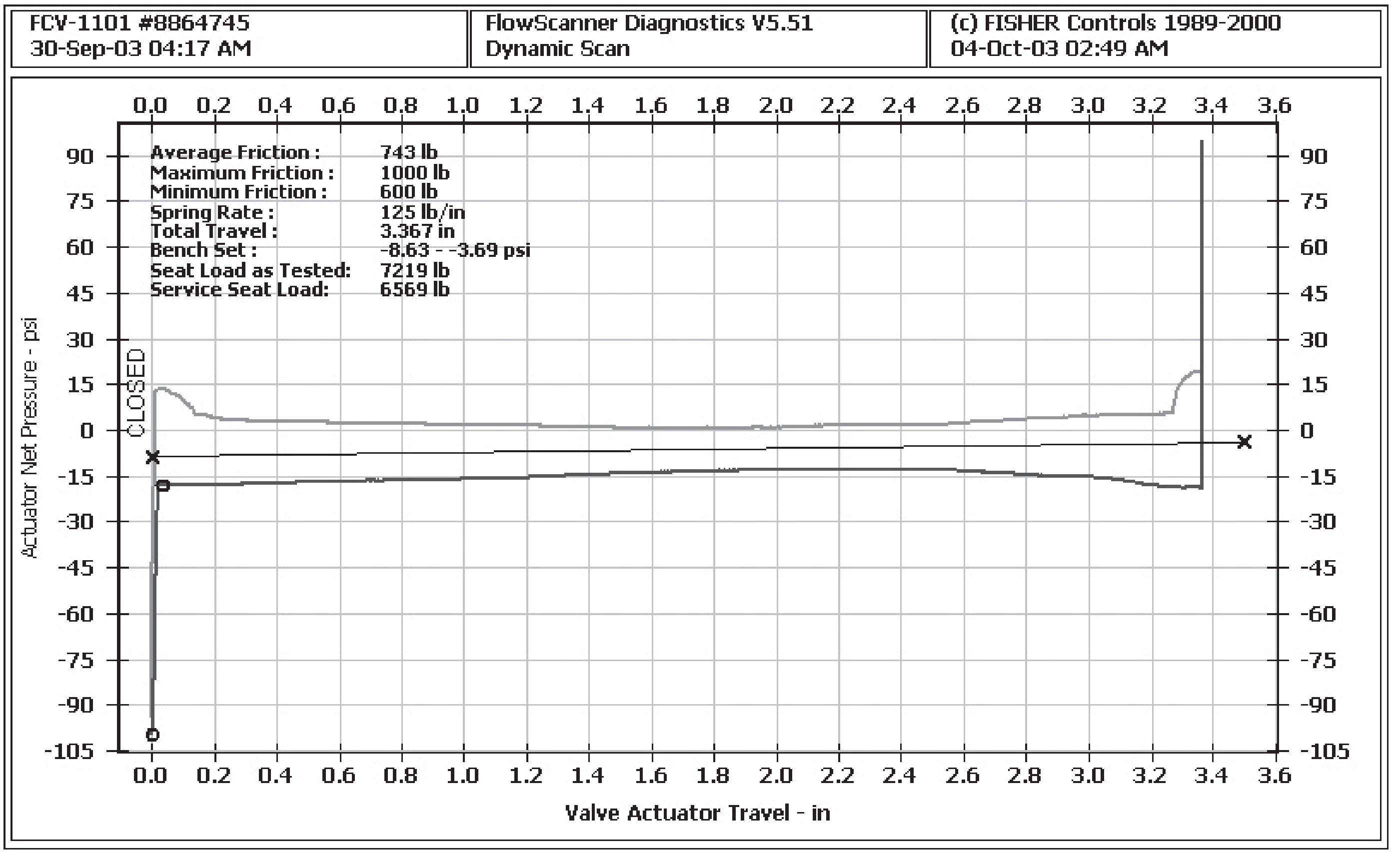


Installation of the Cam and Travel Potentiometer for the Digital Positioner

(Side View)

Dynamic Scan Test

Flowscanner Diagnostics



Test Conditions:

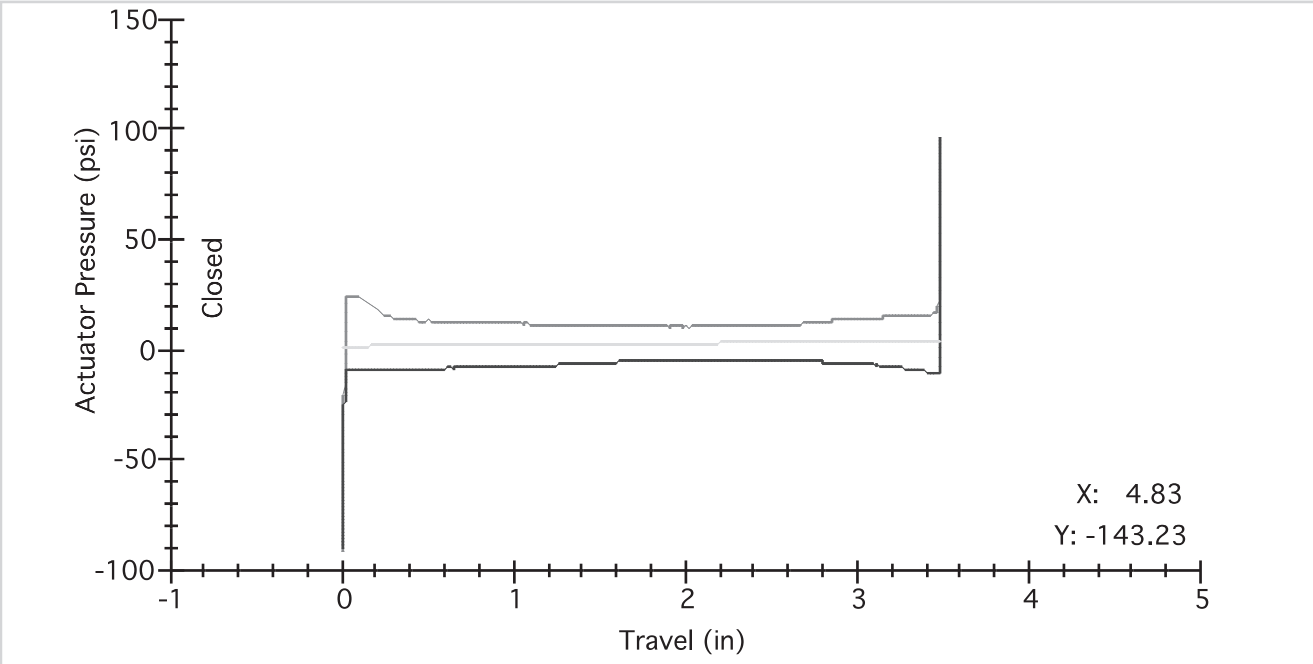
Dynamic testing was performed with the Plant shutdown under Flow conditions.

The top trace going from left to right illustrates the valve going from closed to the full open position.

The bottom trace from right to left illustrates the valve going from full open to the closed positioner.

Dynamic Scan Test

ValveLink Diagnostics



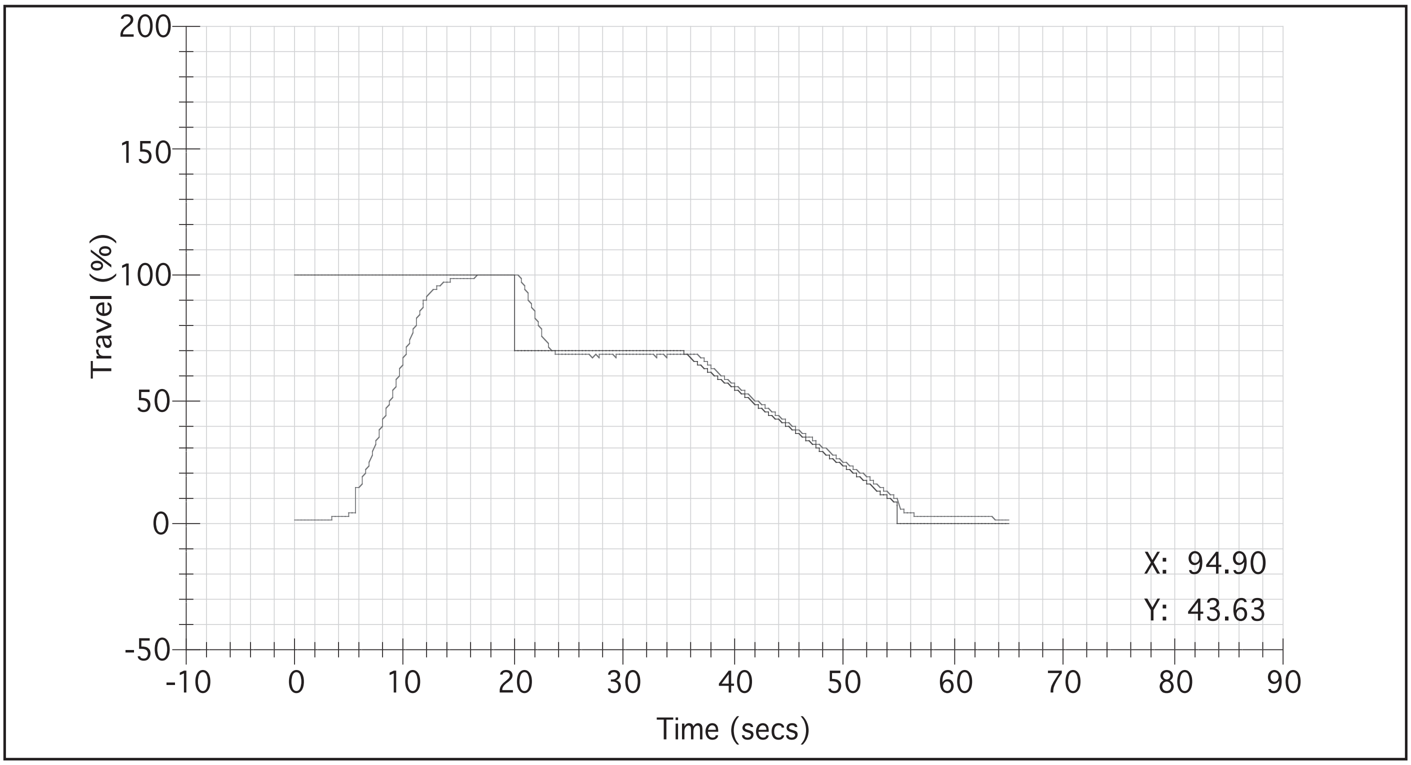
Valve Travel – Closing Stroke (bottom trace)

Valve Travel – Opening stroke (top trace)

The profile characteristics of both Dynamic Signatures from the AMS ValveLink and Flowscanner diagnostics were compared. The comparison demonstrated that the on-board advanced diagnostics in the digital positioner were functional. The intention is to use the On-Board diagnostics in place of the Flowscanner.

- Calibration time for the positioner was reduced from 4 hours to 5 minutes per valve.
- The need to disconnect tubing and lifting leads was eliminated.
- Repeatability for calibrations no longer a concern with digital positioners even when different technicians perform the positioner calibrations.

RAMP Test Simulation from 100% to 5% Power



Ramp Input Signal – top trace

Valve Travel – bottom trace

Ramp testing was performed with the plant shutdown and no process flow from 70% to 8% open within 20 seconds using the AMS ValveLink Diagnostics to ensure the valves would respond to a turbine trip.

- This was done by simulating 100% open full valve travel followed by a step to 70% open (100% Power) to set up the test.
- The air operated valve was stabilized prior to initiation of a 20 second ramp signal from 70% open to 8% open (5% Power).
- Each Feedwater Regulating Valve was returned to service after a Loop Calibration and a function check to cycle the valve.

New technology requires new training

- Knowledge and experience was obtained by working with Emerson Process Controls personnel during an installation of digital positioners at Omaha Public Power District's North Omaha Station.
- Vendor manuals for the positioners and software were obtained in advance to assist Design Engineering with the development and planning of the modification package.
- Site Engineering, Training and I&C personnel attended training at Fisher in Marshalltown prior to the development of the modification package. This was very beneficial in helping everyone understand the installation and calibration of the positioners.
- The digital positioner and software was setup in the I&C shop to perform a functional check of the positioners and test equipment prior to installation in the field. This mock-up significantly reduced hardware installation and software/hardware setup time. In addition this task verified everything was working before the installation.

Potential Benefits:

While the focus on this project was on increasing hardware reliability, there are additional benefits that can result from leveraging this type of technology. These benefits include:

- Faster more stable valve response will enable loops to be tuned and set up closer to operating limits increasing overall output and efficiency. i.e. The plant will generate more megawatts.
- More stable operation of the valves will result, given the capability of the positioner, which will reduce the wear and tear on the valve and major system components that might have to react to variations of flow through the valve. A smoother plant runs better and cheaper with reduced need for corrective maintenance spending.
- Upgrading to modern equipment addresses the issue of equipment obsolescence and technical support.
- Online diagnostics capability will permit a condition-based predictive maintenance approach on the Feedwater System, resulting in better performance at a lower cost.
- Digital equipment can be tuned to match the operating requirements of the system, optimizing process control. This translates into improved plant performance at lower cost as previously mentioned. If necessary, it could be tuned to match the performance of the equipment that it replaces so that the system would not have to be retuned until more experience is gained by the plant.
- Digital upgrade with advanced diagnostics and communications capabilities provides an avenue of transition to future Digital Process Control Systems which will improve plant performance and reduced maintenance. Plant personnel will have remote calibration and monitoring capabilities for component and system performance.

10 Top Things to Consider When Upgrading to Digital Positioners:

1. Develop good communications to ensure the manufacturer understands everything about the application.
2. Make sure all personnel on site participating are familiar with the Digital Upgrade.
3. Ensure your vendor has the knowledge, experience and enthusiasm to work through every phase of the modification.
4. Consider using alternative testing with additional equipment to validate on-board digital diagnostics.
5. Setup and test equipment prior to the installation to ensure everything is operating correctly.
6. The modification process should carefully address all the issues for digital modifications by using available industry guidelines and practices.
7. Obtain training directly from the manufacturer for various plant personnel, such as Design, Training and Craft personnel.
8. Have spare parts and equipment readily available to prevent delays.
9. Participate with a cross section of personnel for the installation of digital controls at another site(s) to learn as much as possible.
10. Attend industry conferences and use resources for industry operating experience information to understand potential problems associated with conventional and digital positioners.

Quote of the Day:

"There are no Bad Positioners, it's just that some work better than others."

References:

Control Valves for the Chemical Process Industry McGraw-Hill 1995, Author: Bill Fitzgerald

The Control Valve's hidden impact on the bottom line" Part 1 and Part 2. Valve Magazine, Summer and Fall, 2004 issues Author: Bill Fitzgerald and Chuck Linden

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Use of Graphitic Pressure Seal Ring Gaskets in Pressure-Seal Bonnet Designed Valves

Bruce Harry
CRANE Nuclear, Inc.

In recent years, the momentum for the use of (Die-Formed) Graphitic Pressure Seal Rings in Pressure-Seal Bonnet designed valves has increased. CRANE Nuclear experiences with Graphitic Pressure Seal Rings started in 1994 and, from the onset, had developed a methodology to evaluate each application. CRANE Nuclear's evaluation process, analysis techniques, lessons learned, installation procedures, applications where Graphitic PS Rings were not recommended, and future development activities, will be discussed during the Symposium presentation.

Pressure seal ring gaskets manufactured from graphite are typically furnished as replacements for the originally supplied metallic materials with silver plating. The advantage of the seal ring manufactured from graphite is its inherent property to better conform to mating surfaces, and will seal even if small imperfections in the sealing surfaces are present.

Two separate characteristics which must be addressed are: 1) the tendency for the graphitic material to consolidate; and 2) when under pressure, to flow. Consolidation affects the initial height of the graphitic Seal Ring set; therefore, mechanical fit-ups must be reviewed to determine dimensional limits for installation and subsequent retightening. It is the tendency for the graphitic material to flow, that requires special provisions for field retrofitting. Each graphitic Seal Ring set consists of a stainless steel Backing Ring. This Backing Ring is placed directly on top of the Seal Ring. The Backing Ring is sized not only to prevent the graphitic material from extruding between parts, but can also be designed to limit the amount of consolidation.

For field retrofitting, the graphitic Seal Ring (with the Backing Ring) is designed to be a direct replacement for the existing metallic Seal Ring, without changes to any of the mating parts, and would not affect the pressure and temperature rating of the valve.

Unlike graphitic gaskets used in Bolted Bonnet design valves, which only perform a sealing function, the Pressure-Seal Bonnet Gasket is designed also as a structural component.

The Pressure Seal Ring Gasket not only affects the alignment of the Bonnet, but is a load path member, directly transmitting the line pressure load to the Retaining (or Segment) Ring, a valve pressure boundary component. For this reason, the substitution to graphitic Pressure-Seal Rings must be carefully evaluated for each application.

Programmatic Approaches to Ensuring Appendix J Leak Tightness Following Maintenance Activities

William A. Loweth
Millstone Power Station
Dominion Nuclear Connecticut, Inc.

Abstract

The presentation will focus on a programmatic approach to assess the overall health of a typical 10 CFR 50 Appendix J valve/penetration assembly, exploiting the interrelationships of Appendix J, inservice testing (IST), Work Planning, motor-operated valve (MOV), air-operated valve (AOV) and other programs. One of several rational approaches to extending Local Leak Rate Tests (LLRTs) up to their next periodic test interval following "mid-cycle" minor maintenance activities, that could affect a valve's leak tightness, will be shown for discussion purposes.

Introduction

10CFR50 Appendix J states, "One of the conditions of all operating licenses for light water cooled power reactors…is that primary reactor containments shall meet the leakage-rate test requirements in either Option A or B of this Appendix." Option B of this Appendix identifies the performance-based requirements and criteria for preoperational and subsequent periodic leakage rate testing. Specific guidance concerning an Option B performance-based leakage test program, with acceptable leakage rate test methods, procedures and analysis are provided in Regulatory Guide 1.163, "Performance Based Containment Leak Test Program."

A review of Regulatory Guide 1.163 indicates the NRC's acceptance of Nuclear Energy Institute (NEI) Industry Guideline NEI 94-01, Rev. 0, for implementing the performance-based option of 10CFR Part 50, Appendix J. With the exception of some Containment Purge and Vent Valves on Pressurized Water Reactors (PWRs), and Main Steam Isolation and Feedwater Isolation Valves on Boiling Water Reactors (BWRs), the Option B process permits extended test intervals up to 60 months.

For penetrations to qualify for this extension of the test interval, NEI 94-01 states "extensions to Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. If the test interval for Type C test is at 30 months; it may be increased to 60 months. If the Type C tests are not acceptable, the test frequency should be set at the initial test intervals. Once the cause determination and corrective actions have been completed, acceptable performance may be reestablished and the testing frequency returned to the extended intervals as specified in this document."

Programmatic approach to ensuring Appendix J leak tightness

So where are we headed with this? Many Utilities are working toward, or have been given, approval to follow the rules of Option B, and to maintain a 30 to 60 month test interval between LLRT type C tests. This risk-based approach makes sense. If the penetration is performing well over time, with repeatable results, AND work activities on components that make up the penetration are assessed for impact and controlled, it is reasonable that the overall "health" of the penetration be maintained between extended LLRT testing intervals.

In years past, Utilities would not second-guess whether the impending work would require an as-found LLRT before they touched the penetration's isolation valves. An as-found LLRT would be performed if there was even a hint the impending work could "disturb" or affect the penetration's ability to perform under design basis loss of coolant accident (DB LOCA) conditions! What would happen if an unexpected work activity on the penetration assembly were to occur between these extended LLRT test intervals? During this period, there appeared to be no clear or agreed to guidance on what was an acceptable work activity that would not affect the penetration's "health", leaving many Utilities to their own devises. The Regulatory Guide and, even more so, the NEI document were fine for describing the means to extend test intervals. But little guidance existed for Utilities to make a conscious and consistent determination to conclude when a LLRT was necessary depending on the work activity. The standard, conservative decision was that the work activity would jeopardize the penetration's "health"! With the onset of more Utilities planning work around specific safety equipment trains during alternate outages, making educated decisions to justify deferring LLRT testing following minor maintenance becomes more important.

In 1995, the BWROG VTRG (Boiling Water Reactor Owners' Group Valve Technical Resolution Group) proposed a rational approach to help Appendix J engineers assess the need to perform LLRT tests at the onset of minor work activities. (Excerpts are provided at the end of this paper as Enclosure 1). With the onset of Generic Letter 89-10, motor operated isolation valves began to be tested for closing and opening capability. Actual repeatable thrust values were being obtained. Diagnostic test data began to give the MOV engineers the "uncanny ability" to make a prediction of a valve's seat condition.

Now for the hard part; do you think it is possible to convince the Appendix J engineer that the valve/seat profile looks pretty basic, the thrust is fairly repeatable between tests… would you think there is a possibility the penetration assembly, consisting of 2 to 3 MOVs, relief valves and manual isolation valves, would still be a good penetration, after the MOV guys had to change out a torque switch????? If we were to diagnostically test an MOV, then take the actuator off its yoke, walk it around containment, bolt it back on, diagnostically retest it and leave the thrust practically where we found it, I would be comfortable in telling Operations the penetration leakage rate would be practically the same.... but would they believe me??

Now, put yourself at a "Mid Cycle" point, you have a good penetration that has passed 2 consecutive tests (worthy of going to 60 months), and "Oh oh! We have to change out the torque switch!!!" Now, how do you get to the next LLRT test interval without an LLRT? In the past (pre-1995), we would, without question, LLRT the penetration, no matter what the MOV guys told us! This would apply to packing changes, limit switch adjustments, etc.

It is at this juncture we want to apply engineering analysis methods, and provide examples of what that review may entail, to support a conclusion that the penetration exhibits good or bad performance. If it is a good performer, provide the justification to not LLRT a penetration in "Mid Cycle".

Taking various pieces of information and data from several in-house programs, a work history review of the penetration would look for a correlation of penetration leakage performance, past work history, and adjacent containment isolation closing thrust performance over time.

Enclosures 2 and 3 are history reviews of 2 penetration assemblies at Millstone Unit 3. The examples illustrate several factors to consider in assessing the health of a penetration. From a review of past work history over the years, one can assess whether, outside of LLRT "space", there may be other factors – packing leaks, MOV gear changes, AOV diaphragm/spring change outs, disk/wedge replacements, as well as valve size, manufacturer, style, safety significance [including a review of core damage frequency (CDF) and large early release frequency (LERF) (which you can get from your probabilistic risk assessment (PRA)/Safety analysis folks) and configuration (horizontally mounted, or vertically mounted), service conditions and fluid media]. Couple this to the history of the penetration's LLRT performance and MOV/AOV thrust data can provide a clear picture of how the penetration has behaved over time. It is at this juncture the Appendix J Engineer can make some reasonable judgments as to how the penetration is affected by different minor maintenance activities.

For example, if further review of the work activities and performance of the associated valves show that, if the closing thrust remains pretty much the same and the penetration is a good one, you have reasonable assurance the penetration is OK. If you put the total thrust back to the as-found condition, you should be able to hold off on the official LLRT test until the next scheduled test interval. Where this approach benefits the utility is in the case of a packing adjustment/changeout during a cycle. This approach could also apply to the replacement of closure springs on an AOV, if subsequent testing can show a closing thrust of similar magnitude is repeated after the change, and the valve strokes consistently.

Qualitatively, it is best to review the resulting performance of all penetrations after outage work activities up front, at the beginning of the run cycle. As the work scope for the next outage is formulated, clear and understandable retest requirements for the penetrations can be made, based on the penetration's health. If a good performer, a retest may only include a diagnostic test that confirms adequate valve seating to the as-left condition. A bad performer may require an LLRT following minor maintenance.

Some observations: The BWROG VTRG position paper suggested that the closing thrust be repeatable to within 10%. This was an effort to get the thrust as close as possible to the as-found condition. Combining all the history pieces together, and assessing whether the penetration was a good performer or bad performer, was key. Also, as the MOV test program matured, MOVs were being periodically tested to the same thrust windows. LLRT data collected in concert with MOV test data concludes a good performing penetration assembly need not be "locked" to the 10% criteria. Conversely, a review of data on a poor performing penetration would make any change in thrust, up or down, suspect.

It should also be noted that this approach does not recommend extension of the 60-month test interval by engineering analysis. Performing an analysis or alternate test is unacceptable, as the as-found test provides clear and objective evidence of performance of the penetration's isolation components.

Conclusion

By utilizing data inputs from established station programs, Appendix J owners can make a reasonable assessment to justify an extension of the LLRT test to the next available test window. Consideration for test results from MOV (AOV) diagnostic test equipment can be used to justify that the valve can perform its intended function, after minor maintenance.

The object of this programmatic review is to provide reasonable assurance the valve and penetration will perform its intended function until the next as-soon-as practical test opportunity. If however after the analysis, there remains some doubt regarding the minor maintenance activity's affect on the penetration, an as-found/as-left test provides clear and objective evidence of performance of the isolation components.

Enclosures:

1. Excerpts from BWROG CTRG task 95-07, page 1, 2 and Attachment 1, 4
2. Performance review example of Penetration 92(o) at Millstone Unit 3
3. Performance review example of Penetration 26(o) at Millstone Unit 3

TASK 95-07

Appendix J/GL89-10 Correlation
BWROG VTRG Committee Position

Retest Requirement Guidelines for Appendix J Valves

PURPOSE:
The purpose of this Document is to provide consistent Local Leak Rate Test (LLRT) retest guidelines to meet the requirements of 10CFR50, Appendix J for manual valves, Air Operated Valves (AOVs), Solenoid-Operated Valves (SOVs) and Motor Operated Valves (MOVs). Also provided is the methodology to provide sufficient justification to implement LLRT test interval extensions allowed by Option B to Appendix J.

BENEFIT TO LICENSEES:
Utilities can minimize redundant engineering evaluation and testing efforts associated with regulatory LLRT requirements by coordinating GL89-10 and 10CFR50, Appendix J provisions. Such coordination can avoid unnecessary levels of safety.

DISCUSSION:
In many cases, the rationale to justify performance (or non-performance) of a LLRT, if maintenance on a LLRT valve is performed during an operating cycle, has been found to be inconsistent from Utility to Utility and even from unit to unit within the same utility. Therefore, Attachments 1 through 9 have been developed to provide consistent guidelines for determining requirements for LLRT.

In addition, review of Rev. 0 of NEI 94-01, “Industry Guidelines for Implementing Performance-Based Option of 10CFR50, Appendix J” (dated 7/26/95), concludes that any licensee who elects to defer LLRTs must provide sufficient justification (See Annex A - NEI 94-01). This document is intended to supplement Annex A in justifying adjustment to the LLRT frequency.

- Attachment 1 can be used during development of the Work Order to determine if an LLRT is required. Engineering review of the retest requirements is necessary to defer LLRT testing.

- Attachments 2-6 provide additional guidance in cases of repacks, torque switch adjustments (for MOVs) and limit switch adjustments (for MOVs and AOVs). When using alternate diagnostic testing as a basis for LLRT deferral, a review that assures the valve and actuator have not undergone any severe environmental or overthrust event(s) since the last LLRT, should be documented.

TASK 95-07

Appendix J/GL89-10 Correlation
BWROG VTRG Committee Position

The basis for the majority of the recommendations are as follows:

- For gate valves, a change in the total available total closing force of less than 10% since the previous leak test, is considered to be within the accuracy of the diagnostic test equipment and a Type C Leak Rate Test would not be required. The closing force is essentially the same. However, significant (>10%) increase or decrease in available closing thrust could allow the disc to seat in a slightly different location and the sealing surface may be different, possibly affecting leakage rates. In these cases, Attachment 6 should be reviewed for applicability.

- Similarly, if the AOV spring tension is set to the same value as previously set, a Type C Leak Rate Test would also not be required since the closing force is essentially the same as the closing force during the previous leak test. Increased closing force on a globe valve could only increase the contact force between the seat and the plug (same seating surface) which would lead to a tighter seal. Therefore, as depicted in the Attachments 1-6, the Appendix J Type C test would not be required.

The NEI 94-01 guidelines recommend component design, safety significance of the penetration, cycle frequency of the valve, flow rate and fluid type, line size and service pressure be considered when extending/adjusting a service interval. These items, as well as the LLRT leakage/MOV(AOV) thrust data correlation over the last two or three test cycles, should be included in any technical justification developed for interval extension.

The NRC has endorsed the use of NEI 94-01 per NUREG 1.163, dated September 1995, with the exception of deferring as-found LLRTs. If maintenance or repair work is planned for a component, an as-found LLRT would be required. Performing an analysis or alternate test is unacceptable, as the as-found test provides clear and objective evidence of performance of isolation components.

Principle Investigators:

W. A. Loweth	G. E. McGovern
Millstone Unit 1 Tech Support	NNECo Programs Engineering

April, 1996

TASK 95-07

Appendix J/GL89-10 Correlation

BWROG VTRG Committee Position

ATTACHMENT 1

POST MAINTENANCE LLRT GUIDELINES

Maintenance activities identified below typically are not allowed an option to evaluate whether or not a LLRT is required. However, there are special circumstances, which should be evaluated on a case-by-case basis.

Maintenance Activity	Valve Type	Post-Maintenance LLRT Required	Comment
1. Solenoid valve removal or replacement (control air to actuator)	AOV	NO	IF AOV is air assist to close, air function must be verified in maintenance plan.
2. Disconnect Instrument Air Lines	AOV	NO	Same as No. 1.
3. Actuator diaphragm removal or replacement. (Actuator not removed)	AOV	NO	Assumes diaphragm is opening mechanism.
4. Spring Preload Adjustment	AOV	See Attachment 4.	
5. Valve diaphragm removal or replacement	AOV, Manual	YES	
6. Actuator removal or replacement.	AOV, MOV, SOV	YES	
7. Disconnect electrical leads	AOV, MOV, SOV	NO	Must verify stroke test is acceptable.
8. Cleaning and replacement of stem grease.	MOV,	NO	
9. Addition of grease to dry stem.	MOV	See Attachment 4.	
10. Overhaul valve internals, i.e., lap seat, change plug, disc or cage, pin replacement.	ALL	YES	
11. Remove or replace Starting coil.	SOV	NO	
12. Motor removal or replacement.	MOV	NO	
13. Stem nut removal or replacement.	MOV	See Attachment 4.	
14. Motor starter contactor replacement.	MOV	See Attachment 4.	
15. Clutch lever removal or replacement	MOV	NO	
16. Packing Adjustments	All	See Attachment 2,3	
17. Limit Switch Adjustment	AOV, MOV	See Attachment 5.	

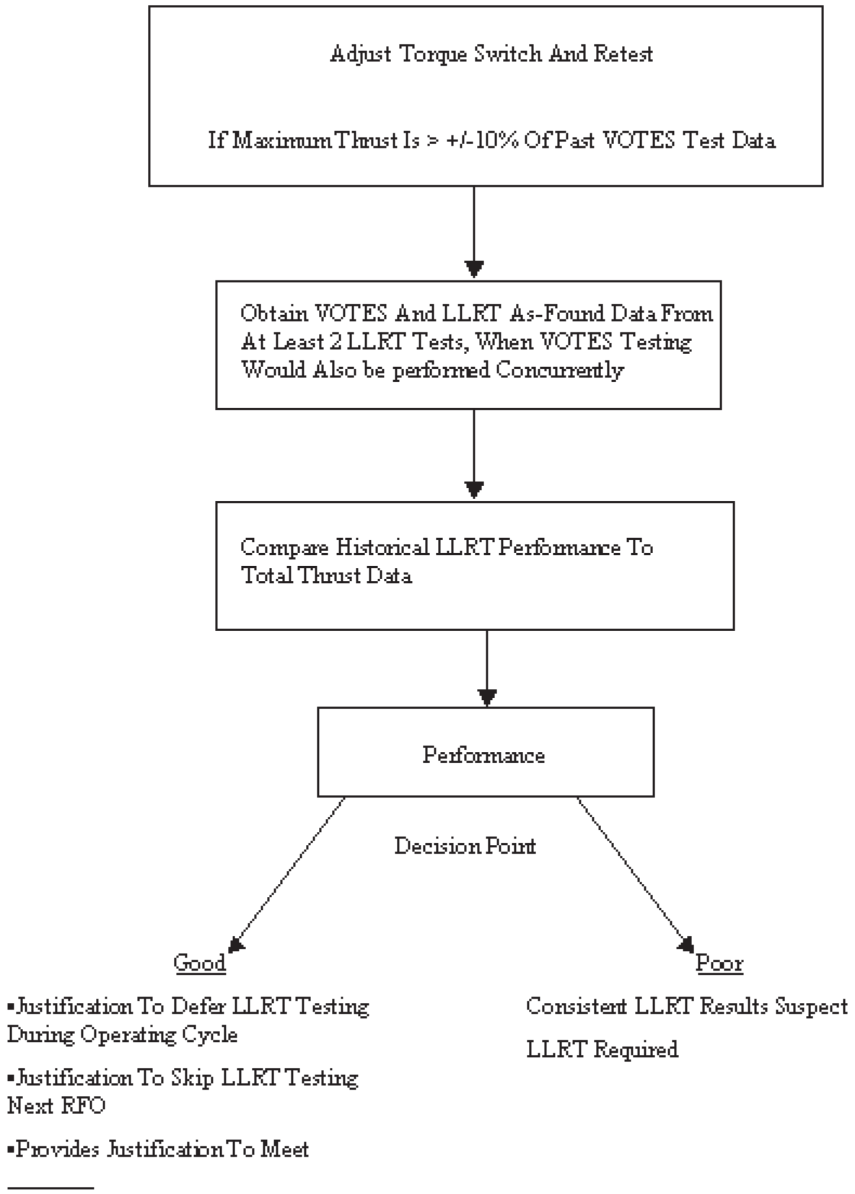
TASK 95-07

Appendix J/GL89-10 Correlation

BWROG VTRG Committee Position

ATTACHMENT 4

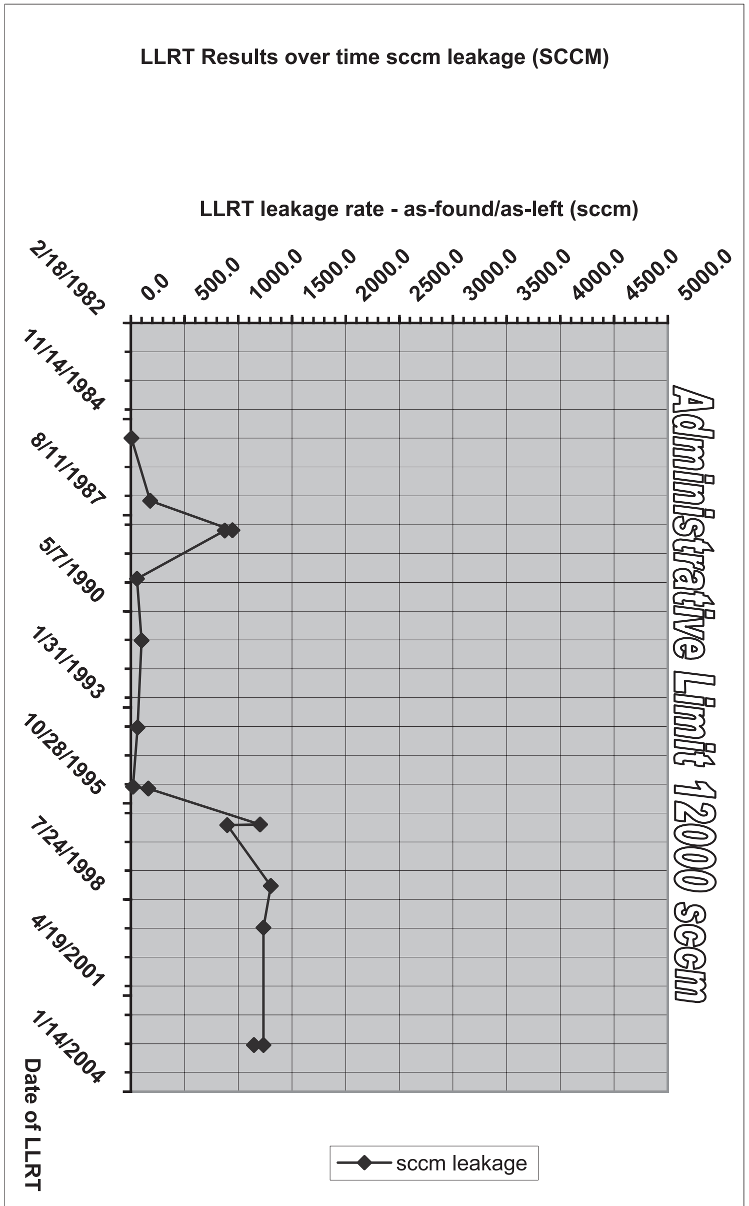
POST MAINTENANCE LLRT GUIDELINE



P6120XP075

Example of available data utilized to assess the "health" of a penetration

Penetration 92 (o)   3RHS*MV8701A   12" Gate Valve



(SBD-3, regeared from 76.26 to 43.9 OAR - 1997)

Westinghouse Flex wedge regear with new spring pack

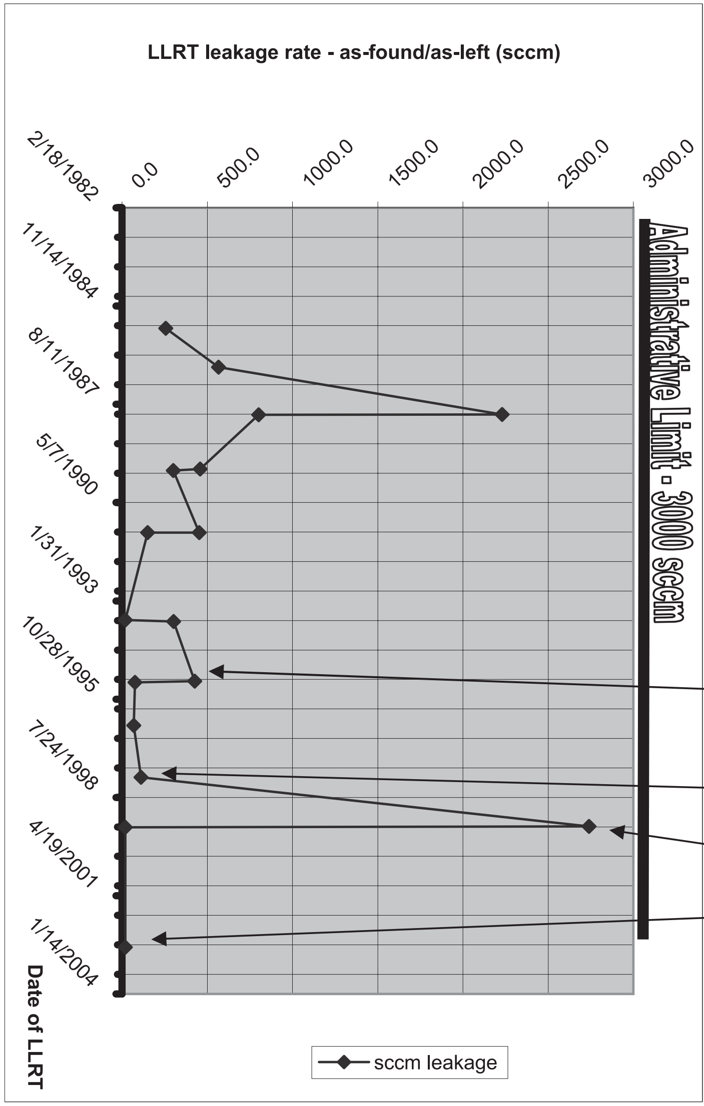
Date	AWO #	Work Performed	
5/28/1995	m39419688	actuator O/H Melamine TS repl.	
5/23/1995	m39419688	actuator replacement QSS installed	
9/15/1995	m39520747	TS byp installation	
6/7/1996	m39572791	PL mod to stuffing bax	
6/719/1996	m39607132	removed/replaced motor	
6/8/1996	M39608501	Removed packing- repacked	
6/13/1996	m39608545	VOTES test and packing retorque	
12/27/1997	m39704929	GL89-10 Act re-gear mod	
3/6/1998	M39803225	Stem nut replacement	93625 lbs TT AL
9/17/2002	m30005121	VOTES test and PM	73179 lbs TT AF 71294 lbs TT AL 9/16/02

ENCLOSURE 2

Example of available data utilized to assess the "heatlh" of a penetration assembly

Penetration 26 (o) 3CHS*MV8105 3" Gate Valve **(was an SMB-00, replaced w/ SB-0)**

Graph of LLRT perfomance over a time period 1982-2002



History review of work activities on penetration 26(o)

3CHS*MV8105 is solid wedge Crane gate valve - New Stem/stemnut added during conversion to a Limitorque SB-0-25 during recovery, circ, 1998 (was a SMB-00-25)

Date	AWO #	Work performed	
4/1/1991	m39104980	replaced melamine torque sw	
4/1/1991	m39104981	VOTES test TS set to 1.25 op/cl	
8/18/1993	m39305500	installed new packing	
8/29/1993	m39310430	operator rebuilt VOTES test w/SRI-2 grease	
8/18/1993	m39317317	Yoke Replacement, relub stem, retest SP	
8/29/1993	m39310430	VOTES test w/ new SP	
5/4/1995	m39417344	repack	
5/14/1995	m39504188	VOTES test TS to 2.875	
5/5/1995	m39507276	replace yoke bolts	
2/6/1998	m39713398	Stem, actuator and packing chg'd regear, QSS inst, EPO grease chg	
3/6/1998	m39803527	packing leak, packing drag 835 lbs before, 1566 lbs after	
5/27/1999	m39806655	repack after LLRT and reVOTES M39814277	AL 20522 lbs TT
9/20/2002	m39907197	SS wedge replacement and static test	AF 21458 lbs TT AL 20360 lbs TT

ENCLOSURE 3

APPENDIX J OWNERS GROUP {APOG} ISSUES

Wendell Brown, *Duke Power*

Jim Glover, *GRAFTEL Incorporated*

Gregg Joss, *Rochester Gas & Electric-Ginna Station*

Abstract

This paper formally introduces APOG to the nuclear industry following its formation in 2003 and provides an overview of the issues currently being addressed by the interim APOG Steering Committee (SC). The issues were selected based upon consensus opinion of the Appendix J program owner attendees at the inaugural Appendix J and Inservice Testing {IST} program owners information exchange meeting held in Scottsdale, Arizona June 9, 10 and 11, 2003.

Introduction

The success stories of various Owners Groups in the nuclear industry are well documented. These groups are self-motivated and take on the task of providing technically sound and cost effective solutions to various regulatory and commercial issues related to plant safety, component reliability and program cost reduction. However, for far too many years, the open exchange of experience and information regarding implementation of 10 CFR Part 50, Appendix J, between individual nuclear power plant Appendix J program owners was essentially non-existent. APOG was created to fill that information exchange gap and to provide a forum to develop industry consensus positions for issues considered key to the general membership of APOG.

APOG employs a website {WWW.APPENDIXJ.COM} to facilitate the exchange of information. Website features include posting of Appendix J questions and queries, access to numerous industry Codes, standards, regulatory documents and industry papers, the capability to conduct information surveys, and an "Ask the Expert" feature hosted by

Jim Glover, the Chairman of ANSI/ANS 56.8 and President of GRAFTEL Inc., APOG's facilitator. Use of the website in conjunction with regularly scheduled SC conference calls, allows APOG to accomplish tasks that traditionally were reserved for working group sessions at regularly scheduled owners group meetings. The corresponding reduction in member travel costs, meeting venue fees, and increase in efficiency realized by employing group discourse via the website and teleconferences, results in a very low annual group membership fee, a welcome relief given today's utility economic picture.

Issues Currently Being Addressed

ISSUE # 1:

Regulatory Guide 1.163, Regulatory Position C 2, endorses a 30 month prescriptive Type C test interval as specified in Section 3.3.4 of ANSI/ANS-56.8-1994 for Containment purge and vent valves regardless of the valves' size (diameter). APOG is developing a technical position {TP} that will define the limiting valve diameter. The intent of the TP is to allow valves having a diameter less than or equal to the limiting diameter to be eligible for performance based Type C test intervals as per Nuclear Energy Institute (NEI) 94-01, section 10.2.3.2.

ISSUE # 2:

The "As-Found" testing requirement delineated by NEI 94-01, is not clear regarding applicability to components which are on a fixed, 30 month prescriptive test interval, versus those on extended intervals (up to a maximum of 60 months). APOG is developing a TP which will define the as-found test requirement applicability for all Appendix J program components.

ISSUE # 3:

The allowable test interval extension period guidance delineated by NEI 94-01 is inconsistent between sections 9.1 and 11.3. APOG is developing a TP that will state under which conditions the 25 % tolerance (up to a maximum of 15 months) applies to Type A, B, C test intervals.

ISSUE # 4:

The issue of boiling water reactor (BWR) plants performing local leak rate testing (LLRT) of their main steam isolation valves (MSIV) with actuating air being applied during the LLRT has been a significant regulatory compliance topic. APOG is developing a TP which will provide guidance on a test methodology which will ensure that leakage through these components is adequately assessed for the design basis event under credited system operating conditions.

Once the APOG SC approves these TP's, APOG will issue them to its members for potential inclusion in their program using the 10 CFR 50.59 review process for all associated changes. In addition, APOG may choose to employ a Topical Report submittal of these technical positions to the NRC.

Conclusion

With APOG still in its infancy, it has gained momentum rather quickly by taking on meaningful issues which can yield significant financial and regulatory compliance benefit to Appendix J program owners. The APPENDIXJ.COM website has been a very active vehicle with over a thousand visits by members and guests posting questions, providing answers and informational feedback, downloading information from the technical library, locating member contact information, etc.

APOG membership is increasing daily and it appears that by the end of 2004 greater than 60% of the operating plants will be active members. By encouraging the NRC, Institute of Nuclear Power Operations (INPO), and NEI to be regular participants in the general sessions of APOG, the establishment of a regular venue for ongoing dialogue will be realized. The benefits of such dialogue include enhanced regulation application guidance and compliance as well as improvement to existing or creations of new, better-informed regulations.

In addition to the regulatory aspect of APOG, the sharing of information and experience between members will result in tangible savings tied to dose reduction, outage duration reduction, increased component reliability with the need for less corrective maintenance, and test methodology and test hardware improvements.

APOG looks to follow in the footsteps of its many successful owners group predecessors by remaining active and contemporary in all Appendix J related matters and issues. The success path involves committed utility membership and active participation by regulatory personnel. For questions about becoming a member or being a regulatory interface to APOG, please contact: Gregg Joss, or Jim Glover/Brad Miller of GRAFTEL Inc.

***NOTE*:**

At the time of this paper submittal, the TP's associated with Issues 1 through 4 above were not yet approved for distribution by the APOG SC. Handouts of the approved TP's will be distributed at the Session venue in advance of the paper being presented.

References

ANSI/ANS 56.8-1994, "Containment System Leakage Testing Requirements"

NEI 94-01, "Industry Guideline For Implementing Performance-Based Option Of 10 CFR Part 50, Appendix J"

10 CFR 50, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing For Water-Cooled Power Reactors"

USNRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program"

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Currently Appendix J Coordinator-Duke Power- Catawba, McGuire and Oconee Stations
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Former member of NEI AHAC Committee which authored revision 0 of NEI 94-01
Responsible for performance of over 65 Type A tests on both BWR's and pressurized water reactors

Gregg Joss
Currently Appendix J & IST Programs Engineer-Rochester Gas & Electric-Ginna Station
30 years commercial nuclear experience
6 years US Navy nuclear experience
Former holder of USNRC Reactor Operator License for 10 years
Responsible for performance of five Type A tests

Session 3(a):
ASME Codes and Standards Issues

Session Chair

Robert Kershaw

Arizona Public Service Company

Summary of Inservice Test Program Issues/Concerns Identified During Recent Assessments/Updates at Various Nuclear Stations

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ABSTRACT

Over the last few years, True North Consulting (TNC) has either assessed or been involved in the overall development, review, and/or update of numerous Inservice Test (IST) Programs. These IST Programs have been at both primary types of reactors; Boiling Water Reactors (BWRs) and Pressurized Water Reactors (PWRs), and have included all of the major US Nuclear Steam Supply System manufacturers and designers; Westinghouse (3 and 4 loop), Combustion Engineering, Babcock & Wilcox, and General Electric NSSS throughout the US and abroad. This paper attempts to identify the more common issues/concerns and questions identified during the development, implementation and review of these IST Programs. For the most part, these findings reflect the various plants' implementation of the IST Program using the 1987 edition/1988 addenda of the American Society of Mechanical Engineers (ASME) *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code). However, more recent findings have been identified and included in this discussion to bring the findings "up-to-date" with the latest issues and concerns identified by facilities using later editions of the OM Code. Primarily the 1995 edition/1996 addenda through the 1998 edition/2000 addenda of the OM Code have been included in this discussion.

The primary purposes of this paper are to provide a platform for discussion of reoccurring IST Program findings, review these findings from a combined larger sample perspective, and to share industry/regulatory guidance or proposed resolutions to many of the problems identified during these IST Program reviews/assessments. The overall objective and hope is that this presentation will provide the industry with a general understanding of issues/concerns identified during development, implementation and maintenance of IST Programs using requirements and industry/regulatory guidance available to ensure that IST Programs are in accordance with requirements of the OM Code and the intent of the Code as delineated by industry and regulatory guidance where applicable.

Since the 1980's, utilities have been trying to successfully and, cost effectively implement requirements of the ASME OM Code (or in earlier years, Section XI), as required by the Code of Federal Regulations, 10 CFR 50.55a. The ASME and the NRC have made great progress in attempting to provide guidance and direction to the industry as a whole; however, many questions still require resolution and/or clarification, to ensure consistency and standardization are reflected in the development, implementation, and maintenance of IST Programs. This approach to IST would result in improved quality and technical adequacy of IST Programs, as well as an overall increase in the reliability and availability of safety related equipment. This will improve overall safety and reliability of nuclear facilities and assure continued support for the nuclear industry as a viable energy option.

To this end, True North Consulting has compiled a list of the most frequent issues and concerns identified during the last few years, along with those methodologies (some questionable) adopted by the industry and regulatory agencies in response to these issues/concerns. It is our belief that, through identification of these frequently occurring issues/concerns and through the described implementation of standardized resolutions that, the ability of IST to assess operational readiness of safety related equipment and systems will be improved.

The paper will first provide a brief general discussion of IST issues/concerns which have been identified using guidance provided by various industry and regulatory documents. This will be followed by a discussion outlining specific issues/concerns within each of three primary IST areas: general requirements, pumps, and valves (including safety and relief valves). The paper will conclude with a discussion regarding issues and problems identified by various NRC Generic Letters, and Information Notices issued over the last few years.

It should be noted that positions taken or stated within this paper are those of True North Consulting and do NOT necessarily reflect those of the NRC or the ASME.

Introduction

Over the past several years True North Consulting has been involved in many aspects of IST Programs, from development of IST Bases documents to updating of IST Programs/Plans to later editions of the OM Code, basic IST overview training, and numerous IST Program and Program Implementation assessments. We have performed these activities on all types of nuclear power facilities (PWRs and BWRs) and virtually all individual NSSS vendor plants (General Electric, Westinghouse, Babcock & Wilcox, and Combustion Engineering). During this period of time, several "recurring" issues and concerns have arisen and continue to be problematic to the nuclear industry. In addition, as a result of the recent OM Code changes, new issues and concerns have been identified associated with the more recent Code requirements in later editions of the OM Code.

It is the intent of this paper to bring to the attention of both the industry and regulators, these issues/concerns which have been previously identified and are continuing to occur, as well as to provide the industry a platform for discussion of some clarifications and guidance already available which may help less experienced IST personnel avoid previously identified areas of concern. It is also the intent to initiate a discussion of more recent questions and problems which have come to light, with the hope of providing a clearer understanding of the "roadblocks" associated in development, implementation, and maintenance of IST Programs, and to identify areas where additional direction to the industry from the regulators and the ASME may be needed.

In some cases solutions proposed to resolve issues and concerns have been stated which may or may not reflect positions held by ASME or regulatory authorities having jurisdiction at the sites. These resolutions or recommendations are only presented as possible guidance or information to be used for resolution of stated issues/concerns identified during these discussions. As many facilities are either currently performing IST upgrades to their existing programs or are contemplating ten-year updates within the next few months, many of these issues and concerns may provide utilities with a clearer understanding of existing issues and thereby prevent the utilities from having to unnecessarily pursue avenues which may not be adequate or which may not provide acceptable solutions for these concerns.

General Regulatory/Industry Concerns

One of the most important aspects of ensuring IST Programs are in compliance with existing regulations is to ensure the scope of each component has been adequately determined by the use of approved regulatory requirements and industry and regulatory guidance.

Scope

Determining the scope of the IST Program continues to be one of the most difficult and problematic areas associated with development, successful implementation, and maintenance of most IST Programs. A large majority of facilities have developed IST Bases Documents to assist in this endeavor, but many of the Bases documents provide inadequate or incorrect scoping guidance. Several factors contribute to this issue some of which include differences in plant design, when the facility was designed and constructed, plant licensing documents, commitments made to regulatory authorities prior to operation of the facility, and changing or unclear regulatory and/or industry guidance. The NRC has attempted to provide guidance to nuclear power plants (NPPs) through various documents issued and actions taken at numerous sites. Attempts to provide guidance and directions regarding scope of IST Programs have included Generic Letter (GL) 89-04, Supplement 1 to GL 89-04, NUREG 1482, additional workshops and symposiums (specifically the NRC Workshop Summary provided in 1997 regarding IP 73756), as well as specific Information Notices (INs)/Bulletins (IEBs), to name a few.

One of the most proven and sound methods of ensuring that a satisfactory IST Program is developed, implemented and maintained is to first develop a detailed IST Bases document. The development of a detailed IST Bases provides a solid foundation and understanding of the safety functions of the various components and systems at the facility. It is recommended that the IST Bases be developed using guidance and direction provided by regulatory and industry documents. Additionally, performance of "peer evaluations" and independent assessments provide further assurance of scope, compliance and cost effectiveness of IST Programs.

Although guidance on scoping and classification for components has been provided by both 10 CFR 50.55a and other regulatory documents such as Regulatory Guide 1.26, NUREG 1482, NUREG 0800 section 3.3.2, and others, many utilities continue to have incorrectly or inadequately scoped boundaries and IST Programs.

One major solution to these "scope" issues that the NRC could provide is to issue "clear and concise" guidance as to the term "accident" and what is meant by this term. Although industry/regulatory guidance has been provided in the past, there are several contradictions and inconsistent practices being used throughout the industry. Even amongst stated guidance, there is "contradiction" and disagreements as to the "meaning" of some scoping statements.

Another primary reason for scoping discrepancies is the significant turnover rate experienced in IST personnel. On average, somewhere between 30-50% of IST Engineers change positions every 2 or 3 years. This results in having a highly significant turnover rate of roughly 75% every 5 years. Many utilities resort to "tribal knowledge" in order to maintain their IST Programs without understanding the underlying "intent" of the Code or the regulations. This results in inadequate or incorrect "interpretations" of Code requirements being promulgated throughout the industry.

One way facilities could deal with this excessive turnover rate and the problems created as a result is to ensure that adequate training and documentation is provided to not only the present IST Program Manager, but to "backup" engineers and staff as well. This would ensure that the IST Program is able to be maintained using acceptable and established Program requirements developed in accordance with industry/regulatory guidance and requirements. Additionally, facilities (and their contractors) need to ensure IST Programs are developed, implemented and maintained using industry/regulatory requirements and guidance rather than developing "individualized" IST Programs.

Finally, facilities need to ensure the Scope of components for IST, as identified in 10 CFR 50.55a, and guidance provided in NUREG 1482 as well as other acceptable resources and documents, has been thoroughly researched and documented as to the inclusion/exclusion of components in the IST Program. These documents should be maintained in accordance with established facility procedures and controlled by the IST Program Manager in accordance with approved station procedural requirements. This will ensure that, with indifference to changes in plant personnel, changes in plant design will be evaluated to ensure continued maintenance of IST Program scope and that Code/regulatory compliance will be maintained.

The understanding of IST "intent" and the terminology used in IST are other significant contributors to scoping issues and concerns.

Again, this lack of understanding could be alleviated by the ASME and regulators providing clear and unambiguous definitions to some of the terminology used in development, maintenance and implementation of IST Programs. For example, several terms continue to cause problems in determining clear requirements for IST Programs. Terms such as practical, practicable, design flow, accident, etc. These ambiguous and sometimes confusing terms continue to prevent consistent implementation of OM Code requirements. Further, facilities not providing adequate, timely and "position specific" training to not only IST personnel but all plant staff personnel who are required to "understand" the various IST requirements associated with successful implementation of IST Programs also contributes to the inability of many utilities to satisfactorily implement regulatory and Code requirements regarding the IST Program.

Other causes for the inability of NPPs to adequately develop scope of IST Programs include lack of ownership, lack of management involvement and control, "hostile environs", etc. Recently, regulators and the ASME have attempted to provide additional clarification and unambiguous guidance regarding scoping of IST Programs. The industry must also share in the responsibility for the lack of consistent and adequate guidance, but the recommendations stated above, if incorporated, would go a long way in resolving many of the existing scoping issues/concerns identified, and would provide a "platform" for the next evolutionary phase of IST (the implementation of performance based and risk informed testing).

Examples of Scope Issues/Concerns Identified

Numerous examples of facilities misinterpreting or misunderstanding the scope for components which should be tested under the IST Program are available. Some of these examples are listed below.

One facility was testing common header check valves used in the Standby Liquid Control System in the IST Program. The plant's Design Bases Document (DBD) stated check valves were required to pass a minimum of 80 gallons per minute (gpm). The plant's IST Program had the check valves listed as Class 2, Cat. C and were included in the IST Program. The check valves were being tested using only one Standby Liquid Control Pump during refueling outages. One Standby Liquid Control Pump was ONLY able to provide approximately 60 gpm. When this concern was identified, the owner concurred with the finding and was immediately involved in determining corrective actions which included revising the IST test to adequately test the check valves to their "full open" position, as required by the OM Code and clarified by GL 89-04. However, as the facility "queried" others in the industry, the final response to the identified concern was that the "accident" (Anticipated Transient Without Scram, ATWS) for which the Standby Liquid Control System (including the subject valves) is credited, is "beyond the IST Bases" as the "accident" is NOT listed in Chapter 14 (15) of the Technical Specifications. Therefore, the method used to test the check valves is adequate and the valves were removed from the IST Program.

Another example of this lack of understanding of the scoping for IST components was identified when a facility's Diesel Generator (DG) support systems (DG Fuel Oil Transfer, DG Air Start) were listed as non-Code components (older facility) and not identified as Class 3 components. As a result, none of these components were identified as requiring inclusion into the IST Program nor were any of these components tested in a way to be able to satisfy "operational readiness."

One facility, having stated in the Design Bases that the minimum recirculation valves used in the Auxiliary Feedwater (AFW) system to provide protection to the AFW pumps were required to open in order to prevent damage to the AFW Pumps as a result of the primary flow path being isolated, did not have these valves listed in the IST Program. Upon identifying this concern to the IST Manager, the resolution to the finding was to CHANGE the DBD to state that the mini-flow valves are NOT required to prevent AFW pump damage, because the AFW pumps would NEVER be in that condition. This was due to the fact that, as the DBD was revised to state, "...the AFW pumps had isolation valves that would Open upon receipt of a safety signal and, even should the isolation valves on one train fail to Open thus rendering one pump inoperable, there are two other AFW pumps that would still be able to satisfy the safety function of the AFW system. This safety function is to inject feedwater into the steam generators to prevent the steam generators from being "blown down, thus rendering the primary heat sink inoperable."

As can be seen from the few examples above, there is clearly a lack of understanding of the scoping requirements for IST components which resulted in, or at least contributed to, the identified issues/concerns observed at several of the stations and described above.

General Requirement Issues

Several general issues/concerns have been identified throughout the IST area which have resulted in numerous problems for the facilities. These have ranged from questions being responded to incorrectly to Code noncompliances and violations being identified with resulting actions taken by the NRC. These include pre-conditioning and skid-mounted components.

Pre-conditioning

Pre-conditioning, the act of NOT testing a component in its "as -found" condition, has been identified over the last several years as a concern at many facilities. The NRC attempted to bring this concern to the industry's attention in 1997 by issuing Information Notice (IN) 97-16. Within the IN were descriptions of what was "acceptable preconditioning" and what may be considered "unacceptable preconditioning". As a result of the IN, the ASME Code Committee looked at possible ways to "define" or provide some additional guidance to the industry, as to what was "acceptable and unacceptable preconditioning". After numerous discussions and proposed definitions however, it was determined that the NRC had provided sufficient guidance within IN 97-16 regarding preconditioning and no additional action or guidance should be taken or provided by ASME. Many Code Committee personnel identified the "preconditioning" as a "deliberate" act. As a result of this "stipulation", the regulators had concerns associated with determination of "intent". This led to the Code Committee action to define or provide additional guidance regarding preconditioning being dropped, and no further action taken by either the ASME or the NRC.

Clearly, the industry had concerns and questions with the lack of further action taken by ASME or the NRC regarding the preconditioning issue, and confusion still exists today as to preconditioning and its affect on IST. TNC has been requested by several utilities to provide guidance as to the preconditioning issue and it is clear the industry in general would like to see further action taken on attempting to define or at least clarify preconditioning and when it would be acceptable.

At the recent Inservice Test Owners Group (ISTOG) meeting, this was further identified as an industry concern. This issue was also discussed at the last Code meeting in December 2003. It is clear from all indications that this issue is not going to go away.

From a practical standpoint, a realistic and scrutable definition of preconditioning would appear to be that "certain preconditioning of components is acceptable provided, the action does NOT affect ability of the facility to detect and monitor for degradation or, in other ways interfere with the ability of the facility to determine operational readiness of a component."

Several utilities have provided "technical positions" regarding preconditioning and many of these upon further review were found to be adequate. There are however, many other utilities who were found to have a lack of understanding of preconditioning in relation to IST.

Skid-Mounted Components

During the late 1970's and early 1980's, numerous relief requests were submitted to the NRC in an attempt to provide or suggest alternate testing methods, or exemption from IST, for certain components which were "mounted" or otherwise connected to a primary components which provided safety functions and were required to be tested in the IST Program, but which were extremely difficult, if not impossible, to test in accordance with the requirements of the OM Code. Primarily, at least initially, these components were associated with Diesel Generator Support Systems such as Fuel Oil, Air Start, Jacket Water Cooling, etc. In addition, solenoid valves used to support air operated valve functions were also included in this scope. Typically, these components were unable to be individually tested as components but were "functionally tested" as a result of testing of the primary components (e.g., DG monthly test, IST testing of the AOVs, etc.).

The NRC in GL 89-04 attempted to provide guidance to the industry concerning "skid-mounted" components and further guidance was provided in NUREG 1482. More recently, the ASME OM Code has been revised to specifically define "skid mounted" components and to provide an exclusion for these components from the IST Program, provided certain conditions are satisfied. These conditions for exclusion are primarily that the components satisfy the definition of "skid-mounted" and, the component is adequately "functionally tested" during testing or operation of the primary component. For example, the solenoid valve is adequately "functioned" when the air-operated valve (AOV) is tested or exercised, even though stroke time or position of the solenoid-operated valve (SOV) is unable to be readily determined or measured.

There are several examples of the "skid-mounted" requirement or definition being incorrectly interpreted or understood. One facility used the "skid-mounted" exclusion to exclude all Diesel Generator (DG) Support components (Starting Air, Fuel Oil, etc.) from IST on the basis that the components ONLY supported the Diesel Generator and therefore were excluded from IST. Even though some of these components did indeed satisfy the IST "skid-mounted" exclusion criteria, there were others (DG Fuel Oil Transfer Pumps and associated valves and, DG Air Start Accumulator check valves) that were NOT "skid-mounted" or did not fully satisfy the IST definition for exclusion of "skid-mounted" components as stated in NUREG 1482, or the later editions of the OM Code.

Component Testing Issues

Pumps (ISTB)

To a large extent, many of the typical pump issues/concerns previously identified in past IST program reviews and assessments have either been eliminated as a result of changes made to the OM Code, or have been so well identified and documented in the various regulatory and industry documents published (i.e., NUREGS, INs, etc.) that the issues/concerns have been virtually eliminated. However, as a result of the recent changes to the OM Code, Subsection ISTB, there have been a few new issues added to the list. Primarily, these new issues/concerns are a result of the new methodology and requirements used in performing IST on pumps; in particular, the comprehensive pump testing requirements stated in the later editions of the OM Code.

Exclusions (ISTB-1200)

There continue to be areas of concern associated with the exclusion/inclusion of driver bearings. Several attempts have been made by the OM Code Committee with regards to clarification of what bearing vibration measurements are required by IST and when and how these bearing vibration measurements are required to be taken.

In particular, the distinction between "rigid" and "flexible" couplings appears to be a general point of confusion. The OM Code Committee and the NRC have attempted to clarify the terms in NUREG 1482, and the NRC Workshop Summary, but there still exists confusion among many of the utilities.

In 2003, the OM Code committee revised ISTB-1200 to further clarify the exclusion by defining the term "flexible coupling" as a coupling which does not allow transmission of vibration loads to the pump. However, since this Code change has not been approved by the ASME, it has not yet been incorporated into the OM Code. It does, as presently written however, provide for a clearer understanding of the term.

Pump Categories (ISTB-1300)

Primarily, the issue/concern associated with this Code requirement is the clear understanding of pump categorization, and when a pump (with multiple safety functions) is a Group A or B pump. In addition, "intent" of the overall pump testing philosophy with regard to the various required tests is also a question being raised at several facilities.

Preservice and Inservice Testing Requirements (ISTB-3100 and ISTB-3200)

One of the primary issues/concerns identified with the later edition of the OM Code is the distinction between Preservice and Inservice testing and the various requirements associated with each.

For example, when a Group B pump undergoes "major maintenance or repair" online, what type of testing will satisfy the requirements of the OM Code, in particular Subsection ISTB-3310. ISTB-3310 requires that, should a reference value or set of values be affected by repair, replacement, or routine servicing of a pump, a new reference value or set of values shall be determined in accordance with ISTB-3300, or the previous value reconfirmed by a comprehensive or Group A test being run before declaring the pump operable. In addition, it is up to the owner to determine if a "pump curve" is required to be developed to satisfy ISTB-3100 requirements.

The issue associated with this requirement is apparent when the repair/replacement is performed on a Group B pump, with no practical way to satisfy the requirements of ISTB-3310 regarding the performance of a Comprehensive or Group A test. The question then becomes how are we able to return the pump which has undergone "major maintenance" to an operable status? Several proposed solutions have been put forth at recent meetings of the OM Code Committee. One of these proposed solutions allows that a Group B test be run on the repaired pump and using the results to "declare the pump operable" pending performance of a Comprehensive test at the next Cold Shutdown. Another of these proposed solutions is to provide justification to the NRC in the form of a relief request on an expedited basis for regulatory approval. Neither one of these proposed solutions has as yet been approved by either the OM Code Committee or been endorsed by the NRC.

Reference Values (ISTB-3300)

Another reoccurring issue/concern identified is associated with the term "pump design flow." Presently, "pump design flow" as used in the OM Code, is NOT defined by the OM Code. Many utilities and regulators have interpreted this term to mean the "Best Efficiency Point" or BEP of the pump, as identified typically on the manufacturer's pump curve. The primary intent of this term regarding IST of pumps, is to ensure the pump is tested on a portion of the pump curve as to allow for the timely detection and monitoring of degradation. Many facilities continue to use the bypass loop and other restricted flow paths, as a reference point for IST. In many cases, this reference value is at or near the shutoff head of the pump and therefore provides little or no ability for the detection or monitoring of pump degradation.

Recently, the OM Code Committee has provided clarification for the "pump design flow point", which should satisfy the intent of the Code, and provides an acceptable method to be used to support IST pump testing. Again however, it needs to be noted that definition for "pump design flow", or the associated Code change, has NOT been approved by the ASME or the NRC and therefore caution is urged in the use of this definition or clarification.

Data Collection (ISTB-3500)

Many facilities continue to use instrumentation that does not satisfy requirements of the OM Code or industry/regulatory guidance provided in various documents including NUREG 1482, the NRC Workshop Summary, and various Code interpretations. The determination and implementation of acceptable instrumentation for pump testing continues to be an issue/concern throughout the IST community. Several changes to the OM Code have been made to provide additional guidance and clarification in the use of instrumentation and the allowances of various "alternatives".

Bypass Loop Flow (ISTB-5100, ISTB-5200 and ISTB-5300)

An area which continues to be identified as an issue/concern is the continued use of "bypass" or "minimum recirculation" flow loops for Quarterly pump tests required by ISTB. In later editions of the OM Code, bypass loops and flows have been defined and clarified by the ASME, however, several issues have been identified with continued use of bypass flow loops for Quarterly IST. Hydraulic parameters are still required to be "fixed" and the variable parameter is still required to be measured, when performing Quarterly Group A or B pump tests. In particular, many PWRs have pumps which are unable to be tested Quarterly using installed instrumentation. Previously, relief was granted using Generic Letter 89-04 Position 9, which allowed the use of non-instrumented minimum recirculation or bypass lines for Quarterly testing, provided the pumps were able to be tested at least once every cold shutdown or refueling outage using a "full" or "substantial" flow path which was instrumented in accordance with the Code requirements. Several regulators have questioned continued use of GL 89-04 positions and NUREG 1482 guidance, due to the fact that the guidance is somewhat "dated". This position has presented somewhat of a concern to some utilities. It is somewhat unclear and of a concern why the use of GL 89-04 positions are being questioned at this time. Generic Letter 89-04 did not have a specified time limit and, therefore, the numerous positions delineated in GL 89-04 and incorporated by the industry should still be valid. Many positions set forth in GL 89-04 have been incorporated into later editions of the OM Code, but there are some not yet incorporated into the Code. As a minimum, positions put forth by GL 89-04, unless proven unacceptable, should be allowed to be referenced in revised IST Programs as applicable, and used as a reference for IST program submittals as a "continued justification" for certain alternatives. This should be acceptable unless the regulators deem it appropriate to formally issue subsequent rules or additional guidance to the industry regarding the use of positions delineated in GL 89-04.

Valves (ISTC)

As with the pumps, to a large extent many of the typical valve issues/concerns previously identified in past IST Program reviews and assessments have either been resolved, as a result of changes made to the OM Code, or have been so well identified and documented in the various regulatory and industry documents published (i.e., NUREGS, INs, etc.) that issues/concerns have been eliminated. However, as a result of the recent changes to the OM Code, subsection ISTC, there have been a few new issues/concerns which have been identified. Primarily, these new issues/concerns are a result of the new methodology used in performing IST on check valves, in particular, bi-directional check valve testing.

Exemptions (ISTC-1200)

There continue to be areas of concern identified with inclusion of manual valves in the IST Program. Many facilities do not have adequate IST bases for the determination of the testing requirements for manual valves. Others do not understand that testing (including position indication and exercising) is required to be performed on manual valves, which have safety functions applicable in the scoping of IST Programs. There also appears to be confusion as to what constitutes a passive or active valve for the manual valve population.

In addition, recently, primarily as a result of Generic Letter 96-06, several facilities are incorrectly or inadequately testing valves in the IST Program for a safety function other than for what the valves were originally designed. For example, several facilities are crediting AOVs for "relieving" pressure from Containment Isolation penetrations in lieu of adding relief valves or simple check valves for this over-pressure protection. The primary concern associated with this is that, in many cases, the AOVs are NOT tested to adequately ensure the disk would "lift" to prevent potential over-pressurization of the penetration. From a practical standpoint, the AOV is essentially being relied upon to fail to seat, or the valve is being required to lift off the seat in order to resolve or address the over-pressurization concerns identified in GL 96-06.

Control valves continue to be "exempted" from IST programs, even though the safety function of the control valve is to Open or Close and NOT just to "modulate." This issue/concern has been identified previously in NUREG 1482, and the NRC Workshop Summary. In addition, clarification has been provided in the OM Code to further address this issue. A Code Case (OMN-8) has also been issued to allow an alternative to the rules for preservice and Inservice Testing of power operated valves used for system control and ONLY have a fail-safe safety function.

In the Code Case OMN-8, the alternative to stroke timing and fail-safe testing of specifically identified control valves is to allow the valve to be "exercised" in lieu of stroke timing testing requirements and acceptance criteria as stated in the OM Code.

Valve Categorization (ISTC-1300)

Categorization of certain valves continues to be a concern, especially when the valve has more than one category function. Examples include valves which are used as relief devices as well as power operated valves; simple check valves used as relief devices; and power operated valves used with Category A and Category C functions. In many cases, only one of the functions is tested or, in other instances, tested in a manner not able to satisfy the requirements stated in the OM Code.

Pressure Isolation Valves (PIVs)

Pressure Isolation Valves used as isolation valves from the Reactor Coolant Pressure Boundary have been identified as having various issues/concerns at several facilities. Some PIVs are either NOT included in the IST Program as PIVs and leak tested in accordance with requirements of the OM Code, or have been inadequately tested in the IST Program. Numerous industry/regulatory documents (e.g., ASME Interpretations, NUREG 1482, GL 89-04, etc.) have identified the PIV testing requirements, but some facilities are NOT even testing PIVs as power operated valves in the IST Program. Although some guidance was provided regarding testing of PIVs in GL 89-04, NUREG 1482 and other industry/regulatory documents, confusion still exists in the industry as to what valves should be included in the IST Program as PIVs and what testing should be required.

Power Operated Valves (ISTC-5100)

Many facilities continue to misinterpret the "acceptable stroke time" value and the "limiting value of full stroke time", as stated in ISTC-5113 and ISTC-5114. The OM Code, OM-10, section 4.2.1.9 (b) and ISTC-5123, allow a "retest" and analysis to be performed if the acceptable range is exceeded, without declaring the valve inoperable. This allows the utility to have an "alternative" to declaring the valve inoperable if valve stroke time has changed slightly, thus preventing unnecessary entry into Limiting Conditions for Operation (LCOs) or requiring other actions which may or may not be providing an adequate corrective action or response to the problem or to the determination of valve degradation. The intent of this allowance to retest the valve and analyze later results is to provide the owner with a method of determining and monitoring degradation; thus assuring operational readiness of a component or, providing guidance as to how to determine and resolve other factors or changes that may have occurred to the component's condition or test method. This allows timely and adequate corrective action to be taken, without requiring more severe corrective action to be initiated until the extent of the condition is more clearly understood. Many times a valve stroke time is affected by either environmental or testing deviations rather than the valve actually being in a degraded or unacceptable condition. In other cases, the valve may be showing very early signs of degradation, that may not warrant an immediate or intrusive action to be taken. This is the purpose of allowing the valve to "analyzed" when the valve exceeds the acceptable range of the Code. This area of the Code used to be considered the "Alert Range" and required corrective action to be taken without allowing a determination of the actual cause of the deviation.

Additionally, many utilities still do not have a clear understanding of how to develop a reasonable "limiting value of full stroke time". The "limiting value of full stroke time" of a power operated valve in the IST Program continues to be required to be established as stated in OM-10, paragraph 4.2.1.4 (a) and ISTC-5113 (b), as applicable. The OM Code also requires a "limiting value of full stroke time" be developed for each power operated valve included in the IST Program. The purpose of establishing this "limiting value of full stroke time" and some additional general guidance for the establishment of the "limiting value of full stroke time" has been provided in NUREG 1482 and the NRC Workshop Summary, as well as other industry and regulatory documents.

The lack of understanding of "limiting value of full stroke time" and the "acceptable range" of a valve continue to be areas of concern which result in two issues or potential consequences. One consequence of this lack of clear understanding of these two terms could be unnecessary and potentially burdensome entry into LCOs, which could further result in unnecessary corrective actions being expedited. This could result in resources and costs being expended for unnecessary actions while more serious concerns may exist and, due to resource limitations, may go undetected. The other consequence of this lack of clear understanding of these two terms could be the failure to declare the valve inoperable and taking timely corrective actions as required by the OM Code in order to satisfy the intent of the IST Program.

Exercising Requirements (ISTC-3520)

Category C Check Valves are required to be bi-directionally tested in accordance with the requirements of ISTC-3522 and ISTC-5221. This has created numerous issues and concerns associated with exercising of check valves and has resulted in several facilities being in non-compliance with requirements of the OM Code. For several years, the industry has been trying to determine methods to provide assurance for check valve operational readiness without burdening the industry with unreasonable testing or acceptability requirements for assuring this condition. From a practical standpoint, bi-directional testing is not a new requirement. IWV and OM-10 have required verification of the valve disk going closed upon cessation or reversal of flow or going to its open position upon initiation of flow. These requirements, in essence, are the intent of "bi-directional" testing. The problems which have been identified with regards to bi-directional testing are lack of understanding of the term "test interval", lack of understanding of the "intent" of bi-directional testing, and continued lack of understanding of "full stroke open" for check valves (as clarified in GL 89-04, NUREG 1482, the NRC workshop summary, and later editions/addenda of the OM Code). In addition, many facilities have failed to adequately understand and implement the various non intrusive methods for determining the ability of the check valve to perform its safety function(s).

Significant efforts have been expended by the industry to address these issues and to provide more complete and comprehensive testing methods for determining actual condition of the check valve. The OM Code has understood the issues and concerns associated with performing testing on check valves in the IST Program and the limitations associated with these testing methods. The earlier Code requirements provided little insight into the intent of performing IST on check valves, and many failures were experienced without being previously detected under the IST Program, or allowing actions to be taken to prevent failure of the check valves. In reality, IST was providing little or no information as to "condition" of the check valve and was actually more of a "go or no-go" type of test. The industry and regulatory authorities have lately developed and endorsed a more acceptable and practical alternative to traditional testing methods incorporated into earlier editions of the Code. ASME has issued Appendix II as a mandatory appendix to the OM Code as referenced in ISTC-5222 to provide guidance and minimum requirements to be used in setting up a "condition monitoring program" for check valves. Benefits of this method are readily apparent, both from an IST perspective and a cost benefit perspective. The purpose of "condition monitoring" is to provide a more comprehensive evaluation of actual condition of the check valve and to establish more "realistic" test methods, requirements and acceptance criteria. This is beneficial in both the ability to ascertain condition of the check valve, and reducing unnecessary testing or monitoring requirements. This method of condition monitoring of check valves, when implemented correctly, will provide for a more accurate and true indication of the condition of the check valve while providing a reduction in cost for check valve testing in the IST Program.

As of this paper, several other components are being evaluated for "condition monitoring" type testing programs in the IST Program. These include AOVs, SOVs, pumps, etc. This will result in a more beneficial and complete evaluation of the condition of these components and the ability of the facility to more precisely and accurately ensure operational readiness of these components. Ultimately, this will result in improved safety and reliability at facilities and a more cost effective method for implementing IST.

Position Verification Testing (ISTC-3700)

Issues and concerns continue to be identified with regards to adequate verification of remote position indication required by the OM Code. Several facilities continue to not require position indication verification testing for solenoid valves, due to the fact that "stem movement is unable to be observed for many solenoid valves". Since the 1970's, remote valve position indication verification has been a requirement. Little has changed with regard to position indication verification of valves with the later editions of the Code. The primary change to the Code for position indication verification was in OM-10 when Table 1 was developed. Table 1 stated that remote valve position indication was required for active and passive valves. Unfortunately, a few utilities still do not perform position indication on passive valves in the IST Program. Primarily these valves have been manual valves with an identified passive safety function.

Another concern identified with regards to remote valve position indication verification is the lack of local observation of position indication verification being "supplemented by other indications such as flow, pressure, etc., where practicable or where local observation is not possible", as required by the OM Code.

Industry and regulatory authorities have taken several steps to clarify remote valve position indication requirements as stated in the OM Code by providing additional guidance and direction in NUREG 1482, the NRC Workshop Summary, OM Code changes and interpretations, as well as other direct and indirect methods. However, it appears that many of these "clarifications" have either gone unheeded or mis-understood as evidenced by recent numerous findings associated with the Code requirements for remote valve position indication verification.

Manual Valves (ISTC-5210)

The lack of manual valves being included in IST Programs continues to be an issue in the industry. Many facilities have not included manual valves in their IST Programs due to a lack of understanding or bases of the safety function of the valve. Other facilities have failed to include exercise testing of manual valves which have active safety functions, as required by OM-10 and ISTC-3500.

In other instances, manual valves have had position indication verification performed, but have not had exercising performed, as required by the OM Code, even though the valves had been identified in the IST Program as active valves. This is also the result of clear lack of understanding of the safety function of the valve, a lack of understanding of the intent of the OM Code, or a combination of both.

Again, the industry and regulatory authorities have attempted to provide guidance and clarification regarding the IST requirements for manual valves in NUREG 1482, and the NRC Workshop Summary. There have also been several interpretations as well revisions to the OM Code, in an attempt to provide further clarification as to the testing requirements of manual valves.

It should be noted that occurrence of manual valve testing issues have decreased significantly since implementation of later editions of the Code. This may be a result of a better understanding of IST, and clarifications provided as described above. It needs to be noted here also, that frequency for manual valve exercising (at least once every 5 years) as stated in later editions of the OM Code (ISTC-3540) has had an exception taken to the test frequency by the NRC. As stated in 10 CFR 50.55a, the NRC requires a maximum of 2 years for the exercising frequency for manual valves, in lieu of the 5 years stated in the later OM Code (1998 edition thru the 2003 addenda).

Other Areas of Concern

Several other areas of concern continue to exist in the valve testing areas. Some of which cause facilities to fail to meet requirements of the OM Code. These include failure of utilities to stroke time or fail safe test control valves which have safety related functions, testing of check valves in parallel using a total flow determination method which does not adequately verify each check valve being able to open to its safety position, failure to stroke time power operated valves as required by OM-10 and ISTC which do not have remote position indication, failure to adequately perform a "fail-safe" test on power operated valves which do not have remote position indication, and failure to adequately perform remote position indication verification as required by ISTC and as clarified by various industry and regulatory documents. These are just a few issues/concerns identified and clarified several years ago and which continue to be identified as issues/concerns at plants using the later editions and addenda of the OM Code.

Pressure Relief Devices (Appendix I)

As with pumps and valves, a few of the more typical safety and relief valve issues/concerns identified in past IST program reviews and assessments have either been resolved, as a result of changes made to the OM Code, or have been so well identified and documented in various regulatory and industry documents published (i.e. NUREGS, INs, etc.) that the issues/concerns have been eliminated. However, unlike many previous pump and valve issues/concerns, many "old" issues for safety and relief valve testing in IST still remain. Some of the more recent changes and interpretations to the OM Code, Subsection ISTC and Appendix I, may provide clarification or additional guidance which could result in a few of these issues/concerns being eliminated in the near future.

Thermal Relief Devices (I-1200, I-1390)

One of the most common programmatic issues being identified at many facilities over the last few years has been "scoping" concerns associated with "thermal relief valves". Numerous attempts at providing clarification and guidance as to when and what safety and relief valves were required in the IST Program scope have been made over the last five or so years, with minimal success. Interpretations, NUREG 1482, and the NRC workshop summary provided the industry with guidance regarding inclusion of certain relief valves which did not directly affect safe shutdown of facilities during an accident, but could impact safe shutdown or accident mitigation functions of certain systems in the plant and were therefore considered important to safety. Many facilities attempted to "exclude" these safety and relief valves from IST Programs by using the justification of safety and relief valves not being specifically required to operate to perform a function that would require operational readiness determination by using IST. However, as numerous interpretations and regulatory/industry documents attempted to show, the valves could affect the ability of systems with which they were associated from being able to satisfy their safety function(s), even though the safety and relief valve itself may not be required to function at the time of the accident to mitigate consequences of an accident or maintain the safe shutdown condition of a facility. The concern was that the component the safety and relief valve was protecting (e.g., heat exchanger), as a result of the safety and relief valve failing to perform its safety function, could potentially cause the component/system to be unable to fulfill its safety function.

The later edition of the OM Code specifically defines a thermal relief device and provides testing guidance specifically related to this particular type of device. This should eliminate much of the confusion associated with "thermal relief valve" scoping concerns and ensure IST Programs include all applicable safety and relief valves. In addition, for class 2 and 3 thermal relief devices, testing frequency and methodology has been relaxed. In particular, "sampling" and the corrective action which requires the increase of the sampling population size have been essentially eliminated by the later Code, where an adequate determination of the cause of failure is provided. This is to ensure that a "generic failure" is identified if applicable, and the required corrective actions are appropriate to the failure mode of the safety or relief valve.

BWR Scram Accumulator Rupture Disks Exclusion (ISTC-1200)

Another major issue/concern identified previously, and essentially eliminated in the latest edition of the OM Code, is the requirement to test the BWR Scram Accumulator non-reclosing pressure relief devices (rupture disks) used in BWRs on the Scram Accumulators. Over the years several utilities tried to eliminate Scram Accumulator rupture disks using various "justifications". Some "justifications" included: de-classifying rupture disks, attempting to establish that rupture disks did not satisfy IST scoping criteria, attempting to exclude the rupture disks as "skid-mounted", etc. However, this Code change has not yet been approved by the regulator and therefore requires caution in use of this guidance.

Category A and B Safety and Relief Valves Excluded (ISTC-1200)

Since the early 1980's many facilities have had difficulty with testing safety and relief valves which had safety functions in both the Category A(B) as a power operated relief valve, and also was included in the Category C criteria as a safety and relief valve. This issue was a result of several facilities testing only one of the Categories for functionality and omitting the other Category of IST testing. Many facilities either eliminated the power operated valve testing or the relief valve testing component for some Category A and/or B valves in the IST Program. As stated in the Code if a valve has the characteristics of more than one category, then IST would be required to include testing to satisfy requirements of both categories, no duplication of testing being required.

For example, in some PWRs, facilities take credit for Power Operated Relief Valves (PORVs) for Low Temperature Over Pressure Protection (LTOP) and therefore the PORVs require testing as a power operated valve. However, PORVs typically have a stroke time on the order of 0.2 seconds and are pilot actuated. As a result, it is difficult, if not impossible, to stroke time PORVs as required by the Code. Also, due to the fact that PORVs normally do not have remote position indication and many problems/concerns have been identified with the testing methodology for PORVs, it was determined by the NRC via numerous relief requests and the ASME OM Code Committee that Code requirements for stroke timing PORVs and requiring position indication verification periodically was an undue burden with no increase in safety.

In addition, several PORVs also have a relief valve function to lift prior to the primary or pressurizer relief valves lifting. This is typically NOT a safety function at many facilities. As a result, the OM Code committee determined to provide an exemption to certain Category A and B safety and relief valves from certain IST requirements (stroke timing and position indication verification) in the later edition of the OM Code.

Set pressure Measurement Accuracy (I-1410)

Confusion has existed over required instrumentation accuracy. Many facilities did not or could not meet the previous tolerance for instrumentation stated in the Code. The later edition of the OM Code has provided specific instrumentation tolerance to be within 1% of the indicated (set pressure). This has resulted, for the most part, in elimination of issues/concerns associated with instrumentation tolerance for testing safety and relief valves in the IST Program.

Other issues/concerns continue to exist associated with the IST for safety and relief valves. Primarily, these issues/concerns are associated with test method, test media, and the associated requirements for providing a "correlation" and certified procedure documenting and addressing these different conditions of testing. Several clarifications and changes have been made to the OM Code which should eliminate much of the confusion associated with some of these requirements. Recent Code interpretations and future Code changes will eliminate others. Still others may be addressed by some future industry/regulatory documents which may further eliminate some of the more persistent issues/concerns. Below is a listing of the more typical issues/concerns associated with safety and relief valves and whether they have been addressed by changes to later Code editions or additional industry/regulatory guidance.

Ambient Temperature (I-1200)

Numerous facilities did NOT require safety and relief valves to be tested at ambient temperature, or provide a certified correlation as to the acceptability of testing certain safety and relief valves at other than ambient temperature when the valve would be required to perform its safety function, as required by the OM Code. The term "ambient temperature" has been defined in the later edition of the OM Code as "the temperature of the environment surrounding a pressure relief device at its installed plant location during the phase of plant operation for which the device is required for over pressure protection." This provides a clarification as to the definition of ambient temperature; however, questions still exist as to the use of ambient temperature when testing safety and relief valves. Several documents have been issued recently to provide clarification as to the testing of safety and relief valves in the IST Program which should alleviate most of the remaining concerns for safety and relief valve testing requirements.

Thermal Relief Application (I-1200)

As stated previously in this paper, numerous utilities do not include "thermal" safety and relief valves in IST Programs as required by the OM Code and clarified by numerous industry/regulatory documents. The term "thermal relief application" has been defined in the later edition of the OM Code as "a relief device whose only over pressure protection function is to protect isolated components, systems, or portions of systems from fluid expansion caused by changes in fluid temperature". This should help to clarify the scoping issues/concerns associated with safety and relief valves, in particular "thermal relief valves".

Safety and Relief Valve Acceptance Criteria (I-1320(c)(1))

Many facilities have NOT been in compliance with the OM Code regarding acceptable range of deviation allowed by the Code. In older editions of the Code typically a 3% band was required. Many utilities could not or did not satisfy the 3% band and provided a "technical position" as to the use of a larger tolerance. Later editions of the OM Code provide for the owner to establish a greater tolerance if justified. This could result in an additional issue associated with the "intent" of the Code regarding safety and relief valve testing not being met, but should provide a relaxation for set points which are "unrealistic" and unable to be met for which the NRC has granted similar relief in the past.

Set Pressure Testing (I-4000 and I-8000)

Numerous facilities have failed to satisfy the successful number of tests required by the OM Code. The OM Code has required two consecutive successful set point tests be performed for each safety and relief valves tested in the IST Program. Many facilities determined the safety and relief valve to be "successfully tested" upon satisfactory completion of the "as found" test. Other facilities were found to not have successfully completed two consecutive successful set point tests. Neither of these results satisfied the OM Code requirement of two consecutive successful set point tests. Although clarification has not been provided to address these specific issues/concerns in the later edition of the Code, the time between set point tests and the clarification of "as found" testing should serve as "pointers" or guidance which may provide some additional clarification.

Correlation/Certification of Safety and Relief Valve Testing (I-4000/I-8000)

Several issues/concerns have been identified with regard to correlation of differences in Code requirements/method of testing safety and relief valves and actual conditions/ methods. If the test media, test temperature, etc., is different than the service media, temperature, etc., then, in many cases, a correlation has to be performed and documented and certified using a procedure. Many of the "required correlations" have been clarified, or in some cases eliminated, by recent changes to the OM Code. Changes to the Code which provide relaxation or alternatives to the Code testing requirements may serve to eliminate additional issues/ concerns. One such example is the requirement to calculate accumulator capacity for test rigs used in testing safety and relief valves in the IST Program. The Code has now been revised to require the accumulator volume be "sufficient to determine the valve set-pressure".

Several Code changes and revisions have been made to enhance safety and relief valve testing requirements and provide clarification, both from the ASME OM Code Committee and the NRC. One major clarification made to the Appendix I requirement for testing relief valves is describing when the IST testing frequency is required to start. The OM Code in subsections I-1320 thru I-1360 states the test frequency for Class 1 safety and relief valves is 5 years and the test frequency for Class 2 and 3 safety and relief valves is 10 years. Concerns and questions have been raised regarding when the 5 or 10 year period starts? Does it require safety and relief valves be tested once every 5 or 10 years regardless of whether or not valves have been installed? Is the test frequency required to be maintained even if the safety and relief valves are "on the shelf"? The OM Code Committee recently provided an interpretation to the test frequency which should provide adequate clarification to the industry to provide for consistency and adequacy of implementation of the later Code requirements. The clarification provided the test frequency starts when "the safety and relief valves have been installed and are required to perform function" or, in other words when the valves have been "wetted". For example, if a Class 1 safety and relief valve was tested 3 years prior to installation at the facility, then the safety and relief valve would be required to be tested within 2 years after installation. This could create a problem with a plant that has a 24 month refueling or the refueling outage has been delayed which would cause the valve to exceed the 5 year frequency. Care needs to be taken prior to installing a safety and relief valve to ensure sufficient time exists to allow the valve to be tested within the test frequency specified in the OM Code, or actions have been taken to obtain approval of an extension of the safety and relief valve testing frequency as required, to ensure compliance with the requirements of the OM Code.

Test Frequencies, Class 1, 2 and 3 Pressure Relief Valves (I-1330 and I-1360)

Numerous issues/concerns have occurred regarding "sampling" of safety and relief valves and the requirements of the OM Code. The Code states that "...a minimum of 20% from each valve group shall be tested within any 24-month interval (Class 1, 48-month Class 2 and 3...). This 20% shall consist of valves that have not been tested during the current 5 (or 10) year interval, if they exist." Several utilities have used this statement to require safety and relief valves in that group only to be tested once every 5 or 10 years as applicable. These utilities erroneously believe that, upon completion of testing of the entire group, no relief valves would be required to be tested until the start of the next test interval. For example, a valve group consisting of four valves which are Class 3, and the Code requirements are met requiring 20% of the valves in this group to be tested on a 48 month interval (as a minimum). If the facility were to test all four valves in the group within the first 24 months, then it was erroneously determined that no other valves in the group were required to be tested until the start of the next ten year test interval. However, the Code would require the testing to start over, if previously untested valves were non-existent.

Some of the confusion caused by earlier Codes has been eliminated with issuance of the later Codes but, obviously, some confusion as to the intent of the Code requirement still exists at certain sites.

Another issue which has been raised regarding test frequency for safety and relief valves is, when maintenance is performed on one or more valves which affects the set point testing of the valve, can credit be taken for the post-maintenance test (PMT) of the safety and relief valve testing being performed as PMT or do the requirements of the Code regarding test frequency take precedence over the PMT performance? For example, when leakage is identified at a Main Steam Safety Valve and maintenance is performed on that valve to correct the leakage concern, can the PMT for that MSSV be substituted for the scheduled IST relief valve test if the valve was NOT scheduled to be tested during the upcoming refueling outage?

Clarification has been provided in NUREG 1482, the NRC Workshop Summary, and various interpretations and Code changes. This clarification requires essentially two tests to be conducted on the safety and relief valves in the IST Program in order to ensure compliance with the OM Code. One is to ensure that an “as found” test is performed on each safety and relief valve at least once every 5 or 10 years, as applicable. The second test requirement is to ensure that each safety and relief valve tested in the IST Program is “sampled” every 24 or 48 months as applicable to ensure any “generic” concerns are identified and adequate corrective action is taken in a timely manner.

Conclusion

There are many other issues/concerns which have been identified during recent assessments, or incidents at nuclear facilities. The ASME and the regulatory agencies as well as other industry support groups have contributed significantly to the reduction in occurrence of many of the earlier issues and concerns identified in the development, implementation and maintenance of IST Programs. These groups continue to strive to make IST a more reliable and cost effective method of determining operational readiness of safety related components used at nuclear power facilities. However, much continues to be needed to ensure the operational readiness of many components in the IST Program.

Several factors contribute to the continued instances of these issues/concerns including: lack of individual and management understanding of the intent of various subsections of the Code, “tribal knowledge”, lack of management support of involvement of the facility in the various industry/regulatory initiatives involving IST, inconsistent/uncontrolled regulatory guidance at the facility level, etc. However, the major factor identified as a cause for this continued failure to implement Code requirements is significant turnover rate of IST Program Managers. This has been identified as an area of concern by both industry and regulatory agencies. For example on average, there is a change of 45-50% of IST personnel in the US nuclear industry every 2 to 3 years. This results in a significant loss of experience at many utilities and subsequently results in the utility’s inability to maintain the much needed IST expertise at site. This many times results in junior level or inexperienced personnel being placed in the position of IST Program Manager with little or no understanding of IST. The OM Code committee and other industry initiatives being undertaken may help resolve the underlying cause for this issue and concern, and many facilities are now providing limited training for IST; however, the real challenge continues to be to provide sufficient clarification and guidance, both regulatory and within the industry, to ensure Code requirements are understood and the overall intent of the IST Program is adequately understood. This will ensure that the approved Code requirements are being satisfied and that IST Programs are being developed, implemented and maintained as required.

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The Future of ASME Nuclear Codes and Standards

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ABSTRACT

With the advent of the global marketplace, it is important that safety regulations continue to be met while government and industry promote international trade. ASME's Codes and Standards is taking steps to become a key international player. Current initiatives include promoting Codes and Standards in industry publications, simplifying access to ASME utilizing the Internet, participating in workshops and offering courses around the world. There is also an increased focus on international participation on Codes and Standards committees. This paper will discuss the goals of the ASME's Nuclear Codes and Standards Department pertaining to the expanded application of ASME Codes and Standards.

INTRODUCTION

As regional and global trade agreements such as the North American Free Trade Agreement (NAFTA), the European Union, and the World Trade Organization (WTO) are created; international boundaries have become less of a hindrance to trade. Companies are continually venturing into new territories in order to lower their costs and increase their market. It is important that safety is not compromised while trade is encouraged. ASME Codes and Standards (C&S), particularly Nuclear Codes and Standards (NCS) is looking towards the future and the need for consistency in safety and design standards.

The current Mission Statement of ASME C&S is "Develop the best, most widely applicable codes, standards and conformity assessment programs in the world for the benefit of humanity. Involve the best and brightest people from all around the world to develop, maintain and promote these ASME products and services world about." ASME's current consensus standards development embraces transparency and openness, impartiality and consensus, relevance, effectiveness and coherence. Future applicability of the standards is dependant on creating interest among these merging and emerging markets.

In the past, committees composed of members from mostly U.S. interests have developed ASME standards. In addition, and perhaps most detrimental to future global applicability, was the development of most standards sans metrication.

One of the keys to expansion is to make participation by international members as easy as possible. In order to increase international participation, the Council on Codes and Standards has proposed to revise current procedures. Changes would include a new level of membership where attendance at meetings was not essential. The responsibility of the international members would be to provide crucial input to the Committee based on their knowledge of the standard's application in their local area. An individual on the committee would act as the representative for a group of experts from a country. Application of the policy of participation would be on a case-by-case basis decided by the committees involved.

The use of Project Teams and the exchange of information via the Internet will make it more realistic to meld ideas across the globe and will reduce Standards development time.

Metrication has been a major undertaking by all ASME staff and volunteers over the past few years. Perhaps the greatest project, metricating the Boiler and Pressure Vessel Code is complete and will be published in July 2004. All Nuclear Codes and Standards are complete and published. Unlike previous attempts at metrication the 2004 Edition of the Boiler and Pressure Vessel Code will include a dual set of units – U.S. Customary and SI. A Code user may use either set of units for design and certification.

For almost five decades the nuclear power industry has been developing and improving reactor technology. Currently, the next two generations of reactors are being developed in several countries. The new reactors have simpler designs and are inherently safer and more fuel-efficient. ASME NCS is seizing an opportunity to aid in the standardization of design, material, quality assurance, risk technologies and eventual inservice inspection and testing requirements.

In the U.S. and abroad, new nuclear plant orders are expected before the end of the decade, with new construction beginning around 2010. It is a goal of NCS to be wholly involved and prepared when the activity begins. The main initiatives are to modify the present ASME Nuclear Codes and Standards as to be applicable to the new generation of reactors, to risk inform current codes and standards, and to evaluate methods to streamline acceptance of the standards in regulations. The Board on Nuclear Codes and Standards (BNCS), the body overseeing all NCS activities, has established a task group to address the new style reactors. This group will function as a manager for additions or changes to the present standards and will work with government officials and Nuclear Steam Supply System (NSSS) suppliers.

A dozen new reactor designs are at advanced stages of planning in Russia, South Africa, Europe, Japan and North America. The new reactors have a more rugged design to make them easier to operate reducing the possibility of core melt accidents. The designs will also have a longer operating life than the current plants, typically 60 years, while also minimizing the effect on the environment and amount of waste produced.

In the past few years, representatives of ASME NCS have been actively participating in events concerning new reactors. Most recently, the focus has been on four types: Pebble Bed Modular Reactors (PBMR), the Westinghouse AP-1000, the Advanced CANDU Light Water Reactor, and the International Reactor Innovative and Secure (IRIS). BNCS workshops on new reactors have been held with Westinghouse PBMR and Atomic Energy of Canada Limited (AECL). Other workshops are being planned for General Electric, General Atomics and Framatome ANP. In addition, BNCS representatives visited the PBMR Project demonstration in Centurion, Republic of South Africa.

Presentations focused on advantages of using ASME Standards, the planned initiatives of BNCS to better serve the needs of the new reactors and discussion of needs that are not met by the current standards.

A benefit of using ASME Standards is the reassurance that they have been promulgated using an open consensus process. This process prevents any one interest from unduly influencing Committee actions. To achieve consensus on an item, the Committee must consider all views and attempt to resolve all objections.

Basic needs for the new reactors can be put into four categories: quality assurance, materials, design, and inservice requirements. Beyond these, the needs are specific to the reactor type. Quality assurance requirements can be found in multiple standards including ASME's NQA-1, ISO 9000 and, locally, such as in Canada's CSA N286 series. Guidance needs to be created so minimum requirements will be met universally.

There is a great need for guidance on materials. Many materials that are not covered in current ASME standards will be used in the production of the new reactors, particularly the High Temperature Gas-Cooled Reactor (HTGR). Some of these materials will be included by expanding property information in current tables, such as high temperature stress strain curves, and including the effects of environment on materials (for example, oxygen and impurities in helium). Proprietary information and the limited number of experts in the use of graphite in nuclear applications may create difficulties in developing a consensus standard. Other non-metallic materials such as carbon-composites and ceramics must also be addressed.

Section III of the Boiler and Pressure Vessel Code "Rules for Construction of Nuclear Power Plant Components" is a good start to design but, as in the case of the CANDU Light Water Reactor, some design details are not addressed. For example, a rolled fitting is used in the CANDU design, but this detail is not included in Section III. Risk informed principles would also be essential in the design of the next generation reactors.

Inservice testing and inspection requirements need to be revisited. Longer operating cycles and components inside the reactor vessel make the current requirements difficult to apply to the new designs. Risk informed principles should also be used in the development of future ISI and IST requirements.

When information on the new generation of reactors is gathered from NSSS suppliers, assignments will be distributed to the appropriate Standards Committees to address the needs identified in the workshop.

The BNCS Task Group on Nuclear Risk Management is also working toward the consistency of Codes and Standards. ASME and the American Nuclear Society (ANS) are proposing a collaborated effort to form a Nuclear Risk Management Oversight Steering Committee. The committee's task would be to oversee standards activities associated with nuclear facilities. Members would be representatives of the U.S. Nuclear Regulatory Commission (USNRC), Department of Energy (DOE), and various other government agencies and standards development organizations, such as ASME, ANS and the Institute of Electronics and Electrical Engineers (IEEE).

Conclusion

By gathering experts in workshop type settings, identifying features that are not currently covered in NCS documents, and working on fixing these missing links, ASME NCS is laying the foundation for expanded application of its Codes and Standards to the next generation of nuclear reactors. Committees under NCS respond to the needs of the public and industry. Input from all stakeholders is always welcomed and encouraged.

If you would like to become involved in the committee or are just interested in gaining more information, the NCS webpages are located on the ASME website (www.asme.org) under Codes and Standards, C&S Committees.

MECHANICAL TESTING DEVICES – ARE THEY PATENTABLE?

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ABSTRACT

Intellectual Property (IP) rights exist in various forms that are useful to the field of valves and pumps. Intellectual property consists of patents, trademarks, copyrights, and trade secrets that are used to protect a variety of new methods of modeling strata, new equipment used in collecting data, and new software analyzing flow rates and capacities.

Today, building and maintaining an IP portfolio is simpler and less expensive than in years past. The first reason is due to a particular decision from the US Supreme Court that has become affectionately known as the Festo case which suggests inventors should not file one large patent, but numerous small ones. The second reason is because of a major legislative decision to provide for inexpensive "provisional patent applications." These "provisional patent applications" are useful in protecting ideas, methods, compositions, software, processes, and apparatus that are not yet completely tested or finished, yet protection is afforded to the "concept."

Intellectual Property (IP) is very similar to real property, in that it can be sold and licensed like real property. Intellectual Property can be used as (1) an asset, (2) a marketing tool, (3) a tool to protect market share, (4) a source of licensing income, and (5) a tool to enhance market share with customers.

The following paper will discuss how to identify what is protectable in the valve and pump industry with regard to testing and how to build a cost effective IP portfolio.

INTELLECTUAL PROPERTY AND MECHANICAL TESTING DEVICES

WHAT CAN BE PATENTED?

Patents enable the owner to have a monopoly on an idea, an apparatus, a method for manufacturing, a system, and/or a business method.

Patents can cover methods for analyzing data, software programs for compiling data, and devices and systems relevant to the pump industry. For an idea or an invention to be considered patentable, the invention must be (a) new, (b) useful, and (c) non-obvious to one "skilled in the art". The elements of "new" and "useful" are fairly straight. The "non-obvious" element has always been a challenge to explain.

Combinations of old elements when assembled in a new way with a new result, can lead to a patentable "non-obvious" idea.

Some patents issued by the United States Patent and Trademark Office (USPTO) in the testing area are listed as Attachment A. The following list includes abstracts from those patents in order to highlight the ideas that are currently being patented in the field:

1. 6,570,949 – METHOD AND APPARATUS FOR TESTING NUCLEAR REACTOR FUEL ASSEMBLIES: A method for testing whether fuel rods of fuel assemblies resting on a working base and under water, of a nuclear reactor are leaking is disclosed. The method includes heating at least one first fuel assembly of a first division of fuel assemblies for driving radioactive fission products out of a defective fuel rod contained in the first fuel assembly. The first fuel assembly is continuously tested by extracting samples of water and continuously degassing the water removed from an area around the first fuel assembly even during the heating resulting in gas. A radioactivity of gaseous fission products released in the gas is continuously recorded. A fuel assembly belonging to a second division of fuel assemblies is heated only if the first fuel assembly belonging to the first division of fuel assemblies has been tested. An apparatus for implementing the method is also disclosed.
2. 6,672,330 – VALVE BONDED WITH CORROSION AND WEAR PROOF ALLOY AND APPARATUSES USING SAID VALVE: A valve is characterized by excellent corrosion and wear resistance and

maintainability due to use of a bonding corrosion and wear proof alloy containing non-continuously distributed eutectic carbide on the sliding portions of various types of apparatuses and valves by diffusion bonding. This serves to improve the maintainability of a thermal and nuclear power plant and to provide a nuclear power plant using recirculating water, which ensures excellent working safety, in particular. The corrosion and wear proof alloy is characterized in that network-formed eutectic carbide in the alloy containing the cast structure base metal and eutectic carbide is formed into (multiple) granules or lumps having a particle size of 30 microns or less so that said eutectic carbide is non-continuously distributed.

3. 6,633,623 – APPARATUS AND METHODS FOR TESTING A JET PUMP NOZZLE ASSEMBLY AND INLET-MIXER: A jet pump for a nuclear reactor includes a riser and an inlet mixer having a set of nozzles and a mixing section for receiving coolant flow from the nozzles and suction flow from an annular space between the reactor vessel and the shroud core. To minimize or eliminate electrostatic deposition of charged particulates carried by the coolant on interior wall surface of the inlet-mixer of the jet pump, and also to inhibit stress corrosion cracking, the interior wall surfaces of the nozzles and mixing section are coated with a ceramic oxide such as TiO.sub.2 and Ta.sub.2 O.sub.5 to thicknesses of about 0.5-1.5 microns.
4. 6,526,114 – REMOTE AUTOMATED NUCLEAR REATOR JET PUMP DIFFUSER INSPECTION TOOL: An inspection apparatus for inspecting welds in a nuclear reactor jet pump includes a probe subassembly rotatably and linearly movably coupled to a frame structure configured to attach to a top flange of the reactor pressure vessel. The probe subassembly includes a plurality of probe arms pivotably coupled to a housing, with each probe arm including a sensor. The probe arms are pivotably movable between a first position where the probe arms are parallel to a longitudinal axis of the probe subassembly, and a second position where the probe arms are at an angle to the longitudinal axis of the probe subassembly. An insertion subassembly couples to the jet pump suction inlet. The insertion subassembly is sized to receive the probe subassembly and guide the probe subassembly into the jet pump through the jet pump suction inlet.

Some of the cases on the list relate to systems usable for testing in nuclear reactors. See Attachment B for an example of an apparatus (device) patent claims section of a system called Device for Materials Testing in Nuclear Reactors, noted as U.S. Patent 5,369,677.

Some system cases exist that are assemblages of known apparatus forming a system that has a new, useful, and non-obvious feature.

In short, patents can be issued for:

1. Methods for doing something;
2. Software programs;
3. Methods of doing business;
4. Systems, which are assemblages of old known components which now do something new; and
5. Apparatus, such as a new type of testing device for valves and/or pumps.

TYPE OF PATENT FILINGS – PROVISIONAL AND UTILITY FILINGS

Several of the cases described above are utility filings based on more limited “provisional” application filings. The scope of patent law in the United States has changed to allow inventors to file a less complete patent application than in the past to protect their ideas. These new cases are called “provisional patent applications”. Generally, provisional patents are used for inventions that are not yet finished or not completely tested. The provisional filing allows the inventor to include additional subject matter or modifications to the original ideas within a 12-months period and still have the benefit of the first filing date of the case.

Facing steep competition, manufacturers are attempting to differentiate their technology in ways that are simply more than “new and improved” without excessive legal fees. Filing a provisional patent application enables a developer to obtain a federal filing date, effectively preserving the date of the invention plus rights in 121 other countries, so that further development can occur, while having some pending protection in place, reducing the need for secrecy and non-disclosure agreements for the idea.

By filing the idea with the United States Patent Office first, many developers find that disputes over ownership of the idea can be avoided.

One example of a company that is now “filing first” and asking questions later is Microsoft. Last year alone, Microsoft has filed 250 times more patent application than it owned twelve years ago. Microsoft recognizes that ideas are:

1. assets;
2. marketing tools;
3. sources of licensing income; and
4. tools for protecting market share.

What does a typical patent protection cost?

Four to six provisional patent applications can be purchased for approximately $26,000 USD. Typically, the cost for a patent dispute is about $600,000 USD in attorney fees.

Does having a few filings avoid a dispute? Maybe.

The traditional patent application is know as a utility patent. Design patents exist for ornamental designs, and plant patents exist for roses and other plants. A utility patent is typically protecting an invention for twenty (20) years from the filing date of the application.

The granted patent monopoly is a right to exclude others from making, using, selling, or importing into the United States, the system, method, or compositions that are "claimed" in the issued patent.

During the first 12 months of a pending provisional or utility patent application case, "no-cost" corresponding pending patent rights exist in more than 121 foreign countries.

All U.S. patent applications must be filed within one year of the first offer for sale or the first commercial use or demonstration of the invention. If the application is not filed within that year, the patent filing will be deemed fraud on the patent office.

Patents are obtained through a lengthy, multi-year process, usually about three (3) years. Generally, numerous steps are involved when obtaining a United States patent. Attachment C of this paper provides a general timeline of this process.

A tremendous amount of detail on this topic can be read at United States Patent and Trademark Office website at www.USPTO.gov.

Copyrights

Unlike Patents that protect an idea, Copyrights protect an original expression as fixed in a tangible medium. Drawings, plans and specifications are all potentially copyrightable if the drawing or plan is in a tangible medium. Legal protection happens instantly when the original copyrightable subject matter is fixed in a tangible medium, such as a digital form.

Beyond the congressionally created legal protection that attaches once the subject matter is in a tangible medium, an author or creator can obtain further rights and remedies by paying $30 USD to the government and filing the proper paperwork at Library of Congress' website, see www.loc.gov for more details.

By simply registering the copyrightable subject matter (i.e. a writing, a drawing, a picture, or a plan) with the Library of Congress and paying the required fee, three (3) additional rights are obtained to protect the subject matter in the event another uses the work without consent:

1. One to five years (1-5) in jail, if an infringer makes more than 10 copies of the registered work in 180 days and the aggregate value exceeds $2500 USD;
2. A minimum statutory damage of $25,000 USD if an infringer makes copies of the registered work, even if the copies are distributed free; and
3. Reimbursement of attorney fees incurred by the owner of the copyright in enforcing the copyright.

Trade Secrets

Yet another type of Intellectual Property is trade secrets. Trade secrets are defined as secrets that give a business a competitive advantage over another. In general, these secrets can include techniques, formulations, and business methods to obtain new business.

Trade secrets can protect any technical or business information that has a potential economic value and is a secret. Reasonable efforts must be made to keep the information secret. An example of a reasonable effort is the use of a Non-Disclosure Agreement (NDA) or a "Secrecy" Agreement. An example of a Secrecy" Agreement is shown in Attachment E.

Each non-disclosure or "secrecy" agreement needs to have at least the following three (3) critical elements:

1. A statement about the scope of the agreement;
2. A statement about the term of nondisclosure (i.e., 5 years, 10 years, or another time period); and
3. A statement regarding non-use of the subject to be disclosed.

If an inventor is receiving information, then the secrecy agreement should have a shorter term and a narrower scope. If an inventor is giving information to a third party, then the agreement should include a longer term and wider scope.

In order to maintain trade secrets, no formal filing procedure to register trade secrets is required.

Trademarks

Finally, a trademark is any word, name, symbol, or device that identifies goods of one company and distinguishes them from goods of another. Trademarks for nuclear engineers can include a company name, such as Mission Valve and Pump.

Other types of trademarks include:

1. Symbols or logos, such as a special arrow that is affiliated with a service like surveying by a particular pump manufacturer;
2. Slogans, such "We know how to check that flow";
3. Colors or color combinations, such as the royal blue for all valves produced by a particular business;
4. Sounds of a pump; and
5. Smells.

Trademarks can be registered on a Federal basis with the United States Patent and Trademark Office. Trademarks can also be filed in a given State with the Secretary of State. Trademarks can be filed both on a federal and state level.

Common law trademarks also exist.

Trademarks must be filed describing a particular good or service using a non-generic and non-descriptive term. A unique trademark filed at the USPTO is then registered on the Primary Register. However, if the mark is either descriptive or generic, the mark can still obtain a federal filing on the Supplemental Register.

Trademarks afford legal protection for the good will associated with the use of the recognized name, symbol, slogan, color, sound, or smell in relation to a good (product) or service.

Trademarks provide exclusive rights within the United States. As long as a trademark is used commercially, it can be renewed.

CONCLUSION

If inventions are not properly protected, the invention can fall into the public domain and may be used by any party without a license or payment. A sound patent, trademark, copyright and trade secret (collectively IP) management strategy involves systematically building an IP portfolio, consisting of different IP rights that cover various aspects of a company's technology and commercial interests.

Most companies protect their company name and major products or services with trademarks. Clever companies protect ideas with one or more patents. Low risk companies protect one or more of their trade secrets with secrecy agreements with third parties, employees, contractors, and even vendors.

Software companies and designers of models typically protect software with copyrights after those ideas are first evaluated for qualification for patent protection.

ATTACHMENT A

6,577,128	NQR method and apparatus for testing a sample by applying multiple excitation blocks with different delay times
6,570,949	Method and apparatus for testing nuclear reactor fuel assemblies
6,566,873	Method of and apparatus for nuclear quadrupole resonance testing a sample
6,486,838	Apparatus for and method of Nuclear Quadrupole Resonance testing a sample
6,459,748	Floating ultrasonic testing end effector for a robotic arm
6,404,835	Nuclear reactor rod drop time testing method
6,222,364	Method of nuclear quadrupole resonance testing and method of configuring apparatus for nuclear quadrupole resonance testing
6,208,136	Method of and apparatus for nuclear quadrupole resonance testing a sample, and pulse sequence for exciting nuclear quadrupole resonance
6,166,541	Apparatus for and method of nuclear quadrupole resonance testing of a sample
6,127,824	Nuclear quadrupole resonance testing
6,111,409	Nuclear magnetic reasonance fluid characterization apparatus and method for using with electric wireline formation testing instruments
6,100,688	Methods and apparatus for NQR testing
6,091,240	Method of nuclear quadrupole resonance testing and method of configuring apparatus for nuclear quadrupole resonance testing
6,088,423	Multiview x-ray based system for detecting contraband such as in baggage
5,958,710	Orphan receptor
5,946,364	Densification test procedure for urania
5,875,406	Method for reducing radioactive waste, particularly oils and solvents
5,841,824	System and method for testing the free fall time of nuclear reactor control rods
5,814,989	Methods and apparatus for NQR testing
5,814,987	Apparatus for and method of nuclear resonance testing
5,786,691	Detection of thermal damage in composite materials using low field nuclear magnetc resonance testing
5,754,610	In-mast sipping modular mast modification
5,717,731	Outage cover for nuclear reactor containment vessel
5,651,334	Steam generator lateral support
5,621,209	Attomole detector
5,591,974	Automated collection and processing of environmental samples
5,544,208	Method and apparatus for in situ detection of defective nuclear fuel assembly
5,504,881	Method for testing and validating the primitives of a real-time executive by activating cooperating task using these primitives
5,491,414	Method of nuclear quadrupole resonance testing of integral spin quantum number systems
5,490,443	Pressure-discharged type retaining system
5,459,767	Method for testing the strength and structural integrity of nuclear fuel particles
5,438,862	System and method for in situ testing of the leak-tightness of a tubular member
5,428,653	Apparatus and method for nuclear power and propulsion
5,377,234	Colloidal resin slurry recycle concentrating system of nuclear reactor coolant water
5,369,677	Device for materials testing in nuclear reactors
5,369,362	Method of and apparatus for NMR testing
5,347,553	Method of installing a control room console in a nuclear power plant
5,304,919	Electronic constant current and current pulse signal generator for nuclear instrumentation testing

5,289,875	Apparatus for obtaining subterranean fluid samples
5,287,390	Alarm system for a nuclear control complex
5,271,046	Manipulator and process for carrying out work in the connection-piece region of a vessel, in particular non-destructive testing
5,271,045	Advanced nuclear plant control complex
5,267,278	Console for a nuclear control complex
5,267,277	Indicator system for advanced nuclear plant control complex
5,265,131	Indicator system for a process plant control complex
5,227,122	Display device for indicating the value of a parameter in a process plant
5,227,121	Advanced nuclear plant control room complex
5,223,207	Expert system for online surveillance of nuclear reactor coolant pumps
5,215,706	Method and apparatus for ultrasonic testing of nuclear fuel rods employing an alignment guide
5,208,165	Method for testing the soluble contents of nuclear reactor coolant water
5,182,955	Borehole formation model for testing nuclear logging instruments
5,151,244	Apparatus for filtering and adjusting the pH of nuclear reactor coolant water for the testing of soluble contents therefor
5,137,086	Method and apparatus for obtaining subterranean fluid samples
5,128,094	Test instrument manipulation for nuclear reactor pressure vessel
5,118,462	Manipulator for handling operations, particularly for non-destructive testing
5,108,692	Non-destructive testing of nuclear fuel rods
5,097,199	Voltage controlled current source
5,095,753	Device for ultrasonic testing of a head screw inserted into a component
5,072,732	NMR instrument for testing for fluid constituents
5,065,097	Testing method and apparatus by use of NMR
5,025,215	Support equipment for a combination eddy current and ultrasonic testing probe for inspection of steam generator tubing
5,009,835	Nuclear fuel rod helium leak inspection apparatus and method
5,008,906	Consistency measuring device for a slurry containing defoamer
4,902,467	Non-destructive testing of nuclear fuel rods
4,875,486	Instrument and method for non-invasive in vivo testing for body fluid constituents
4,866,385	Consistency measuring device
4,851,183	Underground nuclear power station using self-regulating heat-pipe controlled reactors
4,799,305	Tube protection device
4,770,029	Valve testing method and device
4,735,766	Method and apparatus for testing vertically extending fuel rods of water-cooled nuclear reactors which are combined in a fuel rod cluster
4,728,482	Method for internal inspection of a pressurized water nuclear reactor pressure vessel
4,720,422	Material for collecting radionuclides and heavy metals
4,699,753	Reactor refueling machine simulator
4,689,193	Mechanism for testing fuel tubes in nuclear fuel bundles
4,687,992	Method for testing parts, especially of nuclear plants, by means of eddy current
4,652,418	Plug testing and removal tool
4,643,866	Nuclear fuel pellet-cladding interaction test device and method modeling in-core reactor thermal conditions
4,643,029	Ultrasonic probe for the remote inspection of nuclear reactor vessel nozzles
4,642,215	Universal tool for ultrasonic testing of nuclear reactor vessels
4,640,812	Nuclear system test simulator

4,636,645	Closure system for a spent fuel storage cask
4,623,294	Apparatus for carrying out repair, maintenance or testing of apparatus, components and the like in hot cells
4,608,991	Method for in-vivo NMR measurements in the human breast to screen for small breast cancer in an otherwise healthy breast
4,590,472	Analog signal conditioner for thermal coupled signals
4,587,077	Safety actuator release device
4,564,422	Method and apparatus for detection of erosive cavitation in an aqueous solution
4,554,128	Nuclear fuel rod end plug weld inspection
4,526,311	Method for carrying out repair, maintenance or testing apparatus, components and the like in hot cells
4,519,090	Testable time delay
4,518,822	Method and apparatus for automatically establishing telephone communication links
4,517,154	Self-test subsystem for nuclear reactor protection system
4,513,205	Inner and outer waste storage vaults with leak-testing accessibility
4,499,375	Nuclear imaging phantom
4,461,996	Nuclear magnetic resonance cell having improved temperature sensitivity and method for manufacturing same
4,460,920	Automatically traveling tube-interior manipulator for remotely controlled transportation of testing devices and tools along given feedpaths, preferably for nuclear reactor installations
4,460,832	Attenuator for providing a test image from a radiation source
4,453,501	Transducer for determining if steam generator tubes are locked in at support plate
4,452,250	NMR System for the non-invasive study of phosphorus metabilism
4,446,099	Device for protecting control cluster actuating mechanisms during the testing of a nuclear reactor
4,428,236	Method of acoustic emission testing of steel vessels or pipelines, especially for nuclear reactor installations
4,416,846	Nuclear power plant with cooling circuit
4,416,409	Method for manufacturing a metal casing for gate valves used in nuclear reactors and the like
4,415,771	Public alert and advisory systems
4,402,904	Method for determining clad integrity of a nuclear fuel rod
4,395,380	Method of testing fluid flow condition in extension of a pipe
4,384,489	Method of monitoring stored nuclear fuel elements
4,368,580	Apparatus for testing the diameter of a cylindrical hole machined in a very thick part
4,366,711	Method of testing fuel rods for assemblies for nuclear reactors and corresponding apparatus
4,351,824	Polystyrene latex reagents, methods of preparation, and use in immunological procedures
4,324,616	Detachable and leaktight device for closing an orifice of a nuclear reactor vessel
4,319,736	Apparatus and method for manufacturing a metal casing particularly for gate valves used in nuclear reactors and the like, having a large nominal width and a casing manufactured in accordance with the method
4,296,378	Apparatus providing enhanced detection of specimens in inhomogeneous fields
4,292,129	Monitoring of operating processes
4,248,666	Method of detecting leakage of radioactive gas from a nuclear fuel assembly
4,192,173	Eccentric pin mounting system
4,172,760	Neutron transmission testing apparatus and method
4,131,018	Elbow or bent tube manipulator, especially for ultrasonic testing in nuclear reactor installation
4,117,733	Test system carrier for ultrasonic testing of nozzle seams, pipe connection seams and nozzle corners in pressure vessels, particularly reactor pressure vessels of nuclear power plants
4,096,032	Modular in-core flow filter for a nuclear reactor
4,092,217	Fuel elements for nuclear reactors and method for testing the circulation of fuel elements in a core of a nuclear reactor
4,087,323	Pipe connector

4,073,665	Microwatt thermoelectric generator
4,072,559	Method and apparatus for the zone-wise shuffling of nuclear reactor fuel elements
4,067,771	Nuclear reactor containment spray testing system
4,034,599	Device for locating defective fuel
3,996,465	Test rig for subjecting specimens to high temperature behavior tests
3,984,258	Microwatt thermoelectric generator
3,980,503	Microwatt thermoelectric generator
3,980,502	Microwatt thermoelectric generator
3,951,692	Microwatt thermoelectric generator
3,940,311	Nuclear reactor internals construction and failed fuel rod detection system

ATTACHMENT "B"

Device for materials testing in nuclear reactors – Patent No. 5,369,677

1. A device for load-testing of specimens (3) in a nuclear reactor environment, characterized in that at one of the pipes (1) of the nuclear reactor for conveying a first medium under pressure, there is fixed a testing device (2) comprising a first space (14) in open communication with said pipe (1), a movable pull rod (15) arranged in said first space (14), one end of said pull rod (15) being intended to be attached to one half (16) of a specimen (3) arranged in the space (14), the other end of said pull rod (15) being joined to a tensile force device, capable of being influenced by the first medium, for achieving a tensile stress in the specimen (3) via the pull rod (15).

2. A device according to claim 1, characterized in that the testing device (2) comprises a first sleeve (13, 6, 8), connected to the pipe (1) in open communication, and an extension, which is movable in relation to the first sleeve, in the form of a second sleeve (9), said sleeves together surrounding at least part of said first space (14), a pull rod (15) arranged in said first space (14) with one end fixed to the movable second sleeve (9), the other end of the pull rod (15) being adapted to be attached to one half (16) of a specimen (3) fixed in the space (14), said second sleeve (9) being adapted to be influenced by a first medium supplied from the pipe (1) in order to achieve a tensile stress in the specimen (3) via the pull rod (15).

3. A device according to claim 2, characterized in that the first and second sleeves are interconnected by means of a bellows (10), said second sleeve (9) and bellows (10) being surrounded by a third sleeve (11) forming a second space (12) around said second sleeve (9) and the bellows (10), said second sleeve (12) containing or being connectable to a second medium of lower pressure than said first medium.

4. A device according to claim 3, characterized in that said second space (12) is also connectable to a medium of the same or a higher pressure in relation to said first medium.

5. A device according to claim 1 or 2, characterized in that several specimens (3) are connected in series in said first space (54).

6. A device according to claim 1 or 2, characterized in that the testing device (2, 42) is detachably attached to said pipe (1, 41).

Attachment C

Utility Patent Timeline*

	Event	Time
1.	Optional Patentability Search ⬇	3-6 weeks
2.	Optional provisional patent application filed ⬇	3-4 weeks to draft and obtain filing date at U.S. Patent & Trademark Office ("USPTO")
3.	Provisional application sits while applicant develops and tests invention ⬇	11 months from filing date from USPTO
4.	Conversion of Provisional to Utility application ⬇	1 month process to add additional claims and subject matter from testing and to improve figures if used in case
5.	Filing as Utility Application ⬇	
6.	Obtain Filing Receipt ⬇	60-90 days from filing
7.	Receive first rejection from USPTO ⬇	9-16 months from utility filing date
8.	Draft and file Response to 1st Rejection or Draft Response and interview case ⬇	Within 30-60 days of date of Notice of Rejection
9.	Receive 2nd Rejection ⬇	9-16 months from filing of Response to 1st Rejection
10.	Draft and file Response to 2nd Rejection ⬇	Within 30-60 days of date of notice of 2nd Rejection

11.	A. Call Examiner or B. Appeal or C. Receive Notice of Allowance ⬇	Within 140 days from 2nd Rejection Within 180 days from 2nd Rejection, if a final rejection Within 6 months
12.	Prepare formal drawings, advise client of costs of Issue Fee, formal drawings and attorney's fees for completion of work ⬇	Upon receipt of Notice of Allowance and Issue Fee Due
13.	Sent Issue Fee documents with Issue fee and formal drawings, if required, to PTO ⬇	Within 3 months from date of Notice of Allowance and Issue Fee Due
14.	Consider filing Divisionals, Continuations on additional improved subject matter to use same priority date for seamless monopoly ⬇	Within 3 months from date of Notice of Allowance and Issue Fee Due
15.	**Patent Issues**	
16.	3.5 year Maintenance Fee ⬇	
17.	7.5 year Maintenance Fee ⬇	
18.	11.5 year Maintenance Fee	

*This is a typical timeline. Times may vary on a case-by-case basis. There is no guarantee any patent application will issue as a patent.

ATTACHMENT D

CONFIDENTIALITY AGREEMENT

This Agreement, effective this ___ day of _______ , ________ is by and between ________________________., having an address at _________________________ (hereinafter referred to as "__________"), and ______________________________ ____, having an address at ______________________ (hereinafter referred to as "______________").

WHEREAS, the Parties are interested in discussing information relating to ________________ and various proprietary methods for doing business as __________________ and the asset acquisition of certain assets, financials and trade secrets of ________________ (hereinafter "Method for ___________________and the assets, financials and trade secrets of _________ _______ "); and

WHEREAS such discussions may involve the disclosure by ________________ of technical and/or business information which ________________ considers confidential, proprietary and valuable relative to Method __________________as well as the assets, financials and trade secrets of ________________ ;

NOW, THEREFORE, ________________ is willing to disclose such information on Methods __________________and the assets, financials and trade secrets of ________________ only under the following terms and conditions:

1. "________________ Confidential Information" shall be defined to include any information disclosed to ______________ ____ either through disclosures by ________________ representatives and/or affiliates or by third parties on behalf of ___ _____________ or such affiliates (collectively "________________ "), either directly or indirectly, in writings, drawings, photographs, samples, demonstrations or by inspection of plants or other facilities or in any other way and may include any analysis information provided to __________________ or obtained by __________________ on Method ______________ ____and information on the assets, financials and trade secrets of ________________ .

   ________________ Confidential Information shall not apply to information which __________________ can show was:

   (a) in the public knowledge or in the literature at the time of disclosure by ________________ ; or

   (b) already in __________________'s possession, in written form, at the time of disclosure by ______________ without obligation of confidentiality.

   Specific disclosures made hereunder shall not be deemed to be within the above exceptions merely because they are embraced by general disclosures in the public knowledge or literature or in __________________'s possession, and any combination of features disclosed hereunder shall not be deemed within the above exceptions merely because individual features are in the public knowledge or in __________________'s possession.

2. The purpose of disclosure of ________________ Confidential Information to __________________ under this Agreement is to enable __________________ to understand and talk about Method __________________and the assets, financials and trade secrets of ________________ with ________________ and only with ________________ .

3. __________________ agrees not to disclose ________________ Confidential Information received hereunder to any third party and not to use the same, except for the purpose noted above.

4. __________________ agrees to restrict disclosure and treatment of ________________ Confidential Information to only those employees who have a need to know such information to carry out the purposes of this Agreement. ______________ ____ agrees to handle and safeguard ________________ Confidential Information in the same manner as _____________ _____ handles and safeguards its own proprietary information of similar nature.

5. __________________ agrees that it will not make copies or excerpts of ________________ Confidential Information without ________________'s prior written permission and agrees that it will, upon request therefor, return to ___________ _____ any and all such ________________ Confidential Information which is in writing or other tangible form and which is in __________________'s possession or control, including any and all excerpts and copies thereof. All documents, drawings, samples and writings provided to __________________ hereunder and any copies thereof shall be returned promptly to ________________ upon the conclusion of the discussions of this project, unless sooner requested by _______ _________ .

6. This Agreement does not grant and shall not be construed as granting to __________________ a license or any rights under any of ________________'s patent, trademark, copyright or trade secret, or other intellectual property rights except as expressly noted herein.

7. __________________ represents that its officers, employees, and the like who may have access to ________________ Confidential Information are legally obligated to preserve the confidentiality of such information.

8. __________________ agrees to assign and hereby assigns to ________________ any improvement, invention, work of authorship, mask work, idea or know-how (whether or not patentable) that is conceived, learned or reduced to practice under this Agreement, or through discussions with third parties, and any patent rights, copyrights, trade secret rights, mask work rights and other rights with respect thereto. __________________ agrees to take any action reasonably requested by ________________ to evidence, perfect, obtain, maintain, enforce or defend the foregoing.

9. Except as may be otherwise permitted by this Agreement, the __________________ shall not copy, duplicate, reverse engineer, reverse compile, disassemble, record, or otherwise reproduce any part of Confidential Information, nor attempt to do any of the foregoing, without the prior written consent of the ________________ . Any tangible embodiments of Confidential Information that may be generated by a __________________, either pursuant to or in violation of this Agreement, will be deemed to the sole property of the ________________ and fully subject to the obligation of confidence set forth in this Section.

Accepted and Agreed:

By:________________________________	By:_______________________________________
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Qualifying Active Valves for use in Nuclear Power Plants A new Revision to ASME QME-1 Section QV

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The views and opinions presented herein are my own as an engineer and not as Chairman of the American Society of Mechanical Engineers (ASME) Committee on Qualification of Mechanical Equipment Used in Nuclear Facilities (QME). They are not to be construed as the views of ASME, my employer nor of the U.S. Nuclear Regulatory Commission (NRC). The information presented herein may or may not be in the final revised Section QV, "Functional Qualification Requirements for Active Valve Assemblies for Nuclear Power Plants," in ASME QME-1 "Qualification of Active Mechanical Equipment used in Nuclear Power Plants," when it is published. What is published in QME and QV will be the result of ASME's review and ballot procedures and processes.

QME, History of Development

In 1974, NRC issued Regulatory Guide 1.48 which described the qualification of Active Pumps and Valves in Nuclear Power Plants and specifically noted that testing was the preferred method. ASME *Boiler & Pressure Vessel Code* (B&PV) Section III includes rules for the design and testing to ensure integrity of the pressure boundary. However, the Boiler Code did not and does not include qualification of function. The definition of Active, in those days, was basically any Nuclear Safety Related Component that was required to function in order to safely shut down the Nuclear Reactor.

The ANSI N45 committee was in existence prior to the issuance of the Regulatory Guide. The committee was tasked with developing qualification standards. The Committee established two Task Groups to develop qualification standards. These standards were for Pumps and for Valves. In 1974, the Valve Task force (N278) was reassigned to the American National Standards Committee B16 and was designated Subcommittee H.

The first Qualification Standard to be issued was ANSI N278.1-1975. This standard provided the requirements for the preparation of a functional specification by the user to provide information to the manufacturer on the design and operating requirements for an Active Valve, its Actuator and all Appurtenances. Also, in the early 1980s, an MSS (Manufacturers Standardization Society of the Valve Industry) standard was issued and then ANSI B16.41 specifically addressed qualification of Valve Assemblies.

In 1982, the Subcommittee H was again reassigned, this time to its present home, ASME Committee on Qualification of Mechanical Equipment Used in Nuclear Power Plants. This is when the two task groups (Pumps and Valves) were once again united under the same committee.

The Present QME and some Major Differences in Rules for Pumps versus Valves

When the valve group and pump group moved into different committees in 1974, they proceeded down decidedly different paths. Pumps, by their very nature, had always had some sort of performance test in the manufacturer's facility. Everyone is familiar with the shop generated head flow characteristic curve. These tests generally were specified by the owner and the tests were, and are, generally those described by Hydraulic Institute. Valves, except safety/relief valves and control valves, had no such test. Also, in many cases, performance for typical gate and globe valves simply wasn't specified. Generally, the typical valve specification asked for a certain ANSI rating, a type, a material, how it was to be connected into the pipe and, if it had a motor actuator, maybe the design pressure differential across the valve. Generally, except for Main Steam and Feedwater Isolation Valves, the flow rate was never specified much less an accident flow rate due to a postulated pipe rupture.

The Pump Group developed a standard that provided general guidance on what qualification parameters needed to be proven for a pump that was to be an Active Component. This was aided by the fact that Functional testing was not new for pumps; that manufacturers were very used to the idea of specifying nozzle loads on their equipment; and that Architect Engineering Firms were used to the idea of checking pipe generated loads on pumps (a pump is typically an anchor point in a Stress Analysis). Also, there was never any thought of a pump being required to operate if its discharge pipe had a rupture (in that case you specifically do not want it to operate). Hence, there was no need to even think of rupture loads on pump nozzles. The only new wrinkle was Seismic Qualification and that was typically handled through the use of IEEE 344.

With valves, it was significantly more complicated. For one thing, there are many more of them. Second, they are not typically flow tested. Third, some of them are required to isolate a postulated full guillotine rupture and, last but not least, the piping designer never checked the end loads on a valve that was not an anchor. All of these things conspired into a standard that was extremely prescriptive.

The Parents of Section QV and QV as It Is Now

The present QV is, for the most part, based on a standard that was developed in the mid to late 1970s. At that time, it was thought that many new Nuclear Power Plants would be built and that a valve manufacturer would qualify much of the line of products; in effect giving those products the equivalent of an "N" stamp for qualification. There was no thought whatsoever of requiring end loads to be limited. One reason being that the valve was in-line mounted in a piping system and it was very difficult to calculate actual valve end loads transmitted from the pipe if the valve wasn't near a support. It was realized that flow testing was expensive, but you can spread these costs over the several valve sizes that met a set of similarity rules (the parent/candidate valve assembly concept). The present Qualification requirements in QV generally are those that were provided in 1978. What delayed the issuance of B16.41 frankly had little to do with the tests themselves. The delay was primarily caused by rules to allow similarity because a valve that went through the whole test series probably had to be a prototype since the testing likely significantly damaged it.

The group concept was, in the most part, required because valve testing was incredibly expensive. Indeed, it was also not far fetched that in some instances a user who needed two valves might have to buy a third test valve to throw away. Also, it might also be that a user may have to buy a test fixture for the valve and hope that the valve passes. Prototype testing to destruction is common in the auto industry and aerospace where you are making thousands of exact copies. While this might have been acceptable when many thousands of valves were procured, it is extremely prohibitive when only a dozen are procured in a year.

Experiences with the Present QV

Since QME was developed, there has been little new construction domestically. The Standard has been used very sparingly, if at all. Where QV has been used there have been interpretation problems. Judging by the Inquiries that we have received as well as comments from testing labs and valve manufacturers, several concerns became apparent.

First, in many instances the user community was not providing the required functional specification. Simply, they specified to the manufacturer, within the typical procurement type specification, that valves needed to be qualified to either B16.41 or to QME with no delineation of what parameters needed to be ensured what actual design and operating conditions were and what was the acceptance criterion.

Second, we have received comments from testing labs that certain tests (specifically for check valves) were very difficult to perform at best, and very dangerous to perform at worst.

Third, the testing is extremely expensive and, in many cases, cannot be performed with facilities that are available.

Fourth, the scope of those valves to be qualified is well beyond the limited scope of "active" components.

Fifth, many of us on the subcommittee recognize that technology allows many more options than those available when the original concept of valve qualification was envisioned over thirty years ago.

Finally, there have been inquiries that we have discussed and had to say, "Yes that is what it says"; while within the committee we wonder, "How are they going to do that?"

The Concept of the New QV

The new QV is in the process of development. We do have a draft that has received wide distribution comment within ASME. Comments have been resolved for the most part and the next step is the ballot process within ASME. Also, a big plus would be a future endorsement from the U.S. Nuclear Regulatory Commission, something that QME does not yet have.

The new QV considers the following:

- The PC has given us significant analytical power.
- The scope of what needs to be qualified as an active component is quite small in comparison to the overall population in a typical Nuclear Power Plant.
- We now have significant experience with valve testing almost exclusively from industry experiences in responding to NRC Generic Letter 89-10.

- Safety and Relief valves have been flow qualified for years as part of ASME Sections III and VIII.
- New qualification technologies will become available significantly faster than they can be added into QV.
- QV was intended for new construction. However, there may be application for existing Nuclear Power Plants and, possibly, for other industries.
- The present QV can be quite cumbersome to read and understand. There are constant references back and forth to other sections.

Given these basic parameters, the new QV does the following;

- QV almost entirely abandons the parent/candidate concept and, instead, establishes qualification of an assembly and gives guidance on how to prove the production valve is essentially the same.
- The new QV is much less prescriptive in that it provides a set of parameters that must be met and then allows the valve designer/manufacturer to develop the method of qualification similar to what is presently done in the Pump Section of QME.
- The new QV purposely limits the scope of valves that need to be qualified. This is getting back to the original requirement of NRC Regulatory Guide 1.48, Standard Review Plan 3.9 and Generic Letter 89-10.
- The new QV establishes a link between QV and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code), specifically, Code Case OMN-1 and Check Valve Performance Monitoring. This makes certain that the qualification parameters determined with a prototype can be demonstrated in the installation.
- The new QV recognizes that Safety and Relief valves have always had flow testing. QV allows the flow test to be used as credit rather than requiring a separate and different test.
- The new QV allows the valve manufacturer the flexibility to provide end loads to the piping designer that need to be kept to demonstrate isolation of a guillotine rupture. This is a direct result of new pipe stress analysis programs that make checking valve end loads relatively simple. Further, it excludes Safety and Relief valves from end load qualification because these valve types have always had flow induced end loads and piping designers design accordingly.
- The new QV makes the generation of a functional specification mandatory. This is to ensure that the valve designer and manufacturer know what is expected. Also, it provides information to the valve manufacturer wherein he/she can determine if there are system design functions that the type of valve cannot achieve.
- The new QV is reformatted so that the need to reference back and forth is greatly reduced although not completely eliminated. For the most part, once you've selected a valve type, you stay within that section.

A Glimpse at the new QV

Section QV provides for qualification of a valve assembly by a combination of testing and analysis. Functional qualification of a Valve Assembly by extension of Qualified Valve Assembly qualification through limited testing and demonstration of design similarity is permitted. This extension of qualification is based upon the condition that both the valve assemblies utilize the same design concept and that critical dimensional clearances are maintained. Diagnostic testing shall be performed during the qualification testing covered by this standard.

The excerpts from section QV are taken from Draft M of the standard, 2/23/04. This is the version that balloted by the Standards Committee. The published wording may be different.

A major difference between the present and future QV is the allowance of the use of Analysis. This is permitted within the following guidelines:

(a) Analysis is permissible provided that sufficient test verification exists to justify the analysis used, over the qualification conditions involved.

(b) Analysis methods may be used for ensuring accessories and associated attachments are rigid.

(c) Analysis methods based on extensive valve assembly testing programs may be used in conjunction with focused flow testing to demonstrate functional capability. The user should be cautioned that, because of difficulties associated with identifying and predicting factors which affect operating loads for certain types of valves (e.g., flexible wedge gate valves), even when those valve assemblies are identical, it may be necessary to limit the use of analysis in functional capability qualification. Analysis methods may be used in the accelerated environmental aging process per the provisions of Appendix QME QR-B.

The first parameter to consider for the qualification of a valve assembly is its intended use. As I mentioned before, QV qualification is limited to Active Valve Assemblies. The QV definition of Active Valve Assembly is:

"A valve assembly that is required to change position to perform its Nuclear Safety Function."

Note that most Nuclear Safety Related Check Valves fit the definition of "active;" however, the Committee is still formulating a definition.

The new QV is arranged so that qualification requirements are based on valve assembly type. Within each type, there are two categories. The categories are defined as follows:

"Qualification Category A, Valve assemblies that are required to open against or isolate flow under conditions associated with pipe rupture. This flow includes blowdown flow (e.g., injection into a vessel, or isolating a line break with a flow regime that exhibits two phase flow or flow velocities above those experienced in a pumped flow application). Valve assembles in this Category may be in pipes where the ASME Section III stress allowable for the attached pipe may exceed Level B."

"Qualification Category B, Valve assemblies that are required to open to permit flow or close to isolate flow but are not required to open against or isolate flow associated with a pipe rupture. Valve assemblies in this Category are in pipes where the ASME Section III stress allowable for the attached pipe does not exceed Level B. If piping system stress analysis indicates that the Level B stress allowable may be exceeded, then the valve assembly must be categorized as Category A."

Note that these definitions provide linkage to ASME B&PV Section III. This recognizes that pipe loads may be kept below those that cause deformation of the pipe.

With information on valve Type and Qualification Category, qualification requirements are obtained from the following table:

Valve Assembly Qualification Requirement Matrix

Note that each qualification parameter has its own section for each type of valve. This does create some repetition in QV but it does make it much easier for the user to follow the requirements. Referencing back and forth, as is required in the present QV, is significantly reduced. Also, note that qualification for Relief Valves is significantly reduced. This recognizes that relief valves by their nature cannot be Qualification Category A.

Some typical qualification requirements are as follows:

Environmental and Aging

This qualification parameter makes use of experience gained during initial tests for the GL 89-10 program. It also makes use of IEEE 382.

> The qualification of non metallic parts that are critical to function is contained in QR-B.
>
> Friction of valve internal sliding surfaces can increase with age until a plateau is reached. Further, inspections and disassembly/reassembly of valves that expose valve internal surfaces to air can result in a temporary reduction in friction coefficients. Qualification of functional capability must address these phenomena when establishing valve operating requirements.

Environmental Qualification of actuators is performed in accordance with IEEE 323 and IEEE 382 Qualification of other non-metallic parts that are critical to valve assembly performance may be performed in accordance with QR-B.

Sealing capability

This section is separated into main seat and stem leakage. This is the least modified section of QV.

Parameter	Power Actuated		Self Actuated		Relief	
	Cat A	Cat B	Cat A	Cat B	Cat A	Cat B
Seismic	QV-7450	QV-7450	Not Required	Not Required	Not Applicable	QV-7650
End Load	QV-7440	Not Required	QV-7540	Not Required	Not Applicable	Not Required
Functional	QV-7460	QV-7460	QV-7560	QV-7560	Not Applicable	QV-7660
Environmental	QV-7420	QV-7420	QV-7520	QV-7520	Not Applicable	QV-7620
Sealing Capability	QV-7430	QV-7430	QV-7530	QV-7530	Not Applicable	QV-7630

Note 1: Relief valves, by function of their purpose (i.e. pressure relief) cannot be Category A.

Note 2: End Load testing is not required by the definition by the definition of Category B.

Note 3: Seismic evaluation of Self Actuated valves is not required due to the lack of an extended structure.

End Loading

The consideration of end loading is significantly different than the present QV. The new requirements are:

All valves to be qualified to this document shall be designed so that they are in compliance with the rules of ASME B&PV Code Section III subsections NB, NC, or ND 3521 (1) & (2).

The end loading test is not required if, (1) the intended application for the valve does not impose significant end load reactions (e.g., a drain valve with piping attached to one end of the valve does not impose significant loading); or (2) the valve is designed to be installed in piping by bolting the valve between pipe flanges, and the valve body has a generally cylindrical cross section (except for through bolting holes and a provision for actuator mounting and entrance of the valve stem/shaft) of such proportions that the length of the valve body parallel to the pipe run is equal to or less than the inside diameter of the valve (e.g., a wafer style butterfly valve).

For Category A valve assemblies, one of the following is required:

1) Qualify analytically, using a test verified method, the maximum load (forces and moments) that can be placed on the valve body such that operation is not adversely affected. In turn, this load is to be supplied to the pipe system designer who must design his system such that the load cannot be exceeded.

2) Qualify by test for the maximum load that can be placed on the valve body such that operation is not adversely affected. In turn, this load is to be supplied to the pipe system designer who must design his system such that the load cannot be exceeded.

3) Require that the pipe/support system be designed such that the maximum load transmitted to the valve does not exceed the Level B stress limits of ASME Section III.

   If options 1 or 2 are chosen the valve designer shall determine the maximum load that the valve can sustain without loss of function. This information shall be included in the ASME Section III design report for the valve.

End load qualification is not required for Category B valve assemblies.

Seismic Capability

The new QV provides several options for Seismic Qualification. Section QR-A is also extensively rewritten. It is presently in the ballot process at ASME and I will not go into details in this presentation. However, QR-A does allow the use of experience data for Seismic Qualification. This is significantly different than the present QME. Seismic requirements for power operated valve assemblies are:

(a)Seismic qualification is intended to demonstrate the ability of a valve assembly to withstand a loading which is representative of the specified seismic load qualification level.

(b)Qualification of valve assemblies shall be in accordance with of IEEE Std-344 as addressed in NRC Regulatory Guide 1.100 (Revision 2) or Appendix QR-A.

(c)All essential-to-function accessories shall be attached to the valve assembly. The essential-to-function accessories that have not been previously qualified in accordance with IEEE Std-344 as part of the actuator assembly shall be seismically qualified by test in accordance with the test section of IEEE Std-344 or Appendix QR-A.

Functional Qualification

Functional qualification, or flow capability, is another significantly different section in QV. Specifically for Power Actuated valves, this section makes extensive use of experience obtained during the GL 89-10 programs. It does allow the use of analytical data if such data is test verified. There is a large deal of this information available to users groups. This section allows the use of this data or allows a manufacturer to establish their own. However, the prescriptive requirements are now removed for the most part.

The qualification of the functional capability of a Valve Assembly shall be justified using a combination of analysis and diagnostic test data. Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used to supplement the testing in order to minimize the amount of testing needed to qualify the Valve Assembly. The following activities shall be performed to justify the qualification of the functional capability of the Valve Assembly:

(a) Identify the manufacturer, type, size, materials (including internal parts) and rating; stem packing; and corrosion inhibitor (as applicable) for the valve to be qualified.

(b) Perform an internal inspection of the valve for material, surface condition, and critical internal dimensions (including valve internal clearances and edge radii). Evaluate worst-case tolerance combinations in the manufacturing process and verify that the valve will behave predictability.

(c) Establish any orientation requirements and any system piping constraints that are applicable to the qualification of the valve.

(d) Establish fluid conditions (including blowdown) and stroke time requirements that the valve is being qualified to.

(e) Determine the seat leakage limitations (including directional sealing) of the valve.

(f) Determine the stem leakage limitations of the valve.

(g) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the valve under static fluid conditions throughout the valve stroke in both the opening (including unseating) and closing (including seating) directions and verify proper valve assembly.

(h) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the valve in both the opening and closing directions until the coefficient of friction has stabilized and baseline performance parameters established.

(i) While collecting diagnostic test data (including stem thrust and/or torque; fluid pressure and temperature, and stroke time), cycle the valve under applicable fluid temperature, pressure, and flow conditions (from ambient to hot water and steam conditions), environmental conditions, and stroke time requirements throughout the valve stroke (including seating and unseating) and verify the functional capability of the valve under design-basis conditions.

(j) Determine whether the valve is susceptible to pressure locking and/or thermal binding. If so, establish design limitations to prevent pressure locking and/or thermal binding.

The new QV allows the qualification of the actuator and valve separately.

Extrapolation of Qualification for Functional Capability

The new QV abandons the Parent/Candidate concept of the present QV. It does permit extrapolation of qualification of function.

The extrapolation of the qualification of the functional capability of a Qualified Valve Assembly to another Valve Assembly shall be justified using a combination of analytical comparison of physical attributes and diagnostic test data. Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used in lieu of the testing needed to extrapolate the qualification to another Valve Assembly.

Functional Capability of Production Valves

Verification of production valves relies heavily on new technology. This can be thought of as a baseline for in service tests during the life of the valve.

The functional capability of production valve assemblies shall be demonstrated based on verification of the physical attributes, application, and diagnostic test data of the production valve assembly to its Qualified Valve Assembly. At the discretion of the valve assembly owner, the production valve assembly testing may be performed following final installation of the valve assembly. The following activities shall be performed to demonstrate the functional capability of production valve assemblies:

(a) Verify applicability of the production valve type, size, material (including internal parts) and rating; orientation; piping system constraints; stem packing; and any corrosion inhibitor to the Qualified Valve.

(b) Perform an internal inspection of the production valve for material, surface condition, and critical internal dimensions (including verifying that valve internal dimensions, clearances, and edge radii are within manufacturing tolerances) to establish applicability to the Qualified Valve.

(c) Verify applicability of fluid conditions and stroke-time requirements for the production valve to the Qualified Valve.

(d) Verify that the seat leakage limitations (including directional sealing) of the Qualified Valve are applicable to the production valve.

(e) Verify that the stem leakage limitations of the Qualified Valve are applicable to the production valve.

(f) While collecting diagnostic test data (including valve stem thrust and/or torque; fluid pressure and temperature; and stroke time), cycle the production valve under static fluid conditions throughout the valve stroke in both the opening (including unseating) and closing (including seating) directions in order to verify proper assembly.

(g) Verify applicability of the functional capability (including stroke time) of the production valve for opening and closing under fluid conditions to the Qualified Valve through the use of specific test data or a test-based qualification methodology.

(h) Verify that the production valve addresses any pressure locking and/or thermal binding limitations of the Qualified Valve.

Note here that linkage has been made to the OM Code.

Post installation Verification and IST Baseline

The new QV makes a clear link to OM in this regard. Note how on the front end the valve is linked to ASME Section III and on the back end to IST.

The owner is responsible, after the production valve assembly has been installed in the plant, to cycle the production valve assembly under representative fluid conditions as necessary to collect diagnostic data (including valve stem thrust and torque; fluid pressure and temperature; stroke time; MOV motor torque, voltage and current; and AOV operating air pressures and current signals, as applicable) throughout the valve stroke to verify the production valve assembly meets the functional requirements of the qualified valve assembly. The owner can use this diagnostic data to establish the baseline requirements required by In-Service Testing, Section C of ASME OM Code

Valves Other Than Power Operated Valves

The intent of this presentation is to give an overview of the new QV. The foregoing is generally for power operated valve assemblies. There are separate sections for Check Valves and Relief Valves. I will not repeat similar qualifications for the other valve types but I will provide a few new concepts.

Seismic qualification of Check Valves

Seismic qualification of check valves is not required under this standard and may be covered by applicable design codes.

Those check valves with actuating means involving external weights, springs, or a power actuator whose purpose is to provide positive closure or to assist in closure may be qualified by analysis which verifies that the actuating device can not degrade the function or operability during and after a seismic event. Additionally, those check valves with an external actuating device whose sole purpose is to provide a means for in-service testing of operability may be qualified by analysis which verifies that the actuating device can not degrade the function or operability during and after a seismic event.

Functional Qualification For Check Valves

This parameter is significantly changed from the present QV. The difference is that full flow need not be developed. Rather, the disc position is now considered. This limits the flow significantly making qualification somewhat easier.

(a) The valve functional qualification establishes key performance parameters necessary for the evaluation of proper valve sizing to maintain the valve disk in the full open position under normal flow conditions, and the evaluation of valve adequacy for service applications involving flow reversal and resulting pressure surge produced by valve closure. The following activities shall be performed to justify the qualification for functional capability of the Valve assembly.

Identify manufacturer, type, size, material (including internal parts) rating; stem packing; and corrosion inhibitor (as applicable).

Establish orientation and system piping application.

Establish applicable fluid and system flow conditions.

Establish sealing capability requirements for valve.

Establish stem shaft leakage limitations for valve.

(b) Test-based methodologies that have been demonstrated to reliably predict valve assembly performance may be used to supplement valve-specific testing to minimize the range of flow testing in qualifying the Valve Assembly.

Post installation Verification and IST Baseline for Check Valves

Once again, clear linkage to ASME OM is established.

After the valve has been installed in the plant the valve shall be cycled under representative fluid flow conditions as necessary to collect of diagnostic data (disk position etc. as applicable) for use in future performance monitoring as required by Section ISTC of ASME OM Code.

Relief Valves

The new QV recognizes that functional qualification of Relief valves is already adequately covered by other codes and standards and that there is a significant experience database for relief valves.

Functional Qualification for Relief Valves

Functional qualification for Pressure Relief assemblies shall be as delineated in ASME B&PV Code Section III, Subsections NB, NC or ND 7700. The rules of Section III also govern the extrapolation of test results as well as the extension of test results to production valves.

Tests Prior to Initial Operation for Relief Valves

Valve assemblies shall be tested prior to initial installation as delineated in ASME OM Code, Appendix I, subsection I-3100 or I-7100.

Post installation Verification and IST Baseline

After the valve assembly has been installed in the plant the valve shall be tested as required by ASME OM Code, Appendix I, subsection I-3200 or I-7200.

Conclusions

The new QV is intended to recognize new technology as well as experience gained in the last thirty years since the issuance of NRC Regulatory Guide 1.48. It has become easier to read and understand and, hopefully, clears up confusion in the present QV. This is all intended to increase the safety of the public while addressing the large expense of Active Valve Qualification.

References

- Nuclear Regulatory Commission Regulatory Guide 1.48 (May 1973), "Design Limits and Loading Combinations for Seismic Category 1 Fluid System Components," withdrawn 50FR9732, 3/11/1985.
- Nuclear Regulatory Commission Regulatory Guide 1.100 (Revision 2, 1988), “Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants.”
- Nuclear Regulatory Commission NUREG-0800, "Standard Review Plan," Section 3.9.3, "ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures."
- Nuclear Regulatory Commission Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance."
- ANSI N278.1-1975, “Self-Operated and Power-Operated Safety-Related Valves Functional Specification Standard.”
- ANSI/ASME B16.41-1983, "Functional Qualification Requirements for Power-Operated Active Valve Assemblies for Nuclear Power Plants."
- ASME *Boiler & Pressure Vessel Code*, Section III, “Rules For Construction of Nuclear Facility Components.”
- ASME *Boiler & Pressure Vessel Code*, Section VIII, “Rules For Construction of Pressure Vessels.”
- ASME QME-1-2002, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.”
- ASME *Code for the Operation and Maintenance of Nuclear Power Plants*, OM-2001.
- ASME Code Case OMN-1-1999, “Alternative Rules for Preservice and Inservice Testing of Certain Electric MOV Assemblies in LWR Power Plants.”
- IEEE Std-344-1987, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”
- IEEE Std-382-1996, “IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Plants.”
- MSS, Manufacturers Standardization Society of the Valve Industry.

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IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

HISTORICAL PERSPECTIVE

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ABSTRACT

In the early 1980s the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue USI A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience-based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience-based rules could be introduced into IEEE-344 and ASME QME-1. The joint task group proposed a set of technical guidelines for implementation of experience-based qualification in ASME QME-1 and also provided a strategy for implementation. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. This paper provides background and history on this development effort. It also touches on the general principals of experience-based seismic qualification as it applies to Mechanical Equipment.

BACKGROUND

Throughout the 1980s, it became evident that important insights in the seismic performance of equipment, both mechanical and electrical, could be gained by a systematic study of data collected following large earthquakes and seismic testing. This led to several initiatives in the commercial nuclear industry to apply experience data for the seismic qualification of mechanical and electrical equipment.

INITIAL APPLICATIONS OF EXPERIENCED BASED DATA

This section overviews several of initial applications of experienced based seismic qualification that were implemented by the commercial nuclear power industry and the US Department of Energy.

SQUG Effort

In December 1980, the Nuclear Regulatory Commission (NRC) Staff initiated an unresolved safety issue, USI A-46, "Seismic Qualification of the Equipment in Operating Plants," related to seismic adequacy of mechanical and electrical equipment in older nuclear plants. This issue impacted approximately one half of the operating commercial nuclear power plants in the United States. In response to this generic letter, the commercial nuclear utility industry formed the Seismic Qualification Utility Group (SQUG) as the focal point for the resolution of USI A-46. After substantial technical research by both the SQUG and the NRC regarding this issue, the NRC published, in 1987, a detailed approach for resolving USI A-46, in Generic Letter 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." The Generic Letter Procedure sets forth an approach for verifying seismic adequacy of equipment using earthquake experience data supplemented by test results and analyses, as necessary. Licensees subject to USI A-46 were encouraged to participate through SQUG, in a generic program to accomplish seismic verification of equipment. As a result, SQUG developed the "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment."[6] The GIP uses earthquake experience data extensively to demonstrate the seismic adequacy of equipment.

The use of the SQUG-GIP was the first large-scale application of earthquake experience data to demonstrate the seismic adequacy of electrical and mechanical equipment. It was applied to over one half of the commercial nuclear power facilities in the United States. The period of application of the SQUG-GIP for resolution of USI A-46 was from the late 1980s until the mid-1990s.

STERI Effort

Seismic qualification for equipment originally installed in nuclear power plants was typically performed by the original equipment suppliers or manufacturers (OES/OEM). Qualification was usually based on analysis and/or testing performed on prototypes. Sub-components of such equipment were qualified by virtue of their performance in the host equipment. Quality assurance program controls were implemented by the suppliers and normally invoked by utilities to assure continued qualification of replacement items for use in the originally installed equipment. Many of the original equipment suppliers and manufacturers no longer maintain quality assurance programs that provide adequate controls for supplying nuclear equipment. Further, many of these venders are no longer in business. Consequently, utilities themselves must provide reasonable assurance for the continued seismic adequacy of replacement items.

To address the issue, the Electric Power Research Institute (EPRI) working in conjunction with SQUG developed the guideline for Seismic Technical Evaluation of Replacement Items (STERI).[7] This guideline acknowledged the use of experienced based seismic qualification to demonstrate the seismic adequacy of replacement equipment for electrical and mechanical equipment.

NARE

A second program that evolved from the SQUG-GIP effort for the resolution of USI A-46 was the New and Replacement Equipment (NARE) Program [8,10]. Jointly developed by SQUG and EPRI, this guideline provided prescriptive direction on the use of earthquake experience data to demonstrate the seismic adequacy of mechanical and electrical equipment. The application of the NARE guidelines is limited to those commercial nuclear plants that used the SQUG-GIP for the resolution of USI A-46 and adopted the use of the SQUG-GIP into their licensing basis.

DOE-GIP

At U.S. Department of Energy (DOE) facilities, safety analyses and facility-specific modifications in many cases required the evaluation of systems and components subjected to seismic hazards. In the mid-1980s, DOE developed a program that provides guidance for evaluating DOE equipment and distribution systems using experience data from past seismic events and shake table tests.[9]

A primary objective of the DOE Seismic Evaluation Procedure is to provide comprehensive guidance for consistent seismic evaluations of equipment and distribution systems in DOE facilities. Due to the evolution of design and operating requirements, developments in engineering technology, and differing hazards and missions, DOE facilities embody a broad spectrum of design features for earthquake resistance. The earliest-vintage facilities often have the least seismic design considerations and potentially exhibit the greatest difference between their design basis and what DOE requires today for seismic design criteria for new facilities. The approach sometimes used to review the seismic capacity of equipment and distribution systems included sophisticated evaluations or qualification testing that can be very time consuming, complex, and costly. This procedure is designed to be a cost-effective method of enhancing the seismic safety of facilities by emphasizing the use of facility walkdowns and engineering judgment based on seismic experience data.

The DOE Seismic Evaluation Procedure was adapted from Part II of Revision 2 of the SQUG-GIP used by the commercial nuclear power industry. The DOE Seismic Evaluation Procedure built on the procedures and screening criteria in the SQUG-GIP by incorporating DOE-specific requirements and guidance, and broadening the application of the experience-based methodology to equipment classes not contained in the SQUG-GIP.

TRADITIONAL QUALIFICATION APPROACH

Component (excluding distribution systems) seismic qualification as it relates to commercial nuclear power plants can be broken down into two primary areas: electrical and mechanical components. The qualification criteria for mechanical components can also be broken down into two categories:

(a) Leak tight structural integrity

(b) Operational design requirements.

Leak tight structural integrity for most pressure retaining mechanical components since the early 1970's has required some level of analytical evaluation either by meeting explicit ASME *Boiler and Pressure Vessel Code* (BPVC)[1] equations or meeting layout and support requirements which can be demonstrated to meet ASME BPVC design equation requirements. The design of low or zero pressure retaining mechanical components (such as fans, air handling units, chillers, atmosphere storage tanks, etc.) is covered by other industry standards such as ASHRAE, SMANCA, API, etc.

The operability seismic qualification of mechanical components used in nuclear power plants since 1994 was covered by the ASME Committee on Qualification of Mechanical Equipment (QME) who have developed operability qualification standards for pumps and valves. A non-mandatory Appendix A of Section QR of the QME-1 Standard,[2] which was published by ASME in June 1994, provides some general guidance on the application of experienced based seismic qualifications. Prior to the issuance of QME-1, most commercial nuclear power plants used IEEE-344[3] for the seismic operability qualification of mechanical equipment. In fact, all commercial nuclear power plants are currently licensed to IEEE-344 and/or SQUG-GIP for the seismic qualification of mechanical equipment.

Electrical components unlike mechanical components have historically not been required (for seismic qualification) to meet any explicit pressure retaining requirements. They have been qualified by demonstrating operability of performance requirements only in accordance with IEEE (primarily IEEE-344) requirements. IEEE-344-87 Section 9 provides general requirements for the use of experienced based seismic qualification.

ASME/IEEE EFFORTS TO INCORPORATE SEISMIC EXPERIENCED BASED QUALIFICATION INTO INDUSTRY CONSENSUS STANDARDS

With the experience gained in implementing these earthquake-based rules as a backdrop, the ASME and IEEE formed a joint working group in the early 1990s to investigate whether earthquake-based experience could explicitly be incorporated into ASME QME-1 and IEEE-344 Standards. Note that the existing revisions of both QME-1 and IEEE-344 Standards contained suggested approaches for use of experience data, but they are based on explicit one-to-one similarity sand do not incorporate the lessons learned through the 1990s. The joint ASME-IEEE Special Working Group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1 Standards, and published a “Recommendation for the Inclusion of Experience Base Seismic Qualification Methods into IEEE-344 and ASME-QME-1.”[5] A strategy for implementing this approach was also prepared.[4]

ASME QME Efforts

In response, ASME QME committee formed a Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The first draft revisions of Section QR and Appendix QR-A, which incorporated the experience-based approach, were issued for general review in December 1999. These resulted in more than 110 comments on the proposed changes to Section QR and Appendix QR-A. The Subgroup addressed all comments received. The resolution to the comments resulted in a significant rewrite by the SGDQ of the proposed QR and Appendix QR-A language. As a result, updates of Section QR and Appendix QR-A were issued for a second general review on December 2, 2000. This review resulted in 200 additional comments on the proposed code language. The Subgroup reviewed and addressed all of the 200 comments. All persons making comments were formally advised as to how the Subgroup addressed their comments in a letter issued in the third Quarter of 2002.

At the time of the writing of this paper, the final proposed changes to Section QR and Appendix QR-A have been formally Letter Balloted by the ASME Qualification of Mechanical Equipment Main Committee and the ASME Board of Nuclear Codes and Standards (BNCS). Negatives received by the QME main Committee have been resolved and the action has passed the committee. The BNCS procedural negatives are in the process of being resolved. It is hoped the updated sections of QR and QR-A can be issued formally in the 4th Quarter of 2004.

IEEE Effort

IEEE under the Nuclear Power Engineering Committee (NPEC) has initiated an effort to incorporate the recommendations of IEEE/ASME Special Working Group into the IEEE-344 standard. The work is under the cognizance of the IEEE-344 working group. The working group has completed its initial work and the proposed revisions to IEEE-344 are now in the process of being balloted by NPEC.

Conclusion

The proposed changes to Section QR and Appendix QR-A are the culmination of over five years of effort by the SGDQ, and over 20+ years of industry application. During that time, the SGDQ has worked closely with the QME Main Committee, the Seismic Qualification Utility Group (SQUG), the U.S. NRC, the U.S. domestic utilities, the IEEE-344 Working Group and various mechanical equipment vendors, in an attempt to address all concerns and comments in relation to the application of experience-based methods to the seismic qualification of mechanical equipment. It is hoped that by the time this paper is presented the revised Section QR and Appendix QR-A of QME-1 will have been accepted and on their way to publication.

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IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

THE OVERALL TECHNICAL BASIS

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ABSTRACT

In the early 1980s, the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to resolve Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience-based equipment qualification could be explicitly incorporated into ASME Standard QME-1 and IEEE Standard 344. The joint ASME-IEEE working group concluded that experience-based rules could be introduced into IEEE 344 and ASME QME-1. The joint working group proposed a set of technical guidelines and a strategy for use in implementing experience-based qualification in ASME QME-1 and IEEE 344. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ). In 1995, this Subgroup began to develop modifications to the ASME QME-1 Standard that incorporate a detailed methodology for the implementation of earthquake experience-based seismic qualification for mechanical equipment. The updated sections of the QME-1 Standard were approved by the QME Main Committee in the third quarter of 2003. The standard is expected to be approved by the ASME Board of Nuclear Codes and Standards before the end of 2005. This paper provides the overall technical basis for the earthquake experience-based method included in the updated section of the QME-1 Standard. This includes a presentation of the key features of the methodology, the basis for the approach selected, and the basis for the requirements in the standard.

INTRODUCTION

Use of earthquake experience is a well-established, effective method for verifying the seismic adequacy of equipment and is another tool for seismic qualification of equipment in nuclear power plants. Prior to its development, the nuclear power industry relied solely upon testing and analysis as the basis for seismic qualification of mechanical and electrical equipment. However, use of these traditional methods was not well suited to verifying the seismic adequacy of equipment that is already installed in older operating reactors, i.e., nuclear power plants that began construction prior to about 1975. Accordingly, the U.S. Nuclear Regulatory Commission (NRC) embraced use of experience-based methods for resolution of Unresolved Safety Issue (USI) A-46 in Generic Letter (GL) 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." [1] In this generic letter, on page 1, the NRC Staff recognized the benefits of using experience-based methods instead of traditional seismic qualification methods for as-installed equipment:

> "Direct application of current seismic criteria to older plants could require extensive, and probably impracticable, modification of these facilities.[1] An alternative resolution of this problem is set out in the enclosure to this letter. This approach makes use of earthquake experience data supplemented by test results to verify the seismic capability of equipment below specified earthquake motion bounds. In the staff's judgment, this approach is the most reasonable and cost-effective means of ensuring that the purpose of General Design Criterion 2 (10 CFR Part 50 Appendix A) is met for these plants.1"

Most of the utilities that operated the 70 nuclear units affected by USI A-46 formed an owners' group in the early 1980s to develop use of experience data to resolve this safety issue. This owners' group, the Seismic Qualification Utility Group (SQUG), worked with the NRC to develop the methodology and procedures to apply experience data. In addition, SQUG and the NRC worked with the Senior Seismic Review and Advisory Panel (SSRAP), a group of recognized seismic experts from industry, academia, and national laboratories to develop this method. To date, all of the plants still operating that were affected by USI A-46 have applied the experience-based methods developed by SQUG and successfully resolved this safety issue.

Since this experience-based method gained acceptance and was being widely applied in the nuclear power industry, the ASME and IEEE formed a joint working group in the early 1990s to investigate whether this method could be explicitly incorporated into ASME QME-1 and IEEE 344 for seismic qualification of mechanical and electrical equipment. Both organizations have subsequently developed draft revisions of their standards with new sections added to cover use of experience data. The QME Main Committee approved the updated sections of the QME-1 Standard in the third quarter of 2003. The ASME Board of Nuclear Codes and Standards is expected to approve this revision before the end of 2005. The Nuclear Power Engineering Committee of IEEE approved a draft revision of IEEE 344 in July 2003 for general balloting by the IEEE Standards Association. The balloting is taking place during the first and second quarters of 2004.

The experience-based method uses a different approach to seismic qualification of equipment than is used in traditional testing and analysis methods. This paper summarizes the key features of the experience-based method, as applied in the QME-1 Standard, and describes the overall basis for the approach and requirements in the standard.

KEY FEATURES OF EXPERIENCE-BASED METHOD

The five key features of the earthquake experience-based method, as used in the QME-1 Standard for seismic qualification of equipment, are listed below:

(1) A Reference Equipment Class is defined based on equipment performance data collected from facilities where strong ground motion earthquakes had occurred.

(2) Ground motion response spectra are determined at the facilities where the equipment performance data was collected.

(3) An Earthquake Experience Spectrum (EES) is developed to represent the seismic capacity of the equipment from which performance data was collected.

(4) Candidate Equipment is compared to the attributes of the equipment in the Reference Equipment Class.

(5) Seismic demand on the Candidate Equipment is compared to the EES.

A summary of each of these key features follows.

Reference Equipment Class Definition. Data are collected on the performance of equipment that has been exposed to strong ground motion earthquakes. A minimum of 30 independent items of equipment is obtained for each class of equipment being developed. Having 30 independent items provides a statistically significant source of data. The type of data to be collected includes the physical and operational characteristics that define the range of equipment physical characteristics, dynamic characteristics, and functions. These data are used to define the bounds of equipment covered by the Reference Equipment Class. These data are then used to define a set of Inclusion Rules that characterize the features of the equipment that are important to seismic adequacy. In addition, the experience data are used to define a set of Prohibited Features. The Prohibited Features include design details, materials, construction features, and installation characteristics that have resulted in seismic-induced failure of equipment to maintain its structural integrity and perform its specified function.

Ground Motion Response Spectra Determination. A free field horizontal ground response spectrum is established at each of the facilities where the equipment performance data were collected. These facilities are called Reference Sites. This response spectrum is based on recorded data within two structural diameters of the facility, if possible. However, if such data are not available, then other nearby free field ground motion recordings may be used to develop an estimate. This estimate is based on multiple attenuation relationships from strong-motion earthquakes that have similar tectonic environments, crustal properties, and seismological parameters. These ground motion response spectra are considered an estimate of the seismic excitation experienced by the equipment at these Reference Sites. Equipment performance data and the ground response spectra are obtained from at least four different Reference Sites and from at least four different earthquakes. Such diversity provides a measure of assurance that the equipment in the Reference Equipment Class had been exposed to seismic loadings that are broadband and statistically independent.

Earthquake Experience Spectrum Development. The ground response spectra from the Reference Sites are combined to form a weighted average, called the Earthquake Experience Spectrum (EES). The EES represents the seismic capacity of the equipment in the Reference Equipment Class. The weighting factor is based on the number of independent items at each Reference Site.

Candidate Equipment Comparison to Reference Equipment Class. The attributes of the Candidate Equipment being qualified are then compared to the Inclusion Rules and

Prohibited Features of the Reference Equipment Class. If there is a match, the Candidate Equipment is considered to be covered by the Reference Equipment Class. Candidate equipment of a newer vintage than the equipment used to establish the Reference Equipment Class should be evaluated for any significant changes in design, material, or fabrication that could reduce its seismic capacity compared to the Reference Equipment Class.

Seismic Demand Comparison to EES. The seismic demand on the Candidate Equipment, i.e., the Required Response Spectrum (RRS), should be enveloped by the EES for the Reference Equipment Class. The RRS used in this comparison should be a median-centered in-structure response spectrum so that unnecessary additional conservatisms are not introduced into this evaluation; the EES already includes several conservatisms since it is based on free-field ground motion at the Reference Sites rather than the amplified in-structure seismic motions experienced by the Reference Equipment.

Using these five key features of the earthquake experience-based method provides an effective alternative to seismic qualification of equipment using testing and analysis methods.

OVERALL BASIS FOR EXPERIENCE-BASED METHOD

The experience-based method is predicated on the premise that industrial-grade equipment is typically rugged and can withstand the seismic excitation caused by large earthquakes. This premise was demonstrated during development of this method to support resolution of USI A-46. During the past 20 years that data were collected by SQUG, the vast majority of the mechanical and electrical equipment performed satisfactorily during and after significant earthquakes at numerous commercial facilities around the world. This record of success is particularly impressive in light of the fact that the equipment in these commercial facilities was purchased, installed, operated, and maintained without the benefit of extensive quality assurance programs like those used in the nuclear power industry. In those few cases where seismic failures of equipment were identified at these commercial facilities, SQUG performed root cause analyses to identify the specific vulnerabilities to avoid similar failures in nuclear power plants.

In addition to the large quantity of success data, the type of seismic failures that occurred supports the premise that industrial-grade equipment is rugged and can withstand large earthquakes. Most of the seismic failures were the result of a lack of adequate anchorage and adverse seismic interactions with nearby equipment and structures. There were very few failures attributed to equipment design features. It is important to note that these results are based on the performance of real equipment in real earthquakes. Therefore, it can be concluded that installation issues are of primary concern while equipment design features are not nearly as important.

One of the other strengths of the experience-based method is that it relies on a large quantity of equipment performance data collected from numerous earthquakes. This can be illustrated by a pile of sand, as shown in Figure 1, in which each grain of light-colored sand in the pile represents the equipment that successfully withstood the effects of earthquake. By contrast, the few instances of damage are represented by the large dark pieces in this sand pile. Because there are so much success data compared to failure data, the experience-based method departs from the traditional testing and analysis method where significant attention is paid to one-to-one similarity in the qualification process. By contrast, the experience-based method gives less emphasis to one-to-one similarity and instead defines seismic capacity for whole classes of equipment.

To illustrate the ratio of success to failure data, results of data collected for one of the equipment classes in the USI A-46 program are illustrated in Figure 2. The height of each bar in this chart represents the number of Motor Control Centers (MCCs) at facilities that experienced significant earthquakes. These bars, placed along the horizontal axis of this chart, are at the approximate Peak Ground Acceleration (PGA) experienced by the facility during the earthquake. Note that there were only three MCCs that failed to perform satisfactorily. These three instances (represented on the chart with Xs marked through the box) occurred at the Fertimex Fertilizer Plant. These failures occurred because the MCC anchorage was inadequate and the units fell over during the earthquake. By contrast, there were more than 160 instances where MCCs successfully withstood the effects of earthquakes, some of which were very large. Since not all of these MCCs experienced the highest levels of excitation, only those that experienced significant excitation were selected to define an equipment class and establish the Reference Spectrum for the USI A-46 program. Nevertheless, note that the three failures in Figure 2 occurred at a PGA of only about 0.33g, whereas there were about 80 MCCs that successfully withstood higher levels of excitation (up to a PGA of about 0.6g). This illustrates that MCCs (from various manufacturers) are seismically rugged and can withstand large earthquakes, provided they are adequately anchored to the floor.

Another reason that the earthquake experience-based method provides a reasonable alternative to traditional testing and analysis methods is that the seismic capacities that can be developed using this method are limited to the relatively low levels of ground motion from earthquakes. To illustrate this point, consider the capacity spectrum developed for the 20 classes of equipment covered by the USI A-46 program, as shown in Figure 3. This plot includes response spectra at the following four earthquake experience sites.

(1) Pleasant Valley Pumping Plant subjected to the 1983 Coalinga earthquake with a Magnitude of 6.7 and an Intensity of VII at the site.

(2) El Centro Steam Plant subjected to the 1979 Imperial Valley earthquake with a Magnitude of 6.6 and an Intensity of VIII at the site.

(3) Sylmar Converter Station subjected to the 1971 San Fernando earthquake with a Magnitude of 6.6 and an Intensity of VIII at the site.

(4) Llolleo Facility subjected to the 1985 Chile earthquake with a Magnitude of 7.8 and an Intensity of VIII at the site.

The average of these four horizontal ground response spectra is represented by the solid bold line in Figure 3, labeled as the Reference Spectrum for the USI A-46 program. Although the Reference Spectrum is applicable only for the USI A-46 program (i.e., the QME-1 Standard requires a separate, well-documented basis for establishing the seismic capacity of an equipment class), it illustrates the relatively low levels of earthquake ground response spectra for significant earthquakes.

One way to see how relatively low the ground response spectra are for real earthquakes is to compare these spectra to those typically used for shake table testing. Figure 4 includes a plot showing the maximum Test Response Spectrum (TRS) that is often used for shake table testing of components (dashed line). It has a peak spectral acceleration of 14g. In contrast, the USI A-46 Reference Spectrum, shown as the solid line near the bottom of this plot, has a peak spectral acceleration of only 1.2g. Although not all equipment is tested to the maximum TRS shown on this plot, many items of equipment used in nuclear plants are tested at levels many times higher than the ground response spectra for the plant. The point of this comparison is to illustrate that earthquake experience-based seismic capacities (e.g., the USI A-46 Reference Spectrum) are relatively low compared to the TRS used in seismic qualification testing. As such, the earthquake experience-based method can be considered a low level screening method for seismic qualification of equipment.

CONCLUSION

In conclusion, this paper describes the five key features and overall technical basis of the earthquake experience-based method included in the updated section of the QME-1 Standard. In particular, the earthquake experience-based method uses a different approach to seismic qualification of equipment than traditional testing and analysis methods. The earthquake experience-based method relies upon a large amount of success data, collected from several facilities that experienced large earthquakes. This data is used to develop a screening EES, based on the ground response spectra at these facilities, to represent the seismic capacity of the Reference Equipment Class.

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[2] ANSI/IEEE Std 344-1975, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

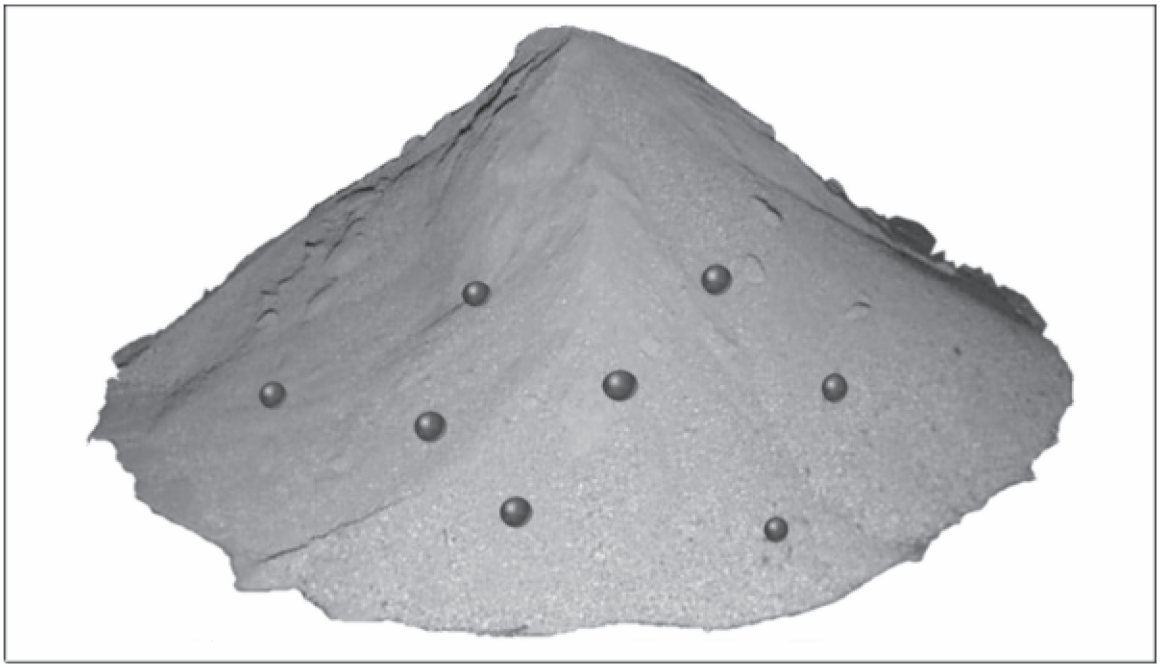

Figure 1 - Pile of Sand Illustrating Large Quantity of Experience Data

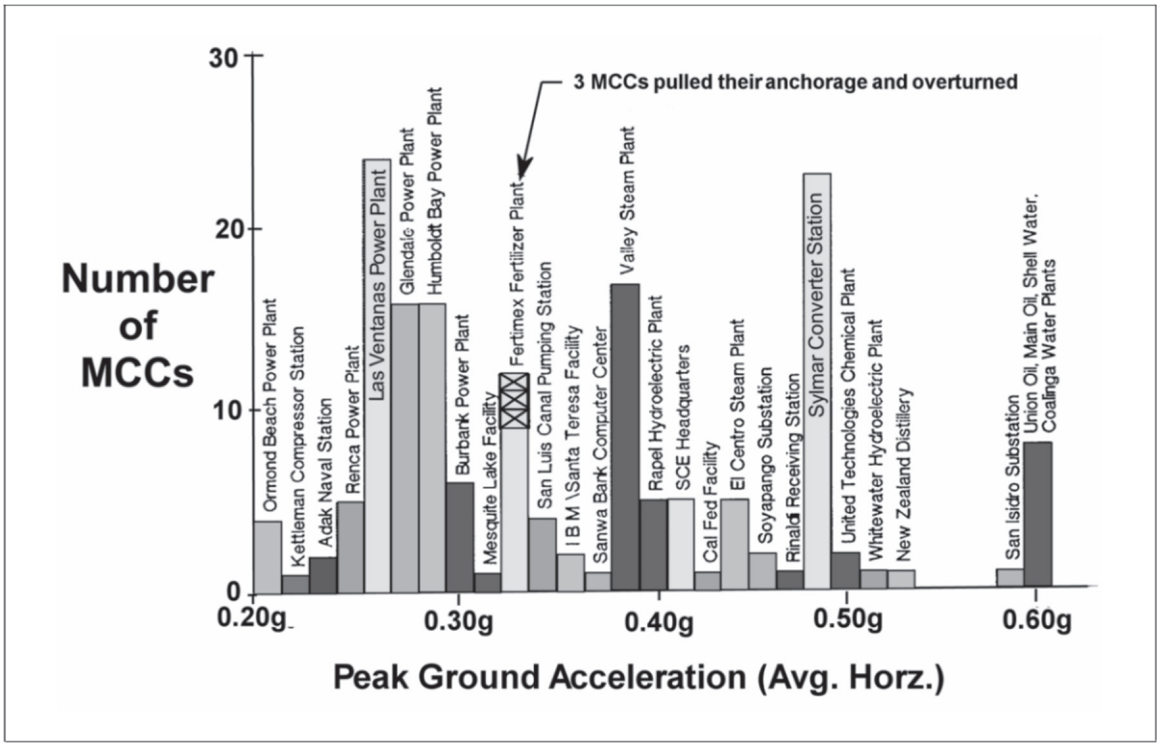

Figure 2 - Earthquake Experience Data for Motor Control Centers

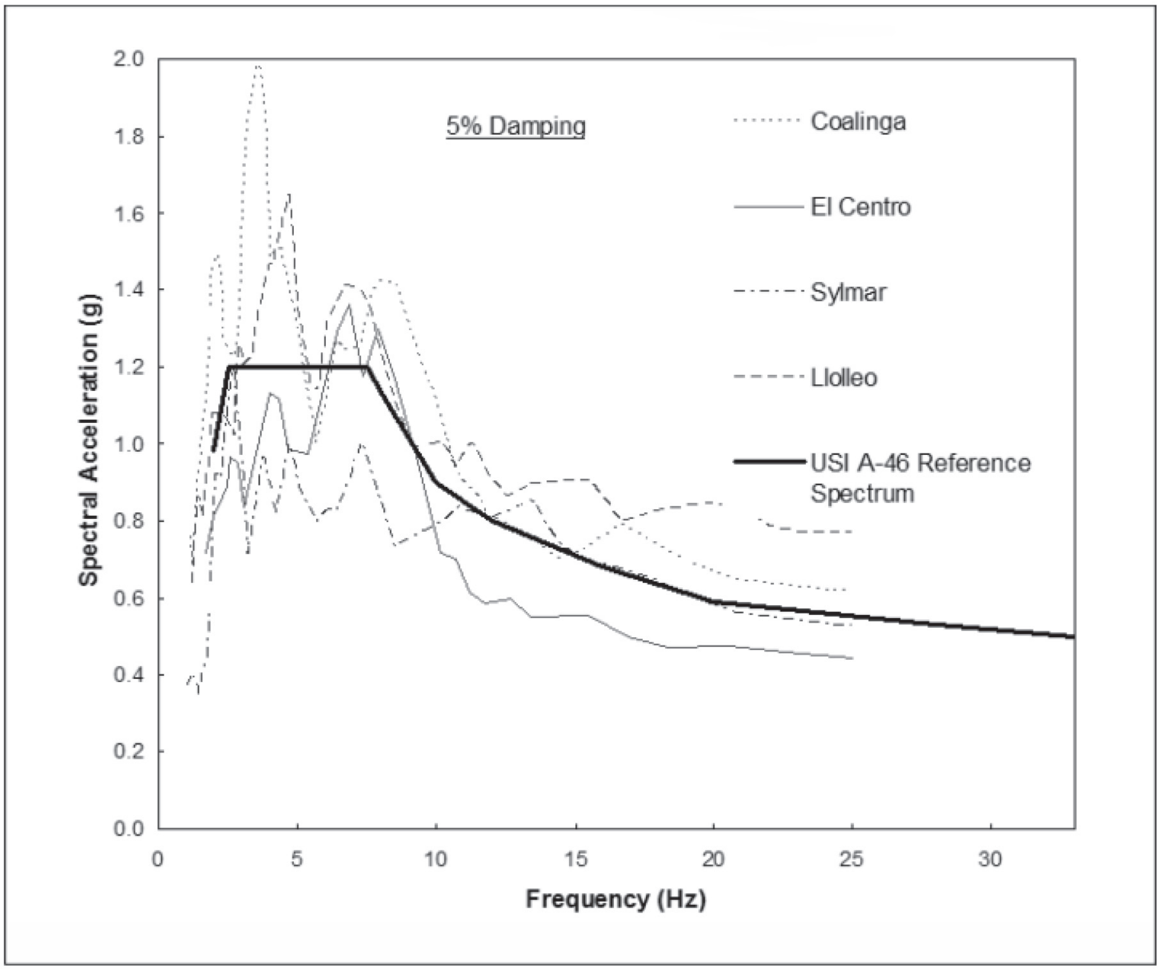

Figure 3 - USI A-46 Reference Spectrum and Earthquake Experience Ground Response Spectra

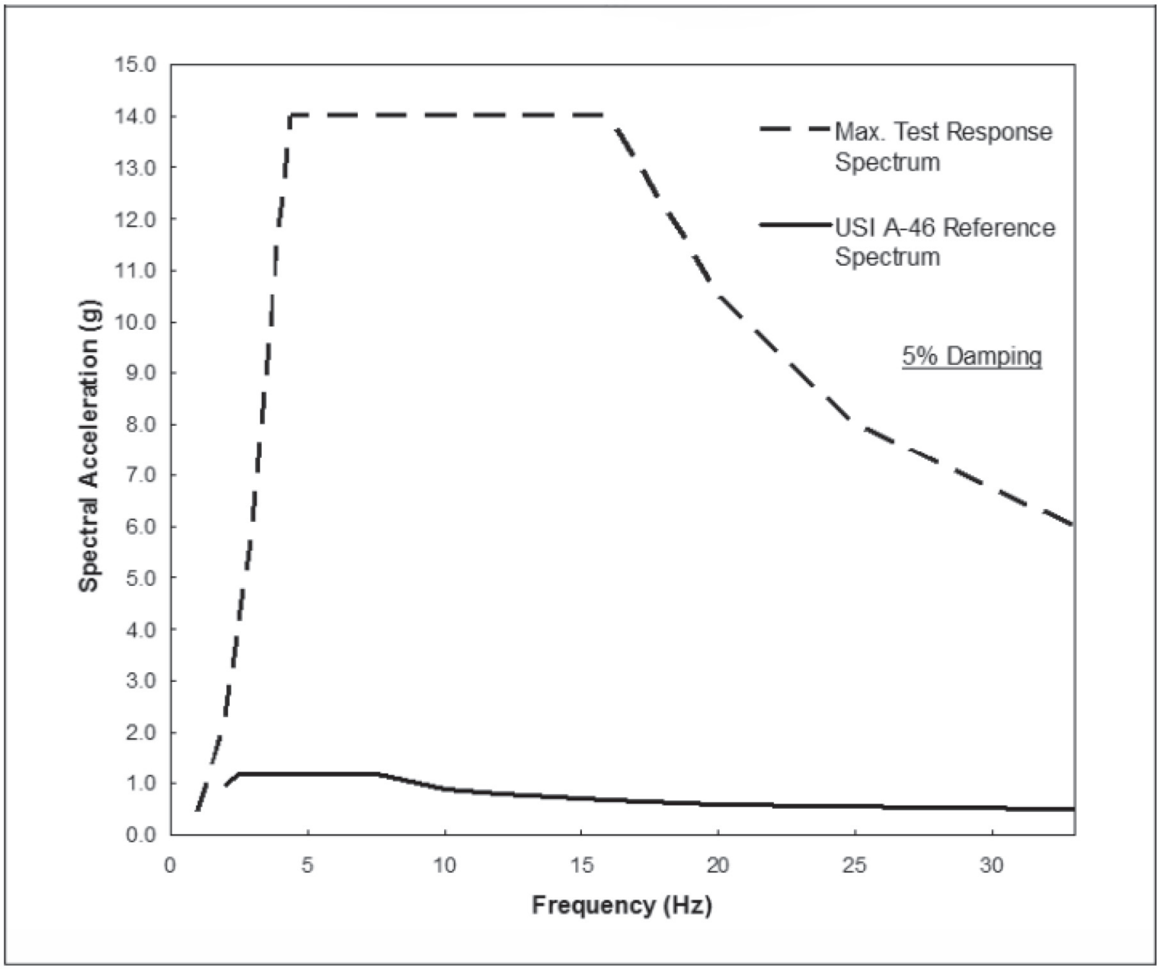

Figure 4 - Maximum Test Response Spectrum vs. USI A-46 Reference Spectrum

(Footnotes)

[1] The "facilities" and "plants" referred to in GL 87-02 are those nuclear power plants that had not committed to using IEEE Std. 344-1975 [2] for seismic qualification of equipment.

IMPLEMENTATION OF EXPERIENCE-BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

PROCEDURE FOR DATABASE GROUND MOTION DERIVATION

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ABSTRACT

In the early 1980s, the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experienced based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendations of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. As part of theses changes, the QME-1 Standard provides requirements for using free field response spectra from earthquake data sites in developing an Earthquake Experience Spectrum (EES) for a class of equipment. This paper provides procedures, along with examples, for deriving earthquake data site free field response spectra meeting the requirements of the standard, using both on-site and remote earthquake records. The procedures presented are the basis of the requirements incorporated into the QME-1 Standard.

PROCEDURE FOR DERIVATION OF DATABASE SITE FREE FIELD RESPONSE SPECTRA

The procedure used to estimate a free field response spectrum at an individual earthquake database site will depend on the number and location of strong-motion recordings that are available from the earthquake that affected the site. The procedure for doing this is summarized below.

There are four possible scenarios for estimating a free field response spectrum at a database site depending on the availability of strong-motion recordings as follows:

1. There is a recording at the database site,
2. There are one or more recordings within close proximity of the database site,
3. There are multiple recordings from the earthquake, but none are within close proximity of the database site,
4. There are none or only one or two recordings from the earthquake, and none are within close proximity of the database site.

The specific procedure for estimating a response spectrum at the database site for each of these scenarios is given below. In each procedure, the term "appropriate attenuation relationship" refers to a spectral attenuation relationship which was derived either empirically or theoretically for a region having a similar tectonic environment, similar earthquake source characteristics, and similar wave-propagation (attenuation) characteristics as the region in which the database site is located; which is applied using earthquake-specific estimates of magnitude, closest distance to the fault rupture, and style of faulting; and which represents local site conditions that are similar to those at the database site . The term "similar site conditions" refers to local soil conditions that fall into the same site classification as discussed below under Local Site Conditions.

Scenario 1. In this scenario there is a recording at the database site. In order for a recording to meet this criterion, it cannot be located any further than about two building dimensions (in plan view) from the database site facility containing the data. This recording will be used without modification to represent the response spectrum at the database site if the recording site and database site have similar site conditions. If the two sites do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions.

Scenario 2. In this scenario there are one or more recordings within close proximity of the database site, but none are within about two building dimensions. Whether a recording is within close proximity to the database site will depend on the distance of the recording and database sites from the earthquake rupture. In general, the distance of the recordings from the database site should not exceed about 5 kilometers (km) unless sufficient justification is given. If the distance between any recording site and the database site is a significant fraction of the distance from these two sites to the earthquake rupture (e.g., greater than about 10%), the recorded response spectrum will be adjusted using scaling factors derived from a set of appropriate attenuation relationships. If the recording site and database site do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions. The response spectrum at the database site will be estimated as the average of the recorded or adjusted response spectra.

Scenario 3. In this scenario there are multiple recordings from the earthquake, but none are within close proximity of the database site. In this case, the recordings are far enough away from the database site that their response spectra will need to be adjusted. This will be done by using spectral scaling factors derived from a set of appropriate attenuation relationships that have been adjusted to have the same average amplitude as the recorded response spectra. To avoid variability due to source radiation pattern and source directivity, a recording will be used only if it has an azimuth (direction with respect to the earthquake hypocenter) that is within about ±22.5 degrees of the azimuth of the database site. If less than about 5 recordings meet these criteria, Scenario 4 will be used to estimate the ground motion at the database site. If the recording site and database site do not have similar site conditions, the recorded response spectrum will be adjusted using the procedure described below under Local Site Conditions. The response spectrum at the database site will be estimated as the average of the adjusted response spectra.

Scenario 4. In this scenario, there are none or only one or two recordings from the earthquake, and none are within close proximity of the database site. In this case, a set of appropriate attenuation relationships will be used to estimate the response spectrum at the database site based on a seismological model of the earthquake. The seismological model will include an estimate of the earthquake's magnitude, seismic moment, stress drop, rupture characteristics, focal depth, and fault-rupture geometry (i.e., length, width, and dip of the earthquake rupture plane). If an appropriate set of attenuation relationships is not available, a stochastic simulation model will be used to adjust a set of attenuation relationships from another (host) region, if there is sufficient seismological data available to model the source and wave-propagation characteristics of the host and target (database site) regions. Application of the stochastic simulation model will include, in addition to those seismological parameters specified above, an estimate of the shear-wave velocity and attenuation (Q) of the hypocentral region of the earthquake and of the earth's crust between the earthquake and the database site. The response spectrum at the database site will be estimated as the mean of the response spectra derived from the adjusted attenuation relationships.

Local Site Conditions

In order for a strong-motion recording to be used in the estimation of the response spectrum at a database site, it must either: (1) be located on similar site conditions, or (2) be modified to account for the differences in these site conditions. Whether a recording site and a database site have similar site conditions will be based on a comparison of the available geological and geotechnical data that are available for the sites.

A recording and database site will be considered to have similar site conditions if they have the same Soil Profile Type as defined in the 1997 edition of the Uniform Building Code (UBC), the 1997 edition of the NEHRP Recommended Provisions for Seismic Regulations for New Buildings and Other Structures or other suitable standard, and the total depth of sediments beneath the site are sufficiently similar (i.e., within about 10% of each other). In such a case, no adjustment of the recorded response spectrum will be required. The Soil Profile Type, designated SA through SF as defined in the UBC and NEHRP Recommended Provisions, will be defined in terms of one or more of the following: (1) average shear-wave velocity, (2) average standard penetration resistance (SPT N-value), (3) average standard penetration resistance of cohesionless soil layers, and (4) average undrained shear strength of cohesive layers. In all cases, the average is taken over the top 30 meters (100 feet) of the soil profile.

Ideally, there should be sufficient geotechnical data at both the recording and database sites with which to unambiguously determine the Soil Profile Type. It is more likely, however, that there will be only general near-surface geological data at the two sites. The exceptions will be those recording sites for which special studies have been conducted to determine the lithology and/or shear-wave velocity profile at the site, and those database sites for which a geotechnical report is available. If sufficient geotechnical data are not available, general geologic descriptions from large-scale geologic maps will be used to define the Soil Profile Type using available empirical correlations between shear-wave velocity and geological information. The only time that this procedure should not be used is when a site is located in an area of complex geology where its classification in terms of a given Soil Profile Type is ambiguous. If such is the case for a recording site, the site's response spectrum will be excluded from consideration. If such is the case for the database site, the database site will be excluded from consideration until sufficiently accurate geotechnical and/or geological data can be obtained.

When an adjustment to the recorded response spectrum is required because its Soil Profile Type is different than that of the database site, this adjustment will be based on one or more of the following as appropriate: (1) empirical site factors derived from a set of appropriate spectral attenuation relationships, (2) site factors recommended in the UBC and NEHRP Recommended Provisions, and (3) other site factors derived from special empirical, theoretical or laboratory studies. When an adjustment to the recorded response spectrum is required because its sediment depth is different than that of the database site, this adjustment will be based on empirical correlations between spectral acceleration and sediment depth.

Personnel Qualifications and Independent Review

The earth-science professionals who will collect and interpret strong motion data are required to have the following minimum experience:

- Ten years of experience in the fields of earthquake seismology, engineering seismology, earthquake geology, strong-motion seismology, and/or geotechnical earthquake engineering.
- Experience in analyzing and interpreting strong-motion recordings and response spectra.
- Experience with developing and/or using strong-motion attenuation relationships.
- Experience with developing seismological models for defining earthquake rupture characteristics.
- An understanding of the impact of local soil conditions on strong-motion amplification.

The database site free field response spectrum derivation should be independently reviewed by an earth-science professional knowledgeable in ground motion estimation, and documented in accordance with Nuclear QA procedures. The independent reviewer should have the same minimum experience required by the earth-science professional who develops the ground motion estimates.

EXAMPLES

1. IBM Santa Teresa Facility HVAC (Scenario 1)

The IBM Santa Teresa Computer Facility is located in the city of San Jose in Santa Clara County, California. It is located about 12 kilometers from the surface projection of the rupture plane of the April 24, 1984 moment-magnitude (M_w) 6.2 Morgan Hill earthquake.

The Morgan Hill earthquake caused limited damage in the Morgan Hill region (Stover, 1984). It was assigned a maximum intensity of VII on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VII were observed in Morgan Hill and southern San Jose. The Santa Teresa Facility falls within the region of MMI VII effects.

1.1 Strong-Motion Recordings

There were four strong-motion recordings at the Santa Teresa Facility (Kinemetrics, 1984). Unfortunately, the only free-field instrument at the site had a malfunction and did not produce a reliable recording. Although many publications have quoted peak accelerations from this instrument, they should be considered unreliable. The most relevant recording was from an accelerograph in the 1-story concrete HVAC building, which recorded peak ground accelerations of 0.33*g* and 0.22*g* in the East and North directions, respectively (Kinemetrics, 1984; Swan and others, 1985). The vertical channel malfunctioned so no vertical record was obtained. The 5%-damped acceleration response spectra for the two horizontal components are shown in Figure 1-1. These spectra were calculated by K. Campbell at 15 periods ranging from 0.04 to 4.0 seconds from accelerograms that he had processed while at the USGS. The original accelerograms were lost, so these are the only spectra that are currently available.

1.2 Earthquake Parameters

Eaton (1987) and Crockerham and Eaton (1987) report the following seismological parameters for the Morgan Hill earthquake:

Date:	April 24, 1984
Time:	21:15:19 Greenwich Mean Time (GMT)
Magnitude:	6.2 M_L
Epicenter:	37.309°N, 121.679°W
Depth:	8.7 km
Strike:	327° (northwest)
Dip:	84° to the northeast

Rake: 180° (strike slip)

Rupture Width: 7 km (from aftershock distribution)

Rupture Length: 25 km (from aftershock distribution

Using strong-motion and teleseismic recordings, Hartzell and Heaton (1986) determined the following rupture parameters for the earthquake:

Average Slip: 1.0 m

Seismic Moment: 2.1×10^{25} dyne-cm

The seismic moment of 2.1×10^{25} dyne-cm is consistent with a moment magnitude (M_w) of 6.2 based on the moment-magnitude relationship of Hanks and Kanamori (1979). Similar estimates of seismic moment were obtained by numerous other investigators.

The following distances from the Santa Teresa Facility to the rupture plane of the Morgan Hill earthquake were calculated from the aftershock distribution of Crockerham and Eaton:

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
Santa Teresa	13.9	206	11.6	12.8

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

1.3 Local Site Conditions

There is no reliable site-specific geotechnical information for the IBM Santa Teresa Facility. However, a geologic map of the area (Helley and Brabb, 1971) indicates that the Facility is located on Pleistocene alluvial fan deposits. There is evidence of three periods of alluvial fan development in the southern Santa Clara Valley. The Pleistocene alluvial fans form a broad apron above the younger fans, extending to the base of the bedrock uplands that form the margins of the Santa Clara Valley. These sediments are coarser grained than those comprising the younger fans and usually display distinctive strongly developed soil profiles characterized by fragipan (hard, brittle loam) in the subsurface. This fragipan is very hard and impermeable and permits little surface water infiltration. Standard Penetration Test (SPT) resistance for the older fan deposits range from 11 ± 9 blows/ft above the fragipan to 88 ± 23 below the fragipan (Helley and Brabb, 1971). Bedrock is known to outcrop about 200 meters northwest of the site, which suggests that the Pleistocene alluvial fan deposits are relatively thin and that bedrock occurs at a relatively shallow depth beneath the Facility.

Because of the presence of the fragipan, it is difficult to classify the soil conditions at the Facility. Fortunately, this is not important since there is a recording on site. Nonetheless, the site is likely to be classified as Soil Profile Type S_C (Soft Rock and Very Dense Soil) based on the soil classification given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 360 and 760 meters per second (m/s).

1.4 Recommended Response Spectra

The recording obtained in the 1-story HVAC building is the recommended recording for the Santa Teresa Facility. However, the building is partially buried on two sides where it is embedded into a soil berm, and its massive concrete slab and walls are likely to have attenuated high-frequency ground motion due to scattering and wave-passage effects. Therefore, it cannot be considered a free-field recording. However, it is the most reliable estimate of the ground motion to which the HVAC equipment was subjected within the building. It is, however, a conservative (i.e., lower) estimate of the free-field ground motion that occurred in the vicinity of the HVAC building. The recommended 5%-damped acceleration response spectrum is shown in Figure 1-2.

2. PALCO Cogeneration Plant (Scenario 2)

The PALCO Cogeneration Plant is located in the town of Scotia in Humboldt County, California. It is located directly over the rupture plane of the April 25, 1992 moment-magnitude (M_w) 7.0 Petrolia (Cape Mendocino) earthquake.

The Petrolia earthquake caused widespread damage throughout the Cape Mendocino region (Reagor and Brewer, 1992). It was assigned a maximum intensity of VIII on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VIII were observed in Ferndale, Petrolia, Honeydew, Rio Dell, and Scotia. The mainshock was followed by two large aftershocks on April 26.

2.1 Strong-Motion Recordings

There was no strong-motion recording at the PALCO Plant. The closest recording to the Plant was 2.3 kilometers away at the Highway 101–Painter Street Overpass in the town of Rio Dell (CSMIP Station #89324). The geographic coordinates of the recording site are 40.503°N latitude and 124.100°W longitude. The free-field accelerograph, which is located in an instrument shelter adjacent to the bridge, recorded peak ground accelerations of 0.55*g*, 0.39*g*, and 0.20*g* in the North, West, and Vertical directions, respectively (Shakal and others, 1992). The 5%-damped acceleration response spectra for the two horizontal components (Darragh and others, 1992) are shown in Figure 2-1.

2.2 Earthquake Parameters

Oppenheimer and others (1993) report the following seismological parameters for the April 25 Petrolia mainshock:

Date:	April 25, 1992
Time:	18:06:05 Greenwich Mean Time (GMT)
Magnitude:	7.0 M_w
Epicenter:	40.332°N, 124.228°W
Depth:	10.6 km
Strike:	350° (northwest)
Dip:	13° to the northeast
Rake:	106° (predominantly thrust)

Similar source mechanisms were obtained by the U.S. Geological Survey (1992), Murray and others (1996), and Graves (1994).

Using strong-motion recordings, Graves (1994; written communication, 1994) determined the following rupture model for the earthquake:

Width (down-dip):	20 km
Length:	28 km
Depth to Top:	6.3 km
Strike:	350° (northwest)
Dip:	14° to the northeast
Rake:	90° to 105° for asperities (predominantly thrust)
	115° to 140° for shallow southern part (oblique slip)
Average Slip:	1.9 m
Seismic Moment:	2.51×10^{26} dyne-cm

The seismic moment of 2.51×10^{26} dyne-cm is consistent with a moment magnitude of 6.9 based on the moment-magnitude relationship of Hanks and Kanamori (1979).

The following distances from the PALCO and recording sites to the rupture plane of the Petrolia earthquake were calculated from the above rupture model and the epicentral coordinates determined by Oppenheimer and others:

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
PALCO Plant	19.8	33	7.3	13.3
CSMIP #89324	21.9	30	7.9	13.6

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

2.3 Local Site Conditions

Shakal and others (1992) describe the recording site as being underlain by 15 meters of alluvium. Heuze and Swift (1991) estimate the shear-wave velocity of the soil beneath the recording site to a depth of about 10 meters to be approximately 200 m/s. There is no similar geotechnical data available for the PALCO Plant. However, a 1:62,500 scale geologic map of the area (Ogle, 1953) indicates that both sites are located on relatively thin, young (Holocene) stream terrace deposits within the Eel River Valley. The terrace deposits are composed of gravel, sand, silt, and clay, with gravel predominating. The Upper Pliocene Rio Dell Formation underlies the terrace deposits to a depth of several kilometers. Massive mudstone, alternating thin sandstone and mudstone, phantom-banded mudstone, and very fine-grained sandstone are the principal lithologic units of the Rio Dell Formation.

Based on the above information, both sites can be classified as Soil Profile Type S_D (Stiff Soil Profile) based on the site classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 180 and 360 m/s. Based on the above information, it can be concluded that both the Plant and recording sites have similar soil-amplification characteristics.

2.4 Recommended Response Spectra

Based on the proximity of the PALCO Plant to the Rio Dell recording (2.3 kilometers), the similar distance from both sites to the rupture plane of the Petrolia earthquake (13.3 and 13.6 kilometers), the similar epicentral azimuths of the two sites (30° and 33°), and the similar soil-amplification characteristics at both sites, it is believed that the Rio Dell recording can be used as a credible estimate of the ground motion at the PALCO Cogeneration Plant.

The recommended 5%-damped acceleration response spectrum is shown in Figure 2-2. This response spectrum is identical to that recommended by Boore (1997) for the same site.

3. Great Western Financial Data Center (Scenario 3)

The Great Western Financial Data Center is located in the city of Northridge in the San Fernando Valley, Los Angeles County, California. It is located directly over the rupture plane of the January 17, 1994 moment magnitude (M_w) 6.7 Northridge earthquake.

The Northridge earthquake caused widespread damage throughout the Los Angeles region (Dewey and others, 1995). It was assigned a maximum intensity of IX on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI IX were observed in Sherman Oaks, Northridge, Granada Hills, along the I-5 corridor just east of the Santa Susana Mountains, and in two neighborhoods of several blocks each in Santa Monica and west-central Los Angeles. Shaking effects consistent with MMI VIII were observed at many locations over a broad area of the San Fernando Valley, and also in parts of Santa Clarita Valley, Simi Valley, Santa Monica, west-central Los Angeles, Fillmore, the University of Southern California/County Hospital complex in Los Angeles, and in a 3-kilometer long, several blocks wide, area of Hollywood along Hollywood Boulevard.

3.1 Strong-Motion Recordings

A single strong-motion recording was obtained on the roof of the Financial Data Center. There was no ground-level recording at the Data Center. There were, however, eleven ground-level recordings within 10 kilometers of the Center. The closest three recordings are on Roscoe Boulevard in Northridge. (LA Code #C130, 2.8 kilometers), Topanga Canyon Boulevard in Canoga Park (USC #53, 5.1 kilometers), and Saticoy Street in Northridge (USC #3, 5.5 kilometers). All three recordings are located close enough to the Financial Data Center to have experienced the same level of ground shaking and earthquake source effects.

The other eight recordings that were located within 10 kilometers of the Data Center are not considered to be representative of the ground shaking at the Center for the following reasons. They were either too far from the Center (i.e., greater than 8 kilometers), they were founded on significantly different geological deposits, or they experienced significant source directivity effects. These latter effects were particularly important for recordings located northeast of the Data Center in the direction of rupture propagation (see the discussion on source characteristics below).

Darragh and others (1995) and Trifunac and others (1994) give a detailed description of the three selected recordings. A summary of this information is provided in the following table.

Parameter	LA Code #130	USC #53	USC #3
Structure	7-story bldg.	1-story bldg.	2-story bldg.
Location	Ground level	Ground level	Ground level
Latitude	34.217°N	34.212°N	34.209°N
Longitude	118.553°W	118.606°W	118.517°W
PGA (g)	0.42 (North) 0.41 (West) 0.35 (Up)	0.39 (S16W) 0.35 (S74E) 0.42 (Up)	0.45 (South) 0.33 (East) 0.80 (Up)

The two horizontal components of the 5%-damped acceleration response spectra of the three selected recordings are shown in Figures 3-1 to 3-3.

3.2 Earthquake Parameters

Scientists of the U.S. Geological Survey and the Southern California Earthquake Center (1996) report the following seismological parameters for the Northridge earthquake:

Date: January 17, 1994

Time: 12:30 Greenwich Mean Time (GMT)

Magnitude: 6.7 M_w

Epicenter: 34.209°N, 118.541°W

Depth: 19 km

Strike: 280° to 290° (northwest)

Dip: 35° to 45° to the southwest

Mechanism: Thrust

Similar source parameters were obtained by many other seismologists (e.g., *Bulletin of the Seismological Society of America*, 1996). According to these studies, the rupture initiated at the hypocenter in the southeast corner of the rupture plane and propagated up-dip to the north and northeast where the largest subevent occurred.

Using strong-motion, teleseismic, GPS, and leveling data, Wald and others (1996) determined the following rupture model for the earthquake:

Width (down-dip):	21 km
Length:	14 km
Depth to Top:	6 km
Strike:	122° (southeast)
Dip:	40° to the southwest)
Average Rake:	101° (thrust)
Average Slip:	1.3 m
Seismic moment:	$1.3 \pm 0.2 \times 10^{26}$ dyne-cm (6.7 M_w)
Avg. Stress Drop	74 bars

The seismic moment of 1.3×10^{26} dyne-cm is consistent with a moment magnitude of 6.7 based on the moment-magnitude relationship of Hanks and Kanamori (1979).

The following distances from the recording and Data Center sites to the rupture plane of the Northridge earthquake were calculated from the above rupture model and the epicentral coordinates determined by Scientists of the U.S. Geological Survey and the Southern California Earthquake Center (1996):

Site	Epicentral Distance (km)	Azimuth (°)	Surface Distance (km)	Rupture Distance (km)
Data Center	4.1	330	0.0	12.6
LA Code #C130	1.4	309	0.0	13.8
USC #53	6.0	273	1.4	15.8
USC #3	2.2	90	0.0	13.2

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Surface Distance is the shortest distance between the site and the surface projection of this rupture plane, and Azimuth is the angle between the epicenter and the site measured clockwise from north.

3.3 Local Site Conditions

There are no reliable site-specific geotechnical data available for the Financial Data Center or the three recording sites. However, a geologic map of the area (Yerkes and Campbell, 1993) indicates that the Data Center and the USC #53 site are located on Holocene alluvium up to 30-meters thick and that the LA Code #C130 and USC #3 sites are located on Late Holocene alluvium up to 3-meters thick overlain by Holocene alluvium. Since it is likely that the buildings that house the accelerographs have foundations that are at least a few meters deep, any remaining Late Holocene deposits, if present at all, are too thin to have affected the recorded ground motions at frequencies less than about 25 hertz (Hz). Underlying the Holocene alluvium is a sequence of Quaternary, Tertiary, and Cretaceous sediments at least 1 to 2 kilometers thick.

Shear-wave velocity measurements were conducted at the USC recording stations using the CXW method. This method uses surface-wave dispersion to infer the shear-wave velocity profile beneath the site. However, Boore and Brown (1998) and Wills (1998) have shown that the CXW method can lead to estimates of shear-wave velocity that are significantly different from those obtained using more traditional down-hole and cross-hole techniques. Based on this conclusion, the CXW-based measurements were not used.

Instead of relying on direct shear-wave velocity measurements, the average shear-wave velocity in the top 30 meters of the Holocene alluvium that underlies the Data Center and the three recording sites was estimated from the shear-wave velocity characteristics determined for different geologic units in California by Wills and Silva (1998). According to this assessment, all four sites can be classified as Soil Profile Type S_D (Stiff Soil Profile) based on the soil classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). This Soil Profile Type has a shear-wave velocity in the top 30 meters that ranges between 180 and 360 m/s. Based on the above information, it can be concluded that the Data Center and the three recording sites have similar soil-amplification characteristics. The similarity in both the amplitude and shape of the response spectra from the three nearby recordings lends further empirical justification to this conclusion.

3.4 Recommended Response Spectrum

All of the recordings are located on the ground floor of 1-story to 7-story buildings. As a result, they are likely to be somewhat deficient in high-frequency ground motions due to wave-scattering and wave-passage effects. Further justification for these kinematic soil-structure interaction (SSI) effects can be found by comparing the response spectrum for the LA Code #C130 recording, which was obtained in a 7-story building, with the two USC recordings, which were obtained in smaller 1-story and 2-story buildings (Figure 3-4). The LA Code #C130 spectrum is found to be lower than the two USC spectra between frequencies of about 4 and 13 Hz. As a result, the selected recordings, and especially the LA Code #C130 recording, are considered to be a conservative (i.e., lower) estimate of the high-frequency amplitude of the free-field spectra at each of these sites.

The three selected recordings are all located southeast and southwest of the Financial Data Center. A contour map of the 0.24-second spectral velocity developed by the SAC Joint Venture Partnership (1995) suggests that short-period spectral amplitudes from the Northridge earthquake increased from south to north across the San Fernando Valley. This suggests that the actual ground motion at the Data Center is likely to have been somewhat higher than indicated by these recordings.

Based on the proximity of the Financial Data Center to the three selected recordings (2.8 to 5.5 kilometers), the similar distance from each of the sites to the rupture plane of the Northridge earthquake (12.6 to 15.8 kilometers), the similar location of all of the sites with respect to the rupture plane of the earthquake, the similar amplitude and spectral shapes of the three recorded response spectra (Figure 3-4), and the similar soil-amplification characteristics at each of the sites, it can be concluded that the average of the LA Code #C130, USC #3, and USC #53 response spectra can be used as a credible, although somewhat conservative (i.e., lower), estimate of the ground motion at the Great Western Financial Data Center. The recommended 5%-damped acceleration response spectrum is shown in Figure 3-5.

Boore (1997) used three entirely different recordings to estimate a response spectrum at the Financial Data Center from the Northridge earthquake. The recordings he used were from the 7-story Hotel in Van Nuys (CSMIP #24386), the Sepulveda VA Hospital in Los Angeles (USGS #637), and the Rinaldi Receiving Station in Mission Hills (LADWP SMA-1 #5968). The latter two recordings were located northeast of the Data Center in the direction of rupture propagation. As a result, the ground motion at these two sites were likely to be larger than those located closer to the Center. For example, the horizontal peak accelerations at the Sepulveda VA Hospital were 0.94*g* and 0.74*g* and those at Rinaldi Receiving Station were 0.84*g* and 0.49*g*, significantly higher than those recorded at the three sites selected in this study.

The SAC Joint Venture Partnership (1995) also estimated ground motions from the Northridge earthquake for a site very close to the Great Western Financial Data Center (their Site 4). A comparison of the recommended response spectrum in Figure 3-4 with that estimated by the SAC Joint Venture Partnership (1995) indicates that the SAC spectrum is higher, especially at high frequencies, than that recommended in this study. For example, SAC calculated peak accelerations of 0.71*g* (North) and 0.49*g* (South) for Site 4; whereas, a mean horizontal acceleration of 0.39*g* was estimated in the current study.

4. Guam Power Generating Facilities (Scenario 4)

The Guam Power Generating facilities are located on the Island of Guam, the largest and southernmost of the Marianas Island chain in the South Pacific. The island is approximately 48 kilometers long and between 6 and 19 kilometers wide. Guam is volcanic in origin. The southern end of the island is mountainous with altitudes ranging from 210 to 400 meters. The northern part of the island consists of a series of coral limestone terraces that are relatively flat and that range from about 60 to 180 meters in height.

The Guam power generating facilities consist of the Piti Power Plant and the Cabras Generating Station in the Apra Harbor area, and the Tanguisson, Yigo, and Dededo Generating Stations on the northern part of the island. According to the Earthquake Engineering Research Institute (1995), all of these facilities sustained some damage during the August 8, 1993 moment-magnitude (M_w) 7.7 Guam earthquake. The Apra Harbor facilities had the greatest amount of damage because of their location in an area of widespread ground-failure effects.

The power generating facilities are located several tens of kilometers northwest of the rupture plane of the Guam earthquake. According to the U.S. Geological Survey (1993) and the Earthquake Engineering Research Institute (1995), the earthquake caused extensive damage to hotels in the Tumon Bay area. Many structures in the Apra Harbor area were seriously damaged due to liquefaction and related ground failure. Minor damage was widespread on the island. A relatively small tsunami was generated and was noted at several locations in the South Pacific, including Japan and Hawaii, with no reported damage. The earthquake was assigned a maximum intensity of IX on the Modified Mercalli Intensity (MMI) scale. Shaking effects consistent with MMI VII were observed at several locations on the northern part of the island (U.S. Geological Survey, 1993).

4.1 Strong-Motion Recordings

The United States Navy maintained three strong-motion instruments on Guam at the time of the earthquake, but no records were recovered from these instruments because of malfunctions. However, the Earthquake Engineering Research Institute (1995) gives a qualitative estimate of the level of shaking on the island from an evaluation of liquefaction effects and damage to concrete bus stops. This evidence supports the conclusion that effective ground accelerations on the island probably ranged from about 0.15*g* to 0.25*g*.

4.2 Earthquake Parameters

The U.S. Geological Survey (1993) reports the following seismological parameters for the Guam earthquake:

Date:	August 8, 1993
Time:	08:24:25 Greenwich Mean Time (GMT)
Magnitude:	7.1 m_b, 8.0 M_s
Epicenter:	12.982°N, 144.801°E
Depth:	59 km
Strike:	255° (southwest)
Dip:	20° to the northwest
Rake:	90° (thrust)

From a complete study of P and SH body waves, Campos and others (1996) relocated the aftershocks and the subevents of the mainshock and proposed a relatively simple model for the rupture process of the event. Based on this analysis, they concluded that the earthquake ruptured a shallow-dipping thrust fault that corresponds to the subduction interface of the Pacific and Philippine Sea plates. Campos and others best single point-source model for the earthquake based on the inversion of teleseismically observed body waves is as follows:

Seismic Moment:	4.5×10^{27} dyne-cm
Centroid Depth:	41.5 km
Strike:	241.67° (southwest)
Dip:	13.77° to the northwest
Rake:	84.91° (predominantly thrust)

The moment magnitude (M_w) given by this inversion is 7.7 according to the moment-magnitude relationship of Hanks and Kanamori (1979). The fault plane solutions reported by Dziewonski and others (1994), the U.S. Geological Survey (1993), and the California Institute of Technology (Caltech) are all quite different from each other and from the solution given above. Campos and others show that their solution is statistically superior to these other solutions because they used better-constrained body-wave data.

Distances from the power generating facilities to the rupture plane of the earthquake were computed from the rupture model derived by Campos and others (1996). This rupture model indicates that the earthquake started with a small foreshock located at the hypocenter. This foreshock was about 8.6 seconds in duration and had a low rate of moment release. Then the first major subevent occurred about 30 kilometers to the northeast of the epicenter at a depth of around 46 kilometers. This was followed by a second major subevent about 12 seconds later that was located 48 kilometers to the northeast of the first subevent. The entire source-rupture process was finished in less than 32 seconds. This model indicates that 42% of the moment release occurred during the first subevent and 57% occurred during the second subevent. Campos and others give the following parameters for this rupture model:

Width (down-dip):	50 km
Length:	100 km
Centroid Depth:	46 km (first subevent); 37 km (second subevent)
Strike:	240° (southwest)
Dip:	12.5° to the northwest
Rake:	89° (thrust)
Average Slip:	2.53 m (first subevent); 3.47 m (second subevent)
Seismic Moment:	4.5×10^{27} dyne-cm
Stress Drop:	118 bars

Campos and others show that the above rupture model is consistent with the distribution of aftershocks and provides a very good fit to the coseismic displacements estimated at various locations on Guam from GPS surveys conducted before and after the earthquake by Beavan and others (1994). Campos and others also found that this rupture model was generally consistent with, but provided a better fit to the GPS displacements, than rupture models proposed by Abe (1994) and Tanioka and others (1995), which were based on an inversion of Tsunami waveforms from Japanese tidal gauge stations.

The following distances from the Tanguisson, Yigo, and Dededo facilities to the rupture plane of the Guam earthquake were calculated from the above rupture model and the epicentral coordinates determined by the U.S. Geological Survey (1993):

Site	Epicentral Distance (km)	Azimuth (°)	Energy Center Distance (km)	Rupture Distance (km)
Tanguisson	60.8	0.4	68.5	66.0
Yigo	65.1	8.9	67.3	64.1
Dededo	59.5	3.8	66.1	63.7

In this table, Rupture Distance is the shortest distance between the site and the seismogenic part of the rupture plane of the earthquake, Energy Center Distance is the distance from the site to the energy center of the rupture as defined by Crouse (1991), and Azimuth is the angle between the epicenter and the site measured clockwise from north.

Consistent with the definition of the energy center given by Crouse (1991), the location of this center was placed at the location of the moment centroid of the first, closest subevent. However, rather than use the independently estimated depth of this centroid, the more conservative estimate of 42.4 kilometers, which represents the projection of the subevent onto the modeled rupture plane, was preferred. Distances for the Piti and Cabras facilities were excluded from this analysis for the reasons specified below.

4.3 Local Site Conditions

The Earthquake Engineering Research Institute (1995) describes the Piti and Cabras facilities as being underlain by soft soils. The Piti facility is described as being located on loose coral fill underlain by lagoonal and estuarine deposits. The Cabras facility is reported to be founded on loose coral fill over a coral reef. The presence of soft soils and the occurrence of ground failure at the Piti and Cabras Plants indicate that they should be classified as Soil Profile Type S_F (Soft Soil Profile requiring special investigations) based on the soil classifications given in the 1997 *Uniform Building Code* (UBC) (ICBO, 1997). Sites in this soil category require site-specific investigations to determine their dynamic soil-response characteristics. As a result, it is not possible to reliably estimate the ground motion at these facilities without performing a dynamic site-response analysis using site-specific geotechnical information.

There are no reliable site-specific geotechnical information for the Tanguisson, Yigo, and Dededo facilities. Instead, the local site conditions at these facilities were determined from a 1:50,000-scale geology map of Guam (Tracey and others, 1964). According to this map, the Tanguisson facility is underlain by reef facies of the Pliocene and Pleistocene Mariana Limestone. This unit is a massive, generally compact, porous and cavernous white limestone of reef origin. The Yigo site is underlain by detrital facies of the Mariana Limestone. This unit is a friable to well-cemented, coarse-to-fine grained, generally porous and cavernous white detrital limestone, mostly of lagoonal origin. The Dededo facility is underlain by the Miocene and Pliocene Barrigada Limestone. This unit is a massive, well-lithified to friable medium-to-coarse grained white foraminiferal limestone.

As reported by Dames & Moore (1994), various geophysical investigations have been performed to investigate the physical nature and configuration of the volcanic rocks and limestone on the island. Of particular interest are seismic refraction surveys and gravity surveys performed in 1982 by the Guam Environmental Protection Agency. The results of these studies indicate that the seismic velocities in the upper part of the limestone are relatively low. The surface layer of limestone, between 30 and 38 meters thick, has an average compressional-wave velocity of 945 m/s. According to Dames & Moore, this corresponds to an estimated shear-wave velocity of 460 m/s. Below the upper layer of limestone is a second limestone layer with an average compressional-wave velocity of 2,040 m/s and an estimated shear-wave velocity of 915 m/s. The volcanic basement beneath the second limestone layer has an average compressional-wave velocity of about 2,835 m/s.

The shear-wave velocity in the upper limestone layer is within the lower part of the range of shear-wave velocities (360 to 760 m/s) that are used to define Soil Profile Type S_C (Very Dense Soil and Soft Rock) in the 1997 UBC. However, considering that the shear-wave velocities reported by Dames & Moore (1994) represent an average of many measurements, it is possible that some of these sites had shear-wave velocities that fell within the upper part of the range of shear-wave velocities (180 to 360 m/s) that are used to define Soil Profile Type S_D (Stiff Soil Profile). Because of this uncertainty, it can be concluded that the Tanguisson, Yigo, and Dededo sites can be classified as either Soil Profile Types S_D or S_C.

4.4 Recommended Response Spectrum

Because of the lack of strong-motion recordings on the island, it was decided to develop a quantitative estimate of ground shaking at the Guam power generating facilities using a selected set of empirical attenuation relationships developed from worldwide strong-motion recordings of subduction earthquakes. These attenuation relationships were developed by Kawashima and others (1984, 1986), Annaka and Nozawa (1988), Crouse (1991), Dames & Moore (1994), Molas and Yamazaki (1995, 1996), and Youngs and others (1997). Each of these attenuation relationships requires a set of specific earthquake parameters in order to use them correctly. Magnitude measures include moment magnitude M_w and Japan Meteorological Agency (JMA) magnitude M_J. Distance measures include epicentral distance, closest distance to the rupture plane, and distance to the energy center of the earthquake. Also required for some relationships are the focal depth, the depth to the closest part of the fault rupture, and the type of subduction event (interplate versus intraslab).

The earthquake parameters used to estimate the ground motions from each of the attenuation relationships are given in the following table.

Parameter	Crouse	Youngs et al.	Kawashima et al.	Annaka & Nozawa	Molas & Yamazaki
Magnitude Measure	7.7 M_w	7.7 M_w	7.6 M_j	7.6 M_j	7.6 M_j
Distance Measure	Distance to Energy Center	Closest Distance to Rupture	Epicentral Distance	Closest Distance to Rupture	Closest Distance to Rupture
Focal Depth (km)	41.5	41.5	—	41.5	41.5
Source Type	—	Interface ($Z_T = 0$)	—	—	—
Component	Average Horizontal	Average Horizontal	Resultant Horizontal	Average Horizontal	Largest Horizontal
Site Conditions	Firm Soil & Rock	Soil & Rock	Firm Soil & Rock	V_s = 300 to 600 m/s	Hard Soil & Rock

In the above table, the value of M_w was estimated from the seismic moment of 4.5×10^{27} dyne-cm determined by Campos and others (1996) using the moment-magnitude relationship of Hanks and Kanamori (1979). The value of M_j was estimated from the average of the estimates calculated from the seismic moment versus M_j relationships published by Sato (1979) and Satoh and others (1997) using this same estimate of seismic moment. An estimate of the average horizontal component of ground motion was calculated from the amplitude of the resultant horizontal component and the largest horizontal component by applying the frequency-dependent ratios developed by Ansary and others (1995).

So as not to give undue influence to the attenuation relationships that are based solely on Japanese strong-motion recordings, the three Japanese relationships were given the same total weight as the other attenuation relationships in the calculation of the weighted average ground motion.

The estimated average horizontal value of PGA calculated from each of the five attenuation relationships for each generic site condition, along with the weighted average from the five relationships, is summarized in the following table.

Note that the range of weighted average PGA estimates (0.130*g* to 0.193*g*) is generally consistent with the range of effective accelerations estimated by the Earthquake Engineering Research Institute (1995) from an evaluation of liquefaction effects and damage to bus stops (0.15*g* to 0.25*g*).

Figures 4-1 and 4-2 show the estimated 5%-damped acceleration response spectra for the Tanguisson facility. Inspection of these figures shows that the estimated spectral accelerations on rock are lower than those on firm soil at all frequencies. Because of the uncertainty in the classification of the sites into one of the 1997 UBC Soil Profile Types,

Facility	Kawashima et al. (1/9 wgt.)	Annaka & Nozawa (1/9 wgt.)	Crouse; Dames & Moore (1/3 wgt.)	Molas & Yamazaki (1/9 wgt.)	Youngs et al. (1/3 wgt.)	Weighted Average
Tanguisson						
Rock	0.151	0.165	0.127	0.090	0.130	0.130
Firm Soil	0.195	0.165	0.216	0.095	0.208	0.187
Yigo						
Rock	0.143	0.171	0.129	0.093	0.134	0.131
Firm Soil	0.184	0.171	0.219	0.099	0.213	0.190
Dededo						
Rock	0.154	0.173	0.130	0.094	0.135	0.133
Firm Soil	0.198	0.173	0.222	0.100	0.214	0.193

the lower estimates for rock, which are consistent with Soil Profile Type S_C, were used to conservatively estimate the expected response spectrum at the three facility sites.

Because of the similarity in the estimated ground motions for the three facility sites, the empirical estimates on rock for the Tanguisson site were used as a credible, although somewhat conservative (i.e., lower), estimate of the ground motion at the Tanguisson, Yigo, and Dededo power generating facilities. The mean, 16th-percentile, and 84th-percentile empirical estimates on rock at the three sites are graphically displayed in Figure 4-3. The recommended (mean) 5%-damped acceleration response spectrum is shown in Figure 4-4. There is insufficient geotechnical information to develop recommended response spectra for the Piti and Cabras facilities.

CONCLUSION

Acceptable procedures for deriving free field response spectra for database sites for use in calculating an Earthquake Experience Spectrum (EES) for a class of equipment have been presented. Four examples have also been presented illustrating the application of the procedures for each of four scenarios. It is seen that the uncertainty in the derivation of the site response spectrum increases from Scenario 1 to Scenario 4. The conservatism in the resulting site spectrum (i.e., the likelihood that the derived spectrum underestimates the actual ground motion experienced at the site) also increases from Scenario 1 to Scenario 4 in order to account for the increasing uncertainty.

ACKNOWLEGMENT

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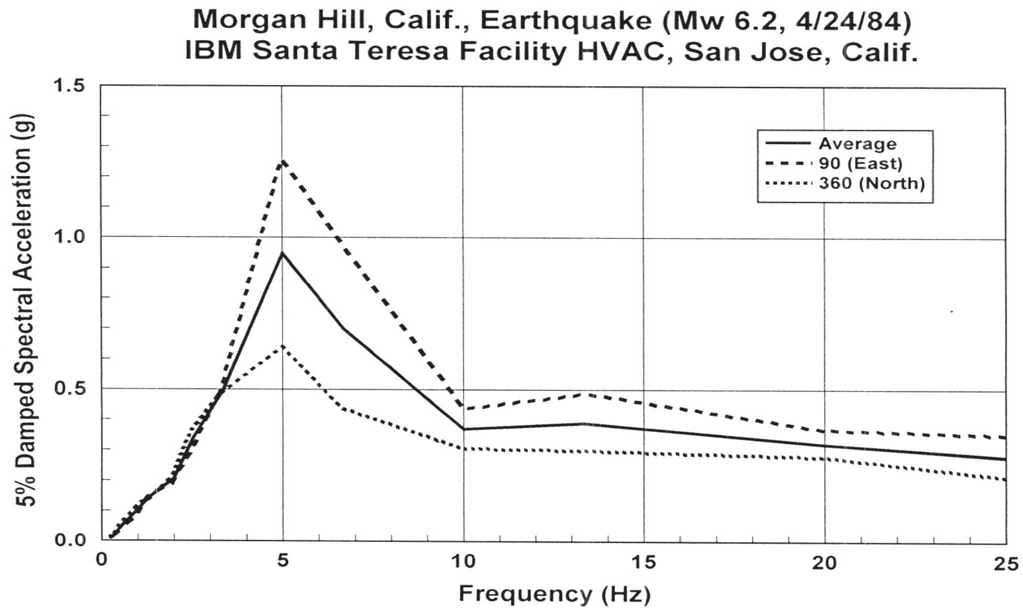

Figure 1-1. 5%-damped recorded response spectra for two horizontal components.

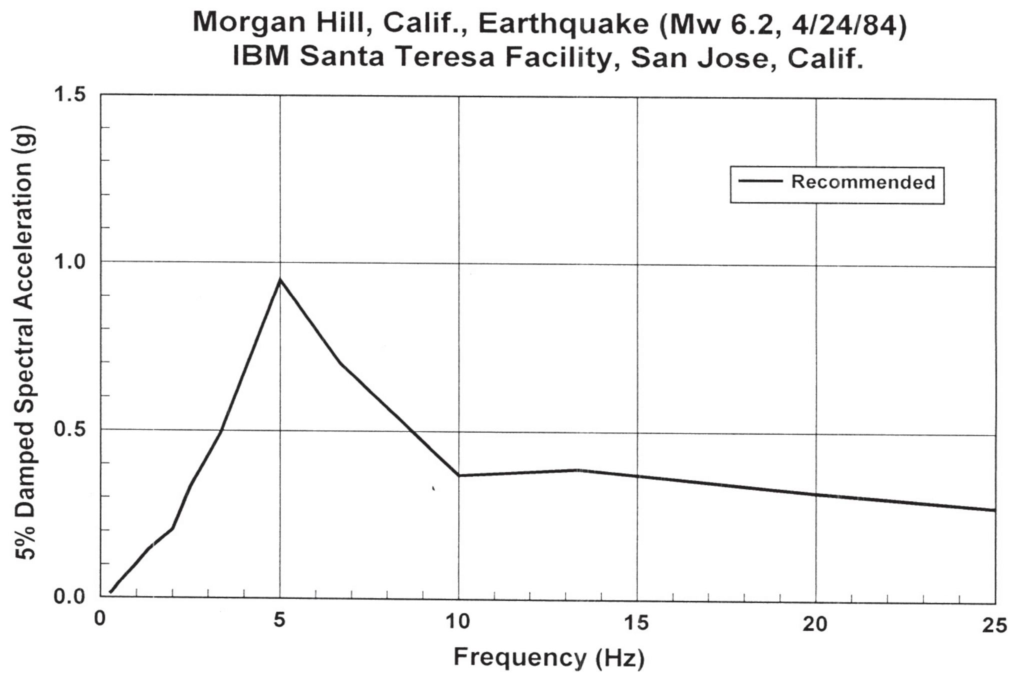

Figure 1-2. Recommended 5%-damped acceleration response spectrum.

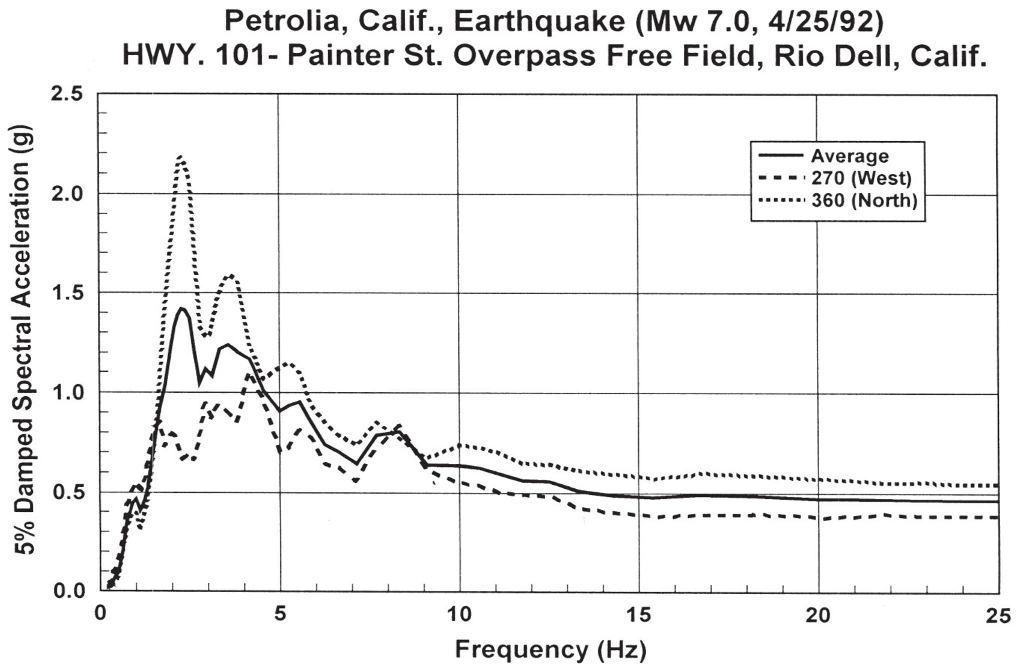

Figure 2-1. 5%-damped recorded response spectra for the two horizontal components.

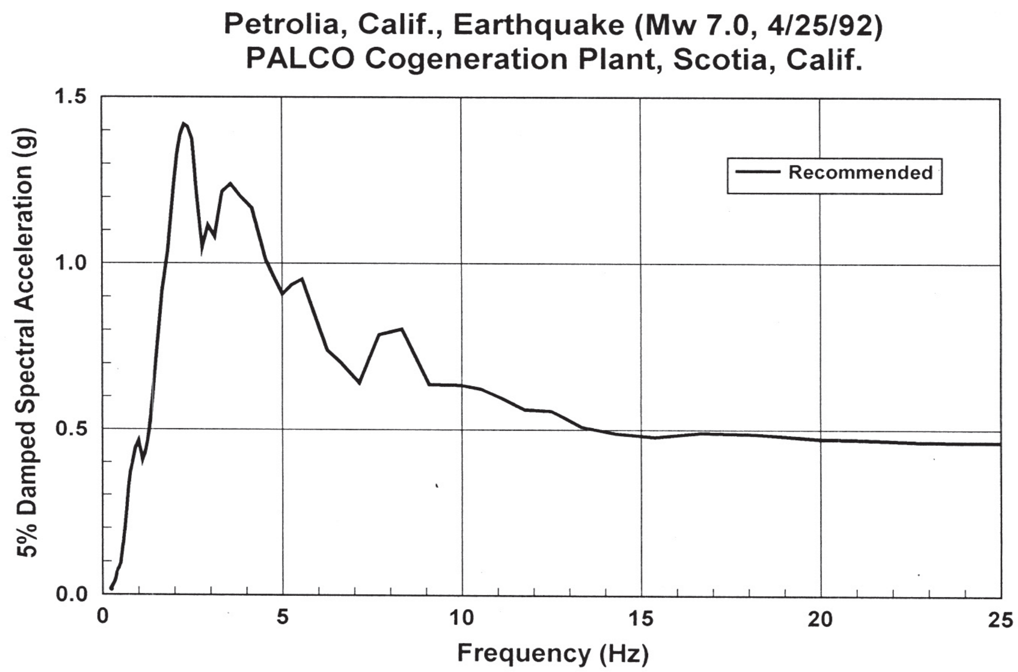

Figure 2-2. Recommended 5%-damped acceleration response spectrum.

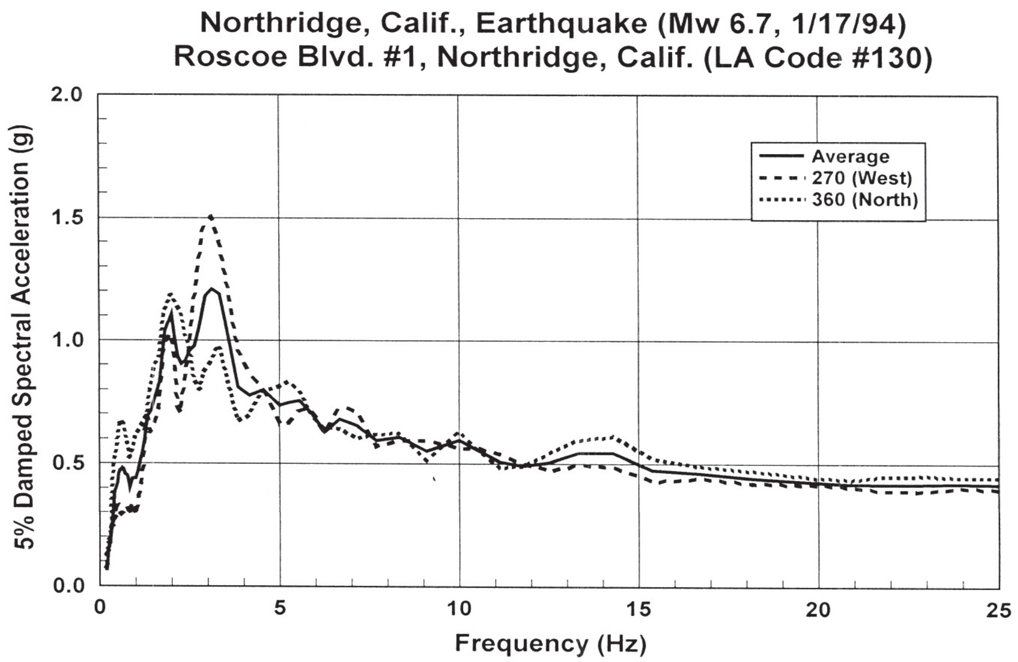

Figure 3-1. 5%-damped recorded response spectra for the two horizontal components.

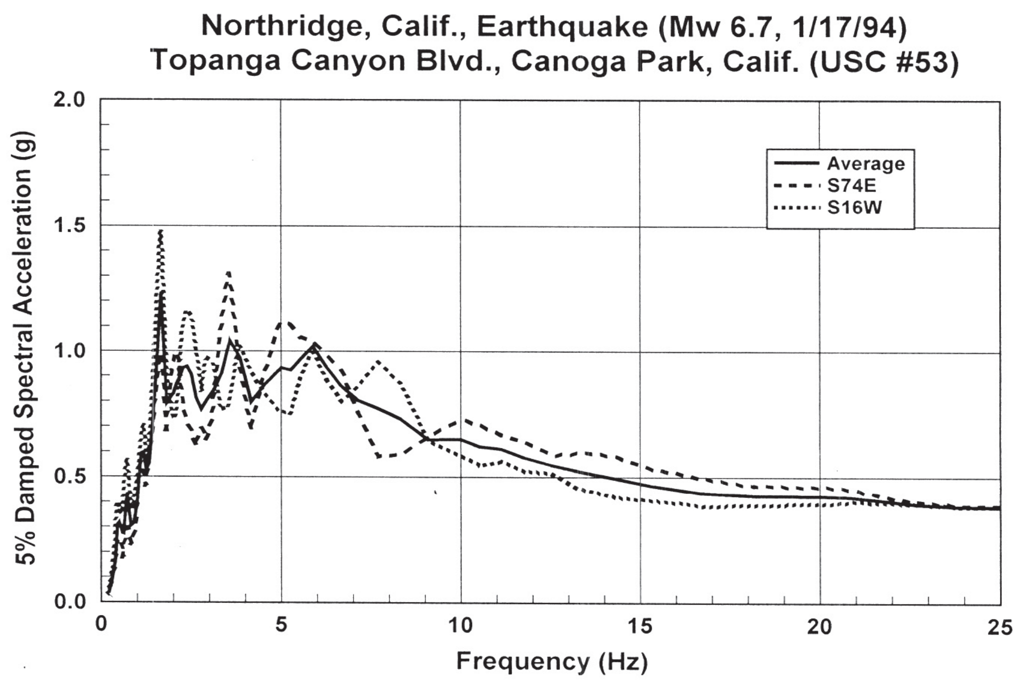

Figure 3-2. 5%-damped recorded response spectra for the two horizontal components.

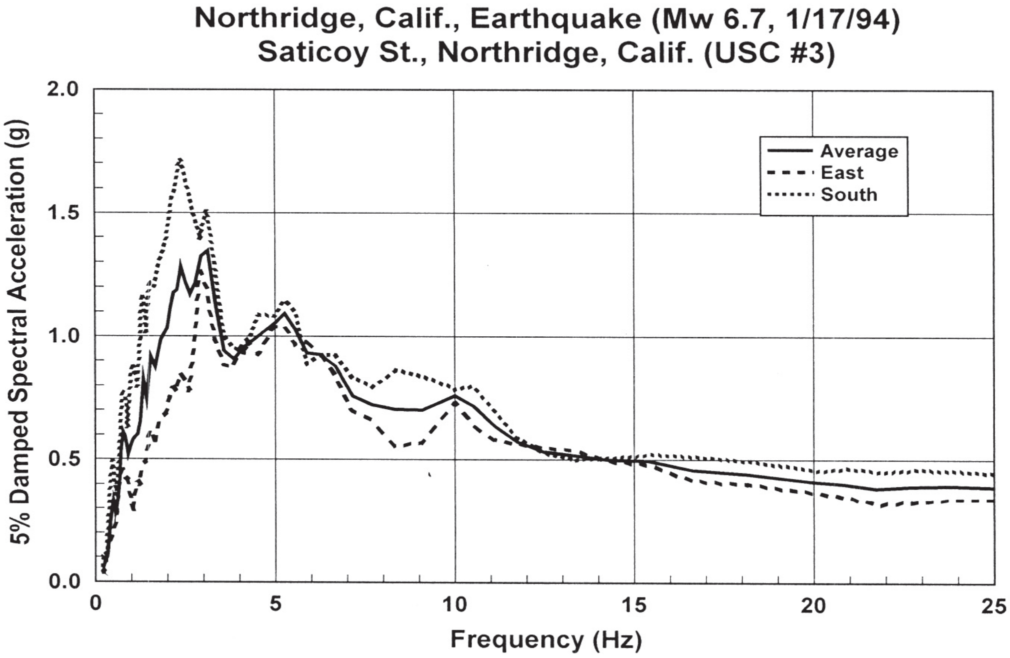

Figure 3-3. 5%-damped recorded response spectra for the two horizontal components.

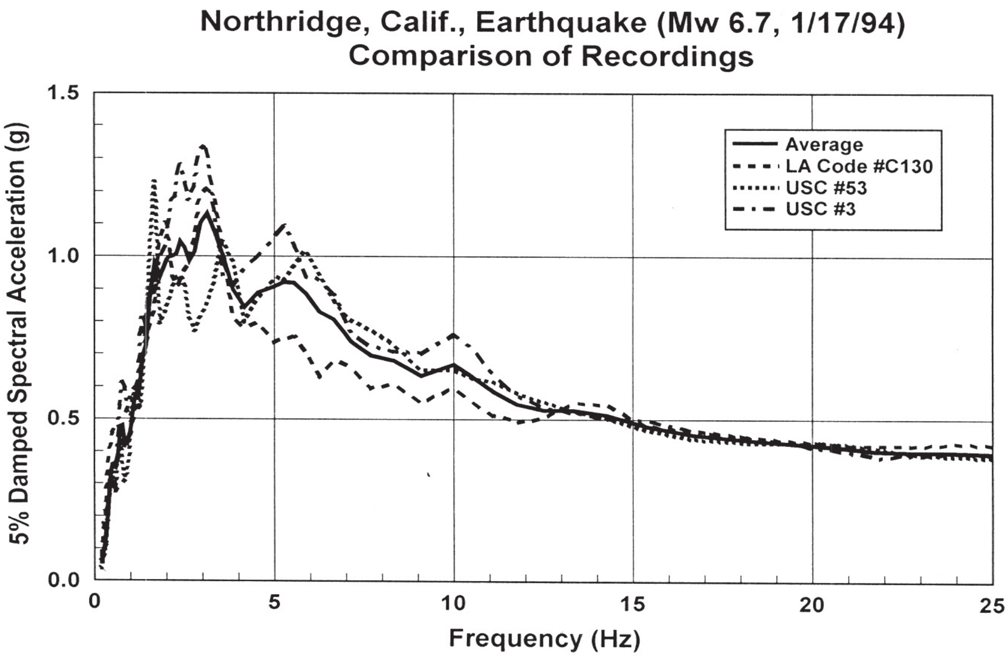

Figure 3-4. Comparison of the response spectrum for the LA Code #C130 recording, obtained in a 7-story building, with the two USC recordings, obtained in smaller 1-story and 2-story buildings.

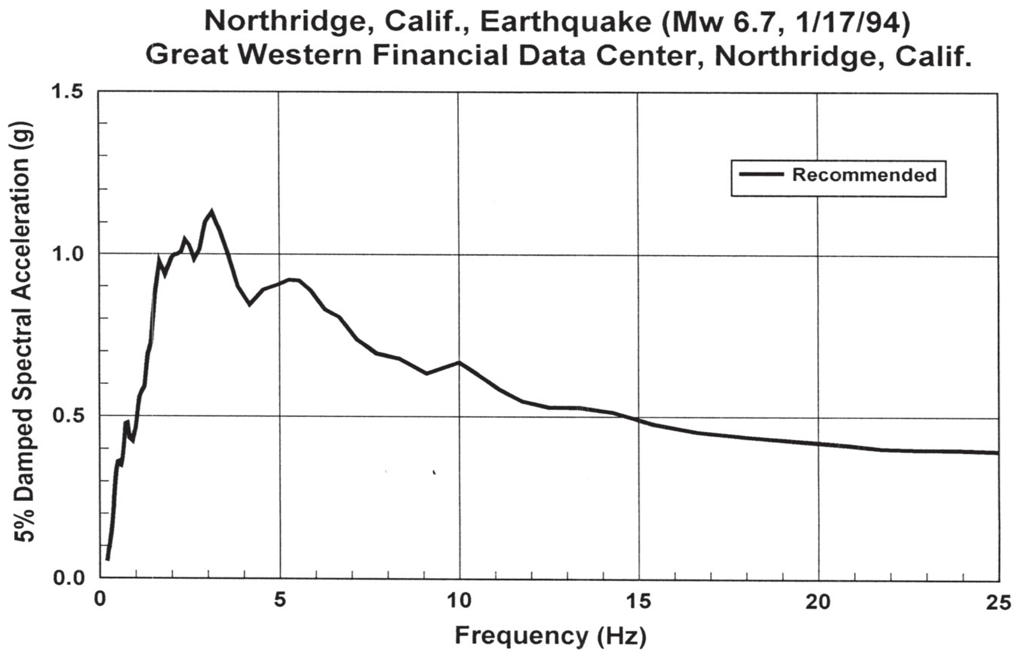

Figure 3-5. Recommended 5%-damped acceleration response spectrum.

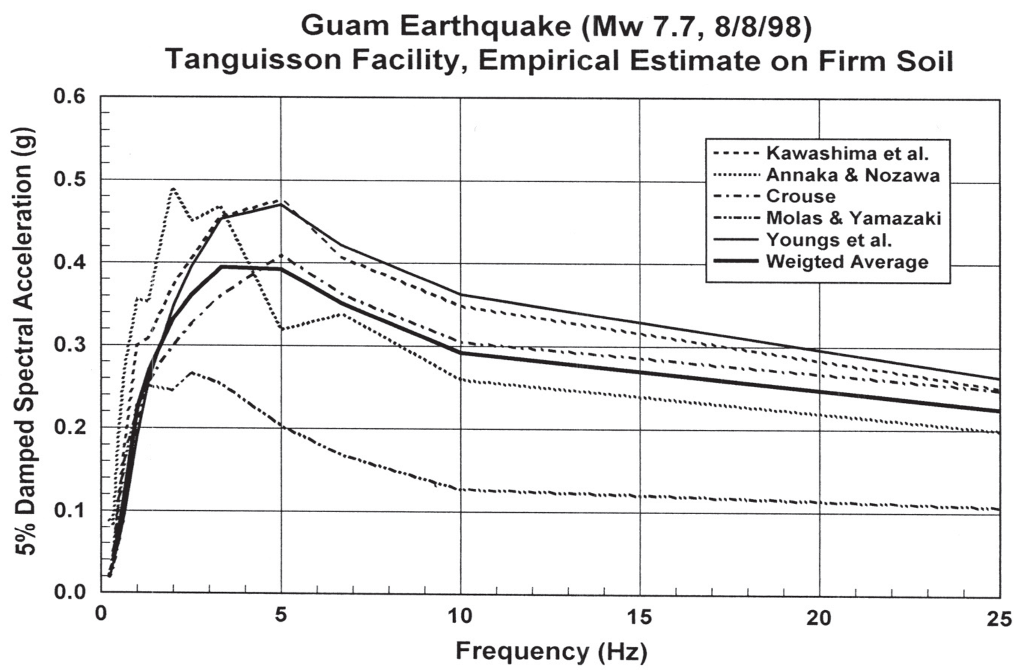

Figure 4-1. Estimated 5%-damped acceleration response spectra for the Tanguisson facility.

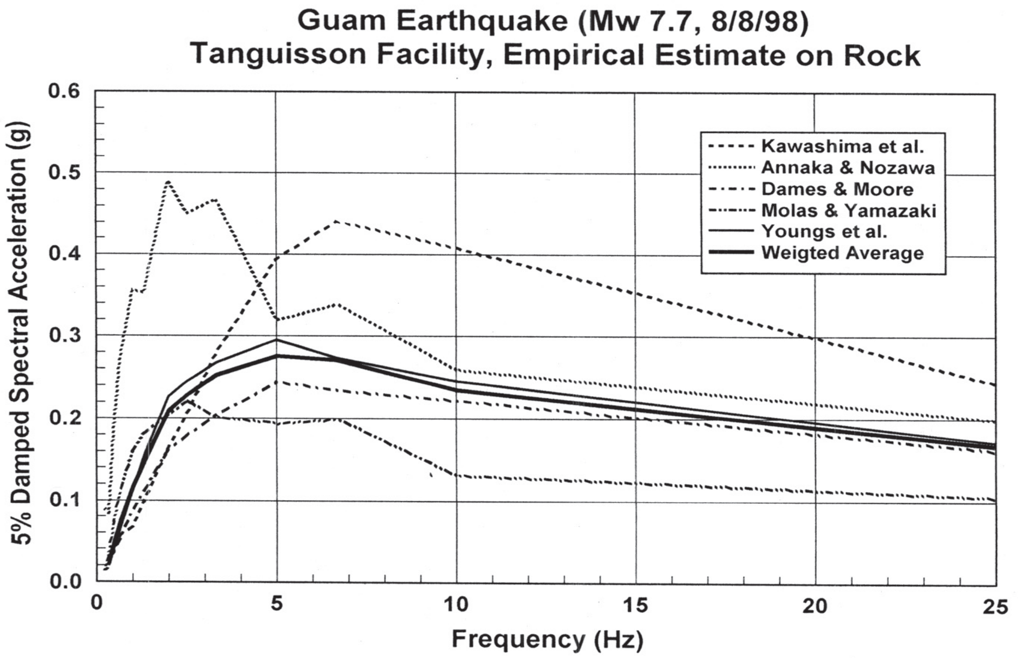

Figure 4-2. Estimated 5%-damped acceleration response spectra for the Tanguisson facility.

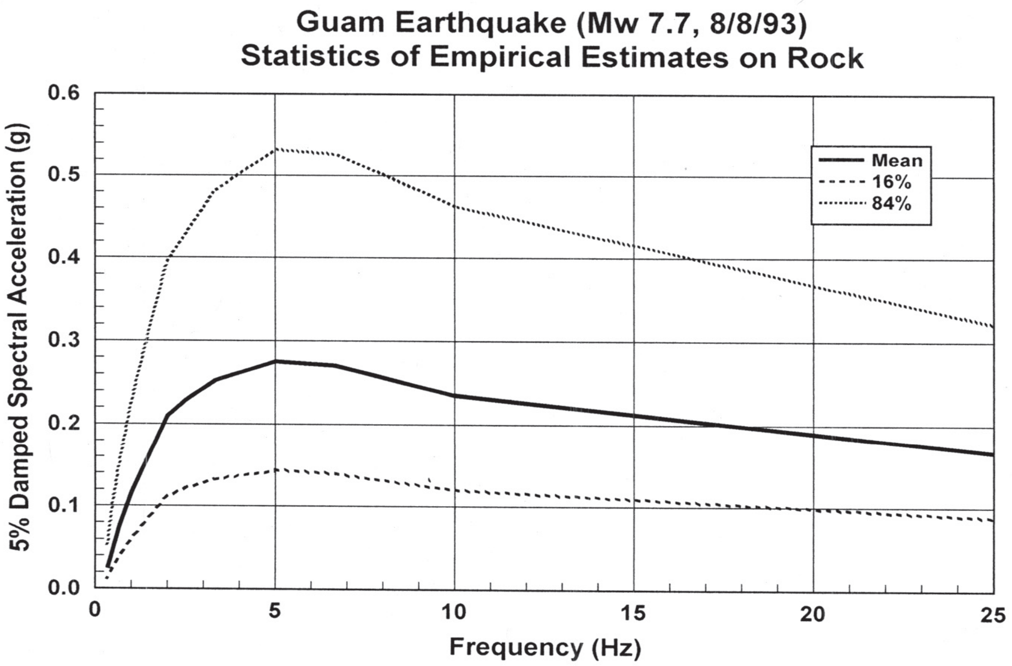

Figure 4-3. Mean, 16th-percentile, and 84th-percentile empirical estimates on rock.

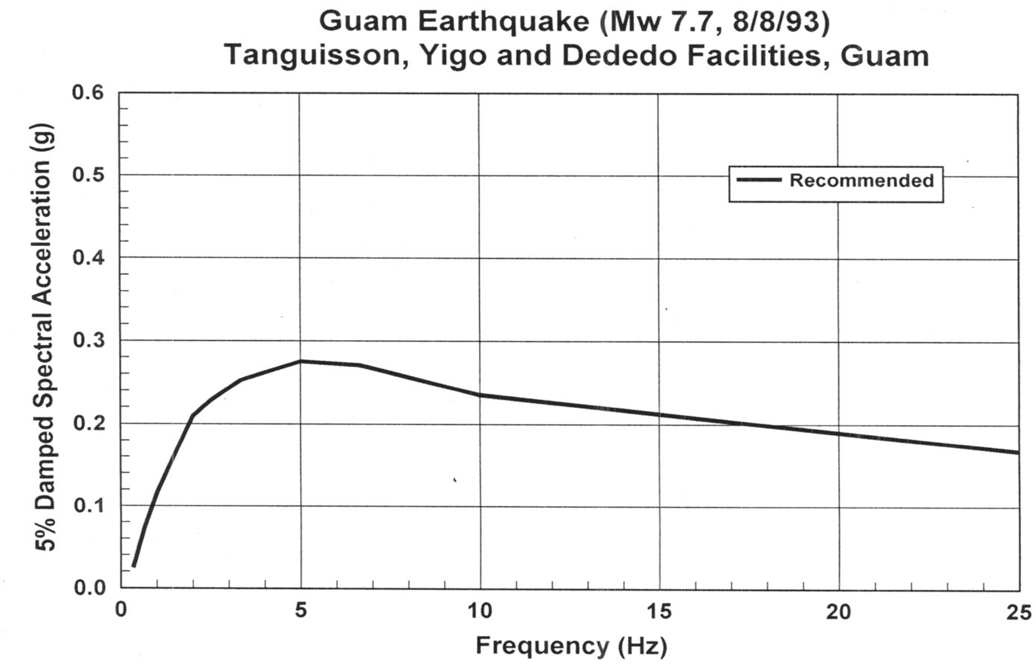

Figure 4-4. Recommended (mean) 5%-damped acceleration response spectrum.

EXPERIENCE BASED SEISMIC EQUIPMENT QUALIFICATION IN THE ASME-QME STANDARD

EQUIPMENT CLASS DATABASE SIZE REQUIREMENTS

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ABSTRACT

In the early 1980s the Seismic Qualification Utility Group (SQUG) was formed to develop a generic methodology to disposition Unresolved Safety Issue (USI) A-46. Working in conjunction with the regulatory authorities and industry, SQUG developed a methodology and procedure to apply earthquake experience data to demonstrate the seismic ruggedness of electrical and mechanical equipment for resolution of USI A-46. In the early 1990s, the ASME and IEEE formed a joint working group to investigate whether earthquake experience based equipment qualification could explicitly be incorporated into ASME QME-1 and IEEE-344. The joint ASME-IEEE working group concluded that experience based rules could be introduced into IEEE-344 and ASME QME-1. In response, the ASME QME Main Committee formed the Subgroup on Dynamic Qualification (SGDQ) to implement the recommendation of the joint ASME-IEEE Special Working Group. The Subgroup recently completed this effort and the QME-1 standard will include a prescriptive methodology to apply actual earthquake experience to the seismic qualification of mechanical equipment. As part of these changes, the QME-1 Standard provides requirements on equipment class database size for estimating seismic capacity based on earthquake experience data. This paper provides the technical basis for the required equipment class sample size and the associated reduction factors required for smaller sample sizes for using earthquake experience data.

Introduction

Section QR-A7422 specifies a minimum of 30 independent items that performed satisfactory to define an equipment class. Also in that section it provides Table QR-A7422-1, "Reduction Factors," for cases where there is less than 30 independent items. Depending on the number of independent items, a reduction factor is selected per the table and then multiplied times the earthquake experience spectrum (EES) of QR-A7412 to produce an EES that has the same statistical confidence level as a reference active mechanical equipment class comprising 30 independent items. The following is the technical basis for the sample sizes and reduction factors for the number of independent items for use in estimating equipment seismic capacity using earthquake experience data.

Sample Size and Reduction Factors

Let the average spectral capacity of a given equipment class, defined as a 5% damped spectral acceleration value averaged over the 3-8 Hz frequency range, be represented by the random variable C. The distribution of C is taken as lognormal with a known (assumed) log-normal standard deviation, β_c, but an *unknown* lognormal mean, $\ln(\underline{C})$, where $\underline{C}$ represents the median capacity.

Let the average spectral demand that the equipment class has been subjected to, defined as a 5% damped *free-field* spectral acceleration value averaged over the 2.5-8 Hz frequency range, be represented by the random variable D.
The distribution of D is taken as log-normal with a known (assumed) log-normal standard deviation, β_D, but an estimated lognormal mean, $\ln(\underline{D})$, where $\underline{D}$ represents the median demand.

Next consider n *independent* equipment items from the equipment class, with *known* free-field spectral demand $\{D_1,\ldots, D_i,\ldots, D_n\}$ resulting in an average *Reference Spectrum* value, D_{ave} = RS. Each of the n items has survived the respective input motion represented by D_i <u>without damage</u>. Caveats are used in defining the equipment class to exclude items with damage due to non-engineered attributes such as lack of anchorage or inadequate restraint.

The ratio of capacity to demand, C_i/D_i, for all n items is greater than unity, or

$$C_i/D_i > 1,$$

since no damage has been observed in any of the n equipment items belonging to the equipment class.

The ratio of spectral capacity to spectral demand, X = C/D, is also a lognormal variable with mean $\ln(\underline{X}) = \ln(\underline{C}/\underline{D})$ and log-normal standard deviation $\beta_X = \{(\beta_D)^2 + (\beta_C)^2\}^{1/2}$. The probability of failure for an item of equipment is given by

$$P_F = P(X<1) = F(X=1),$$

where F is the cumulative distribution function (CDF) of X.

If a reduced variate u is defined as $u = \ln(X)/\beta_X$, $u_0 = \ln(\underline{X})/\beta_X$, then

$$F(X) = \Phi(z),$$

where $z = u - u_0$ and Φ is the normal CDF. Thus,

$$P_F = F(X=1) = P\,(u<0) = P(\,z< -u_0) = \Phi(-u_0)$$

The probability of survival for an equipment item is

$$P_S = 1-P_F.$$

Now, given n pairs of independent D_i, C_i with *known* D_i and average RS but unknown C_i , apply the constraint, $X_i = C_i/D_i > 1$, since no failure has been observed in the n equipment items. If the X_i are ordered such that $X_1 < X_i < X_n$, the minimum probability of survival is given by

$$P(X_1 > 1) = \Pi_i\{1-F(X_i)\}_{\ Xi=1} = (1-P_F)^n.$$

Since $\underline{C}$ is unknown, it can only be specified by the assignment of a confidence coefficient. The lower confidence limit on P_F is found by considering the probability of an *assumed* failure for an (n+1)th item of equipment. This probability of failure is taken as the confidence level, γ, such that the observed result of n cases of no failure is the best that could have occurred. Thus,

$$\gamma = 1 - (1-P_F)^{n+1}$$

is the probability of failure for *at least* one item given the survival of n items.

Now the population mean, $\ln(\underline{X})$, which assures that, for a given level of confidence γ, the lowest capacity/demand ratio of n equipment items will be greater than unity may be estimated by requiring

$$P_F = 1- (1-\gamma)^{1/(n+1)} = \Phi(-u_0),$$

or

$$-u_0 = \Phi^{-1}\{1- (1-\gamma)^{1/(n+1)}\}.$$

Since $u_0 = \ln(\underline{X})/\beta_X$,

$$\underline{X} = \underline{C}/\underline{D} = e^{u_o\beta X}.$$

If the median demand, $\underline{D}$, is estimated as $\underline{D} = D_{ave} = RS$, then the capacity associated with 95% confidence is given by

$$C_{95} = RS\ e^{u_o\beta X}.$$

The High Confidence Low Probability of Failure (HCLPF), or 95% confidence of less than a 5% failure probability, is given by the 5% capacity level, or

$$C_{HCLPF} = RS\ e^{u_o\beta X-1.645\beta C} = RS\ F_K.$$

where the factor $F_K = e^{u_o\beta X-1.645\beta C}$ is the reduction or knockdown factor applied to the reference capacity spectrum, i.e., EES, to achieve a HCLPF capacity value.

Taking $\beta_D = 0.3$ and $\beta_C = 0.4$ as representative lognormal standard deviations for spectral demand and capacity, then $\beta_X = 0.5$, and the following tabulation of capacity/demand ratios for a confidence coefficient γ = 0.95, or a 95% confidence level, for equipment survival is obtained for class group sizes ranging from 60 to 15.

n	P_F	$(-u_o)$	$\underline{X} = \underline{C}/\underline{D}$	F_K
60	0.047924	-1.66533	2.299	1.191
50	0.057048	-1.58005	2.203	1.141
40	0.070461	-1.47237	2.088	1.081
35	0.079847	-1.40611	2.020	1.046
30	0.092114	-1.32785	1.942	1.006
25	0.108830	-1.23277	1.852	0.959
20	0.132946	-1.11257	1.744	0.903
15	0.170750	-0.95121	1.609	0.833

A class group size of 30 is the minimum number of items necessary to demonstrate that the reference capacity spectrum, i.e., EES, without applying a reduction factor, represents a conservative estimate of the HCLPF capacity.

True Median Capacity

The development outlined above provides an estimate of the population mean, $\ln(\underline{C})$, which, for high levels of confidence, will be conservative (i.e., low) compared to the true population mean. The situation, as a set of n observations of no damage for the demand level recorded or estimated for each observation, may be interpreted as a sample taken from a large population of equipment meeting the attribute limits or caveats of the equipment class per QR-A7421. Estimating the *sample mean capacity*, or $\ln(\underline{C})$, for which the conservatism is removed would provide an estimate of the true median capacity of the equipment to be used in risk-informed seismic evaluations of equipment.

One method of achieving this capacity estimate is to consider the HCLPF values computed above, RS F_K, as one-sided lower tolerance limits based on the sample size and sample mean value. This may be represented by

$$\ln(C_{np\theta}) = \ln(\underline{C}) - k_{np\theta},$$

where $C_{np\theta}$ is the lower tolerance limit such that the probability is p that at least a proportion θ lies below $C_{np\theta}$ (or a proportion 1-θ lies above $C_{np\theta}$), and where $k_{np\theta}$ is the tolerance factor based on p, θ, and sample size, n.

In general, for the case of a known (or assumed) standard deviation (Hald, 1952),

$$k_{np\theta} = -\Phi^{-1}(\theta) + \Phi^{-1}(p)/(n)^{1/2}.$$

If p = 0.95 and θ = 0.05, and $C_{np\theta} = C_{HCLPF}$ = RS F_K, then

$$\{\underline{C}/RS)_{tol} = F_K\, e^{knp\theta},$$

and the following tabulation is obtained using the prior results for F_K:

n	F_K	$e^{knp\theta}$	$\{\underline{C}/RS)_{tol}$
60	1.191	2.102	2.503
50	1.141	2.119	2.418
40	1.081	2.142	2.317
35	1.046	2.158	2.258
30	1.006	2.177	2.190
25	0.959	2.202	2.113
20	0.903	2.237	2.021
15	0.833	2.288	1.907

Another estimate of the mean spectral capacity may be achieved by noting that the HCLPF capacity may be approximated by the 1% value ($\Phi^{-1}(0.01) = -2.326$) of capacity (Kennedy, 1999):

$$C_{HCLPF} \approx \underline{C}\, e^{-2.326\beta C}.$$

Again, let C_{HCLPF} = RS F_K. Then

$$\{\underline{C}/RS\}_{1\%} = F_K\, e^{2.326\beta C},$$

resulting in the alternate tabulation:

n	F_K	$e^{2.326\beta C}$	$\{\underline{C}/RS\}_{1\%}$
60	1.191	2.536	3.020
50	1.141	2.536	2.894
40	1.081	2.536	2.742
35	1.046	2.536	2.653
30	1.006	2.536	2.551
25	0.959	2.536	2.433
20	0.903	2.536	2.291
15	0.833	2.536	2.113

Viewing these two mean capacity estimates as upper, $\{\underline{C}/RS\}_{1\%}$, and lower, $\{\underline{C}/RS)_{tol}$, bounds, the median capacity may be estimated by the geometric average of the two bounds:

n	$L=\{\underline{C}/RS)_{tol}$	$U=\{\underline{C}/RS\}_{1\%}$	$(UL)^{1/2}$
60	2.503	3.020	2.635
50	2.418	2.894	2.525
40	2.317	2.742	2.378
35	2.258	2.653	2.321
30	2.190	2.551	2.226
25	2.113	2.433	2.183
20	2.021	2.291	2.096
15	1.907	2.113	1.990

Sensitivity to β_C

The sensitivity of β_C on the results is checked for n=30:

β_D	β_C	β_X
0.3	0.450	0.54
0.3	0.400	0.50
0.3	0.335	0.45

n	β_C	F_K	$\{\underline{C}/RS)_{tol}$	$\{\underline{C}/RS)_{1\%}$	$(UL)^{1/2}$
30	0.450	0.978	2.347	2.787	2.390
30	0.400	1.006	2.190	2.551	2.226
30	0.335	1.047	2.009	2.283	2.037

The sensitivity of the results to the uncertainty β_C is small.

Conclusion

The technical basis is provided for the minimum number of independent equipment items to define an equipment class using earthquake experience as specified in section QR-A7422 and the reduction factors, given in Table QR-A7422-1, required for reducing the EES when a smaller number of independent items are used to define an equipment class. The reduction factors per Table QA-A7422-1 are a conservative (lower) round off of the reduction factors calculated in this paper. Also, the results were shown not to be very sensitive to the assumed log-normal standard deviation of capacity.

References

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Session 3(b): Valves III

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Comparison of IST Conditional Monitoring Check Valve Programs to the Industry's Process Approach to Equipment Reliability

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ABSTRACT

The latest Nuclear Industry's Equipment Reliability Process and Check Valve Condition Monitoring via Appendix II of the ASME OM Code are two newly evolving approaches to improving equipment performance. Though both processes originated from separate initiatives, surprising similarities in approach and concepts are contained in each. This paper will present a comparison of the two processes and the potential advantages obtainable by a marriage of the two.

INTRODUCTION

This paper discusses the similarities of the ASME Check Valve Condition Monitoring and the Nuclear Industry's Equipment Reliability processes. It then attempts to extend these similarities to a view of a common process. It is not intended to provide a step by step strict site implementation approach, but to present a potential concept of what could be, if acted on with innovation and creativity.

OM-22 CONDITION MONITORING

Based on experiences of its members and industry, the ASME OM-22 Working Group on Check Valves, in the early '90's, began to explore alternatives to the classic prescriptive nature of ASME Codes and Standards. The current Code at the time was more directed at "failure finding" activities than the establishment of a process to insure check valve performance. Additionally the Code's prescriptive nature, dictated actions requiring expenditures of resources and station impact which did not improve performance, or allow new techniques. The prescriptive nature also did not provide the flexibility to adjust/modify its requirements due to plant design or operation, requiring of Code cases and relief requests. OM-22's work led to the conclusion that an alternative approach was advisable if these issues were to be addressed.

"Conditioning Monitoring", a process rather than a prescriptive Code, evolved from this work. By identifying the key components of a process, OM-22 found a way to ensure reliable check valve performance without dictating specific test activities or performance intervals. The results of that effort are found today in the ASME OM Code, Appendix II, "Check Valve Condition Monitoring."

Nuclear Industry's Equipment Reliability Process
Nuclear Industry has noted over the years a significant improvement in the reliability and performance of nuclear power stations, but still strives to seek further improvements. The significant benefits which could be derived from a classic organizational approach of focusing on Engineering, Maintenance and Operations had been achieved. Experience gained in assistance visits and benchmarking at both domestic and international utilities, indicated that to gain further significant improvement a different approach would be required. A focus on "process" was initiated; under this approach, all of the attributes that contribute to the success of the process are integrated regardless of what organization (i.e., Maintenance, Engineering, Operations) they are assigned to. The operation and support of a nuclear plant were divided into an integrated set of processes. Equipment Reliability process will be explored in this paper. The Equipment Reliability process focuses on maintaining a high level of safe and reliable plant operation in an efficient manner. It represents the integration and coordination of a broad range of equipment reliability activities into one process for plant personnel to evaluate important station equipment, develop long term health plans, monitor equipment performance and condition, and make continuing adjustments to preventive maintenance tasks and frequencies based on equipment operating experience. It would include activities normally associated with reliability centered maintenance (RCM), preventive maintenance (periodic, predictive, and planned), Maintenance Rule, surveillance and testing, life cycle management (LCM), planning and equipment performance, and condition monitoring. The intent was to identify, organize and integrate equipment reliability activities into a single efficient and effective process.

These two efforts, ASME's OM Appendix II and the Nuclear Industry's Equipment Reliability process, evolved from two entirely different worlds and approaches, but both shared one common focus, that of providing a process which would provide superior equipment reliability. Appendix II works in a world of regulatory requirements, while industry's processes are recommendations.

OM-22's effort involved a small group of ASME Code and check valve experts who were focused solely on check valves and Code requirements.

The Nuclear Industry's Equipment Reliability process evolved from numerous station visits/benchmarkings and involved an industry-wide experienced group whose efforts focus on a universal process involving equipment reliability of all critical station equipment.

From two such different views, the focused narrow single component vs the high level industry wide focus, the attributes which were determined to be most critical to success are remarkably common.

Fundamental to both efforts is a belief that failure of critical components is not acceptable. To OM-22 it meant that requirements which would only detect failures after they occurred would not be enough. The Industry's Equipment Reliability process establishes a policy/philosophy that "All plant equipment critical to safety and reliable generation shall be designed, maintained, and operated to ensure 'failure-free' performance."

Here are the common areas, which both efforts deemed to be critical to ensuring equipment reliability.

COMPONENT IMPORTANCE & GROUPING

Section II-2000 of the ASME OM Code requires grouping check valves by the intended purpose of the Condition Monitoring program, and the analysis of test results, maintenance history, design characteristics, application and service conditions. Owners are also required to assess the significance to plant safety if extended intervals are planned.

Industry's Equipment Reliability process initial step is the scoping and identification of Critical components taking into account critical system functions, a component's risk significance to these functions, Probabilistic Safety Analysis (PSA), and Maintenance Rule. Industry's process then under "Continuing Equipment Reliability Improvement" will develop component templates which group components based on similar service, duty, environment and design.

For both efforts an initial step is to rank components by significance. Next, components are grouped by common environment, duty and design. Done well, these groupings are fundamental for providing focus and leverage for the remaining effort. In the review of past component history, industry events, and preventive maintenance activity feedback, all information is not simply assessed against an individual component but against the group.

ANALYSIS

Section II-3000 of the ASME OM Code contains the requirements for analysis of test/maintenance history of groups to establish a basis for specific tasks. The analysis includes identification of failure modes/mechanism, determines critical failure mechanisms and determination of tasks to address or detect these identified failure modes.

Industry's process, under "Continuing Equipment Reliability Improvement", discusses an almost identical evaluation/analysis process. It identifies failure/degradation modes, and evaluates if they can be detected by Predictive Maintenance (i.e. condition monitoring) task or addressed by a PM task to control known failure due to wear/age.

EQUIPMENT RELIABILITY TASK IDENTIFICATION

Section II-4000 of the ASME OM Code utilizes the groups of valves to identify the task and task frequencies to address the analysis of failure modes provided. Tasks can include functionality tests, performance monitoring, non-intrusive Predictive Maintenance (PdM) or traditional PM. This section also requires identification of attributes that will be trended.

Industry's process, under Performance Monitoring identifies parameters, which can be monitored/trended at both a system or component level to detect performance degradation.

Industry's process, under "Continuing Equipment Reliability Improvement," performs virtually the same task that the OM Code does under section II-4000, in identifying PM and/or PdM tasks to address predominant failure modes.

ESTABLISH A LIVING PROGRAM

After the performance of each Condition Monitoring task, Section II-4000 of OM Appendix II requires a review of results to determine if changes to optimize the program are required.

Industry's process, under PM Implementation, documents the "as-found" condition at the conclusion of each PM task, and then assesses if it indicates a need to revise the program. Under Performance Monitoring, if the trending of parameters indicates performance is degrading, a similar review of the program is required.

The heavy emphasis on feedback of results and requiring that the process must be "living," in both programs, is one of the critical attributes identified which may not have been emphasized in the past.

INTEGRATION OF CORRECTIVE MAINTENANCE

Section II-5000 of OM Appendix II requires that, if corrective maintenance is performed on a check valve, that the analysis used to establish the program for that valve be reviewed to determine if changes are required.

Industry's process, under "Corrective Action," evaluates corrective maintenance and unanticipated failures to determine cause and take appropriate actions with the program to address them.

CONFIGURATION MANAGEMENT

Section II-6000 of OM Appendix II, requires documenting the rationale/basis of the program.

Industry's process calls for documentation of the critical component classification basis, performance monitoring parameter plan, and PM basis.

CURRENT PROGRAM STATUS

OM 22

Since incorporation of the option for Conditioning Monitoring into the 1996 Addenda of the ASME OM Code, and endorsement by the NRC via the Rulemaking Process, more utilities are seriously looking at revising their programs to take advantages of the efficiencies and increased equipment reliability which can be obtained. Additionally due to the new Code requirements which require bi-directional testing, Condition Monitoring is an appealing option especially for hard to test valves. Other papers including one being presented at this symposium have presented the benefits of a program transition to Appendix II Condition Monitoring. ("Enhancing your Check Valve Program by Invoking Appendix II Condition Monitoring," July, 2004, M. Robinson, NIC)

The implementation of a check valve Condition Monitoring program is typically narrow in focus and only addresses those check valves within the scope of the ASME Code. All of the Appendix II Condition Monitoring Process steps discussed above are usually addressed via a specific focused station procedure to implement solely Condition Monitoring on these ASME Code check valves. It develops steps and requirements to address each requirement of Appendix II, including assessing component significance, and analyzing component design/performance. Special steps are even taken to capture and evaluate results from planned check valve disassembles, review of Operating Experience and review of Corrective Actions. It is important to note that the focus of this entire effort is usually limited (varies between utilities) to only the ASME Code check valves.

Nuclear Industry's Equipment Reliability Process

Since creation in the late 90's, more and more utilities are embracing the Nuclear Industry's Equipment Reliability (ER) Process, driven by a desire to capture step improvement in overall equipment reliability than can be obtained by their current departmentalized approaches. Though the reliability of today's nuclear plants has significantly improved over the decade, all involved realize we can go further. With limited resources, the success being seen by the implementation of this Process (ER) by some utilities and the obvious efficiencies obtainable by changing to a focus on a process, more utilities are exploring implementation of ER Process site or fleet-wide.

Since the Process is station-wide, it requires that all of the process steps discussed above be implemented across the station. Typically a detailed evaluation of the site work process is performed to insure that the Process is effectively and efficiently incorporated. The change of focus from Departments (i.e. Maintenance, Engineering, Operations) to process, requires a change to even the culture of the station. Examples of areas which are reviewed/revised when implementing the Process station-wide are:

- Causal Determination of appropriate Corrective Maintenance actions
- Prioritization of Key Equipment Problems
- Establishment of System & Component Performance Criteria
- Aging & Obsolescence Issues
- Post Maintenance Testing
- Documentation of "As-Found" Equipment Condition from PM Tasks

A benefit of the application of the Process is in its focus on the connection and flow between the various parts of the process. Every nuclear station addresses the areas listed above, but each area was typically developed at a different time, is the responsibility of a different department, and was developed more as stand alone efforts. This process approach can focus on the linkages and flow between the areas.

A key component of the Process is the development of a component reliability plan, which is typically captured in a template. As an example of the application of the Process, a discussion will follow on how a component reliability plan (PMTemplate) was applied to Check Valves at PPL, Susquehanna. Note that an identical process was performed on other station components (i.e. fans, breakers, pumps, relays), but we will focus on Check Valves.

Development of a PM Template

- All station check valves are evaluated for component importance against a common standard used site wide to determine which valves were most critical to the safe operation and electric generation of the station
- All check valves were evaluated for duty and environment, which could impact performance
- Historical site and Industry performance experience & maintenance data was assessed
- Effective PM task, parameter monitoring, PdM tasks which address failure modes were identified
- Analysis of Information

Template development focuses on combining all information into an effective plan, which insures reliable operation, appropriate to the component's importance. Effective Component grouping is used to leverage the advantages of the process. Groupings are keyed to component importance, duty and environment under this format.

COLUMN	1	2	3	4	5	6	7	8
Component Importance Criticality	High	High	High	High	Low	Low	Low	Low
Duty/Service	High	Low	High	Low	High	Low	High	Low
Environment	Severe	Severe	Mild	Mild	Severe	Severe	Mild	Mild

Where unique performance variables are identified (i.e. unique design), new groupings are created as appropriate. A PMTemplate was developed to capture the basis of these evaluations.

A typical section of the Check Valve PMTemplate is presented below:

TITLE	PM SCOPE	PM BASIS
Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document * to insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE This Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ (ESW, Service Water, mud or debris carrying lines) will required increased attention particularly if internals have not been upgraded to stainless steel and are know to flutter. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.

The corresponding frequency related to the 1 thru 8 grouping would be as shown below:

COLUMN	1	2	3	4	5	6	7	8
FREQUENCY	RANGE 6 YEARS	RANGE 6 YEARS	RANGE 10 TO 12 YEARS RANGE (with review) 18 YEARS	RANGE 12-20 YEARS	RANGE 6 YEARS	RANGE 6 YEARS	RANGE 10 TO 20 YEARS SAMPLING TECHNIQUES MAY ALSO BE USED	RANGE 16-NEVER YEARS SAMPLING TECHNIQUES MAY ALSO BE USED

For special cases, due to past performance/reliability concerns, a unique PMTemplate task can be created, but in general it has been found that this is not necessary. When properly grouped by component criticality, environment and service, the PMTemplate provide a solid foundation for ER. NOTE: that a key component of ER, is that it is a living process, so if PM Feedback, performance monitoring, industry experience, etc, indicate improvement is advisable, a reassessment of the PM is called for. At points like this, the true benefit of the Equipment Reliability Process, becomes apparent. When data supports a review of a single PM Task, the review is not limited to the PM on that component, but expands to assess all components, which share the same component importance, environment, and duty. The assessment could determine:

That further trending and evaluation is required

Some unique characteristic of this check valve was not addressed via the current grouping, and the specific check valve is assigned to the appropriate group or a unique group is developed for this.

The assessment determines that improvements to the entire group are appropriate and the changes are applied to all check valves in the group.

At PPL, if Code requirements for forward or reverse flow testing are fully met, the ER Assessment of the check valves still compares it to the group it would be located in. If disassembly at a specified frequency is required per Industry ER process, the PM template would also be applied to the valve.

Similarly for check valves for which exception to the Code is taken and disassembles are done to comply with ASME Code, a comparison is made to what the PMTemplate group requirements would be. In most cases the Code required disassembly is at a shorter interval. This evaluation is documented and the check valves are left as unique groups.

The analysis of component performance and its associated plan are developed and documented including not only the traditional PM task, but also system and component monitoring, Predictive Maintenance and other condition monitoring tasks. Many utilities are dedicating people to focus on their PM Feedback process. PM Feedback captures the “as-found” condition of equipment during PM Tasks and the analysis/assessment of the knowledge gained against the basis and scope of the PM Task.

Typical Incorporation of IST in PMTemplate when Programs are Treated Separate

IST Reverse Flow Test	Perform Reverse Flow Test: * Isolate keep-fill source * Open test valve to drain test volume * Observe substantially restricted flow through test valve * Quantify leakage and compare to acceptance criteria or compare final pressure to initial pressure (If test media is air)	IST Program - ASME Code OMa-1988, Part 10 ASME IST Code dictates frequency.

IST Full FLOW TESTING Testing performed in conjunction with Operations SO’s	IST Program - ASME Code OMa-1988, Part 10 GL 89-04 Disassembly Group ASME IST Code dictates frequency.

COLUMN	1	2	3	4	5	6	7	8
FREQUENCY	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program	Freq Per IST Program

WHERE CAN ONE GO FROM HERE

Too often the advantages of combining processes are lost; one group being responsible for regulatory requirements another for preventive maintenance. By addressing the common threads of these processes, significant benefits are possible. Having demonstrated the similarities of both processes where can a station go next?

COMBINING ASME CONDITION MONITORING & INDUSTRY'S ER PROCESS

Under both programs, a common grouping philosophy can be applied. If the utility does not elect to perform a "risk ranking," it can establish a rule that all IST check valves are Critical HIGH, but the grouping will still provide a valuable function.

COLUMN	1	2	3	4	5	6	7	8
Component Importance Criticality	High IST	High IST	High IST	High IST	Low	Low	Low	Low
Duty/Service	High	Low	High	Low	High	Low	High	Low
Environment	Severe	Severe	Mild	Mild	Severe	Severe	Mild	Mild

The identification of appropriate reliability tasks and documentation can be identical for both ASME Code check valves and non-Code valves. The first step under such a combined approach would be to identify the "Right Preventive Maintenance Task at the Right Frequency." Typical tasks might be as listed below:

TASK	TITLE	PM SCOPE	PM BASIS
P	Monitor & Trend Keepfill Pressure	Isolate keepfill pressure and determine time for pressure to decay	
F	Forward Flow Verification	Monitor flow during pump operations to insure check valve opens	
T	Monitoring of Temperature	Monitor temperature downstream of check valve to detect excessive leak-by	As part of Engineering walk-down, the temperature down stream of check valve can be monitored to identify excessive leak-by. Though the task is not quantitative when excessive leak-by occurs it can be identified by this method. The ease of performance of this task to provide confidence in conjunction with other tasks warrants its use. Task is effective when downstream piping is uninsulated.
D	Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document * Insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE This Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ (ESW, Service Water, mud or debris carrying lines) will required increased attention particularly if internals have not been upgraded to stainless steel and are know to flutter. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.

This step creates initial groups based on common factors. It should not differentiate ASME Code and non-Code valves. Such groups are beneficial to the "living program" because it allows for the easy transfer of experience, improvements, and issues to address all valves regardless of their ASME Code status. For Code valves with more stringent requirements (i.e. frequency restrictions), sub tasks can be created which capture these requirements, but still allow the ability to compare all feedback and inputs to improve the reliability and performance of all valves in the overall group. See the example below, showing how Task D could be split into non-Code (D1) and Code (D2) sub tasks.

TASK	TITLE	PM SCOPE	PM BASIS
D1	Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document *to insure ability to free swing, proper disk stop and side to side clearance exist	GENERIC SWING CHECK VALVE Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ require increased attention. The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation.
D2	ASME CODE Disassembly and Inspection	Inspect valve internals per MT-GM-003 * Compare wear rate with past history or similar valves * If not a bonnet hung check, full swing disk and document *to insure ability to free swing, proper disk stop and side to side clearance exist	ASME SWING CHECK VALVE Task ensures operability of the valve for the next interval. Disassembly has proven to be the most effective method of determining the internal condition of check valves. Template Frequency ranges are based on generic SSES/industry experience and common fail modes. Swing checks installed in severe environ require increased attention The generic frequencies given assume the valve has not proven to be a bad actor or is known to have a history of severe flutter either due to misapplication or system operation. **ASME Code imposes restrictions on extension of frequency and upper limit to maximum frequency**.

Note in the example above the actual PM Task and Scope are identical. All similar valves in the station fall under Task D due to similarity. For this example, Task D applies to all normal swing check valves, which have been confirmed to demonstrate past good performance. Over 100 to 200 valves might fall under this task. The only difference, which is factored in, is the frequency restrictions of the ASME Code.

Two thoughts to keep in mind: 1) A check valve does not know as it sits in the plant, whether it is a Code valve or not. It responds to its duty and environment and the tasks that are performed on it. 2) The Station does not need to set two standards for equipment reliability, one for Code components and one for non-Code, in today's world the station demands excellent reliability from ALL critical check valves.

"LIVING PROGRAM"

ASME Condition Monitoring and Industry Process share a critical common theme, that their programs must be maintained as "living." For neither is it satisfactory to simply establish task and frequency. Both require constant feedback and trending of results to confirm the original basis for task/frequency, and to insure constant awareness of changes both from the plant and industry, that could affect the program.

If developed with an eye to the requirements of ASME OM Code Appendix II, Condition Monitoring and the recommendations of Industry process, one common efficient process can be established which meets both. Areas to address would include:

Preventive Maintenance Feedback

Operating Experience Review

Component Performance Monitoring

Corrective Action Reviews

CONCLUSION

The Nuclear Industry's Equipment Reliability Process and ASME Check Valve Condition Monitoring Appendix II strive to establish processes that ensure equipment reliability. Though Industry's focus is a station-wide approach and ASME is narrowly focused on check valves, their conclusions regarding the critical aspects of an effective program are remarkably similar. A summary comparison is proved below.

AREA	**Industry ER Process**	**OM-22 Condition Monitoring**
Program Scope	Station Wide	ASME Check Valves
Enforcement	Recommendation	Code Compliance
Identification of Component Importance	Yes	Yes
Reliance on Component Groupings	Yes	Yes
Analysis of Equipment History And Failure Modes	Yes	Yes
Identification of Task/ Monitoring to Insure Reliable Performance	Yes	Yes
Documentation of Task Basis required	Ye	Yes
Restriction on Frequency	No	Yes
Evaluate of in scope check valve failures	Yes	Yes

The lack of efficiency and cost of small focused programs can be extremely high, provide limited flexibility, and tie up critical resources. With some innovation and openness to a different approach, it appears that the marriage of the process/requirements of these two programs can produce an overall process, which is not only more cost effective and efficient, but produces even higher equipment reliability. If the Industry's ER Process is married with ASME OM Code Appendix II Condition Monitoring for all check valves, the opportunity for increased knowledge transfer and learning is created. The improvements learned from a special situation on a non-Code check valve will inherently be linked to similar Code check valves and vice versa.

If you are implementing one or both of these processes, it should be done with an eye open to encompassing the concepts offered by each of these processes in a single integrated approach.

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TRENDING CAPABILITIES OF NON-INTRUSIVE TECHNOLOGIES FOR CHECK VALVES

Nuclear Industry Check Valve Group (NIC)

Presenters:

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ABSTRACT

ASME ISTC 1995 Edition through Summer 1996, Appendix II provides an option to implement a check valve condition-monitoring program. The condition-monitoring option requires that utilities expand upon current check valve performance trending. Technologies and practices such as non-intrusive diagnostics, disassembly, and operator verification are widely used to monitor valve performance. However, most utilities only trend non-intrusive test failures since the information gathered was primarily qualitative in nature. A knowledge of which performance and functional parameters identified diagnostically that is detectable as well as trendable was required. In order to more effectively utilize available techniques, quantification of the data collected by each method that resulted in trendable information that would predict various types of valve degradation. Effective trending is expected to result in substantial reductions in both operation and maintenance costs and will allow nuclear utilities to implement ASME and Nuclear Regulatory Commission condition monitoring requirements. It was in response to this need that the Nuclear Industry Check Valve Group (NIC) initiated Phase 4 of their ongoing research program.

INTRODUCTION

The Nuclear Industry Check Valve Group (NIC), established in 1989, has facilitated a number of projects to further the reliability of check valves within the Industry. Inclusive of these projects has been an ongoing research program to investigate the capabilities of non-intrusive techniques to study check valve functional characteristics and internal conditions. The first three phases of this test program were conducted by NIC's Non-intrusive Examination Committee (NEC) during the period of 1991 – 1993. Phases 1, 2 and 3 assessed the performance of non-intrusive technologies in the three main fluid media encountered in nuclear plants – water, air, and steam, and are documented in NIC-01-Water, NIC-02-Air, and NIC-03-Steam [1,2,3]*. These previous tests established the capabilities and limitations of the non-intrusive technologies to detect valve disk position and disk motion, and to identify various degraded conditions of the valve internals. NIC's efforts resulted in widespread use of acoustics, magnetics (AC & DC), and ultrasonics for check valve testing. In 1996, the NEC prepared the Non-Intrusive Analysis Guide to provide standardized guidance on techniques of evaluating and interpreting data acquired using non-intrusive technologies. Phase 4 testing was prompted by the need to examine the trendability of non-intrusive data, acquired over time, to serve as a predictive measure of valve internal degradation.

The objective of Phase 4 is to assess the capabilities and limitations of currently available check valve testing and diagnostic methods to detect and trend valve internal conditions, quantitatively or qualitatively. The scope of Phase 4 was developed by the NEC and administered by a volunteer Technical Advisory Group (TAG) and 17 funding nuclear plants. The objective was to identify those parameters that could be trended reliably, repeatedly, and defensibly to help detect the onset of an imminent failure condition and thus constitute a basis to plan valve maintenance. This report documents the results of the first group of tests, completed in November of 2002, which examined the application of acoustics, magnetics, ultrasonics, and radiography to various types of check valves using water and air as the fluid media. This stage of testing investigated the feasibility of trending varying levels of artificially induced valve degradation that approximated the actual degradation identified in the industry through the use of commercially available non-intrusive technologies. Participation in the testing was open to the TAG and all funding utilities. Both major providers of non-intrusive diagnostic equipment and services, Crane Nuclear Services and Framatome ANP, participated. Kalsi Engineering provided the flow loop and served as independent program manager, overseeing the testing. NEC TAG-designated test coordinators provided governing oversight during the tests. NIC-04 Interim Report: November 2002 Testing was distributed to the funding utilities December 2003.

** Numbers in parenthesis denote references*

Whereas Phases 1, 2, and 3 qualified various technologies for non-intrusive testing techniques, Phase 4 aimed at extending the applicability of these technologies as well as perhaps introducing new technologies that may be used in characterizing check valve performance. Table 1.1 distinguishes the difference in scope of the Phase 1, 2 and 3 testing and the current Phase 4 testing.

EXPERIMENTAL PROGRAM

Group 1 Tests

To properly evaluate the non-intrusive techniques, a testing program was developed to evaluate the technologies under carefully controlled laboratory conditions. The flow loop comprised three parallel lines for water tests and a separate line for air tests. The scope of testing included four technologies:

- Acoustic emission
- Ultrasonic
- Eddy current
- DC magnetic

Every parameter obtained by applying each of these technologies was evaluated to determine if changes in its magnitude correlated with the level and type of artificially induced degradation. Tests were conducted at a pre-selected flow rate with an engineered upstream turbulence source that induced high levels of disk instability of the type that could lead to accelerated wear of valve internals in typical plant applications. Tests were initially conducted on a new valve to provide baseline data for comparison against subsequent parametric degradation tests.

The check valves used in this study were provided by NIC. Tests were conducted on a 6-inch stainless steel swing check valve, a 6-inch carbon steel tilt disk check valve, a 4-inch double-disk check valve, and two 2-inch stainless steel lift check valves. These valves were selected based on their availability and on the basis of how well they represented a typical range of valve sizes and valve types used in the industry. Various types and levels of degradation were induced in these valves, including; as applicable; worn hinge pin, worn stud pin, worn plug, degraded springs, etc.

Each non-intrusive diagnostic system vendor used its own proprietary standardized processes to acquire and process data. Plant experts in those specific systems to validate data collection and analysis techniques oversaw the data collection and analysis by vendors. The vendors then post-processed test results to evaluate the trendability of various non-intrusive diagnostic examination data.

	Primary Objective	Failures Modes Studies
Phases 1, 2, & 3	• Evaluate NIT technology capabilities • Verify disk stability • Verify operability – full open and full closed (Section XI)	• Stuck open • Stuck closed • Restricted motion • Detached disk • Worn internals
Phase 4	Investigate the feasibility of trending the degradation of internals to detect onset of “yellow light” failure	• Abnormal wear of hinge pin, hanger arm, plug & guide • Degraded spring • Seat leakage

Table 1.1: Scope of NIC Phase 1, 2, 3 and 4 Test Programs

Subsequent to flow loop testing all valves were shipped to TVA's Sequoyah Nuclear Station for radiographic technology evaluation.

With the baseline for reference, the five technologies were in general able to detect changes in levels of degradations qualitatively. The technologies demonstrated the ability to provide useful information about the condition of check valve internals. Once more completely understood, such trending could become a basis to detect the onset of a failure condition and provide a basis to disassemble and visually inspect valve internals provided adequate testing could be performed at the plant.

TEST RESULTS

Some Phase 4 (Group 1) test results are:

1. Demonstrated the ability of commercially available non-intrusive diagnostic systems to trend internal degradation in check valves under laboratory / controlled conditions.
2. Identified non-intrusive parameters that exhibited noticeable changes in their values in relation to changed degradation levels where others did not.
3. Assessed the capability of valve operating conditions and test scenarios to yield conclusive evidence of valve internal condition wear, etc.
4. Usage recommendations developed: e.g., reinforced the need for proper baseline data, understand test conditions and valve design.

RECOMMENDATIONS

1. The objective of Phase 4 testing was to assess the capabilities and limitation of currently available check valve testing and diagnostic methods to trend valve internal conditions. The NIC Non-intrusive Examination Committee recognized from the onset of Phase 4 that multiple sub-phases of testing and examination would be required to fully achieve this objective. The insights gained from the first series of check valve tests under Phase 4 lend credence to the NEC's conclusion that there are parameters reflective of internal conditions that can be detected and trended via non-intrusive technologies.
2. Additional testing should be performed to verify and validate conclusions reached and to build upon the insights gained from this series of tests. Continuation of Phase 4 testing, in a laboratory atmosphere, will provide the following benefits:

- Testing of numerous valve styles and sizes in a relatively short period of time,
- Finite control of internal degradations and flow parameters,
- Verification of first series (and subsequent) test results; e.g., repeatability,
- Potential refinement of existing non-intrusive technologies or development of new technologies,
- Industry-recognized processes with which individual utilities will be able to qualify non-intrusive technologies for trending of valve internal degradation.

NIC Trending Program (Phase 4) — Group 1 Test Accomplishments

Valve Type	Number of Degraded Specimens Testing	Total Number of Tests (Tests/ Specimens x 2 Vendors)
Swing	• 3 hinge pins • 6 hanger arm inserts • 1 hinge pin & hanger arm combo	90
Tilt	• 4 hinge pins	40
Double Disc	• 3 hinge pins • 2 springs	60
Piston 1	• 2 plugs • 3 springs	50
Piston 2 (soft seat)	• 3 plugs	30
	TOTAL	**270**

270 unique check valve flow tests performed at Kalsi Flow Loop 20+ separate Radiography tests at TVA Sequoyah Nuclear Station

3. NIC supports the continued use of non-intrusive testing. In the early 1990s, NIC performed Phase 1, 2, & 3 studies to evaluate technologies that have been successfully and reliably demonstrated to assist in determining the operational readiness of check valves. Since then NIC has successfully continued to demonstrate, improve and refine the applications to those technologies. Detection and trending of internal degradation has been a continued open item, for which Phase 4 was implemented.
4. Participating plants should review any historical NIT data to provide input where the Phase 4 report can be validated and where it can not, based on plant data. This information could be used to determine future testing.

ACKNOWLEDGEMENTS

The NEC Technical Advisory Group (TAG), chaired by Mr. Domingo A. Cruz of Constellation Energy Group, spearheaded this project and led it from the preliminary discussion stage to completion of the first group of tests. Contributing utility TAG members were Mr. Jim Brewer of South Carolina Electric & Gas, Mr. Ivan Whitt of TXU, Mr. Ron McGuire of Tennessee Valley Authority, Mr. Ron Cameron of Constellation Energy Group, Mr. Steve Quan of Arizona Public Service, Mr. Tony Maanavi of Exelon, Mr. Roger Sagmoe of NMC, and Mr. Frank Kelly of AEP Indiana Michigan Power. Non-utility TAG members included Mr. Mike Robinson of K&M Consultants, Mr. Vinod Sharma of Kalsi Engineering, Messrs. Lew McKeague and Jason Campbell of Framatome ANP and Mr. Ernie Noviello of Crane Nuclear Services.

Mr. Sharma served as the independent project manager and provided project oversight and technical guidance. Mr. Ron McGuire and Mr. Ron Cameron served as test coordinators, assisted in keeping the testing program on schedule, and provided day-to-day coordination between Kalsi laboratory personnel, vendors, and NEC TAG members present during the tests. Messrs. Ernie Noviello, Lew McKeague, and Jason Campbell provided specialized expertise in non-intrusive data acquisition, data analysis, and technical reporting. Mr. Ron McGuire provided radiographic examination oversight and technical reporting at the Sequoyah facilities following flow loop testing at Kalsi Engineering.

Mr. Mike Robinson took the lead in ensuring that the program scope was comprehensive enough to benefit the widest set of utility needs and also in securing the crucial utility funding that made this program viable. Sincere appreciation is expressed to the following participating nuclear utilities for their financial support, without which this testing program would not have been possible:

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Southern California Edison – San Onofre

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TVA – Sequoyah

Duke Energy – Oconee
TVA – Watts Bar

Duke Energy – McGuire
TVA – Browns Ferry

Exelon – Byron Station

NMC - Palisades

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Enhancing your Check Valve Program by invoking Appendix II Condition Monitoring

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INTRODUCTION

Have you considered going to Condition Monitoring for check valves?

Are you doing a code update in the near future or have you recently gone to a later code edition?

If you have done either and have not yet implemented Appendix II, "Check Valve Condition Monitoring Program," then you could be missing an opportunity to reap significant benefits. Yes, those utilities who have implemented Appendix II are already seeing savings in maintenance, testing, and in man rem costs. How is this accomplished? This paper will outline the steps to take and explain the benefits that are achievable in an effort to help you make the decision to invoke Appendix II Condition Monitoring for Check Valves.

History

In the mid 1980's, several utilities were experiencing an increase in failures of check valves. Through coordinated efforts by the Nuclear Regulatory Commission (NRC), the Electric Power Research Institute (EPRI), and the Institute for Nuclear Power Operation (INPO), studies were started to determine the causes of these failures. The following were determined to be the factors contributing to this increase in failures:

1) When the plants were designed, many of the components were purchased based on design criteria using worst case scenarios. For many of the components worst case is accident condition, and does not consider normal operating conditions. An example is Combustion Engineering designed plants, where the shut down cooling system also doubles for the low pressure safety injection system. The design criterion for shut down is approximately 1500 gpm @ 85 psig. During an accident the criteria changes to 3400 gpm @ 97 psig. As per the design specs, it is indicated that the valves for this system should be built to the accident condition. Herein lies the problem, the system sees continuous operation during shutdown in the shut down cooling mode. The actual system flow through and dp (differential pressure) across the valve is much less than design conditions. Because of this, the valve may not be reaching full open and may be unstable in the system. In other words, the valve is improperly sized. Because of this the valve may be unstable in the flow stream and degrading at an accelerated rate.

2) Another problem found was that many of the valves were placed in areas of the system where the flow may not be properly developed and uniform within the piping. Recommendations from manufacturers of the valves were not complete, or compromised due to space restrictions. A properly installed check valve should have at least ten diameters upstream and five downstream for the flow profile through the valve to be laminar. In the nuclear industry, to maintain leak tightness most plants rely on

welded rather than flanged valves to eliminate leak paths. To maintain the least amount of welding, many of these valves were placed just before or after elbows, isolation valves, control valves, pumps, and other equipment. Because of this, the valves do not see the uniform flow profiles they were designed for, and can cause an increase in failures.

3) Maintenance activities, including disassembly for Code inspections, were causing problems. Manufacturers are reluctant to give out design information which includes dimensions, tolerances, and clearances. Proprietary information is always a consideration for manufacturers when providing design information to customers. The maintenance guides and procedures supplied with the valve leave a lot to be desired. Since they give no criteria on the valve, i.e., the condition it needs to be in to be considered operational, it is difficult to determine whether or not a valve is functional when it is outside the design condition. When the utility does an inspection or maintenance they have a great chance of missing something since they have so little information. Rework and failures have increased due to improper maintenance and inspections.

4) Another problem, rapid valve closure in flowing liquid lines, may cause substantial pressure surge. In the case of check valve closure the velocity of the flowing liquid and the speed of closure are interrelated so that in many applications the fastest possible closure is desirable. The speed of closure is understood in terms of the shortest possible time following the instant of flow reversal. This follows from the consideration that the shorter the time interval can be made, the slower the velocity of the reverse flowing liquid will be.
As in the case of shutoff valves, check valve closure can also cause downstream fluid column rupture. Under certain conditions a succession of closure "hammers" may result. In most cases it isn't that the check valve is not working correctly, but that the wrong type of check valve was installed. This has occurred more often than previously believed.

In response to such patterns in contributory factors , INPO issued Significant Operating Event Report, SOER 86-3 that directed all utilities to put into place a review of their check valves that were required for the safe shutdown and operation of the plant and establish a living program assure that check valve failures be predicted prior to the actual occurrence. All utilities were required to respond to this SOER.

The Utility industry responded by calling for the development of a standardized guidance to be developed by EPRI and embodied in the "Applications Guide for Check Valves" (NP-5479), to provide the electric power utility industry with comprehensive and readily available information on the appropriate parameters for selection, installation, maintenance and reliable service (usage) of check valves in various nuclear power plant systems. For the purpose of definition, "usage" or "service" applies to the periods of plant operation under design conditions in which forward flow occurs through the check valve including normal (minimum through maximum flow range) conditions, as well as, upset, emergency, and faulted conditions simulated during valve tests. The major objective of the EPRI Check Valve Application Guide is to provide accurate technical guidance for utility engineers to determine if currently installed check valves are misapplied for long term reliability. The information can also be used for selecting check valves for new systems and plant modifications. The guide is intended to present information on check valve size, location, orientation, type, construction details and other parameters pertinent to valve performance. This information also enables utilities to prepare plant specific review plans and procedures in a convenient format convenient. Use of the technical information in the application guidelines is intended to improve valve reliability and in-turn improve plant availability and plant safety.

It was recognized that some existing check valve installations may not be optimal when compared with the application guidance given in this document. Also, to significantly modify the installation may not be the only alternative for appropriate corrective action.

Though the utilities followed the requirements of the SOER and the applications guide, other concerns began to arise. The first was that the formulas provided for determining the velocity required for opening and maintaining a check valve open in the stable condition need to be reviewed. The second was that the only way to really determine the condition of a check valve was to perform a disassembly and inspection. However, as described earlier, disassembly may only cause an increase in possible failures. It was obvious that a new venue was needed to answer these problems.

The industry formed the "Nuclear Industry Check Valve Group" (NIC) to provide a forum for the exchange of information and to provide a method to help in increasing the reliability of check valves. The first objective of this group was to conduct an experimental research program to investigate the ability of existing non-intrusive techniques to analyze the condition of check valves. The study included evaluating three technologies, testing eleven check valves in six different sizes, three types, and made of two different materials. The three technologies were acoustics, ultrasonics and magnetics. Each technology was evaluated to see if it could determine the position and movement of the disc and detect numerous valve degradations. Tests were performed at various flow rates and flow conditions including uniform approach flow, artificially induced turbulence, cavitation, forward flow and seat leakage. Tests were conducted with a new valve (undegraded condition) to provide baseline data for subsequent degradation tests. With the baseline data for reference, the three technologies in general were able to distinguish beyond a new valve and a valve with degraded internals. They could identify the source of the degradation and in some cases were able to distinguish the level of degradation (15 and 30 percent). They could determine if the disc was missing, stuck or operating normally throughout its entire stroke. The ultrasonic and magnetic techniques were able to determine mean disc position and identify magnitude and frequency of disc flutter. A secondary objective of the study was to collect data on the minimum velocity required to fully open (Vopen) and firmly backseat (Vmin) the check valves. These research activities were completed and the results are available through NIC.

Since then the Nuclear Industry Check Valve Group has met at least twice a year and since 1991 in conjunction with the ASME OM-22 Working Group on Check Valves so they can assist with the development of and changes being made to the Code.

The ASME OM-22 Working Group on Check Valves was formed in 1990 in part to incorporate the findings of the SOER 86-03 into Code space. It was found that the SOER program approach was more likely to identify a degraded check valve in an incipient failure condition, than the IST Code in 1990 that focused on primarily detecting a failed valve. A satisfactory IST test did not provide any additional assurance of continued reliable operation for if the valve was in a state of incipient failure it would not fail its next IST test without allowing for any preventive measures to be implemented. . The ASME OM-22 Working Group Check Valves took these things into account, and developed Appendix II "Check Valve Condition Monitoring".

The intended purpose of Condition Monitoring is improved performance, optimization of testing, and preventive maintenance activities.

A COMPARISON OF TRADITIONAL IST AND CONDITION MONITIORING

Traditional IST only takes a mere snapshot of the valve. A traditional test could only determine information that the valve would provide service in the safety direction when the test was performed. A Condition Monitoring Program would provide the information for extended performance of the valve. An example is a valve that only has a forward safety flow direction. In this case the valve under traditional IST would require only forward flow verification. This may be performed as a system flow test. In this case the disc could be missing and it would still pass. In a condition monitoring program the valve failure mechanisms would be determined, i.e. leakage, disc stud wear, sticking open, etc. Testing which would concentrate on trending towards those failures would be determined and the most cost effective test would be used. In addition to that, both directions of flow would be tested to provide assurance that in the valve being tested, the valve disc is present and that the valve is functioning, and not acting as just a piece of pipe as would have been the case in the traditional IST surveillance.

One such example is where a valve was missing its disc, though it was passing its required Code test. This valve had a requirement to only be tested in the open position and the only test being performed was a System Flow Test. Without the disc the valve had no problem passing the test.

If the valve had been tested using Appendix II it would have been required to have been tested in both directions. Also, Condition Monitoring would have developed a testing strategy requiring a baseline test with the valve in the known satisfactory condition. After that a test frequency to collect trendable data which would indicate condition would be implemented. If a trend continues to be favorable, the frequency may be stepped out (lengthened). If the trend becomes unfavorable, the test frequency would be shortened or possibly a better or more comprehensive test would be employed. Once the trend becomes negative it is time to perform maintenance prior to the valve's failure.

In a traditional program the valve is tested as part of a system rather than as a component. The traditional program does not test for specific expected failure mechanisms as in a Condition Monitoring Program. The Condition Monitoring Program determines, for each valve, the expected failure mechanism and through a process determines testing which will provide information which can be trended. In this case the valve trend provides an alert as to when maintenance is needed, not allowing the valve to go to failure.

Traditional IST does not allow for new technologies and philosophies being developed. In a Condition Monitoring Program, as technologies change and testing methods become more meaningful, utilities are allowed to incorporate improvements without relief request or prior approval. A Condition Monitoring Program requires feedback which includes reviews of past testing and methods to make sure they are meaningful. Because of this, it allows the program to be revised, as it is a living program.

Traditional IST does not allow for you to take credit for other programs or testing. Traditional IST requires a test which is set at the beginning of each update and the only way to change is through relief or to wait until the next update. In a Condition Monitoring Program you can take credit for other programs and testing being performed. If another test is developed or needed which would yield trendable results, credit can be taken for it.

In a traditional program all check valves are treated the same. A swing, piston, dual disc, etc., are all tested the same. There is no consideration as to the type of valve or its possible failure mechanisms. Condition Monitoring takes this into consideration from the beginning. It presents a more accurate picture of the valve, its application, and its history. An example is a piston check valve that has a high rate of being stuck closed in dirty water systems. In the same system, a swing check valve has only a slight chance of being stuck closed. In this case the piston check needs to be tested for this failure possibility at a greater frequency than the swing check. In a traditional program all would be tested the same. Unlike Condition Monitoring, a flexible program, Traditional IST is very prescriptive.

Benefits of going to Condition Monitoring

Condition Monitoring provides a much more meaningful testing program. As discussed previously, a Condition Monitoring Program requires testing of the condition in known wear areas of the valve which would lead to a failure. The testing, therefore, provides the most pertinent information to ensure the valve's ability to function at least until the next test interval if not further.

Probably one of the most cost effective benefits of Condition Monitoring is that it allows the utility to determine the frequency of testing based on past history (up to limits imposed by NRC). This has become even more cost effective due to other changes in the Code such as Option B for leak testing. This is an example where two programs can work together supporting each other and can save money doing so. Presently, Option B allows testing frequencies to go to a five year maximum interval and Condition Monitoring has a step wise interval extension requirement which cannot exceed ten years. Since the Option B test is a good monitor for most valve degradation the test can be performed under that program and credit can be taken for both.

In Condition Monitoring, the stepwise interval extension referenced above provides additional savings. Once a valve or group of valves has passed their test and there is no evidence of degradation, testing may be stepped out one cycle. The utility may continue to increase the interval between testing provided that the interval between testing of any individual valve does not exceed ten years as presently imposed by the NRC. With Code changes being considered, the interval is expected to be increased. The proposed change in interval will be based on refueling cycles, and will not exceed eight cycles for a group of size of 4 or more valves.

Condition Monitoring allows grouping of valves for testing. If valves are of the same size, type, and application, they can be grouped together. By doing so, the interval can be extended once a baseline condition has been established. For example, a single valve would require a baseline test and one more test at the decided time interval. If it were grouped with three similar valves once a baseline was established for each valve, one valve would be tested at the first interval, the next at the second interval, the third at the next interval, and the fourth at the next interval. This result in eight tests in the first six years of operation on an eighteen month fuel cycle compared with twelve tests in the first six years if the valves were not grouped.

The testing which is imposed in a Condition Monitoring Program determines both the valve's operational readiness if called upon, and the condition to continue to be ready until the next test interval. This testing will be more comprehensive and will determine that the valve condition is satisfactory.

A Condition Monitoring Program is a living program, not prescriptive, which can be continually updated as test results indicate, or as surveillance technologies improve. There is no requirement for relief from the program as changes occur or the industry matures. Condition Monitoring allows justification of the program and revisions at any time. As new test methods become available they can be incorporated into the program by the user.

Condition Monitoring creates a meaningful and practical solution to monitoring check valve performance.

The NRC is supportive of utilities implementing the Condition Monitoring section of the Code. This alternative has only been available since the summer of 1996, but only a few utilities have adopted it. NIC believes that all utilities might be required to implement this alternative in the future.

Presently, no relief request is required to adopt Condition Monitoring using Appendix II based on the Rule Change where a licensee's Code of record is the 1995 Edition with the 1996 Addenda or later.

TRANSITIONING TO A CONDITION MONITORING PROGRAM

Several plants with a Code of record earlier than the 1995/96 Code have requested to use Appendix II. Owners committing to Condition Monitoring are expected to receive prompt approval from the regulator. Based on the number of procedures that an Owner may need to modify, to revise their IST and Check Valve Programs, it is reasonable for Owners to request implementation over suitable time period (e.g., the process will be implemented over two year time period).

An alternative is adopting Condition Monitoring during your station's ten year Code update.

Owners should review the entire O&M Code to determine the best approach for their individual situation. This depends on the data available from their INPO Check Valve Program, their organizational structure, how much additional testing (e.g., bi-directional testing) they already perform, the interval changes available to accomplish bi-directional testing, etc.

Owners also need to be aware of the modifications in the 10 CFR 50.55 Code that modified the Appendix II requirements. This, as the process is understood, pertains to all plants, even those who obtained permission to use Appendix II via an earlier relief request that predated the November 1999 revision of 10 CFR 50.55a.

There were five issues outside of the Code change that ASME made in the1999 rule and need to be incorporated into any program. The items to be included are:

1. Bi-directional testing requirements
2. Intervals and step wise interval extensions
3. Trending
4. Safety significance
5. Discontinuation of Condition Monitoring

Before anyone can proceed, it must be decided what valves will benefit from this program. If there is previous knowledge that can be applied to the Code Program, or if the knowledge can be developed in conjunction with a corrective action program initiative, the Condition Monitoring Program provides the approved process.

With the use of Condition Monitoring, groupings provide a great benefit. Groupings are intended to allow the user to benefit from information and knowledge gained from other valves which are similar in design and exposed to the same service. Groupings will also aid in determination of the testing philosophy.

The intended purpose should be either improved performance, or optimization of testing and preventive maintenance activities.

Condition Monitoring Program Development

The first step for any program is the need to develop a procedure. The purpose of developing a procedure is to integrate control, define responsibilities, and provide process to improve and/or maintain the requisite reliability of the check valves.

Procedure:

Must define responsibilities which include but are not limited to:

- Performance
- System
- Design
- Maintenance
- Procurement
- Reliability
- Component

Define the process:

- Determine the Basis for Check Valves in the program
- Criteria for Diagnostic (i.e. Normal open / closed)
- Testing Techniques (Non-intrusive, conventional, etc.)
- Strategy
- Trending
- Reporting
- Records

Determine the benefits:

- Know the valve design / application.
- Know the failure mechanisms
- Defining the testing.
- Testing that does not allow for failure.
- Defined test frequency.
- Cost savings
  (Maintenance, Testing and Outage).

What must be committed to?

- Formal Program
- Includes all IST Check Valves
- Bi-Directional Testing
- Discontinuing requires going to code of record (‘ 95 code)
- Reviewing every two years

What must be included?

- Written Program
- Design Review is conducted
- Plant Maintenance and failure reviews get conducted
- Industry Maintenance and failure reviews get conducted
- Document the results of these reviews
- Evaluate the predictive maintenance practices
- Determine test methods
- Identify the testing and methods
- Verify the test methodology
- Determine performance / predictive testing frequency

When updating to Condition Monitoring, or at the next Code update, it is required to commit to taking your entire IST check valve population to the latest Code of record. For valves on which you do not invoke Condition Monitoring, it is required to continue the testing that is presently done, at the same frequency, and bi-directional testing of all the valves must be included at that same frequency. This may be a burden. But by putting the valves into Condition Monitoring you are still required to perform bi-directional testing, but not necessarily at the same frequency, and the prescriptive test is not required. An example is a valve for which the Code requirement includes full flow verification and a leak test. It may be a burden to verify full flow (i.e., accumulator dump valves, Safety Injection valves, etc.), and performing a full flow test on many valves provides no indication of their health. Because of this, Condition Monitoring may only require partial flow to meet the bi-directional testing requirement. This may add up to significant savings.

Current State of Condition Monitoring Programs and Actual Plant Specific Benefits and Problems

Benefits of Check Valve Condition Monitoring for Seabrook (OR09)

Summary:

- Seabrook Station has 108 valves included in the Check Valve Condition Monitoring Program.
- Condition Monitoring implemented in August, 2000 as part of the Code 10-Year Update.
- The last outage in fall of 2003, OR09 started to see the benefit with the interval extensions.
- Seabrook has aligned the Local Leak Rate Test (LLRT) testing that included check valve closure verification to the Appendix J Option B.
- Accumulator check valves do not require the accumulator “blows” since implementation of check valve condition monitoring. Positive indication of check valve opening which involves draining through the check valve is performed. This was actually an interval extension for OR09.
- Prior to check valve condition monitoring implementation, check valves on the primary side were disassembled for IST testing. These valves are now tested using alternate methods such as verification of differential pressure during various plant evolutions, tagging/draining evolutions, open verifications during plant evolutions (i.e., reactor coolant system evacuation and cavity fills), and the use of non-intrusive testing.
- Non-intrusive testing of Condensate Storage tank check valves is performed on-line and using interval extensions. Previously, valve disassembly and radiography were employed.
- The reactor coolant pump seal injection check valves are verified closed with non-intrusive testing during the outage and interval extensions have been applied. The first extension was used during OR09.

Man-hour savings:

- Approximately 900 man-hour savings for maintenance/ valve crews including scaffolding and insulation
- Approximately 380 man-hour savings for the testing group including LLRT

- Non-intrusive test engineer had a savings of 50 mrem for the outage due to the interval extensions for non-intrusive testing of the seal injection check valves

Benefits of Check Valve Condition Monitoring for McGuire (2EOC-14)

Work Hours (WH's) and dose savings for 2EOC-14 as a result of partial implementation of the Condition Monitoring Program at McGuire:

Maintenance (includes valve crews, scaffolding, and misc. tasks) 1100 man hours (based on original estimate developed in September 2001)

ALARA estimated dose savings 1154 mrem

2-4 hours of critical path time saved by not having to dump accumulators.

The above WH estimate does not include:

1) Operations (OPS) Test Group savings for elimination of acoustic testing of Cold Accumulator Check Valves, 10" cold leg primary checks, and 6" RHR checks.

2) OPS retest/functional verifications. Much of this was eliminated but no WH estimates are available.

Benefits of Check Valve Condition Monitoring for Catawba

The work hours and man rem savings were higher for Catawba Unit 1 outage with one difference. Catawba put many more valves into the program prior to the outage (118) and some were thermal reliefs that had never been bi-directionally tested. Several of these valves failed because when flow was put through the valve the soft seats (15-20 years old) partially washed out. This was expected. All of these valves were small; less than 1", and maintenance was completed quickly with no impact. The overall savings has not been documented yet is greater than McGuire's.

Benefits of Check Valve Condition Monitoring for Wolf Creek

- There are 55 valves in the Condition Monitoring Program
- Implemented in 1996 using a Relief Request.
- Benefits were found immediate upon implementation
- We have aligned the program to take advantage with other programs such as Option B Leak Testing.
- Eliminated high dose disassembly
- Reduced dose and labor associated with temporary instrumentation
- Aligned App J frequency with check valve test frequency
- Simplified bi-directional compliance
- Enabled credit for non-traditional measures (valve body wall thinning, credit for good performance, maintenance history)
- Eliminated rigid requirements to enable getting many tests off of outage critical path.
- This is an example of before and after going to Condition Monitoring Benefit:
  Auxiliary Feedwater full flow testing was performed in Mode 3 at the end of outage and set back power ascension. This test is now performed during power ascension.

Benefits of Check Valve Condition Monitoring for Millstone

There are 166 valves at Millstone Unit 3 and 117 at Millstone Unit 2 in the Condition Monitoring (CM) Program

Millstone station has adopted the 1996 code, subsection ISTC for IST check valves. The Condition Monitoring option is used on 26 valves at Unit 2, and 88 valves at Unit 3.

Benefits were first found in extended intervals for very burdensome disassembly inspections. In the last unit 2 and unit 3 outages we did not have to do some inspections and realized great savings in outage time, man-hours and man-REM.

Fewer disassemblies means lessened chance of the possibility of maintenance induced problems.

We now have better ability to align inspections with "A" or "B" train refueling outages.

The Appendix J Program, using Option B can go to 60 months in a few groups; and we use a CM evaluation to credit this testing.

We are crediting everyday operation of the plant for certain open function (bi-direction) requirements.

On-line credited surveillances and disassemblies for Condition Monitored valve groups is a great savings.

We have not reduced the number of disassemblies. We have dropped or lessened the amount of difficult disassemblies and inspections (D&I's) and added some simple, isolable, on-line D&Is. A good trade.

Millstone Units 2 and 3 will continue to dump all accumulators to credit outlet check valve strokes although we will do it at reduced pressures and less instrumentation than previous tests.

We have developed ultrasonic testing (UT) techniques to verify closure of seal injection lift check valves and some tilting disc valves.

Millstone doesn't have any figures but man-hour and man-rem savings have been realized.

Benefits of Check Valve Condition Monitoring for Byron

- The program includes all required IST Check Valves in this program, no cherry picking.
- Byron elected to go to Condition Monitoring, based on expected benefits to the station and component reliability, not as a result of the ten-year update. This was as a result of good past maintenance/diagnostic history and a solid check valve program (SOER 86-03).
- Condition Monitoring is well aligned with other programs, i.e. Option B.
- Program was implemented by June 2000-September 2001.
- There are 38 valve groupings in the program. Each group consists of 1 to 8 valves per unit, totaling 146 valves. Byron is a Two Unit, Four Loop Westinghouse pressurized water reactor (PWR).

Some examples of specific valves in the program and the benefits to the station since implementation, see below.

System	Valve ID	FREQUENCY/TEST METHOD	BENEFITS/SAVINGS
AF	1/2AF001A/B, 003A/B, 29A/B	Changed from 36-month disassembly to diagnostic surveillance on line every 36 months (per train).	Savings included maintenance /Operations (OPS)/ Radiological Protection (RP) /Scaffold. $20K Reduction of 12 hours from outage window
CS	1/2CS008A/B	Changed from 36 month disassembly to 54 month disassembly	Saving = $16K per valve which included RP/OPS/ Mechanical Maintenance (MM)/Scaffold/ Engineering
CS	1/2CS003A/B, 1/2CS011A/B, 1/2CS020A/B,	Changed frequency from 36 month disassembly, what was done to 54 month disassembly	Saving per train for 3 valves are $15K which included, RP/OPS/MM/Scaffold/ Engineering
FW	1/2FW079A-D	Tilting disc check valves were replaced with Nozzle Check at the same time that CM was implemented. Disassembly of at least one of four valves was required during each refueling with scope expansion to correct anomalous findings. Currently using diagnostics on one loop per outage.	Total cost savings after installing new valve and implementation of CM is $220K per outage. This was included cost for MM/OPS/Insulators/ Scaffold.
SI	1/2SI8948A-D 1/2SI8956A-D	Changed diagnostic testing from 4 loops to 1 loop per outage.	Savings included reduction of critical path 6 hours, which is $200K per refueling outage, Savings, including RP/MM/OPS/Insulators/ Scaffold $60K per outage
CV	1/CV8368A-D	Changed from radiography of four valves per outage to disassembly of one valve each outage	Total savings included RP/OPS/RT/Scaffold/ Insulators/Engineering is $30K per refueling outage. No longer requires 5 hours limited access to containment due to radiographic testing (RT)

Benefits of IST Check Valve Bi-directional Testing and Condition Monitoring Efforts at Palisades Nuclear Plant

- There are 25 groups and 38 valves in the Condition Monitoring Program.
- Fully implemented in 2003 using a Relief Request that was approved per NRC SER (3/1/02).
- Benefits (production costs and dose) were realized immediately upon implementation.
- We are fully integrated and aligned with the Appendix J—Option B Leak Rate Testing Program to take advantage of extended test frequencies for good performing valves (60 months versus 18 months) for exercising.
- Eliminated high dose disassembly and inspections.
- Simplified bi-directional compliance (e.g. no relief requests submitted and cold shutdown partial flow testing eliminated).
- Increased failure detection.
- Eliminated rigid exercising requirements to enable getting many tests out of outage scope and off critical path.

Check Valve / IST Program Condition Monitoring Implementation (Code Update)

The IST/CKV Program Engineers have worked together to update these two programs to the OMa-1996 Code for Check Valves, which was completed in December of ‘03. This was in response to previous check valve failures and program weaknesses. The Check Valve Program is now aligned with the best industry practices, integrates the latest and most extensive non-intrusive mythologies and techniques, and preventive maintenance activities have been optimized.

There have been extensive improvements made in the check valve program area in regards to performance and condition monitoring. Substantial savings have been realized in both operations and maintenance (O&M) and personnel dose. The EPRI Condition Monitoring Template classification and preventive maintenance (PM) guidance has also been incorporated for a blended approach to PM optimization. The condition monitoring analyses documents are complete and thorough, incorporating operating experience, maintenance and corrective action histories, and test results.

There are many more examples that could be sighted, but the bottom line is that CM has paid for itself many times over. The same methodology is also utilized on non-IST valves in the check valve program.

Conclusion

As anyone can see from the information above, invoking Appendix II “Condition Monitoring for Check Valves” will only increase a plant’s safety while saving on manpower, man-rem exposure and rad waste. Overall, plants going to condition monitoring do have some up front costs. These expenses should be able to be recovered by the first outage following implementation, if not sooner. For further information, contact any of the utilities who supported this paper or attend a meeting of the Nuclear Industry Check Valve Group, where Condition Monitoring is always discussed.

Supporting Examples:

System/Valve	Intervals and Methods	Savings and Benefits
Various Appendix J—Option B check valves	18 month exercising to 60 month exercising and leak testing. Inspection PMs aligned with 60 month LLRT to reduce number of leak tests (as-found/as-left). Non-intrusive monitoring data collected online versus outage.	No relief request needed to align good performance and exercising test frequencies Operators able to perform other work. Dose eliminated.
SIRW Tank Outlet Checks (24” swing checks on ECCS pump suction headers)	Spectacle flange not needed to be swung to align flow path. Non-intrusive testing eliminated. 10-year inspection on both valves ended. Aligned with ASME pressure test of suction piping for verifying closure with seat leakage. HPSI pump ASME test flow used for crediting open.	Eliminated 6 hours of critical path time. 40 man-hours and 400 mrem dose savings for testing portion only. One inspection takes 100s of man-hours and dose.
Containment Sump Check Valves (24” tilting disc checks on ECCS pump suction headers)	Manual Exercise test with torque wrench was used to measure breakaway. Breakaway test results were not repeatable. Changed to measure shaft rotation and torque using air-operated valve diagnostic equipment under CM. Once repeatability is established using this new methodology, then test intervals will be extended.	CM allowed a tailored test methodology to be developed employed. This saved a relief request from being developed and approved.
ECCS Pump Suction and Discharge Checks	Trains aligned to test one valve per outage during full flow (most repeatable test conditions) using non-intrusive techniques. Note: Partial flow tests were maintained quarterly so as not to impact PSA Model/Risk Ranking.	Initial interval established under CM for non-intrusive testing (NIT) is 3 years (changed from 18 months). Next interval change should go to six years or better. Inspection PM activities were deleted.

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Experimental Investigation of Swing Check Valve Performance

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Abstract

In spite of its simple design, structure and operating mechanism, a swing check valve is one of the critical components which adversely affect the safety of the nuclear power plants if they fail to function properly. Therefore, it is important to evaluate the performance condition of the swing check valves in safety-related systems, where the opening characteristics and the minimum flow velocity are major factors to identify the performance of a swing check valve. The minimum flow velocity necessary to just open the disc at a full open position is referred to as V_{OPEN}, but V_{MIN} is defined as the minimum velocity to fully open the disc and hold it without motion.

In the present study, the existing minimum velocity model for a swing check valve is modified by considering four different forces acting on the disc such as back seating force at the full open position, weight of the disc assembly, flow inertia, and pressure differential forces. This model can also predict the position of the disc for a given average flow velocity. For verifying the present model, an experimental loop is designed and installed to measure the disc positions with flow velocity, V_{OPEN} and V_{MIN} for 3-inch and 6-inch swing check valves. The tests were performed at various conditions of upstream flow disturbance source and distance from the tested check valves. These experimental results are presented and compared with the model predictions.

Introduction

Check valves have been used in many pipeline systems throughout nuclear power plants and play an important role in the operations and protection of plant components and systems. The functions of a check valve are to prevent flow reversal in a piping system due to the shutdown of a pump or the closure of a control valve, and to allow forward flow in response to flow direction. So, check valves have been considered to be the simple and passive component requiring no further concern till quite recently. In addition, the minimum flow velocity required to open the disc fully and thus prevent motion (V_{MIN}) is sometimes ignored. However, check valves must operate properly and reliably when called upon to perform their design function. Also, one important lesson learned in the industry is that valves of similar design may have exceedingly different performance characteristics. Thus, check valves have been the subject of investigation and testing for a number of years.

Chiu and Kalsi [1] developed the theoretical model for determining V_{OPEN} velocity. They used the simple moment balance equation about the disc hinge of a swing check valve but the forces necessary to hold the disc without motion were not considered in the model though they introduced the seating force margin of 20% to consider the effects of turbulence fluctuation and upstream flow disturbances. This margin leads about 10% higher value than V_{OPEN}.

To derive the V_{MIN} velocity, Rahmeyer [2] considered four different forces acting on the disc such as back seating force of the valve body against the fully open disc, disc assembly weight, flow inertia and pressure differential force. However, he combined the pressure differential and the back seating forces into a single moment using a coefficient for pressure drop and backseat forces. Also, it is recommended to improve or adjust his model to consider the effects of the upstream flow disturbances on the V_{MIN}. These models are included in EPRI report [3] as V_{OPEN} and V_{MIN} equations, respectively.

The conditions at which the disc of a swing check valve opens fully are directly related to the velocity of the upstream flow. For example, the upstream piping components such as valves, elbows, reducers, and expansions modify the flow profile approaching the valve, resulting in the change of the relationship between the flow rate and the position of valve disc. Even at high flow velocities, upstream conditions that cause the disc not to open fully may exist, but those conditions are often overlooked.

In this paper, the existing model to predict the minimum required velocity and the valve positions with the average flow velocity for a swing check valve is modified and the experimental loop to measure the disc positions with flow velocity, V_{OPEN} and V_{MIN} will be described. These experimental results are also presented to compare with the model predictions.

Analysis

Background

The movement of the valve disc depends on the hydraulic forces, disc weight, valve hinge friction force, inertia, and any external forces if they exist. In general the effects of the disc inertia, disc weight and the external forces are describable in a straightforward way. However, the friction induced at the hinge is difficult to evaluate but its effect is usually not significant. Rahmeyer suggested that any friction of the valve hinge would be negligible in his experiments on large-size check valves [2]. The hydraulic force plays the most significant role in determining the valve behavior, including disc opening performance. But the hydraulic force historically has not been characterized properly.

The hydraulic force is the force due to the fluid flow around the disc of a swing check valve. Theoretically, the hydraulic force can be calculated from the pressure distribution around the valve disc. However, it is nearly impossible to determine the pressure distribution analytically or experimentally due to complicated flow patterns. As an approximation, the hydraulic force is often estimated by the difference of pressure measured at two locations across the check valve where steady one-dimensional flow assumption dominates.

The hydraulic force has been described in three categories by previous investigator [2, 4-7]: pressure difference across check valves; relative motion between the fluid flow and the disc rotation; and both of two components. Rahmeyer [2] assumed that the hydraulic force is composed of two terms attributable to flow velocity and pressure difference, respectively. He determines the coefficients to quantify the hydraulic moment by measuring the valve discharges but the pressure drop coefficient is considered as a constant. Botros et al. [4] applied this approach to a check valve in gas flow with some modifications. Uram [5] estimated hydraulic force by the difference of pressure measured across the check valve. Both Pool et al. [6] and Ellis and Mualla [7] represented the hydraulic force as two terms of flow and damping. They used a similar approach to determine both the flow and damping coefficients. The flow coefficient was determined experimentally from a steady state flow test and the damping coefficient by free movement of the disc in initially still water.

Modeling

In this study, the similar approach to Rahmeyer's one is taken. It is assumed that the hinge friction force is negligible and the flow in the pipe is fully developed. Thus, the forces acting on the check valve disc are due to: the submerged weight of the disc assembly; the flow around the valve disc; the pressure differential across the valve and disc; and back seating forces of the valve body against the fully open disc.

As shown in Fig. 1, the disc assembly weight and the back seating force exert a closure torque for the horizontal orientation. On the other hand, the fluid and pressure differential forces exert a torque in a direction to open the disc. Therefore, the position of the check valve disc at any time, evaluated as the angle of the disc from vertical, may be found using a balance of those four forces acting on the valve assembly. By balancing torques about the axis through the center of the disc, the velocity required to maintain the disc position without motion at a full open angle can be expressed by:

$$V = \sqrt{\frac{M_{WT} / \rho}{\frac{\pi}{4} \cdot K_{VEL} + K^{*}_{\Delta P} - K_{SEAT}}} \qquad (1)$$

where the definitions of M_{WT} and K_{VEL} are the same as in Reference 2, as shown in Table 1. The parameter $K^{*}_{\Delta P}$ is the torque parameter only due to the pressure differential force across the disc:

$$K^{*}_{\Delta P} = \frac{1}{2} \cdot C_D \cdot A_D \cdot L \qquad (2)$$

where C_D is the disc pressure drop coefficient, A_D is the disc area, and L is the length from the hinge pin to the center of the disc. Note that $K_{\Delta P}$ in Rahmeyer's model is the combining torque parameter due to the pressure differential and the backseating forces as follows:

$$\begin{aligned} K_{\Delta P} &= A_D \cdot L \cdot C_D \\ &\cong A_D \cdot L \cdot (K_b \cdot \theta)^{-3} \end{aligned} \qquad (3)$$

where K_b is the coefficient for the pressure differential and back seating forces.

In Eq. (1), K_{SEAT} is the torque parameter due to the back seating forces of the valve.

$$K_{SEAT} = C_{SEAT} \cdot W_{DISC} \cdot (L/D_i)^2 \qquad (4)$$

where W_{DISC} is the weight of the disc, D_i is the inside diameter of the valve inlet, and the back seating coefficient C_{SEAT} is as follows:

$$C_{SEAT} = \frac{0.065 \cdot (\Delta\theta)^2}{\rho \cdot g} \qquad (5)$$

Equations (4) & (5) results from the assumption that the torque due to the back seating force is the same as the kinetic energy of the valve disc at the full open position. The basis of this assumption is that the additional torque, required to maintain the position without motion after the valve fully opens, approximates the kinetic energy due to the disc tapping at the full opening position. To obtain the disc velocity, the natural frequency of the disc is needed. The disc natural frequency can be approximated as twice of the turbulent eddy frequency:

$$f_{EDDY} = 0.08 \cdot V / D_i \qquad (6)$$

from the suggestion by Griffith and Sununu [8]. Then we can determine the disc velocity V_{DISC} using the following equation:

$$V_{DISC} = L \cdot \Delta\theta \cdot (2 \cdot \pi \cdot f_{EDDY}) \qquad (7)$$

from which the kinetic energy of the disc at the full open position, and therefore the expressions of Eqs. (4) and (5), can be obtained.

When using the Eq. (1) to obtain the disc position at a fluid velocity, K_{SEAT} is zero. If we want to determine V_{MIN}, however, Eq.(4) should be used to calculate K_{SEAT}.

Experiments

Experimental Loop

As shown in Fig. 2, a check valve performance test loop with two horizontal 3-inch and 6-inch test sections was designed and constructed for this study. Figures 3 and 4 are the photographs of the experimental loop and two swing check valves with instruments for the test, respectively.

The main components of the loop are two water storage tanks, centrifugal pump with rated capacity of 5.4 cubic meters per minute (m^3/min) at 71.35 meters (m), two flow meters, test section, and flow control valves, including the several pipe segments. The capacity of each storage tank is 2 m^3, and the pump is driven by an electric motor.

The test section is of modular construction, allowing piping configuration changes for upstream flow disturbance testing. For the tests, the type of the disturbance sources, such as elbow and globe valve, and the position of the 3-inch or 6-inch swing check valves in the test section can be adjusted. The main pipes have an inner diameter of 143 millimeters (mm) (6 inch) but the pipes of 77 mm (3 inch) diameter was connected to the main loop for 3-inch valve tests (see Fig.2). The 3-inch swing check valve has a disc diameter of 82 mm, a disc full open angle of 61.3-degree, and the weight of the disc assembly in air of 1.3 kilogram (kg). The 6-inch valve has 134mm disc diameter, 62.7-degree disc full open angel, and 4.9 kg disc assembly weight.

Instrumentation

The water flow rate is controlled by the two downstream remote control valves (2-inch and 6-inch) indicated in Fig. 2. Flow measurement is made with both of the turbine flow meter and electromagnetic flow meter. The range of the turbine flow meter are 80~ 800 cubic meters per hour (m^3/hr) with an accuracy of ±1.0% full scale. On the other hand, the low flow rate, especially for 3-inch valve tests, were covered using the electromagnetic flow meter provided more accurate flow measurements with the range and accuracy of 5 ~ 180 m^3/hr and ±0.5% full scale, respectively. The average flow velocities are calculated from the flow measurements and the valve inlet diameter.

Pressure transmitter and pressure taps are located at the equivalent distance upstream and downstream of the test valves. The range of the pressure transmitter is 0~25 bar with 0.15% full scale. The differential pressure is also measured with a differential pressure transmitter. The potentiometer-type radial displacement transducer is used to measure the disc angular position. The backstop load is also obtained with load cell with the maximum measurable load of 200 kg to investigate the effect of the tapping on the disc stud integrity.

Test instrumentation feeds data directly to a high speed computerized digital data acquisition system which can display and process the data in real time. All the data collection and processing routines were written using the software developed for the tests.

Test Description

Flow loop tests on instrumented check valves were performed to validate the model prediction. During the test, the measured data include flow rate through the valve, valve disc position, differential pressure of the check valve, upstream and downstream pressures, and water temperature.

Steady state testing identifies characteristics specific to the valve design such as flow capacity, and the velocity required to fully open the check valve (V_{OPEN} & V_{MIN}). Additional experiments were performed to investigate the effects of the upstream disturbance source and distance from the check valve. The elbow and control valve (globe valve) are chosen as the disturbance source and the location of the disturbances are 2, 4, 6, 8, and 10 diameters upstream of the check valve.

Results and Discussion

Test Results

Figure 5 shows a set of three curves of the measured disc positions according to the average flow velocities for each of the 3-inch and 6-inch valves. Each curve is associated with three flow conditions such as uniform, elbow at 2 diameters upstream of the check valve, and globe valve at 2 diameters upstream of the check valve. The disc full open angles of these two valves are 61.3 and 62.7 degrees, respectively. From this figure, it seems that there is negligible effect of upstream flow conditions on the opening characteristics of the valve, because the curves are almost collapsed into one. However, Figs. 6 and 7, a plot to compare the disc fluctuations with the average flow velocity, show that the highest disc fluctuations are for elbow case. The effect of upstream flow condition can also be seen in the Figs. 8 and 9 which indicate the back stop load measured with the average flow velocity.

Figure 10 shows the maximum disc fluctuations with the elbow and globe valve at 2, 4, 6, 8, 10 diameters upstream of the 3-inch and 6-inch check valves. The measured V_{OPEN} and V_{MIN} for elbow case are presented in Fig. 11. The V_{MIN} velocity is determined as the minimum flow velocity at which the backstop load begins to increase after the disc is fully opened and the fluctuation level of disc is reduced below one degree. As one would expect, V_{MIN} is measured to be larger than V_{OPEN} but it seems that the effects of elbow and globe valve on both velocities become very small at distances of 4 diameters and beyond from the check valve.

Disc Pressure Drop Coefficient

Rahmeyer [2] proposed that the pressure drop coefficient be a function of the disc position in degrees as follows:

$$C_D = (K_b \cdot \theta)^{-3} \quad (8)$$

where combining the pressure differential and back seating forces, values of 0.025 and 0.035 are suggested as K_b for predicting V_{OPEN} and V_{MIN}, respectively. In this study, the disc pressure drop coefficient can be determined from the experimental data shown in Fig. 1 and Eq. (1) with $K_{SEAT} = 0$. The results are shown in Fig. 12, including the parametric calculations from Eq. (8) with $K_b = 0.12$, 0.04, 0.035, and 0.025. It can be seen that regardless of the upstream flow conditions, the best fitted values of K_b are 0.12 and 0.04 for 3-inch and 6-inch check valves, respectively. From this figure, K_b seems to be dependent on the valve size and further study on this would be desirable.

In Fig. 13, the model predictions with the best-fitted values of K_b are compared with the measured data for uniform flow condition, including V_{MIN}. The results show a good agreement between the predictions and the measured data.

Comparison with Rahmeyer's Model

The predictions of the disc position vs. the average flow velocity using the present model are compared with the experimental data and the predictions using Rahmeyer's model. The results for 3-inch and 6-inch check valves are shown in Figs. 14 and 15, respectively. From both figures, it can be seen that Rahmeyer's model with $K_b = 0.025$ does not predict the present valve position data well. However, his model predicts the valve positions with better agreement for the use of $K_b = 0.12$ and 0.04 for 3-inch and 6-inch check valves, respectively.

Concluding Remarks

The existing minimum velocity model for a swing check valve, Rahmeyer's model, is modified by considering four different forces acting on the disc such as back seating force, disc assembly weight, flow inertia and pressure differential forces. In this study, the back seating force and pressure differential force are separately treated. From the comparisons of the model predictions with the experimental data show that the present model predicts the experimental results well but Rahmeyer's model with his K_b of 0.025 does not predict the present data well. However, his model predictions with $K_b = 0.12$ and 0.04 for 3-inch and 6-inch check valves, respectively, show better agreement.

The upstream flow disturbances due to elbow and globe valve at 2 ~ 10 diameters upstream of the check valve produced minor effects on the check valve performance compared to the uniform flow condition.

Acknowledgement

This study has been carried out under the Nuclear R & D Program funded by the Ministry of Science and Technology (MOST) in Korea.

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8. P. Griffith and J.E. Sununu, *Wear in Check Valves Due to Flow Induced Motion*, Nuclear Engineering and Design, Vol.115, pp. 323-330, 1989.

Table 1 Minimum Flow Velocity Models for Swing Check Valves

	Model	
Chiu & Kalsi [1]	$V_{MIN} = \sqrt{\dfrac{g \cdot B \cdot W_{EFF} \cdot \sin\theta}{2 \cdot \rho \cdot A_D \cdot \cos^2\theta}}$	- B = buoyancy correction factor (0.9 for water) - W_{EFF} = effective disc assembly weight.
Rahmeyer [2]	$V_{MIN} = \sqrt{\dfrac{M_{WT}/\rho}{K_{VEL} + K_{\Delta P}}}$ where $M_{WT} = B \cdot W_{EFF} \cdot \sin(\theta + \beta) \cdot L$; $K_{VEL} = A_{EFF} \cdot (h + 0.5 \cdot z) \cdot \cos\theta$; $A_{EFF} = \sqrt{2 \cdot D_d \cdot z^3 \cdot \cos^3\theta - z^4 \cdot \cos^4\theta}$; $K_{\Delta P} = A_D \cdot L \cdot (K_b \cdot \theta)^{-3}$	

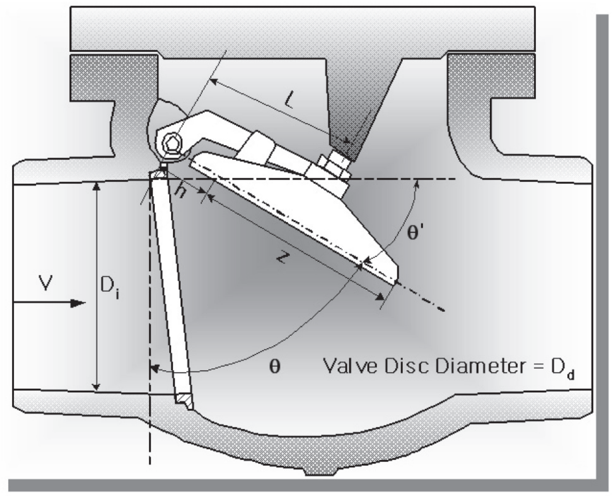

Fig. 1 Typical Swing Check Valve for Minimum Flow Velocity Model

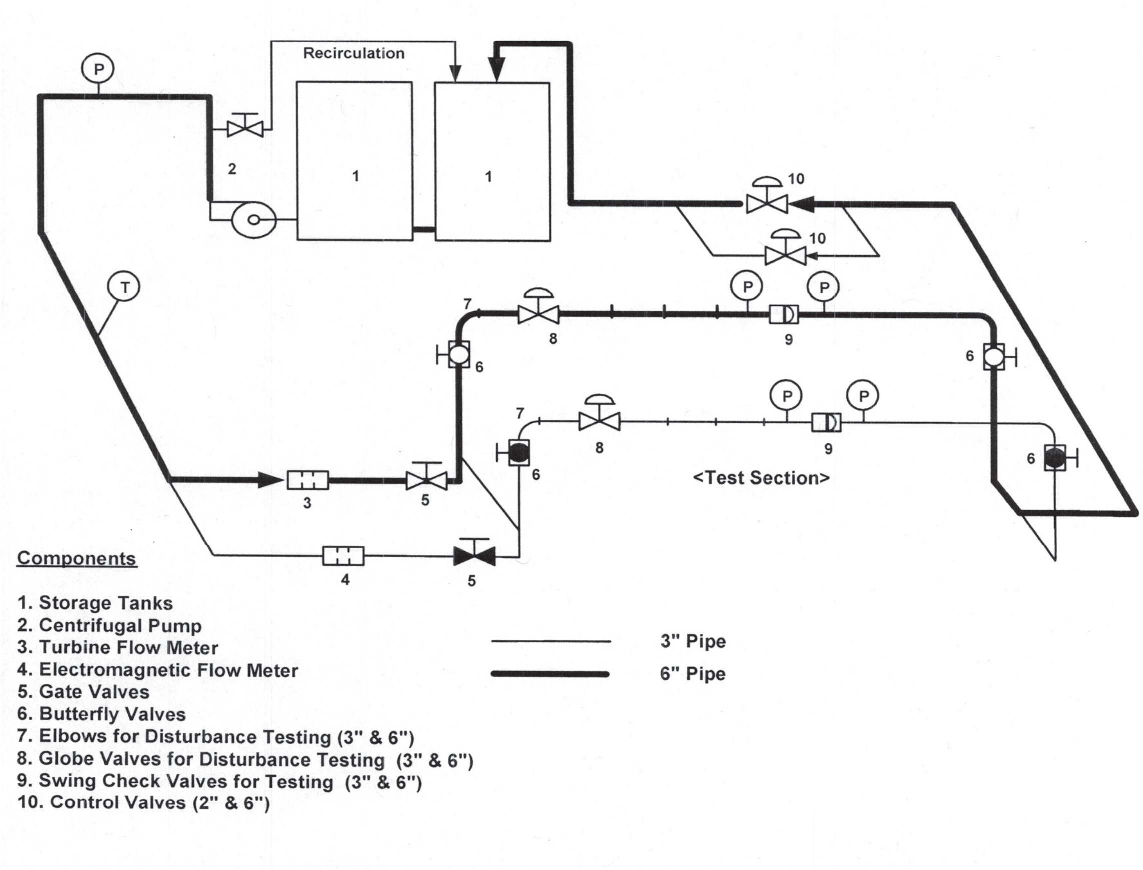

Fig. 2 Schematic Diagram of Experimental Loop for Swing Check Valve Performance Tests

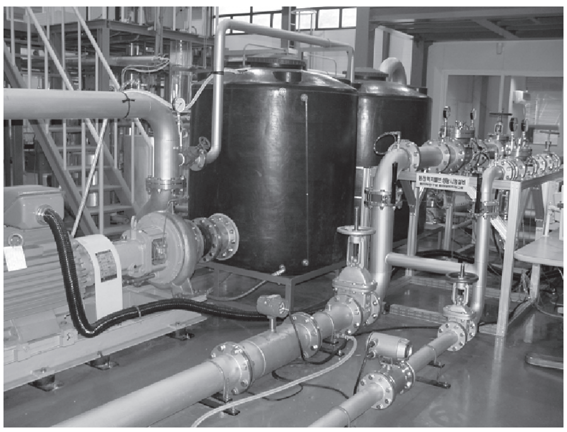

Fig. 3 Picture of Experimental Loop

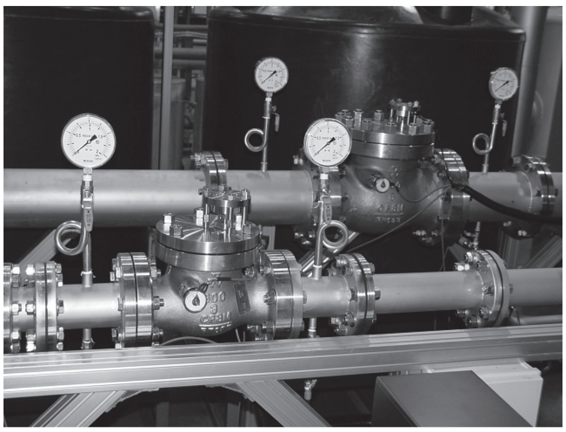

Fig. 4 3-inch and 6-inch Swing Check Valves for Tests

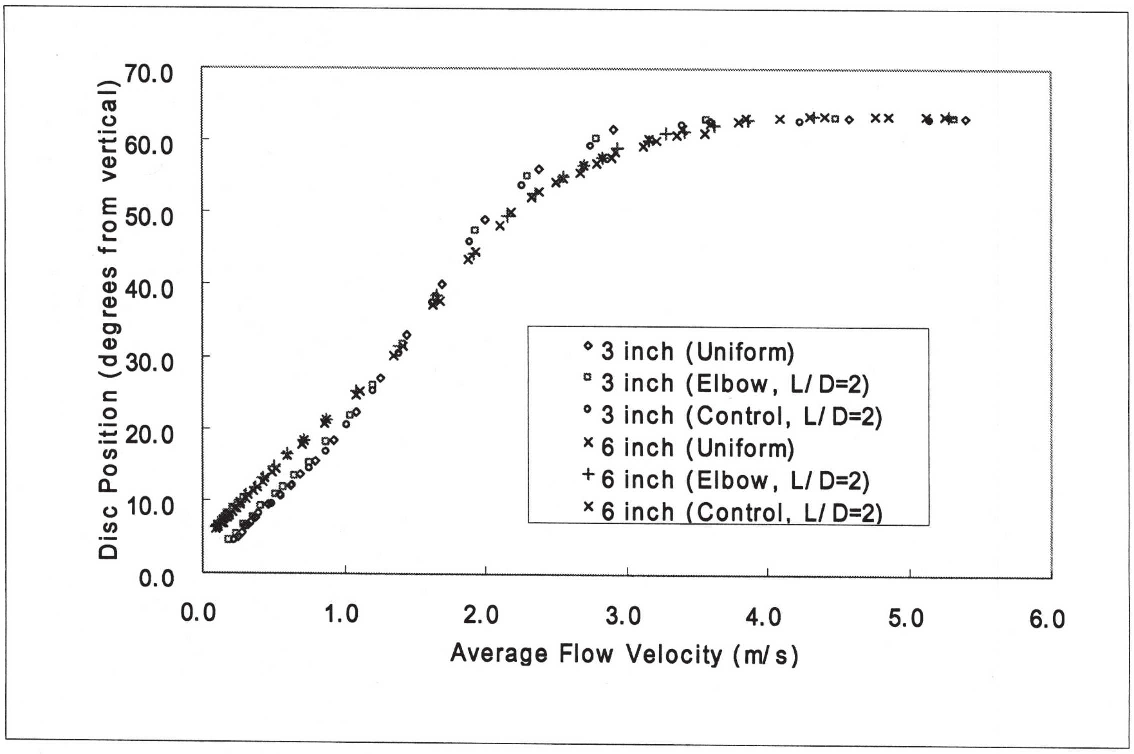

Fig. 5 Measured Disc Position with Average Flow Velocity through the Valve

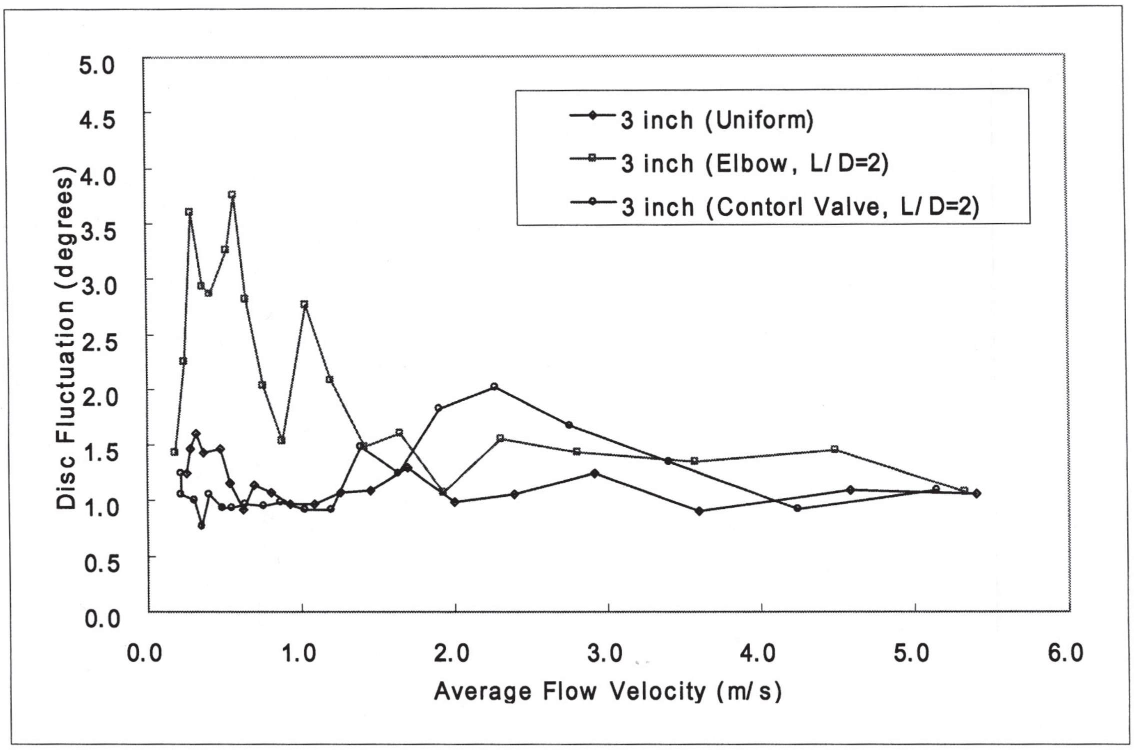

Fig. 6 Typical Disc Fluctuation vs. Average Flow Velocity for 3-inch Swing Check Valve

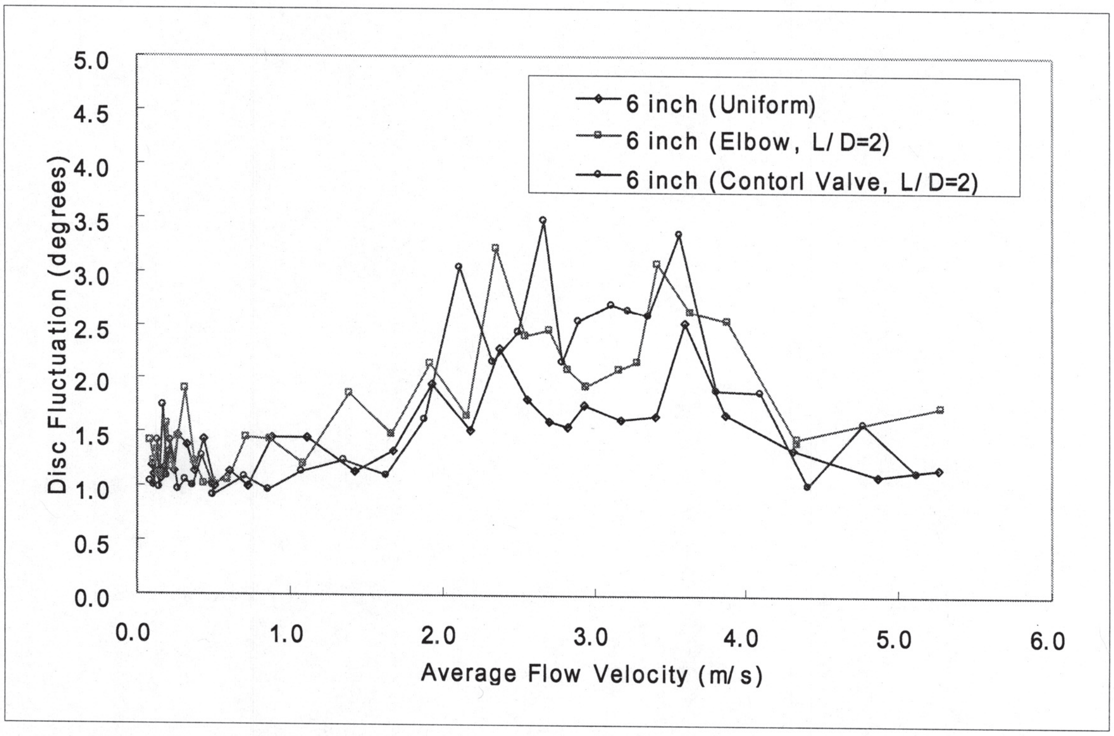

Fig. 7 Typical Disc Fluctuation vs. Average Flow Velocity for 6-inch Swing Check Valve

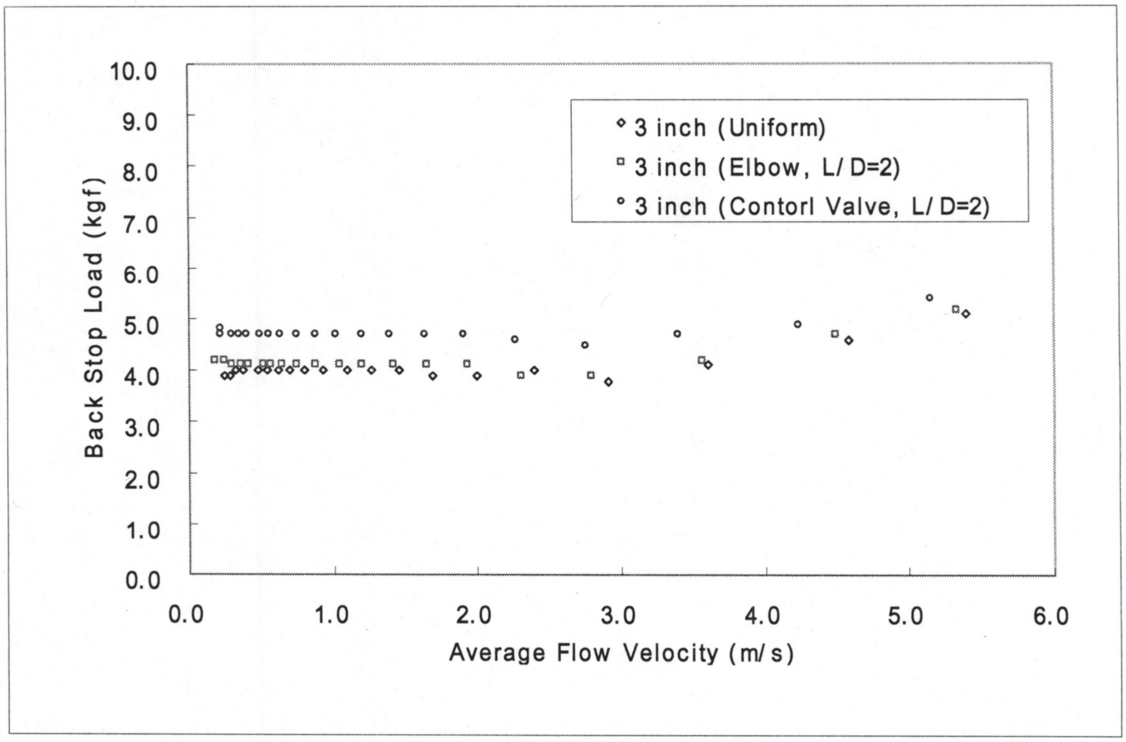

Fig. 8 Back Stop Load for 3-inch Swing Check Valve

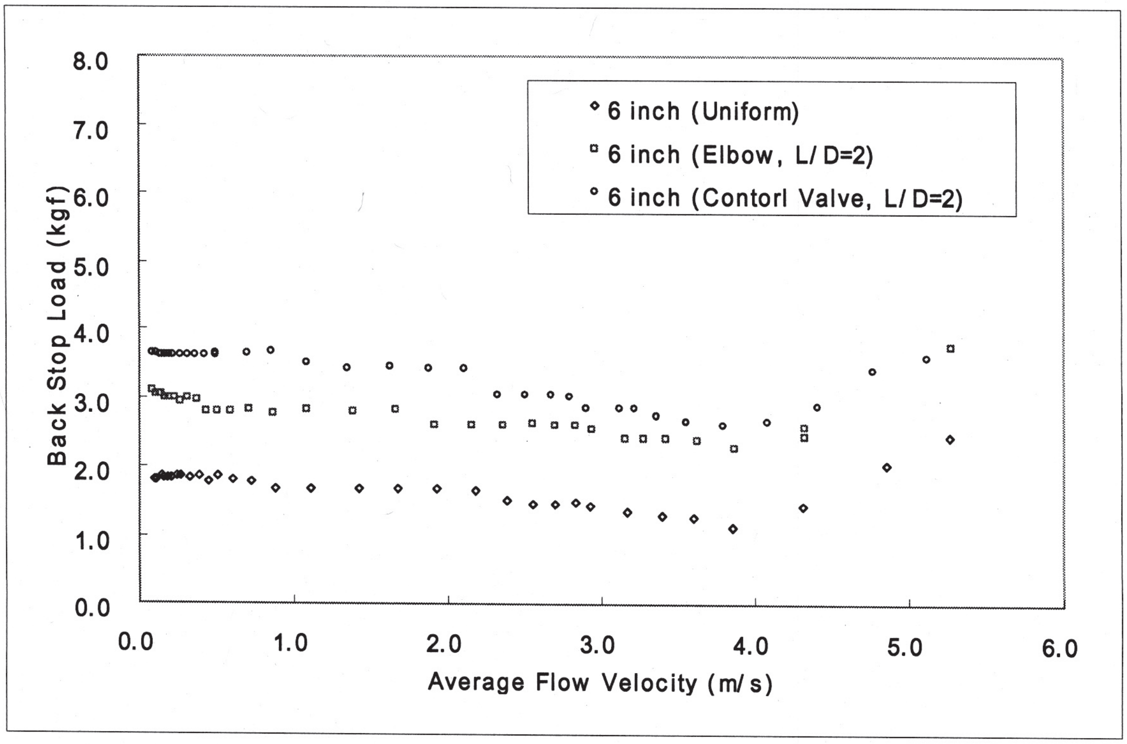

Fig. 9 Back Stop Load for 6-inch Swing Check Valve

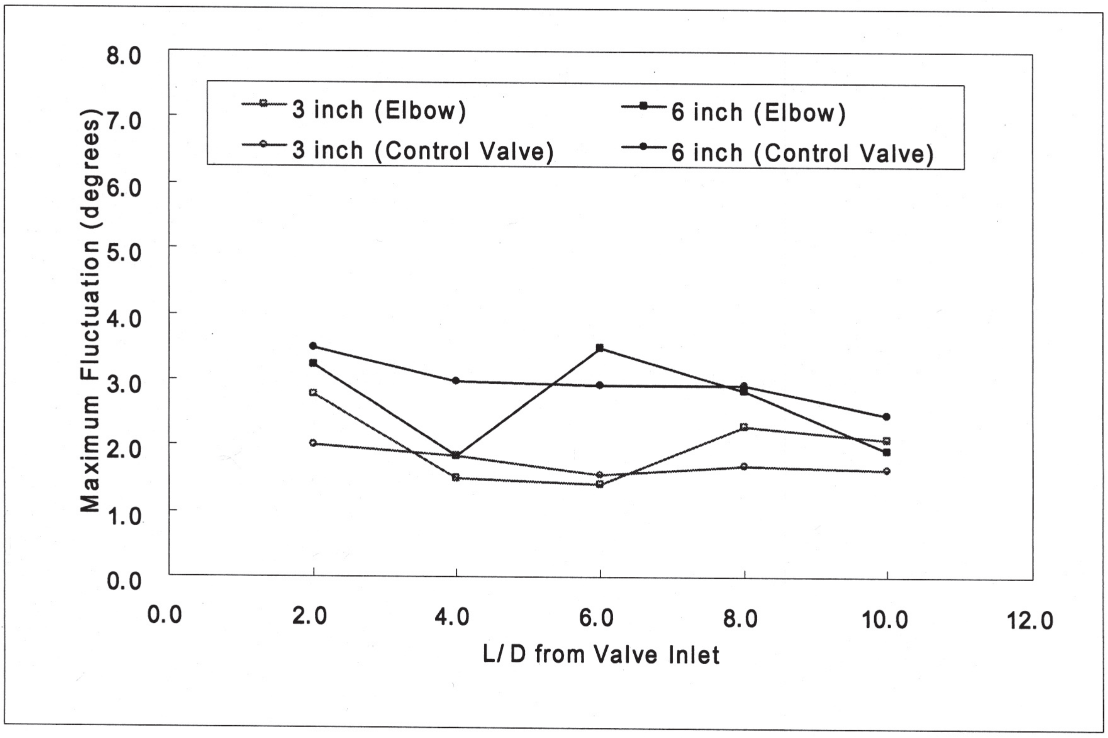

Fig. 10 Maximum Fluctuation with Disturbance Source and Distance from Check Valve

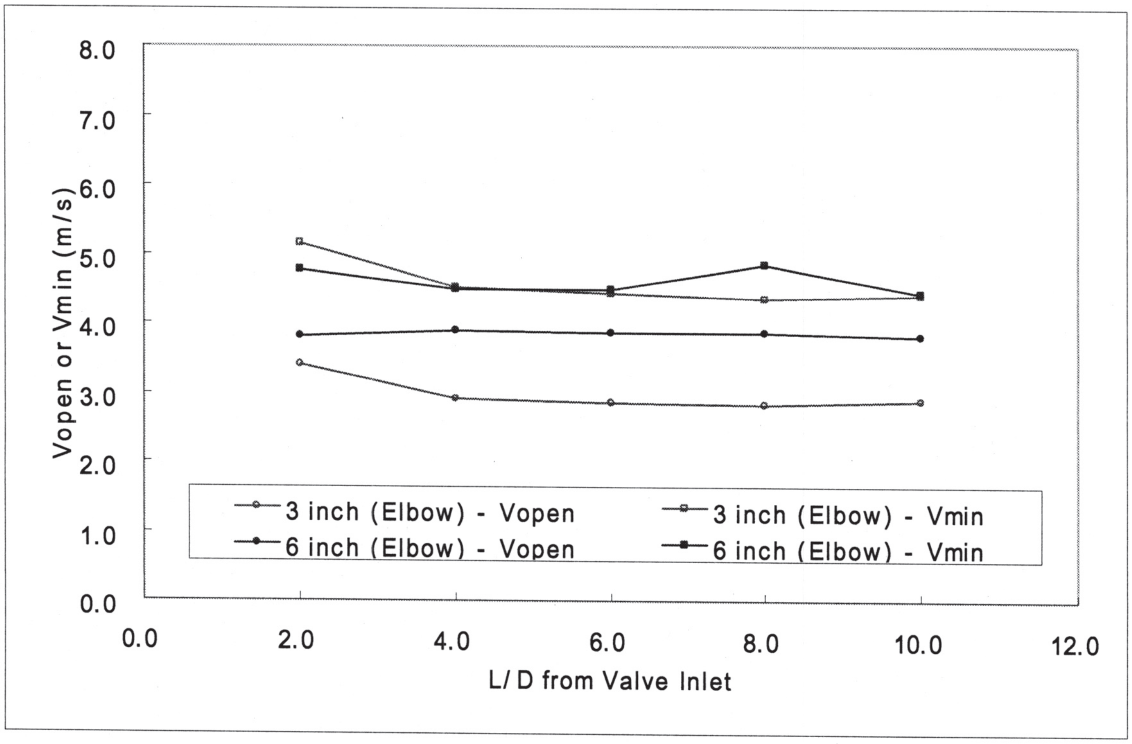

Fig. 11 ***V_{OPEN} and V_{MIN} with Disturbance Source and Distance from Check Valve***

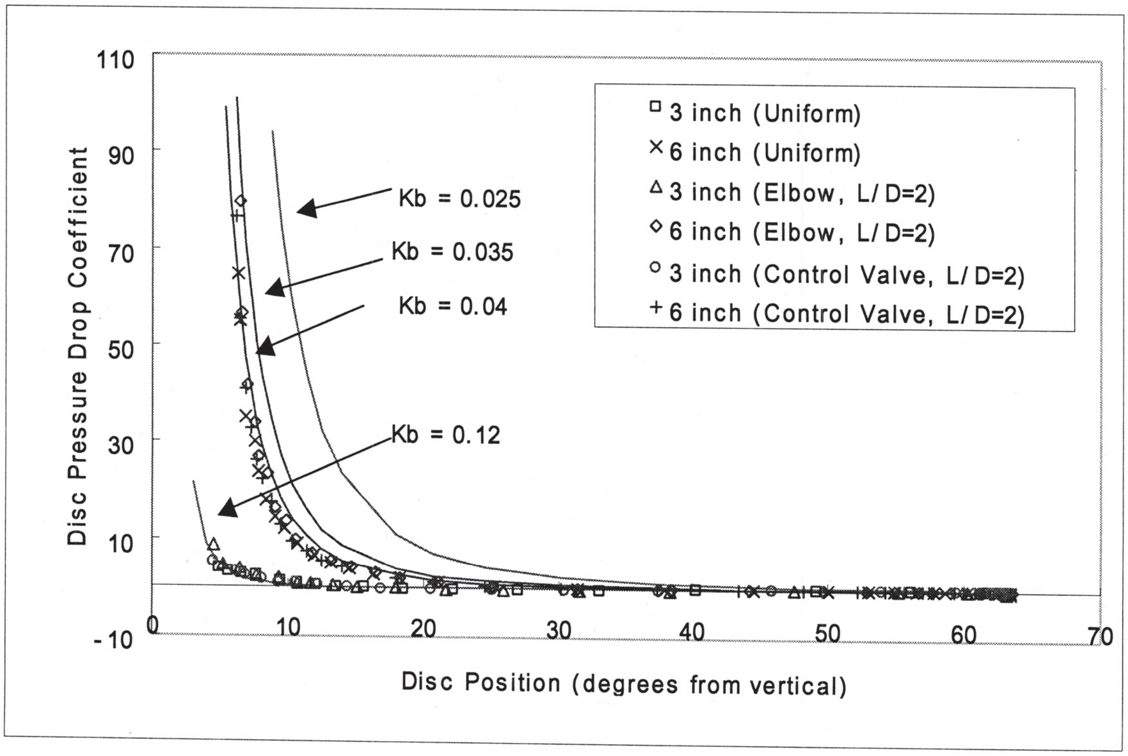

Fig. 12 Measurements of Pressure Drop Coefficient C_D

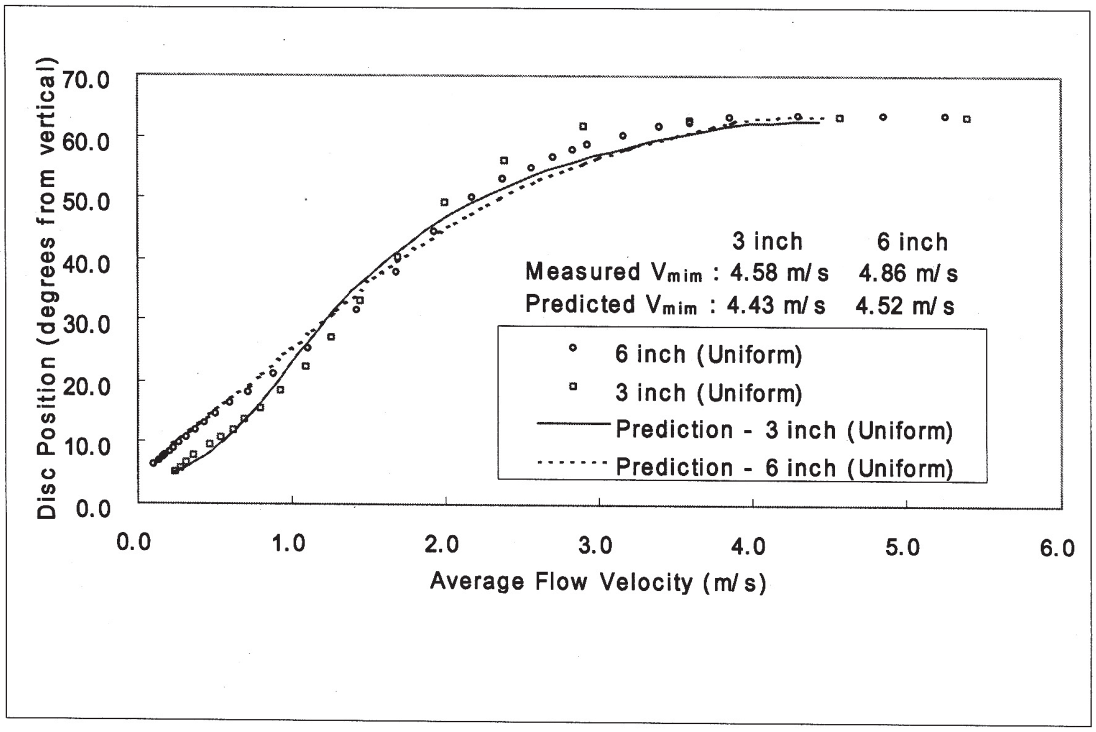

Fig. 13 ***Comparison of Model Prediction with Experimental Data***

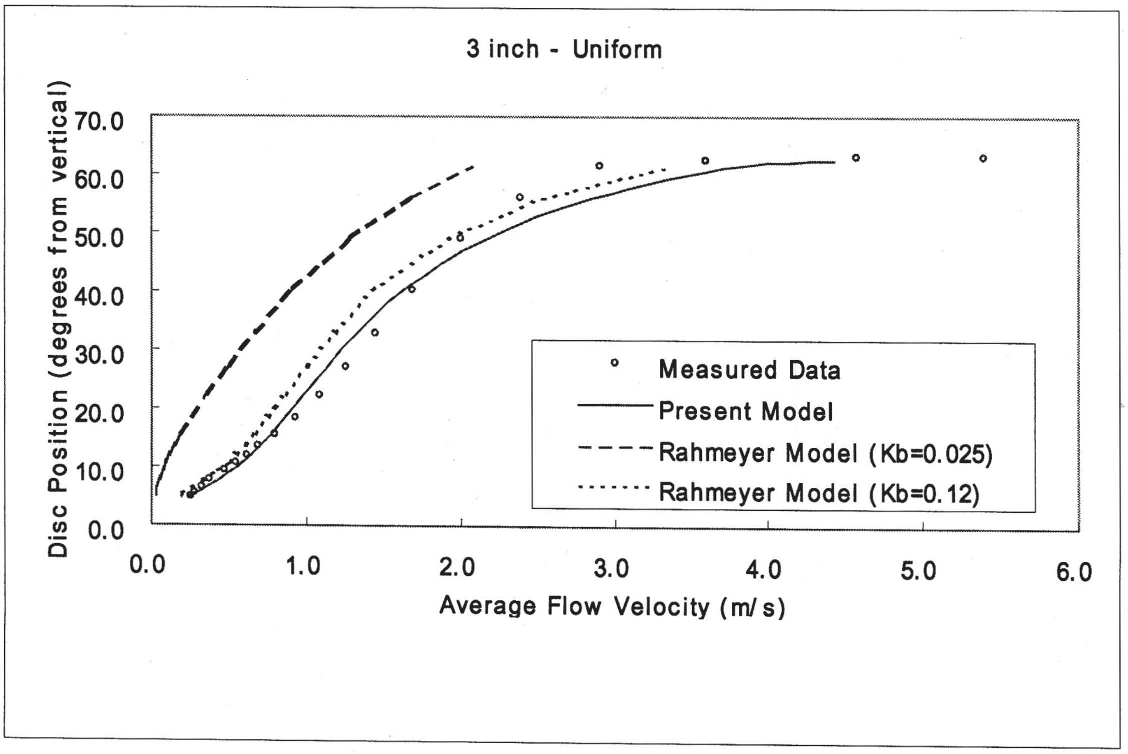

Fig. 14 Comparisons of Present and Rahmeyer's Models with Experimental Data for 3-inch Swing Check Valve

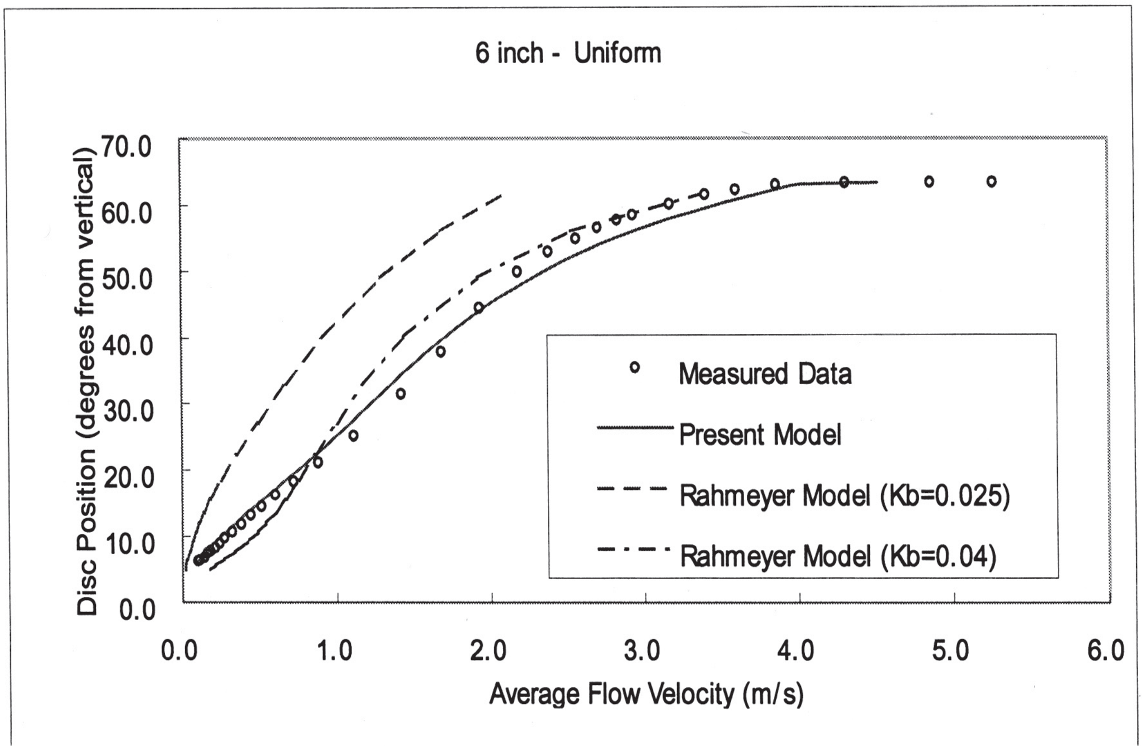

Fig. 15 Comparisons of Present and Rahmeyer's Models with Experimental Data for 3-inch Swing Check Valve

Instrument Air Application Review – Enertech NozzleCheck Design Eliminates Maintenance Rule and Appendix J Test Failures

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Abstract

Rochester Gas and Electric's Ginna Station initiated a project to eliminate chronic Local Leak Rate Test (LLRT) and Maintenance Rule failures of a small bore check valve in the Instrument Air System using advanced valve design technology. Starting with the root cause analysis of the problem, this paper outlines all aspects of this project: the evaluation of various replacement candidates, an economic cost justification and the design change process. It concludes with a performance evaluation of the replacement valve after 18 months of operation.

INTRODUCTION

The Instrument Air system at Ginna, a 490 MWE, Westinghouse design Pressurized Water Plant, is used to supply air to various components both inside and outside the Containment building. Air is supplied to Containment via two Containment isolation valves, one AOV located outside and one check valve located inside, **See Figure 1**. To ensure that fission products are contained within the Containment during a Loss of Coolant Accident (LOCA), all piping penetrations have Containment boundary valves that are required to seat tightly against a postulated accident pressure of 60 psig (pounds per square inch gage). In accordance with the test frequency established per Appendix J, OPTION B, these isolation valves undergo an LLRT that is conducted to verify the capability of the valve to contain the release of radioactive fission products.

The performance requirements for Containment boundary check valves exceed the ability of many valve designs. Since most check valves were designed to support high-pressure seat leakage tests, many will not pass the stringent requirements of site-specific LLRT's even in the as-new condition. When the adverse effects of corrosion, disc oscillation, debris and numerous open-closed cycles are factored in, it is even more unlikely that a check valve will maintain tight shutoff following numerous operating cycles.

To improve performance and resolve obsolescence issues, Ginna Station replaced the original swing check with a poppet style check valve design that utilized a soft seat and spring assisted closure to overcome the obstacles caused by the low differential pressure LLRT. This design also failed to meet the expectations of long-term LLRT success without requiring refurbishment each outage. An alternate design was selected for replacement that utilized a unique pressure-velocity profile along the disk that eliminated wear related degradation by providing the necessary force to fully open the valve. This design has been inspected and tested after one eighteen month cycle with no indication of wear or degradation of seat tightness. Although the implementation of a Design Modification of an ASME Section III component is costly, this proved to be a cost justified endeavor that not only reduced operating expenses but improved plant safety.

APPLICATION DESCRIPTION

Tag #:5393

Operating Pressure:	115 psig
Operating Temperature:	300° F
Normal Operating Flow:	5 scfm (standard cubic feet per minute)estimated to occur 90% of the time.
Velocity @ 75 scfm:	53.63 ft/sec (feet per second)
Upstream piping configuration:	straight
Valve Orientation:	vertical flow up, **Figure 2**

Testing Requirements: An LLRT is performed using a Leak Rate Monitor (LRM) Thermal Mass Flow Measurement Device connected to the downstream vent connection with the upstream section vented to atmosphere. The test is conducted as follows:

1. Isolate test volume
2. Pressurize downstream side to 60 psig using the integral regulator in the LRM

3. Record the makeup air flow rate required to maintain 60 psig once indicated leak rate is stable

A successful LLRT is one where the leak rate is less than the Administrative value, in the case of V-5393, less than 2480.0 sccm (standard cubic centimeter per minute).

In addition to the LLRT, Ginna's IST (In Service Testing) program requires a full-open and prompt closure valve exercise verification at a refueling interval frequency.

SUMMARY OF PROBLEMS

The originally installed swing check valve was replaced in 1993 due to obsolescence and poor LLRT performance. A soft seated, poppet check valve was selected to replace the swing check based on the advantages of its spring loaded, soft seated design. Although the poppet check valves passed the LLRT during factory acceptance testing, the valves could not pass the site LLRT after one cycle of operation. The poppet check valve was removed from the system, disassembled and inspected. Excessive wear along the stem and stem guide was noticed during the inspection. This wear was indicative of disc oscillation over an extended period. It didn't appear that the valve ever fully opened. This wear increased friction during the closing stroke and imposed angular and transverse misalignment preventing the valve from achieving proper seat-to-disc engagement. This wear also resulted in a longer closure time during the prompt closure test. Refurbishment of the valve required new o-rings, seat, stem and in some cases, a new body. Parts were kept in stock to support maintenance without impacting outage schedules or equipment availability. A summary of the cost of maintenance activities:

Maintenance to support rebuild of the valve:

25 hours x $65/hr = $1625

Post Maintenance Testing and data entry:

15 hours x $65/hr = $975

Analysis by Systems and Performance Engineering:

10 hours x $65/hr = $650

Replacement Parts: = $4000

Total Refurbishment Cost per Outage $7250

In addition to maintenance costs, the following issues contributed to the cost justification:

- Inability to extend LLRT testing per Appendix J, Option B
- Non-compliance with Maintenance Rule
- Appendix J Program Repeat Failures
- Negative impact on Probabilistic Safety Assessment

THE MODIFICATION PROCESS-REVIEW OF SELECTED REPLACEMENT VALVES

The primary cause of the chronic failure of the poppet check valve was attributed to misalignment of seating surfaces due to wear along the shaft. The goal of the replacement valve selection process was to find a valve which would supply system loads while essentially maintaining a full-open position, thereby minimizing the wear of critical surfaces under normal service conditions.

The force acting on the disc at a velocity of 54 ft/sec of air with a density of 0.585 lbm/ft3 (pounds mass per cubic feet) is equivalent to the force exerted by ambient water velocity of approximately 5 ft/sec. To simplify the discussion related to Vmin, we will refer to velocities based on ambient water. Ginna wanted a check valve with a Vmin less than 5 ft/sec(water) to eliminate the wear caused by disc oscillation. Experience with swing check and piston check designs indicated the following Vmin assuming straight upstream piping with no proximity to turbulence:

Vmin of Swing Check: 10-20 ft/sec water

Vmin of lift check: 20 ft/sec water

Vmin of poppet check: 10 ft/sec water

Since swing and lift checks could not meet the design objectives of operating in the full open position, and the poppet check exhibited accelerated wear, an alternate check valve design was evaluated. Ginna had installed 14" Model DRV-B and 8" Model DRV-Z NozzleCheck valves in the Service Water and CCW pump discharge applications, respectively, in 1994 to eliminate problems primarily related to water hammer. These valve designs had shown no indications of wear induced by low velocity operation after many years of operation in contrast to the hinge pin wear observed with the originally installed swing checks.

Ginna requested a preliminary application review from Enertech and they recommended a Model ERV-Z valve design based on its ability to operate in the fully open position at relatively low velocity without sacrificing flow coefficient. The NozzleCheck product line, comprised of four basic models, had been utilized in over 800 critical Nuclear Plant applications around in the world to replace conventional check valves in challenging applications. This experience provided a good experience base but none of the applications were identical to the service and testing conditions of Ginna. A rigorous design review was conducted to ensure that the ERV-Z would provide the desired performance characteristics. This review compared the ERV-Z, Figure 3, with the installed poppet check, Figure 4, and isolated the similarities and differences that would be the basis for the final valve selection.

Design Review Summary

Body Design

The Poppet Check and NozzleCheck are both Axial Flow Check valves. Ginna's Poppet check valve had a three-piece body consisting of screwed-end, end pieces with a wafer body sandwiched between them sealed with an O-ring on the downstream and with the seat on the upstream side. The ERV-Z NozzleCheck body is manufactured as a one piece casting, bar or forging. The Poppet Check valve body has no change in internal diameter (ID) along the length of the center section; its shape is symmetric similar to a pipe. The NozzleCheck body is contoured with a gradually decreasing ID, which reaches a minimum on the inlet side of the disc and is gradually increased along the length of the valve. There are no joints that must seal tightly on the NozzleCheck body design eliminating the risk of body leakage.

The Poppet Check integrates the disc guide into the body as one piece. The NozzleCheck design utilizes a separate diffuser that is retained in the body using a retaining ring that is captured in a slot machined on the body ID near the outlet of the valve. Having a separate diffuser was viewed as an advantage since it could be easily replaced if the sliding surfaces were damaged instead of replacing the center section of the body.

Disc Guiding

The disc and shaft are one-piece in both designs. The weight of the disc/shaft is supported by a bearing surface within the body of the Poppet Check and within a diffuser in the NozzleCheck. This bearing surface is downstream of the seat on both designs offering protection from direct impingement of the fluid minimizing contamination of the sliding surface with media borne debris and corrosion products. The percent of shaft length engaged in the guide was higher for both the fully open and closed disc positions in the ERV-Z design. Maximizing shaft engagement offers an advantage in horizontal applications but was not considered a factor in this vertical application where there is no radial loading.

Seat Design

The poppet check design used a Viton seat captured in the body that acts as both a seat and also a body seal. There is a wide area contact between the disc and seat. As the nuts are tightened on the studs, compressing both the upstream seat/seal and the downstream O-ring seal, the seat moves in response to the compression. This may have been a factor in the inability of the poppet valve to pass the LLRT since it creates the potential for misalignment between seat and disc.

The NozzleCheck soft seal is retained within the disc, Figure 5. The Viton O-ring is the primary seal with a metal-to-metal backup seal if the O-ring were to be removed. The O-ring provides a relatively narrow contact band compared to the poppet check valve and is not affected by any compression of the body. This was viewed as a contributing factor affecting seat leakage performance.

Geometry of Flow Path

The difference between the two check valve types is most apparent in the comparison of flow patterns. The flow through the NozzleCheck is similar to that through a convergent-divergent nozzle, a gradually decreasing and then gradually increasing area creating a low-pressure zone immediately downstream of the disc. This low-pressure area generates a force on the disc in the open direction. The low pressure is gradually recovered as the area expands towards the outlet of the valve. The shape of the diffuser, coupled with the body contour, provides a smooth, symmetric flow path with no projected disturbances to cause vortices or turbulence. The poppet check disc protrudes into the flow path with no diffuser on the downstream side. This allows pressure to equalize on both sides of the disc once the poppet partially opens. This equalization of pressure prevents the disc from achieving a fully open position and causes the disc to oscillate degrading the surfaces of the shaft and bearing surfaces.

To model the effect of different valve geometries, Enertech built a test loop similar to the configuration of the Ginna application with the check valves in a vertical, flow up orientation. This loop was used to circulate water through specially designed NozzleChecks with see-through bodies. The test was conducted with two different diffuser designs. Valve 1 had a 2" diffuser with the outside diameter decreased eliminating the nozzle shape resulting in a larger flow area. Valve 2 had a standard ERV-Z NozzleCheck geometry with a 1.5" diffuser. Figure 6 compares the Cv (flow coefficient) and Figure 7 compares the difference in percent open. This test illustrates the dramatic effect of the geometry of check valve internals. Without a specific convergent-divergent nozzle geometry, there is no low-pressure area created which is necessary to provide the force required to hold the disc fully open without oscillation.

When velocity was increased to greater than 13 ft/sec (135 gallons per minute) , the modified NozzleCheck didn't open past 30%. When the standard diffuser was used, with the same spring, the valve fully opened at the calculated velocity of approximately 4 ft/sec (40 gallons per minute). Even with smaller internals, the valve achieved the full open position and attained a much higher Cv compared to the larger diffuser with the standard contour machined away. This allows a stronger spring to be used, providing seat load and alignment, and still achieve full open operation compared to valves without this specific nozzle geometry.

Final Selection of a Replacement Valve

The decision was made to purchase two, 2" ANSI 300, ASME Section III, Class 2, ERV-Z NozzleChecks. The final NozzleCheck configuration was designed to minimize the extent of the modification by maintaining the following characteristics similar or identical to the poppet check valve:

- Body material
- Disc material
- Seat material
- End connections
- Weight
- Face-to-face dimension

The factory acceptance testing was performed by vendor and Ginna Engineering personnel and consisted of a "prompt closure" test and a 60 psid (pounds per square inch differential) LLRT. Ginna constructed an exact replica of the associated plant piping configuration which was shipped to Enertech's facility and used during the prompt closure tests.

The acceptance LLRT results were: ERV-1, 0.1 sccm and ERV-2, 0.3 sccm .

The valve demonstrated instantaneous closure during the prompt closure test and maintained the 60 psig downstream pressure after the upstream volume was rapidly vented.

The standard ERV-Z design has been upgraded over the last few years by providing sliding surfaces of a differential hardness and of extremely wear resistant materials to allow operation in high cycle applications without wear or galling. In this application, since full-open operation was expected during normal operation, the 316SS (Stainless Steel)-on-316SS sliding surface configuration was maintained with little expected risk of galling.

IMPACT ON SYSTEM HEALTH

The installation of the ERV-Z, Figure 8, was a relatively easy evolution since the size, end-connections and weight of the valve were maintained. The estimated payback was estimated to be two cycles when all factors were evaluated. After 18 months of operation, the NozzleCheck was tested at 60 psid per the LLRT procedure with zero leakage. It also passed the Refueling interval valve exercise/prompt closure IST test with essentially an instant closure and no detectable delay or lag when traveling to the closed position.

Upon consecutive rounds of ASME Code and Appendix J LLRT testing during RFO's (refueling outages) 2003 and 2005, the test interval for the LLRT could be extended out to 60 months in accordance with OPTION B. In addition, all associated repetitive maintenance tasks could likewise be extended. The Maintenance Rule compliance issue will be resolved which has a valuable regulatory, albeit intangible, price benefit. The Appendix J program would be rid of a consistent poor performer, which would positively impact the status of the overall program. The valve availability is not really impacted since the poppet check valve always remained operable and in service even at its peak as a poor leakage performer. There is no significant ALARA benefit since the valve is in a non-contaminated system and is located in a low-dose rate area, typically 1 mrem (millirem) or less.

CONCLUSION

Many of the testing, inspection and performance requirements imposed on check valves in safety related, nuclear plant applications exceed the capabilities of many traditional check valve designs. Normal flow rates are many times much less than worst-case accident/design flow rates causing check valve discs to oscillate causing wear to sliding and rotating surfaces. Even the highest quality check valve designs may moderate wear that is sufficient to create misalignment of the seat/disc interface preventing the valve from passing under low pressure seat leakage tests. In these applications, valves that fully open at very low velocity, are necessary to provide a long term, maintenance free operation without leakage.

The proprietary design of the NozzleCheck valve was developed in 1935, primarily to eliminate water hammer damage, and has been installed in nuclear plants since 1972. The low-pressure area created by the conversion of pressure to velocity provides a valuable opening force on the disc allowing the valve to function in the fully open position when other check valve designs operate partially open. The full open, non-oscillating operation, in combination with a strong spring force, provides a tight shutoff at both low and high-pressure after many cycles of continued operation. In many applications, the NozzleCheck is an economical alternative to repetitive corrective and preventative maintenance that also increases safety and reliability.

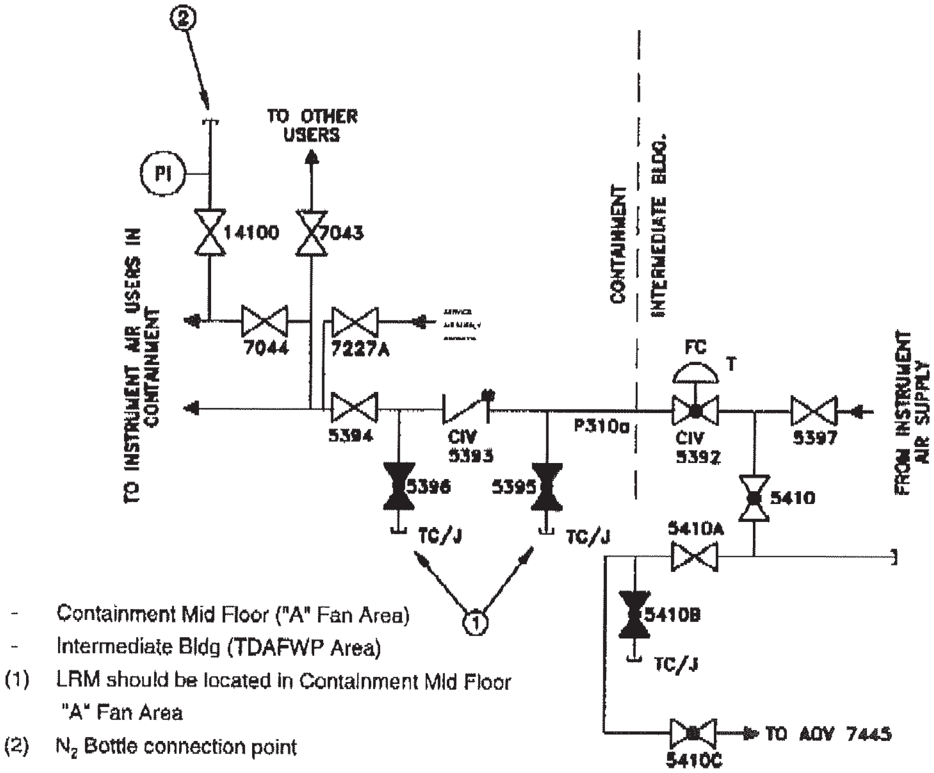


Figure 1 – System Schematic

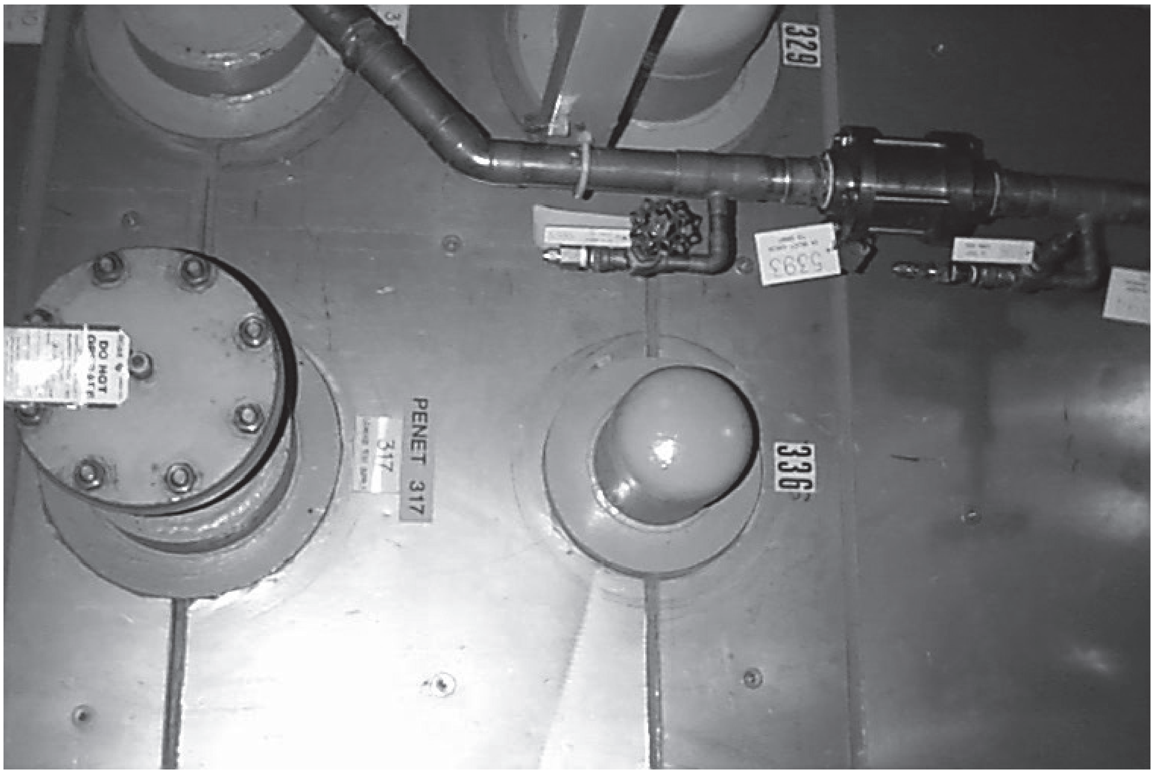
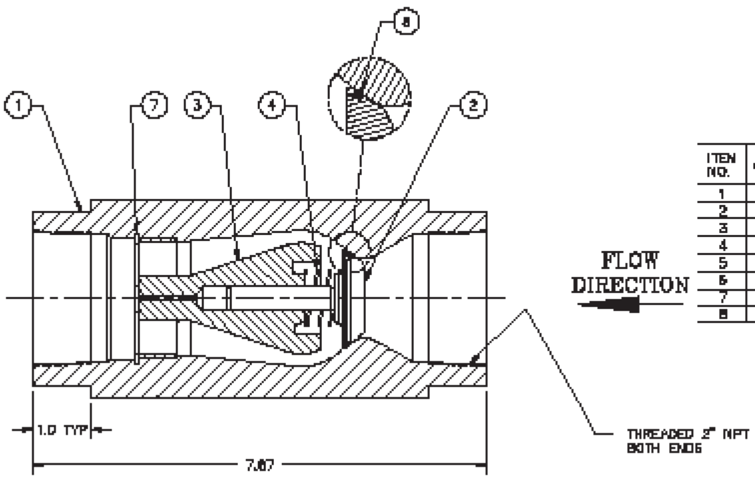


Figure 2 – Picture of Poppet Check Valve Installation



ITEM NO.	QTY	DESCRIPTION	MATERIAL SPEC.
1	1	VALVE BODY	SA 479 TP316
2	1	DISC	SA 479 TP316
3	1	DIFFUSER	300 SERIES ST. STEEL
4	1	SPRING	17-7 PH ST. STEEL
5	1	NAMEPLATE	STAINLESS STEEL
6	2	DRIVE SCREW	STAINLESS STEEL
7	1	RING, RETAINING	STAINLESS STEEL
8	1	SEAL, O-RING	VITON

Figure 3 – ERV-Z drawing

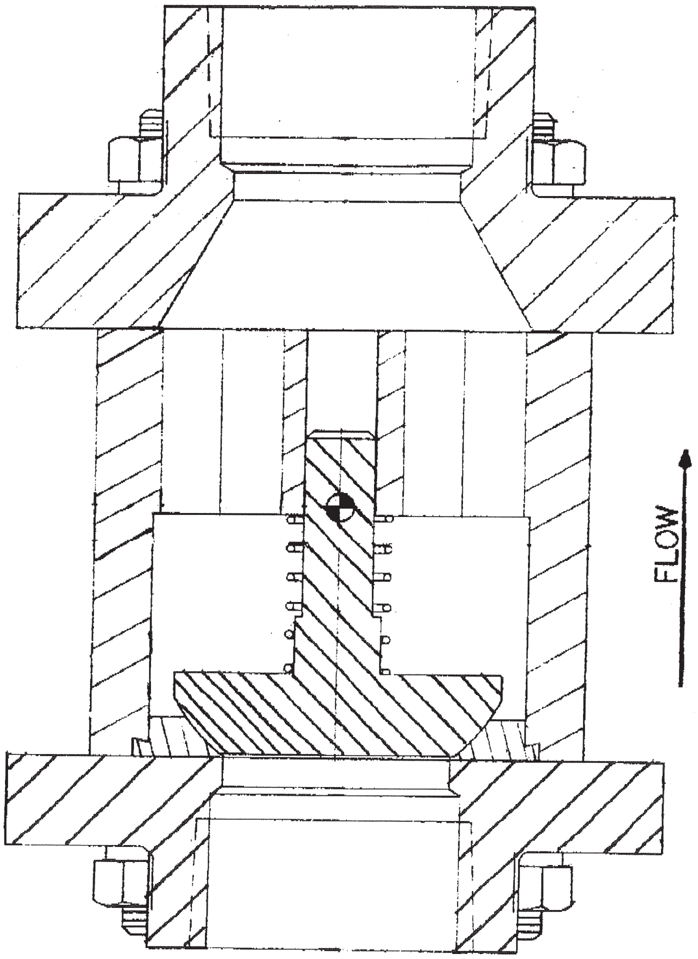


Figure 4 – Poppet Check Valve Drawing

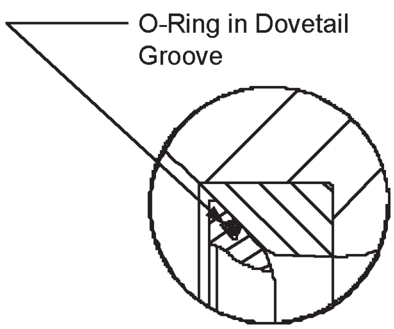


Figure 5 – ERV-Z Soft Seat detail

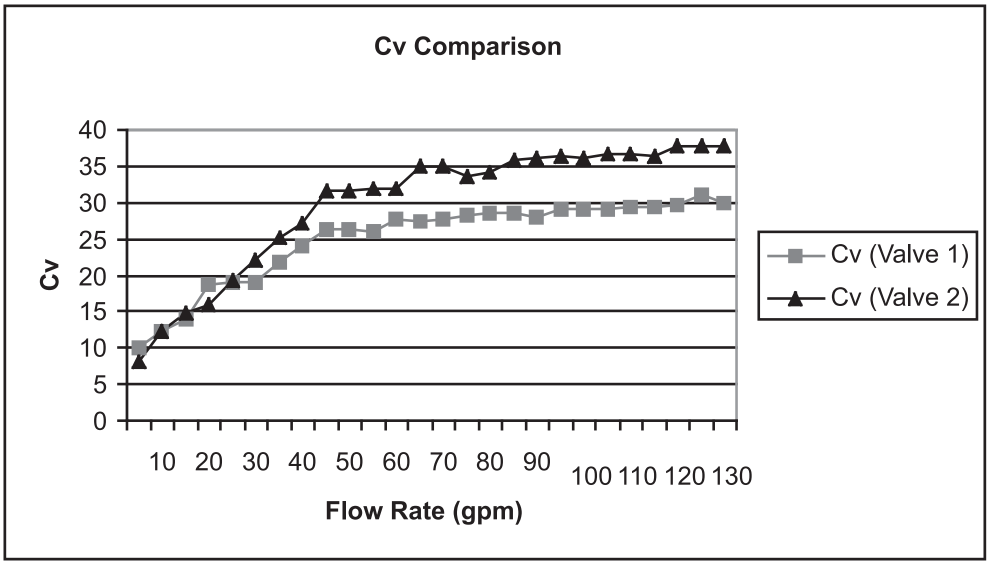


Figure 6 – Cv Comparison

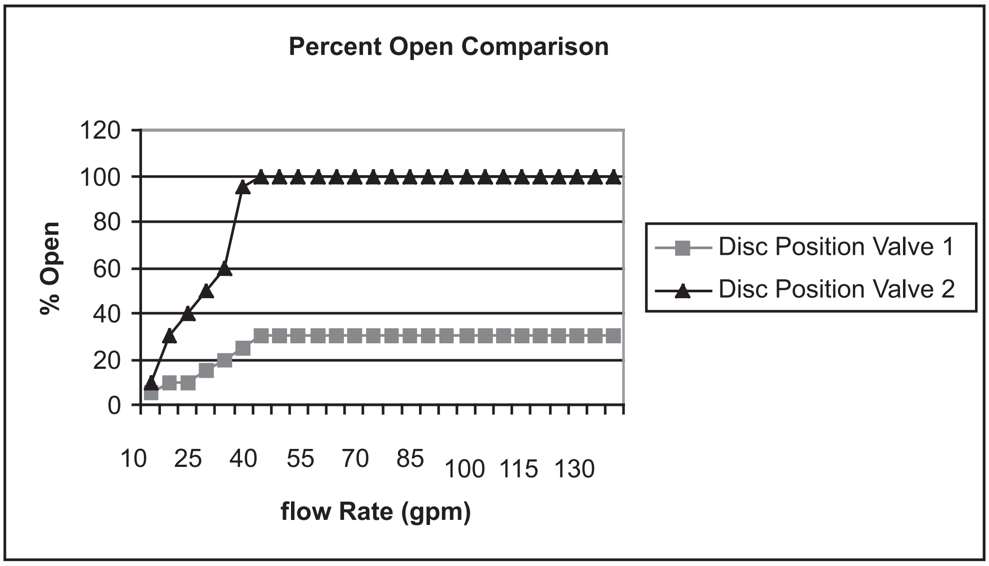


Figure 7 - % Open Comparison

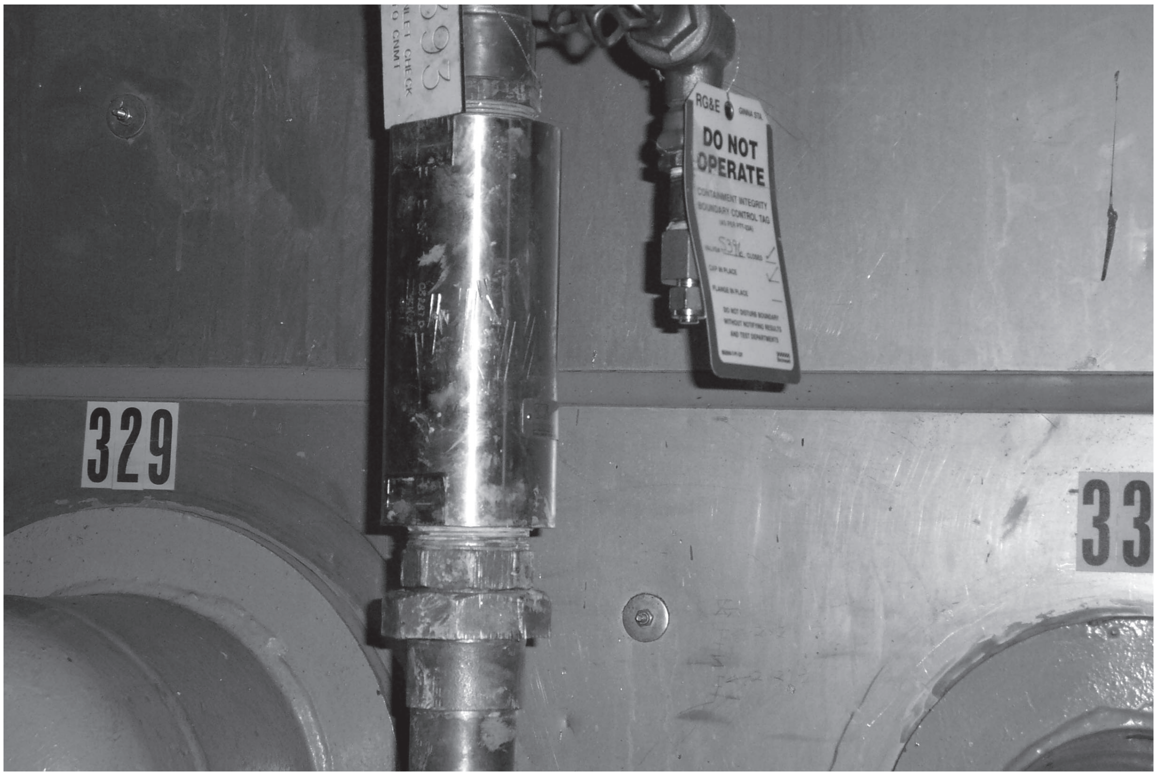


Figure 8 – ERV-Z picture installed

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Lessons From Cycle Isolation Loss Recovery

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TXU Energy

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This is an abridged version. A color copy of the complete paper in pdf format is available for downloading at www.leakdetect.com

ABSTRACT

This paper discusses how integration of several technologies enhances valve repairs. It also describes a safety problem that has been found at several plants in the course of valve testing and repair.

In a typical case, significant losses were recovered from leaking cycle isolation valves and steam traps at Comanche Peak. So far, Unit 1 output has increased by 2.8 MW and Unit 2 output has increased by 1.6 MW.

Atypical is the degree of repair success achieved at Comanche Peak by integrating several technologies in the repair process.

Two principal root causes for this leakage were identified. Generic problems were discovered such as improper body to bonnet torque causing inadequate gasket crush and the old methodology for actuator setup resulting in insufficient seat load.

The old actuator calibration technology was incapable of measuring seat load, friction band, internal binding and other critical attributes that affect seat integrity. A dynamic analyzer was used for the first time on cycle isolation valves.

At other plants, including two nuclear plants, deep cavitation pits were found by borescope downstream of leaking heater dump valves. The borescopes were used after leak testing because LDS found that heater dump valve leaks indicate the possibility of cavitation. Conventional UT is not adequate to address this problem because the cavitation is so localized. At one plant, not tested by LDS, the pit blew out under pressure, with very unfortunate consequences for the people nearby. Others have come close.

LDS recommends borescoping 20-30 times a year, and so far less than ten cavitation pits are found per year. That is a very high hit rate for a potentially severe problem.

Case histories, references and specific recommendations are presented.

EXECUTIVE SUMMARY

- Due to use of LDS equipment/services and implementing effective repairs, during a 1-year time frame (from the initial surveys until the first round of repairs were complete) a total of 4.4 MWs were recovered (2.8 MWs on Unit 1 and 1.6 MWs on Unit 2).
- The dollar value of the MWe gain achieved in the first year was approximately 10x the cost of performing the initial survey. The cost/benefit and quick payback for an initial survey should be an "easy sell" to management as long as a commitment exists to make effective repairs.
- Components were effectively and accurately categorized by leakage quantity as well as prioritized for rework by estimated energy loss.
- Due to finding block valves with no leakage (tight) conditions, some cycle isolation valves could be reworked on-line. In addition block valves with leakage could be reworked during outages to facilitate cycle isolation valve rework on-line.
- Categorization of the leakage condition (i.e.-Large, Medium, Small, or Tight) has been proven to reliably predict the type and extent of damage (soft metal/hard metal) to be reworked. Maintenance, Operations, and Engineering personnel have good confidence in the results obtained.
- Generic problems were discovered such as improper body to bonnet torque causing inadequate gasket crush and the old methodology for actuator setup resulting in insufficient seat load.

- Results from monitoring can support cost/benefit decisions on upgrading components (such as steam traps) or more thorough maintenance techniques.
- Testing can be done on any component, whether cycle isolation related or not, suspected of leakage to confirm or deny their condition and need to rework (such as ECCS/ Containment boundaries or Main Steam safety valves).
- Capabilities can be effectively developed for in-house personnel to perform monitoring and evaluate results.
- It was found that in general cycle isolation components that had been regularly monitored via temperature measurements were in better leakage condition than those not monitored regularly. The LDS testing is efficient and the results are more reliable than experienced with temperature monitoring. The scope of components to be repaired increased significantly over what temperature monitoring facilitated.
- Even though it was previously thought that cycle isolation leakage was not a significant problem, it was found that it was. This may be true at many other plants.

Introduction

Since 1979, LDS has been testing valves for internal leakage, using instruments originally developed for nuclear submarines. There have been many improvements in that time. The latest improvements produced a step increase in the success of valve repairs. They resulted from the synergistic integration of several technologies, and from the establishment of a valve task force having all of those technologies on board.

The second topic is a common hazard that we have found at many plants, nuclear and fossil.

Early in year 2000 Comanche Peak evaluated alternative cycle isolation monitoring methods to increase the scope of components monitored. Reducing cycle isolation component leakage can typically be the largest area for MWe improvement at nuclear units. Cycle isolation comprises components that can pass higher energy fluids to lower energy portions of the secondary cycle, particularly the condenser. These components can be generally categorized as:

- Normally closed valves leaking or not fully closing,
- Steam traps improperly working or degraded,
- Orifices eroded or improperly sized allowing excessive energy flow to pass through.

Comanche Peak personnel had historically been using hand held temperature instruments to perform cycle isolation component monitoring. Temperature readings were limited by insulation, failed to identify important leakers, and did not indicate what leakage was most important.

The first step was to form a valve task force. Members included planners, operators, actuator calibrators, mechanics, maintenance engineers, the performance engineer, and LDS.

Comanche Peak contracted Leak Detection Services, Inc. (LDS) to perform an initial survey on both units 1 and 2. The scope of components to be monitored was evaluated and greatly increased from previous efforts. 'Operations Troubleshooting Plans' were developed and approved to implement and control the monitoring evolution for each set of components.

Pre-Outage Survey Results

During the period 3 April 2000 -- 13 April 2000, Leak Detection Services, Inc. conducted a valve leakage survey at Comanche Peak Units 1 and 2. The objectives of the surveys on Units 1 and 2 were to identify leaking cycle isolation valves and steam traps for repair during the next outage as well as to assess the condition of block valves to determine if repairs could be performed on-line.

Before the surveys were started, an economic analysis was performed. Those valves were excluded from the survey.

We tested 739 valves and steam traps on the two units combined and found 448 to be leaking of which 239 were important to cycle isolation. We also found 291 tight valves, of which 118 were important to cycle isolation.

Table 1 summarizes the results of the April 2000 surveys of Comanche Peak Units 1 and 2.

CONCLUSIONS	LRG	MED	SML	Totals
Leaking Total	115	154	179	448
Tight Total				291
Cycle Isolation Leaks	96	53	90	239
Cycle Isolation Tight				118

Table 1 -- Comanche Peak Units 1 and 2 Combined Survey Results -- April 2000

Drip Pot Level Control Valves

LDS estimated that together drip pot level control valves (LCVs) accounted for at least half of the total cycle isolation losses. The estimate included 27 of these valves on Unit 1 and 25 on Unit 2. Of the 52 total that required repair, 45 were large leakers approaching the upper limit of our ability to measure.

Steam Dumps

There were only a few steam dump valves on the Action Reports and none had large leaks. This was favorable since steam dump valve repairs are expensive.

Actuators

Actuators are the root cause of many valve leakage problems. Several air actuators were recalibrated during initial testing but the success rate at reducing leakage was less than 20%.

Pre-Outage Severity Order Calculations

To estimate the effect of losses and repairs, calculations were made based on the Acoustic Signature Amplitude (ASA) readings from the LDS ValveAlyzer® System, the square of the nominal diameter of the item, and the differential enthalpy across the component. The results of these calculations were then summed and normalized, calculating the percentage of the total cycle isolation leakage due to each component.

Figure 2 shows the results of calculations for Unit 1. Unit 2 was similar. Drip pot level control valves accounted for most of the cycle isolation leakage.

Figure 2 reflects loss estimates. This methodology uses reasonable assumptions and a series of linear equations to approximate a complex, non-linear process. The result was a useful ordering of leaks in terms of their potential affect on cycle isolation and output.

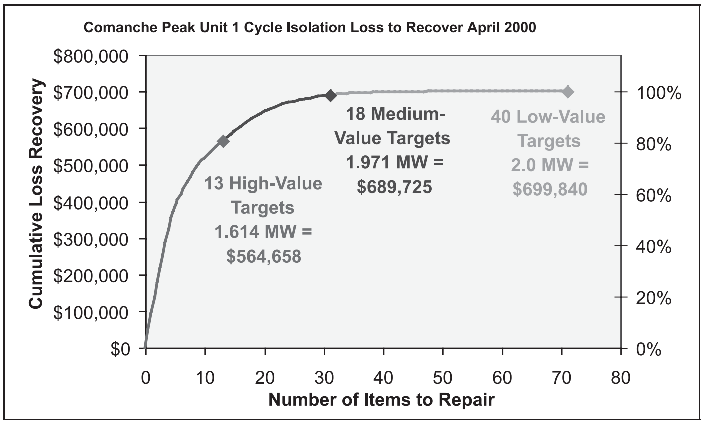

Figure 2 – Unit 1 Losses Found April 2000

The following parameters were used to calculate the results:

Nominal Rated Output	1,150	MW	Outage Interval	18	Months
Replacement Cost	$30.00	per MW-Hr	Cycle Isolation Loss	2.00	MW
Capacity Factor	90%	Annual			

Pre-Outage Survey Recommendations

LDS offered advice for specific problems based on their experience at other plants. In the case of drip pot level control valves, there were 52 of these on the Action Report of which 45 had large leaks. There was reason to believe most of them would require complete replacement, but there are some things that can be done before the outage to enhance planning. First, calibrate the actuators on all of the large and medium leakers. If many of the stem positions change as a result of that calibration, they should be retested before the outage. Second, try to inspect internally at least four of the valves on-line before the outage. The stack must be carefully measured so you will know you will get enough crush on the cage gaskets. In addition, do complete actuator and control calibration using dynamic calibration instruments before the outage and for every valve repair or replacement.

On-Line Isolation Of Worst Leakers

Temporary isolations led to MWe gains and the conclusion that permanent isolations were possible because they caused no drip pot level alarms.

- The well-publicized MWe gains from eliminating just a few leaks made all concerned even more determined to eliminate the rest of the leaks.

Temporary Isolations

Following the initial April 2000 Survey, and based on recommendations from Engineering, Operations Department temporarily isolated some of the large leakers.

No level alarms were seen. The estimated MWe gains were:

1) The ‘before MSIV’ (Main Steam Isolation Valve) drip pot drain line orifices and bypass AOVs were completely isolated. Unit 1 saw 0.3 to 0.5 MWe gain. Unit 2 saw 0.5 to 1.0 MWe gain.
2) The MSR heating steam drip pot drain line steam trap bypass AOVs were isolated again. Unit 1 saw 1.0 to 1.6 MWe gain. Unit 2 saw 0.7 to 1.1 MWe gain.
3) The main steam drip pot (prior to the strainers) drain line steam trap bypass AOVs were isolated. Unit 1 saw 0.7 to 0.9 MWe gain. Unit 2 saw 1.0 to 1.5 MWe gain.

These clearances were left in place either until the AOVs were worked at power or until the start of next refueling outage (when they were reworked).

Permanent Isolations of Main Steam Isolation Valve (MSIV) Drains

The initial LDS survey had identified 3 of the 4 valves in Unit 1 as having large leaks and all 4 of the valves in Unit 2 as having large leaks. Isolating both the valves and their associated orifices during normal power operation was implemented as a permanent change. A 0.3 to 0.5 MWe gain was realized by isolating these lines on each unit.

Setting Priorities

There were many valves and steam traps on the LDS action list. Short outages allow only a little time for valve work. Decisions had to be based on:

- Which were the most important,
- Which could be done only in an outage,
- Which could be attempted on-line before the outage, and
- Which could be at least temporarily avoided because their potential for output improvement was small.

Valve and Steam Trap Damage Prediction

The accuracy of planning depends on knowing the repair scope in advance. Leakers are placed on the LDS action list only if the leaks are categorized as Medium or Large. *The Large, Medium, and Small categories predict the extent of damage to be repaired.*

On Unit 1, there were 71 valves and steam traps with large or medium leaks important to cycle isolation. On Unit 2, there were 78 of these leaking valves and steam traps on the action list.

LDS estimated the severity of damage. The Large, Medium, and Small categories predict the extent of damage as follows:

- **(LRG) -- Large**. Indicates that the soft metal is being attacked. Body damage is likely. Seats and plugs may be cut deeply.
- **(MED) -- Medium**. Indicates damage to the hard metal only. Lapping is the most likely repair required.
- **(SML) -- Small**. The leak leaves no visible damage in valves, but grows larger quickly in steam traps. Take no action on valves, but repair traps.

Actuator and Controller Calibration

LDS recommended using a dynamic analyzer to calibrate before doing any internal repairs. If many of them closed tighter, retest to see if they could be taken out of the work scope.

Cycle Isolation Leakers by Valve Function

Figure 3 shows the numbers of leakers by valve function.

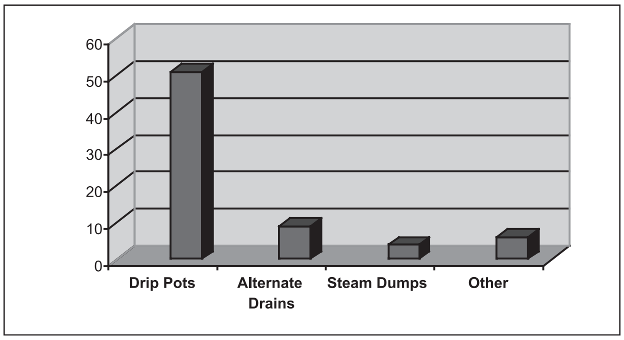

Figure 3 – Leakers by Valve Function

Drip Pot Level Control Valves
The LDS report of the pre-outage survey put the Main Steam drip pot level control valves at the top of the list for action. They were responsible for at least half of the total cycle isolation losses. All others were a distant second.

Steam Dumps
Steam dump valve leaks were not a significant contributor to the total losses. Three were found with medium leaks on Unit 1 and none on Unit 2.

Alternate Drains
There are only a few alternate drain valves on the Action Reports. On Unit 1, there are only four. On Unit 2, there are six. LDS recommended calibrating the control loops, including the actuators, because those are the most likely root causes. They are sometimes the only cause of alternate drain leakage.

Block Valves
About half of the total valves tested were block valves that were used in the process of testing cycle isolation valves. They are not directly important to cycle isolation because they are normally open, but those results determine which valves could be isolated on line and which ones would have to wait for an outage. Some of the leaking block valves were selected for outage work so the cycle isolation valves could be worked after the outage on-line.

Steam Traps
Steam traps made up about a quarter of the Action Items and none were found to be tight by testing. For these thermostatic traps, large leaks can be reduced to medium leaks but no better than that unless the design is changed to a different type such as a disk trap. Regardless, the steam traps were not very high on the priority list.

Repairs On-Line Vs During Outages

There are two reasons for reworking valves on-line versus during an outage: (1) outage time durations have decreased in order to be competitive in today's market; and (2) availability and experience of contractor support during outages.

Advantages of on-line refurbishment:

- Decreased outage scope.
- Instant thermal loss recovery.
- Plant personnel are proficient with performing maintenance on their particular valve types and are familiar with maintenance procedures.
- Repairs can be verified directly after refurbishment.

Disadvantages of on-line refurbishment

- Drip pots removed from service.
- Typically single isolation valve protection on cycle isolation valves
- Heat Stress has to be monitored on personnel.
- Extended repair time on valves that require valve body replacement.

Work Avoided

Operations personnel identified numerous Main Steam Safety valves as having seat leakage. Due to the room acoustics it is difficult to identify the valve that is audibly nosier than the others. Each steam header has five safety valves installed with the valves ranging from 2'-6" to 3'-6" apart.

Knowing the industry problems with Main Steam Safety valves sticking after refurbishment, verifying the exact valve that is leaking will eliminate unnecessary valve refurbishments and additional future testing.

LDS equipment located the valves that actually were leaking and eliminated several valves that were previously identified as having seat leakage.

Prior to every outage, the Main Steam Safety valves are tested to verify seat tightness. This method of verifying seat integrity by LDS equipment is another cost saving attribute in addition to thermal loss savings.

Rework of Valves

Figure 4 shows the numbers of different repair actions required.

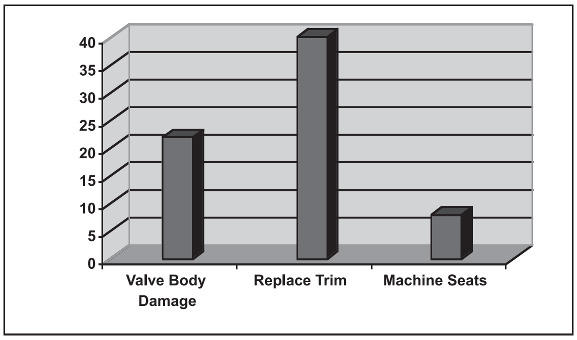

Figure 4 – Leakers by Repair required

Air Actuated Cycle Isolation Valve Rework

The LDS survey report showed which isolation valves for the Air Operated valves were leak tight. Using this information, the Air Operated valves with tight isolation valves were refurbished on-line and all others were moved into the outage scope. Approximately twenty-five (25) of the fifty-five (55) large leakers were refurbished on-line.

Initial Actuator Diagnostics

As predicted by LDS, the diagnostic tests revealed that approximately fifty percent (50%) of the actuators tested did have low bench set values and many regulators were found leaking. In all cases, adjusting the bench set did not reduce the seat leakage.

- The internal damage was already too severe.

Initial Internal Inspections

Initial inspections of the first valves worked on line confirmed the LDS predictions of severe internal damage. Seat ring and plug seating surfaces had steam cuts at the seating interface. Lower body gasket land area and adjacent areas had steam cuts and erosion. Steam cuts on plug and seat ring sealing surfaces were due to insufficient seat load during valve set up. Damaged lower gasket land was caused by inadequate bolt load due to improper torque values listed in maintenance procedures.

Large AOVs

The seat leakage on the Steam Dumps and Alternate Drains are primarily due to valve actuator set-up and instrument drift.

MS Drain Valve Bodies

LDS had predicted body damage, and numerous discontinued Fisher DBQ style valve bodies did have damage.

AOV Refurbishment Innovations

Valve bodies were measured for reference to new parts to verify correct gasket crush. Prior to and during torque application, the gap between flanges was measured with feeler gages to ensure even gasket crush is applied and final desired gasket crush was established. Torque was applied in small increments to eliminate uneven gasket crush and misalignment of valve internals that could cause increase binding or friction.

Since friction can affect critical parameters (seat load, stroke length, etc), each packing seal ring was torqued to 50% of recommended torque value during initial packing installation. Packing torque was increased in small increments until either 100% torque value was achieved or to the point friction began to affect critical parameters.

Manual Bypass and Isolation Valve Refurbishment

Inspections found disk-to-seat damage, bonnet backseat and gasket area degradation, and valve body damage.

Disks were either replaced with a new assembly or machined to restore an acceptable finish. Backseat and gasket areas were machined to the desired finish. Blue checks were performed on disk-to-seat and stem backseats to verify seat contact line.

New valves were also disassembled to verify the above criteria. New valve bodies were installed and as-left blue checks were performed to verify no seat distortion resulted during body installation.

After refurbishment, all valves were tested with LDS equipment to verify repairs.

Steam Traps

Essentially all of the steam traps showed lack of function (i.e., little to no shutoff capability) and were large- to medium-sized leaks. Considering the long time since any maintenance was performed on the traps, this presented a potential erosion concern in addition to the lost MWs.

When the replacement and maintenance costs were compared to the estimated savings there was no cost benefit to be realized. This left the concern that the traps may have suffered extensive body damage due to erosion. Evaluation of the rework costs vs. replacement costs indicated them to be very close. About 15 to 20 traps received a like-for-like replacement.

Cost-Benefit Comparison

The entire first-year cost was recovered in about four months, and the benefits have produced about $1,000,000 per year since then.

Post-Outage Tests

Post-outage performance tests

MWe gain evaluations were performed. Unit 1 was producing 2.8 MWe more than a year earlier due to cycle isolation component rework identified by the LDS monitoring. Unit 2 was producing 1.6 MWe more than a year earlier due to cycle isolation component rework identified by the LDS monitoring.

Post-Maintenance Valve Leakage Survey

After maintenance on the leakers identified by LDS, a post-maintenance ValveAlyzer test was performed to determine the success of the refurbishment. Comanche Peak had a Ninety-Eight percent (98%) success rate.

Unit 1 Post-Maintenance Megawatt Recovery

Before the outage, LDS estimated that Unit 1 had cycle isolation leakage of about 2 megawatts. After the outage, Comanche Peak reported recovery of 2.8 megawatts from reduced cycle isolation leakage.

Figure 5 – Unit 1 Cycle Isolation Leakage Loss Recovery November 2001 shows the effect of repairs on the Large and Medium cycle isolation leakers on Unit 1. A table showing individual details was also supplied.

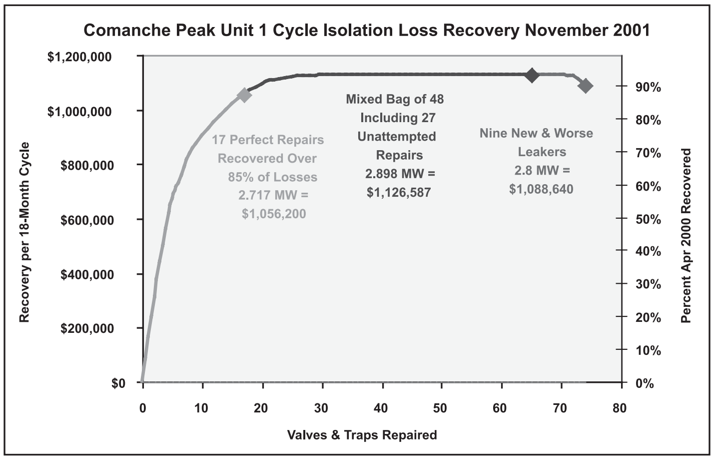

Figure 5 – Unit 1 Cycle Isolation Leakage Loss Recovery November 2001

The following parameters were used to calculate the results. Replacement cost and capacity factor are reasonable values, but are not exact.

Nominal Rated Output	1,200	MW	Cycle Isolation Loss	2.800	MW Recovered
Replacement Cost	$30.00	per MW-Hr	Cycle Isolation Loss	3.149	MW Total
Capacity Factor	90%	Annual	Cycle Isolation Loss	0.349	MW Remaining
Outage Interval	18	Months			

To put the numbers in perspective, other plants have recovered more in terms of megawatts and much more in terms of dollars, but that was due to having more losses to recover and to having much higher replacement costs in most other parts of the country.

Rarely have plants been able to do the repairs so well on the first try that they recover almost 90% of the total cycle isolation leakage.

Figure 5 clearly shows the importance of knowing not to undertake repairs that would cost more than could be gained in terms of increased output.

Actuator Calibration Improved Tightness

Actuator calibration is a frequent cause of valve leaks. If you can find a leak on a newly repaired valve with an actuator, check the actuator calibration, and correct it if necessary.

The post-maintenance ValveAlyzer test identified a Medium leaker. 2-HV-2172 is a 1.5-inch drain valve from Main Steam. After troubleshooting the actuator, the bench set was found to be low. The proper bench set was re-established and the leak was reduced to a very small leak (only successful if you catch the leak prior to cutting the seat). See traces below:

The overlay traces shown in Figure 6 directly illustrate the effect of the lower bench set adjustment.

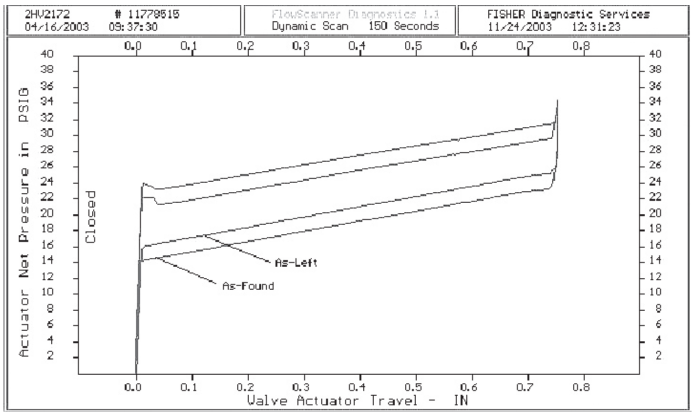

Figure 6 – Overlay Flowscanner Traces

After the actuator was put back in calibration, we recorded new signatures with the ValveAlyzer. The signature of the air-operated valve dropped by about 10 dB, while the upstream and downstream background signatures stayed about the same.

Successes

The LDS part of the process was just routine, but the degree of success by Comanche Peak was very unusual in comparison to most other plants. The differences were in teamwork and thoroughness. At other plants, disputes over budgets, manpower, control, blame and credit make teamwork difficult.

Valves are part of every fluid system in the plant, but different people are responsible for different aspects of the care and feeding of valves. No single person or organization can provide tight, functioning valves without the cooperation of other people and other parts of the plant organization.

Operators operate them and depend on them, but there are right ways and several wrong ways to operate valves. Purchasers must make sure the correct parts are available. Planners have to assign the right people at the right times. Mechanics work valve internals, but AOV techs must make sure they stroke correctly. Welders install them, but if they do it wrong, they can burn the seats at the same time. Engineers select and approve valves for each application.

Just testing the valves requires a nice degree of teamwork. The testing cannot begin until the Operations Department approves the test procedures. Operators must stroke valves, and doing that with the plant on line requires a high degree of mutual confidence. AOV testers should be available to calibrate actuators during testing. Engineers answer technical questions and count the gains, but sometimes do not want to share the credit with the maintainers. Repair funds and manpower come from the maintenance department budget, which usually does not include extensive cycle isolation valve repair. Sometimes, exceeding the previous maintenance budget has negative consequences even if there are overall gains for the plant and the company. The maintainers want part of the credit for any gains achieved, but do not want leaks to be blamed on their past work.

- Assembling the team and keeping it focused is an important job.

Powerplants in general and nuclear plants especially are extremely reluctant to commit an innovation. Most plant people feel they already know how to operate and maintain valves, and are reluctant to make changes. They are often afraid that doing something a different way means what they did before was wrong.

Before any work started, LDS spent a lot of time trying to explain what would be required to facilitate testing and get good repairs. We discussed several instances in which there was a breakdown in teamwork, with predictable consequences. Comanche Peak listened carefully, assembled a team, did all that was recommended, and then went beyond that.

Integrated Valve Team

The first different thing Comanche Peak did was to bring the entire team to a meeting with LDS. Operations, Maintenance and Engineering people were all in the same room, and the meeting took most of one whole day. The team leader made it clear that he was not interested in blame, and that there would be liberal sharing of credit to the success of the team.

There were many questions, and some of them were answered right there. Other questions were taken away to find answers later. At the end of that meeting, LDS was just one member of the team. Cycle isolation leakage was never a full-time job for any member of the team. Each team member left with a good understanding of what his part would be and what he could expect from others on the team. The original team members have stayed together and supported each other even to this day.

Root Causes and Solutions

Comanche Peak was eager to find the root causes of the leakage and to develop workable solutions to previous problems. They were not constrained to continue the old ways that had caused so many problems in the first place.

When it became clear, as predicted by LDS, that many of the worst leakers also had actuators that did not keep the valves closed, they made sure every actuator got as much attention as the valve internals.

Stems were cut, seats were cut, disks were cut, and bodies were cut under the seats, so they sought and found the root causes. Then, they eliminated the mistakes that produced those root causes of valve failure.

When they saw packing follower torque affect actuator performance, they started using the Flowscanner to find the adequate amount of torque that would not affect actuator performance.

When even newly refurbished valves arrived with inadequate gasket crush, they did their own measuring and blue checking before they installed the valves.

Best of all, they supported each other all the way.

Those innovative and thorough efforts led to a very high rate of success for repairs.

Good Working Relationship With Ops

With on-line testing and on-line maintenance in the offing, a good relationship with the operations department was essential. LDS had yet to develop the valve database and determine the test procedures required, but typical test procedures were discussed with Ops. Ops explained what paperwork was required, and LDS, working with Engineering, developed the required “Troubleshooting Plans.”

The Operations Department assigned operators, sometimes two at a time, exclusively to the testing, and later to the on-line maintenance. Cranking long-stemmed isolation valves on steam dumps or alternate drains takes a lot of physical effort. They kept at it through the heat of a Texas summer, and the testing speed set a new record for a first survey at a nuclear plant.

Long discussions led first to the temporary isolation of the worst leakers, and eventually to the permanent isolation of some unnecessary drains.

Now that they are aware of the ValveAlyzer capabilities, operators sometimes request leak tests on suspected leakers before they write maintenance requests.

Early Success

The decisions to attempt on-line isolation and to do repairs on line led directly to early successes. Measurable megawatt gains came quickly, and well before the outage started. Those early successes galvanized the attention of management and the valve team.

Management Support

This is a two-way street. The team needed support from management for funding, and for keeping the members assigned. Management needed hard evidence, and soon, to support their original decision.

When on-line maintenance work was proposed, it required management support. The support flowed the other way when the team was able to document significant gains very soon thereafter.

One of the hardest things for a manager to do is to give up direct, continuous, in-line control of the people assigned to him. It makes it difficult for him to evaluate their work, and the people on the team could worry about their personnel evaluations. That was not a problem at Comanche Peak.

Confidence in Test Results

The ValveAlyzer by LDS is a proven, highly reliable piece of equipment used to analyze valve conditions. Degraded valve conditions were verified during refurbishment. All valves listed on the initial survey showed some type of degradation that caused seat leakage.

By comparing valve component damage to the decibel rating found during testing, specific component damage can be identified. This assists planning.

Spreading Credit

LDS maintains that there should be no limit to credit for a job well done. Comanche Peak was already following that philosophy. Spread praise and credit around liberally. It will come back to you multiplied many times.

To this day, each team member can recount the contributions of every other team member, without hogging any of the credit to himself. They do not have to praise themselves. The other team members and their managers do it for them. Even the managers get credit applied indirectly because of the success of the team they help flourish.

Undetected Cavitation Pits

Hazard Description

Undetected cavitation pits may exist between HP Heater Dumps and the downstream isolation valves. The danger arises if the downstream block valve to the condenser is shut, pressurizing the pipe with a hole or a weak spot. If the pit is bad enough, the piping may blow out at the pit.

Even if a large, through-wall hole exists, there will normally be vacuum in the pipe between the leaking heater dump and the condenser. Instead of blowing steam, it will suck air until the downstream isolation valve is closed.

So far, the precursors we know are large or medium leaks on HP heater dumps or feed pump recircs. We have learned of only one cavitation pit downstream from a feed pump recirc, but there have been many pits found downstream from HP heater dumps. Sometimes the cavitation is ongoing, audible, and visible on the acoustic signature, but other times it is not. The absence of current cavitation does not mean there was not cavitation in the past.

Finding a large or medium leak, hearing cavitation, or seeing it on the acoustic signature means serious damage is possible, but not certain. Even if cavitation is not ongoing while we are leak testing, it does not mean that there was not cavitation at some other time. The only way we know to make sure the damage is not there is for you to inspect the inside of the piping.

Out of 20-30 borescope inspections done at our urging annually, less than ten find cavitation pits.

Our regular clients have us test all of their HP Heater Dumps for leakage before every outage, but there are long intervals between outages. Cavitation pits could develop in the long intervals between our surveys. The units are on line while we do our leak testing, so the piping cannot be borescoped then. We do not have the facilities to borescope during outages, but you do.

Our practice so far is to do several things whenever we see large or medium leaks on HP heater dumps or feed pump recircs:

- First, we never close a block between a heater dump and the condenser.
- Second, when we find HP heater dumps leaking, we always ask that the downstream blocks be tagged open.
- Third, we try to explain that UT is inadequate for this problem because a cavitation pit is very localized.
- Fourth, we always tell people it is likely that they are hearing cavitation when banging, rattling or pinging is ongoing.

When the cavitation pit becomes a through-wall hole, a vacuum leak will start. Many plants try to localize a new vacuum leak by systematically closing downstream isolation valves to the condenser. Never do that. If closing the HP heater dump downstream isolation valve stops the vacuum leak, the weakened pipe could blow out at any time.

References

Some of the places where cavitation damage has been found are listed below. The people are the ones we know, but they may not be the ones most familiar with the damage found. They should know who is the most familiar.

Labadie Plant
Steam came out from under the insulation between the dump valve and the closed downstream isolation valve. The plant borescoped inside the pipe and found a large, through-wall hole obviously caused by cavitation.

Tony Balestreri, 314-992-8249

Brunner Island SES
This accident happened before our incident at Labadie, but we did not learn about it until after Labadie. A cavitation pit between the HP heater dump and the closed downstream block valve blew out while pressurized.

Paul Knapp, 717-266-7532

South Texas Nuclear Project
A cavitation hole was found in an HP heater dump. It was so bad the manufacturer could not rebuild the valve. They had to replace the valve.

Al Haedge, 361-972-8455

North Anna Power Station
LDS recommended borescoping after we found a leaking HP heater dump. A cavitation pit was found in the bottom of the valve.

Ed Thomas, 540-894-2784

Plains Escalante Generating Station
LDS recommended borescoping downstream from several leaking heater dumps. The plant found several cavitation pits downstream of heater dumps and one feed pump recirc.

Mike Marinsek, 505-876-5219

Action Recommended

Please tag open all of your HP heater dump and feed pump recirc downstream isolation valves.

Please distribute this information and try to get it discussed in safety meetings.

This is an industry-wide problem that can affect any steam unit, nuke or fossil.

Session 4(a): Regulatory Issues

Session Chair

Thomas G. Scarbrough

U.S. NRC

PERIODIC VERIFICATION OF DESIGN-BASIS CAPABILITY OF SAFETY-RELATED MOTOR-OPERATED VALVES

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Abstract

The safe operation of a nuclear power plant depends on motor-operated valves (MOVs) in fluid systems successfully performing their safety functions. As a result of problems with MOV performance, the NRC issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 96-05, "Periodic Verification of the Design-Basis Capability of Safety-Related Motor-Operated Valves," requesting that nuclear power plant licensees verify initially and periodically the design-basis capability of MOVs in safety-related systems. The NRC also issued GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," requesting that licensees ensure that safety-related power-operated gate valves susceptible to pressure locking or thermal binding are capable of performing their safety functions. Licensees of all active operating reactor units have completed their programs to verify initially the design-basis capability of safety-related MOVs in response to GL 89-10, and to address potential pressure locking and thermal binding of safety-related power-operated valves in response to GL 95-07. In response to GL 96-05, the owners groups developed an industry-wide Joint Owners Group (JOG) program for periodic verification of the design-basis capability of safety-related MOVs. Most licensees committed to implement the JOG program as part of their response to GL 96-05. The NRC staff reviewed the establishment of GL 96-05 programs at individual nuclear plants through significant reliance on licensee commitments to implement the JOG program on MOV periodic verification. JOG has completed its MOV dynamic testing program, and prepared its topical report for use by licensees in implementing their MOV periodic verification programs. The NRC staff is currently reviewing the JOG final topical report. This paper provides an update of the NRC staff activities regarding the periodic verification of the design-basis capability of safety-related MOVs, and monitoring of the industry's efforts to ensure proper performance of safety-related MOVs.

I. INTRODUCTION

The safe operation of a nuclear power plant depends on motor-operated valves (MOVs) in fluid systems successfully performing their safety functions. MOVs must be capable of operating under design-basis conditions, which may include high differential pressure and flow, high ambient temperature, and degraded motor voltage. The design of the MOV must apply valid engineering equations and parameters to ensure that the MOV will operate as intended during normal plant operations and design-basis events. Manufacturing, installation, preoperational testing, operation, inservice testing (IST), maintenance, and replacement must be conducted by trained personnel using proper procedures. Surveillance must be performed and testing criteria must be applied on a soundly based frequency in a manner that suitably detects questionable operability or degradation. Moreover, these activities must be monitored by a strong quality assurance program.

The regulations of the U.S. Nuclear Regulatory Commission (NRC) require that components that are important to the safe operation of a U.S. nuclear power plant be treated in a manner that ensures their performance. Appendix A, "General Design Criteria for Nuclear Power Plants," and Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50) contain broadly based requirements in this regard. In 10 CFR 50.55a, the NRC initially required U.S. nuclear power plant licensees to implement provisions of the American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel Code (B&PV Code) for testing of MOVs as part of their

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. NRC has neither approved nor disapproved the technical content.

IST programs. In 1999, the NRC revised 10 CFR 50.55a to incorporate by reference the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) for inservice testing of MOVs. The NRC also supplemented the quarterly MOV stroke-time testing specified in the ASME Code by requiring that licensees verify MOV design-basis capability on a periodic basis.

Operating experience at nuclear power plants in the 1980s and 1990s revealed weaknesses in many activities associated with MOV performance. For example, some engineering analyses used in the original sizing and setting of MOVs did not adequately predict the thrust and torque required to open and close valves under design-basis conditions. Both regulatory and industry research programs later confirmed the weakness in the initial design and qualification of MOVs. For example, the NRC Office of Nuclear Regulatory Research sponsored an extensive program at the Idaho National Engineering and Environmental Laboratory (INEEL) to study the performance of MOVs under various flow, temperature, and voltage conditions. In addition, the nuclear industry sponsored a significant program by the Electric Power Research Institute (EPRI) to develop a computer methodology to predict the performance of MOVs under a wide range of operating conditions. Poor MOV performance also resulted from shortcomings in maintenance programs, such as inadequate procedures and training. Further, testing of MOVs to measure valve stroke times under zero differential-pressure and flow conditions was shown not to detect certain deficiencies that could prevent MOVs from performing their safety functions under design-basis conditions.

II. VERIFICATION OF MOV DESIGN-BASIS CAPABILITY

In response to weaknesses in MOV performance, the NRC staff issued Generic Letter (GL) 89-10 (June 28, 1989), “Safety-Related Motor-Operated Valve Testing and Surveillance.” In GL 89-10, the NRC staff requested that licensees ensure the capability of MOVs in safety-related systems to perform their intended functions by reviewing MOV design bases, verifying MOV switch settings initially and periodically, testing MOVs under design-basis conditions where practicable, improving evaluations of MOV failures and necessary corrective action, and trending MOV problems. The NRC staff requested that licensees complete their GL 89-10 programs within approximately three refueling outages or 5 years of the issuance of the generic letter.

In support of the regulatory activities to ensure MOV design-basis capability, the NRC Office of Nuclear Regulatory Research identified areas in which research and analysis were required to assist in evaluating MOV programs at nuclear power plants. For example, the NRC performed research to evaluate (1) performance of MOVs under pump flow and blowdown conditions; (2) output of ac-powered and dc-powered MOV motor actuators; (3) the increase in friction of aged samples of valve materials; (4) methods to determine appropriate values for stem friction coefficient; (5) pressure locking and thermal binding of gate valves; and (6) the effect of ambient temperature on stem lubricant performance. The NRC sponsored flow testing of several MOVs by INEEL under normal flow and blowdown conditions. The testing revealed that (1) more thrust was required to operate gate valves than predicted by standard industry methods; (2) some valves were internally damaged under blowdown conditions and their operating requirements were unpredictable; (3) static and low flow testing might not predict valve performance under design-basis flow conditions; (4) during valve opening strokes, the highest thrust requirements might occur at unseating or in the flow stream; (5) partial valve stroking did not reveal the total thrust required to operate the valve; (6) torque, thrust, and motor operating parameters were needed to fully characterize MOV performance; and (7) reliable use of MOV diagnostic data requires accurate equipment and trained personnel. The NRC provided detailed test results in NUREG/CR-5406 (October 1989), “BWR Reactor Water Cleanup System Flexible Wedge Gate Isolation Valve Qualification and High Energy Flow Interruption Test;” NUREG/CR-5558 (January 1991), “Generic Issue 87: Flexible Wedge Gate Valve Test Program;” NUREG/CR-5720 (June 1992), “Motor-Operated Valve Research Update;” and NUREG/CR-6100 (September 1995), “Gate Valve and Motor-Operator Research Findings.” The NRC summarizes some of the results of the MOV research program in NRC Information Notice (IN) 90-40 (June 5, 1990), “Results of NRC-Sponsored Testing of Motor-Operated Valves.” Additional examples of MOV research sponsored by the NRC are discussed later in this paper.

To assist nuclear power plant licensees in responding to GL 89-10, EPRI developed the MOV Performance Prediction Methodology (PPM) to determine dynamic thrust and torque requirements for gate, globe, and butterfly valves based on first-principles of MOV design and operation. EPRI described the methodology in Topical Report TR-103237 (Revision 2, April 1997), “EPRI MOV Performance Prediction Program.” The EPRI MOV PPM program included the development of improved methods for prediction and evaluation of system flow parameters; gate, globe, and butterfly valve performance; and motor-actuator rate-of-loading effects (load sensitive behavior). EPRI also performed separate effects testing to provide information for refining the gate valve model and rate-of-loading methods; and conducted numerous MOV tests to provide data for development and validation of the models and methods, including flow loop testing, parametric flow loop testing of butterfly valve disk designs, and in-situ MOV testing. EPRI integrated the individual models and methods into an overall methodology including a computer model and implementation guide. On March 15, 1996, the NRC staff issued a safety evaluation (SE) accepting the EPRI MOV PPM with certain conditions and limitations. On February 20, 1997, the staff issued a supplement to the SE on general issues and two unique gate valve designs. On April 20, 2001, the staff issued Supplement 2 to the SE on Addendum 1 to EPRI Topical Report TR-103237 addressing an update of the computer model.

On September 8, 1999, the Nuclear Energy Institute (NEI) submitted Addendum 2 to EPRI Topical Report TR-103237-R2, which described the development of the Thrust Uncertainty Method that takes into account conservatism in the EPRI MOV PPM to provide a more realistic (less bounding) estimate of the thrust required to operate gate valves than predicted by the PPM. In this effort, EPRI compared the thrust required to operate sample gate valves during flow loop tests conducted as part of the development of the PPM to the thrust requirement predicted by the PPM to establish a representative prediction ratio for the actual-to-predicted thrust required to operate the valves. In applying the Thrust Uncertainty Method, a licensee would use the representative prediction ratio to reduce the EPRI MOV PPM thrust prediction for a specific gate valve to a nominal value. The licensee would determine a thrust prediction uncertainty for that valve based on the EPRI MOV PPM thrust prediction and the nominal thrust prediction obtained using the Thrust Uncertainty Method. The licensee would then establish a minimum thrust to be provided at the control switch trip setpoint (or flow isolation) for the applicable MOV, based on the nominal thrust prediction of the Thrust Uncertainty Method combined with applicable bias and random setup uncertainties (including rate-of-loading effects, diagnostic test equipment uncertainty, control switch repeatability, and the thrust prediction uncertainty). In Supplement 3 (dated September 30, 2002) to the SE on the EPRI PPM, the NRC staff concluded that the Thrust Uncertainty Method developed by EPRI is acceptable for the prediction of minimum allowable thrust at control switch trip (or flow isolation) for applicable motor-operated gate valves under cold water applications within the scope of the Thrust Uncertainty Method, based on the NRC staff's review of Addendum 2 to the EPRI Topical Report as supplemented by NEI submittals dated January 5 and December 6, 2001, and June 10, 2002. Therefore, the NRC staff stated that the Thrust Uncertainty Method may be applied consistent with the criteria specified for the EPRI MOV PPM in EPRI TR-103237-R2 and Addenda 1 and 2 to TR-103237-R2, as supplemented by NEI submittals dated January 5 and December 6, 2001, and June 10, 2002. The NRC staff noted that its findings and conclusions on the use of the EPRI MOV PPM, and applicable limitations and conditions, are provided in the SE dated March 15, 1996; the SE supplements dated February 20, 1997; April 20, 2001; and September 30, 2002.

NRC Information Notice (IN) 96-48 (August 21, 1996), "Motor-Operated Valve Performance Issues," alerted licensees to lessons learned from the EPRI MOV program. Among the lessons learned were: (1) the thrust requirements to operate some gate valves under pump flow and blowdown conditions were higher than predicted by the valve manufacturers; (2) a potential exists for gate valves to be damaged when operating under blowdown conditions such that the thrust requirements can be unpredictable; (3) the effective flow area in some globe valves can be larger than expected and can cause thrust requirements to be higher than predicted; and (4) the friction coefficients for sliding surfaces in gate valves can increase with service before reaching a plateau. In IN 96-48, the staff noted that some of the EPRI information is applicable to gate, globe, and butterfly valves regardless of the type of actuator operating the valve.

Nuclear power plant licensees implemented the recommendations of GL 89-10 through a combination of design-basis reviews, revision of MOV calculations and procedures, static and dynamic diagnostic testing, industry-sponsored research programs, and trending of test results. The industry expended significant resources to resolve the deficiencies in the design, qualification, and application of safety-related MOVs that led to the issuance of GL 89-10. The results of the GL 89-10 programs and their implementation include (1) MOV sizing calculations and switch settings have been revised to reflect actual valve performance; (2) improved valve performance prediction methods have been developed; (3) valve internal dimensions are being addressed to provide assurance of predictable gate valve performance under blowdown conditions; (4) friction coefficients in new or refurbished gate valves have been found to increase with service until a plateau reached; (5) MOV output prediction methods have been updated; and (6) personnel training and maintenance practices have been improved. The NRC staff has evaluated the MOV program at each nuclear plant through onsite inspections of the design-basis capability of safety-related MOVs. The NRC staff has closed its review of GL 89-10 for each active U.S. nuclear power plant.

III. LONG-TERM ASPECTS OF MOV PERFORMANCE

On September 18, 1996, the NRC staff issued GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," to provide recommendations for assuring the capability of safety-related MOVs to perform their design-basis functions over the long term. In GL 96-05, the NRC staff requested that licensees establish a program, or ensure the effectiveness of their current program, to verify on a periodic basis that safety-related MOVs continue to be capable of performing their safety functions within the current licensing basis of the facility. The guidance in GL 96-05 supersedes the guidance in GL 89-10 on long-term MOV programs.

In GL 96-05, the NRC staff noted five attributes of effective programs for periodic verification of safety-related MOV design-basis capability at nuclear power plants:

(1) A risk-informed approach may be used to prioritize valve test activities, such as frequency of individual valve tests and selection of valves to be tested.

(2) The valve test program provides adequate confidence that safety-related MOVs will remain operable until the next scheduled test.

(3) The importance of the valve is considered in determining an appropriate mix of exercising and diagnostic testing. In establishing the mix of testing, the benefits (such as identification of decreased thrust output and increased thrust requirements) and potential adverse effects (such as accelerated aging or valve damage) are considered when determining the appropriate type of periodic verification testing for each safety-related MOV.

(4) All safety-related MOVs covered by the GL 89-10 program are considered in the development of the periodic verification program. The program includes safety-related MOVs that are assumed to be capable of returning to their safety position when placed in a position that prevents their safety system (or train) from performing its safety function; and the system (or train) is not declared inoperable when the MOVs are in their nonsafety position.

(5) Valve performance and maintenance are evaluated and monitored, and the periodic verification program is periodically adjusted as appropriate.

JOG Program on MOV Periodic Verification

In response to GL 96-05, nuclear power plant owners groups developed an industry-wide Joint Owners Group (JOG) Program on MOV Periodic Verification to obtain benefits from sharing information between licensees on MOV performance. Elements of the JOG program included (1) an "interim" MOV periodic verification program for applicable licensees to use in response to GL 96-05; (2) a 5-year dynamic testing program to identify potential age-related increases in required thrust and torque to operate gate, globe, and butterfly valves under dynamic conditions; and (3) a long-term MOV diagnostic program based on information from the dynamic testing program. On October 30, 1997, the NRC staff issued an SE accepting the JOG Program on MOV Periodic Verification with certain conditions and limitations.

Licensees of 98 reactor units have participated in the JOG program. The JOG 5-year dynamic testing program included 176 valves that received three dynamic tests with at least a 1-year time interval between the tests. An additional 14 valves received two dynamic tests with at least a 1-year time interval between the tests. In total, the JOG program included 514 dynamic valve tests and involved 52 person-years of effort. The JOG program constituted the largest set of MOV dynamic tests obtained to date for use by U.S. nuclear power plant licensees.

One of the key observations from the JOG program was that an increase in the required thrust or torque did not occur due only to the passage of time (without operation of the valve under dynamic fluid conditions). Further, the JOG program results indicated that significant service-related degradation in valve performance is not expected for MOVs as currently designed, installed and maintained in nuclear power plants. However, the MOV tests revealed that, where the initial valve factor is low because of prior disassembly of the valve or its limited service under dynamic fluid conditions, the thrust requirements for gate valves can increase significantly up to a bounding value over their service life. The program also found that a significant variation can occur in the operating torque requirements for butterfly valves with bronze bearings without a hub seal installed in untreated water systems; and for butterfly valves with non-metallic bearings.

On February 27, 2004, the JOG submitted Topical Report MPR-2524 (Revision 0, February 2004), "Joint Owners' Group (JOG) Motor Operated Valve Periodic Verification Program Summary," providing the long-term recommendations for MOV periodic verification to be implemented by licensees as part of their commitments to GL 96-05. The NRC staff plans to prepare an SE on its evaluation of the JOG topical report. The NRC staff hopes to complete the SE later in 2004.

Owners Group's MOV Risk Categorization Methodologies

Licensees are applying risk insights in implementing their long-term MOV programs. In Topical Report NEDC 32264, "Application of Probabilistic Safety Assessment to Generic Letter 89-10 Implementation," the Boiling Water Reactor Owners' Group (BWROG) describes a methodology to rank MOVs according to their relative importance to core damage frequency and other considerations to be applied by an expert panel. On February 27, 1996, the NRC staff issued an SE accepting the BWROG methodology for risk ranking MOVs with certain conditions and limitations. On June 2, 1997, the Westinghouse Owners' Group (WOG) submitted Engineering Report V-EC-1658 (Revision 1) describing an MOV risk-ranking approach for Westinghouse-design nuclear plants. On April 14, 1998, the NRC staff issued an SE accepting the WOG methodology for risk ranking MOVs with certain conditions and limitations.

Performance of ac-Powered MOV Actuators

In that the JOG program focused on potential increases in valve operating requirements, licensees address potential degradation in the output of MOV motor actuators by their plant-specific programs. In the late 1990s, the NRC sponsored research at INEEL to study the performance of ac-powered MOV motor actuators manufactured by Limitorque Corporation, under various temperature and voltage conditions. For the Limitorque ac-powered motor-actuator combinations tested, the research indicated that (1) actuator efficiency might not be maintained at "run" efficiency published by the manufacturer; (2) degraded voltage effects can be more severe than predicted by the square of the ratio of actual to rated motor voltage; (3) some motors produce more torque output than predicted by their nameplate rating; and (4) temperature effects on motor performance appeared consistent with the Limitorque guidance. The NRC study of ac-powered MOV output is described in NUREG/CR-6478 (July 1997), "Motor-Operated Valve (MOV) Actuator Motor and Gearbox Testing." The nuclear industry also evaluated the output capability of ac-powered MOVs at several plants. In response to the new information on ac-powered MOV performance, Limitorque provided updated guidance in its Technical Update 98-01 (May 15, 1998) and Supplement 1 (July 17, 1998) for the prediction of ac-powered MOV motor actuator. The NRC alerted licensees to the new information on ac-powered MOV output in Supplement 1 (July 24, 1998) to IN 96-48.

Performance of dc-Powered MOV Actuators

Following the NRC review of ac-powered MOV performance, the NRC sponsored research at INEEL to study the performance of Limitorque dc-powered MOV motor actuators under various temperature and voltage conditions. For the Limitorque dc-powered motor-actuator combinations tested, the research indicated that (1) ambient temperature effects were more significant than predicted; (2) use of a linear voltage factor needs to consider reduced speed, increased motor temperature, and reduced motor output; (3) stroke-time increase is significant for some dc-powered MOVs under loaded conditions; and (4) actuator efficiency may fall below the published "pullout" efficiency at low speed and high load conditions. The research results are provided in NUREG/CR-6620 (May 1999), "Testing of dc-Powered Actuators for Motor-Operated Valves."

On June 23, 2000, the BWROG forwarded Topical Report NEDC-32958 (March 2000), "BWR Owners' Group dc Motor Performance Methodology - Predicting Capability and Stroke Time in dc Motor-Operated Valves," to the NRC staff for information. On October 2, 2000, the BWROG recommended an implementation schedule of 12 months or the first refueling outage (whichever is later) for first priority MOVs (those with one- or two-cycle JOG static test frequencies), and two refueling outages for second priority MOVs (remaining GL 96-05 MOVs) with a start date of when the NRC acknowledged the methodology. On August 1, 2001, the NRC issued Regulatory Issue Summary (RIS) 2001-15, "Performance of dc-Powered Motor-Operated Valve Actuators," that informs licensees of the availability of improved industry guidance for predicting dc-powered MOV actuator performance. In RIS 2001-15, the NRC staff stated that, based on a sample review, the BWROG methodology represents a reasonable approach to improvement of past industry guidance for predicting dc-powered MOV stroke time and output. The staff considers the BWROG methodology to be applicable to Boiling Water Reactor (BWR) and Pressurized Water Reactor plants because of similarity in the design and application of dc-powered MOVs. With the availability of the new BWROG methodology, the staff considers that the regulatory issue of adequate prediction of dc-powered MOV performance can be effectively resolved through implementation of improved industry guidance. During a public meeting on March 4, 2004, the BWROG stated that all of its members had completed the implementation of the improved dc motor methodology for the first priority MOVs and that its members were in the process of implementing the methodology for the second priority MOVs. The BWROG did not report any significant concerns or problems with the implementation of the improved dc motor methodology.

Effects of Aging on MOV Internal Surfaces

In support of the NRC review of the JOG program, the NRC sponsored studies at INEEL and Battelle Memorial Institute in Columbus, Ohio, of the effects of aging on Stellite 6 which is used on sliding friction surfaces in valves. The tests of specimens in environments of temperature, pressure, and water chemistry typical of BWR nuclear plants were intended to determine the effects of film buildup on seating surfaces and the impact of the film on valve performance. The test results are provided in INEEL/EXT-99-00116 (April 1999), "Summary and Evaluation of NRC-Sponsored Stellite 6 Aging and Friction Tests," and NUREG/CR-6807 (March 2003), "Results of NRC-Sponsored Stellite 6 Aging and Friction Testing." The results of the aging tests identified the presence of a very thin oxide film after exposure times of only a few days. The test results indicated that friction increases as the test specimens age with the friction stabilizing prior to 120 days of aging. In general, the first test stroke revealed higher friction than succeeding strokes. The friction was reduced during subsequent strokes as the oxide film was removed. From the test program, periodic valve operation does not appear to have a significant effect on friction. However, valve operation shortly before a test might have an impact on the test results.

Effects of Aging and Temperature on MOV Stem Lubricants

To provide additional support for the NRC review of long-term MOV programs, the NRC sponsored a study at INEEL of the aging of stem lubricants and the effects of ambient temperature on their lubricating properties. The results of the research are provided in NUREG/CR-6750 (October 2001), "Performance of MOV Stem Lubricants at Elevated Temperature," and NUREG/CR-6806 (September 2002), "MOV Stem Lubricant Aging Research." The reports note that only a limited sample size was used in the test program. Nevertheless, the test results indicated that the stem friction coefficient for some lubricants can increase significantly under high ambient temperature conditions. The increased stem friction coefficient can cause a loss in the thrust delivered by the MOV motor actuator. For the valve stem tested, the program found that the new MOV Long Life lubricant performed similarly or in an improved manner to other lubricants previously tested.

Plant-Specific MOV Periodic Verification Program Review

Each U.S. nuclear power plant licensee submitted a description of plans for periodic verification of the design-basis capability of safety-related MOVs in response to GL 96-05. The NRC staff reviewed the licensee submittals and conducted inspections of GL 96-05 programs at a sample of nuclear plants. The staff prepared an SE to document its review of the response to GL 96-05 by each licensee. Where a licensee committed to implement the JOG program, the NRC staff relied to a significant extent on that commitment in preparing the SE without the need for plant-specific inspection activity in most instances. The NRC staff reviewed GL 96-05 programs of licensees that did not commit to the JOG program by a separate process of submittals and inspections, as appropriate. The NRC has completed its review of GL 96-05 programs for each active U.S. nuclear power plant. As licensees implement their long-term MOV programs including incorporation of the JOG program results, the NRC will monitor those programs using Inspection Procedure 62708, "Motor-Operated Valve Capability," as part of the NRC reactor oversight program.

Importance of MOV Followup Activities

The NRC staff continues to monitor plant-specific issues that could impact the capability of safety-related MOVs to perform their design-basis functions. For example, the NRC issued Information Notice (IN) 2003-15 (September 5, 2003), "Importance of Followup Activities in Resolving Maintenance Issues," to remind licensees that followup activities to verify implementation of corrective actions are an important part of a successful plan to resolve maintenance issues for safety-related components. In IN 2003-15, the NRC staff discussed the failure of an MOV at a U.S. nuclear power plant in January 2003 when its motor pinion gear moved along the motor shaft, and caused the motor to stall when contacting the declutch mechanism. In response to the MOV failure, the licensee inspected over 300 MOVs and found many deficiencies in motor pinion gear connections despite a long history of related industry information. When responding to operating experience and component performance information, it is important to have a clear plan of action to identify specific potentially affected components, and to address and track them to completion in a reasonable time based on their safety significance. The revision of maintenance procedures will only resolve a generic issue if the revised procedures are implemented during work activities. Where revised procedures are not implemented, the potential for common-cause failure can continue to exist for affected components in multiple plant systems.

IV. ASME ACTIVITIES TO IMPROVE MOV INSERVICE TESTING AND QUALIFICATION

The ASME Code specifies that stroke-time testing of MOVs be conducted as part of the IST programs of nuclear power plants on a quarterly frequency where practical. The NRC and the industry have long recognized the limitations of stroke-time testing as a means of assessing the operational readiness of MOVs to perform their design-basis safety functions. The NRC requires U.S. nuclear power plant licensees implementing the ASME OM Code to supplement the quarterly MOV stroke-time testing specified in the Code with a program to verify MOV design-basis capability on a periodic basis.

In response to concerns regarding the adequacy of MOV stroke-time testing, the ASME Operations and Maintenance Code Committee developed performance-based ASME Code Case OMN-1, "Alternative Rules for Preservice and Inservice Testing of Certain Electric Motor Operated Valve Assemblies in LWR Power Plants, OM Code 1995 Edition; Subsection ISTC." As an alternative to quarterly stroke-time testing, ASME Code Case OMN-1 allows periodic exercising of all safety-related MOVs once per refueling cycle and periodic diagnostic testing under static or dynamic conditions, as appropriate, on a frequency determined by MOV performance in terms of margin and degradation rate. In GL 96-05, the NRC staff noted that the method in ASME Code Case OMN-1 could be used as part of a licensee's response to the generic letter.

In Regulatory Guide (RG) 1.192 (June 2003), "Operation and Maintenance Code Case Acceptability, ASME OM Code," the NRC staff indicates that ASME Code Case OMN-1 is acceptable in lieu of stroke-time testing in the 1995 Edition up to and including the 2000 Addenda of the OM Code when applied with provisions for leakage rate testing. The NRC staff also indicates that licensees who implement Section XI of ASME BPV Code may use OMN-1 in lieu of stroke-time testing subject to the RG 1.192 conditions. The NRC staff states that licensees who implement OMN-1 must apply all of its provisions. The conditions for use of OMN-1 in RG 1.192 are:

(1) The adequacy of diagnostic test interval for each MOV must be evaluated and adjusted not later than 5 years or 3 refueling outages (whichever is longer) from OMN-1 implementation.

(2) If the exercise intervals for high-risk MOVs are extended, licensees must ensure that the increase in Core Damage Frequency and risk is small and consistent with the Commission's Safety Goal Policy Statement.

(3) Licensees must categorize MOVs using the methodology in ASME Code Case OMN-3 consistent with the RG 1.192 conditions, or use other MOV risk-ranking methodologies accepted by NRC with the conditions in the applicable safety evaluations.

The NRC staff also notes in RG 1.192 that the benefits of performing a particular test should be balanced against the potential adverse effects.

In RG 1.192, the NRC staff indicates that Code Case OMN-11, "Risk-Informed Testing for Motor-Operated Valves," is acceptable in supplementing the risk insights in Paragraph 3.7 of OMN-1 with the following conditions:

(1) In addition to the IST provisions of Paragraph 3 of OMN-11, MOVs within the scope of OMN-1 that are categorized as Low Safety Significant Components (LSSCs) must satisfy the other provisions of OMN-1, including the determination of proper MOV test intervals.

(2) Paragraph 3(a) of OMN-11 must be interpreted as allowing the provisions of Paragraph 3.5 of OMN-1 related to similarity and test sample to be relaxed when grouping LSSC MOVs. Provisions in Paragraph 3.5 related to evaluation of test results, sequential testing, and analysis of test results per Paragraph 6 of OMN-1 continue to be applicable to all MOVs within the OMN-1 scope.

(3) If extending high-risk MOV exercise intervals, licensees must ensure that the increase in Core Damage Frequency and risk is small and consistent with the Commission's Safety Goal Policy Statement.

In RG 1.192, the NRC staff also notes that the condition regarding allowable methodologies for MOV risk ranking also applies to OMN-11.

The NRC staff has granted requests from nuclear power plant licensees to apply OMN-1 as an alternative to the quarterly MOV stroke-time testing in their particular ASME Code of record. Currently, ASME is preparing a revision to OMN-1 to improve its application to more nuclear power plants by clarifying several aspects of the code case while retaining the safety improvement that is achieved through increased knowledge of the design-basis capability of MOVs obtained from diagnostic testing. Over the longer term, it is recommended that ASME replace the quarterly MOV stroke-time testing specified in the ASME Code with performance-based provisions similar to those in ASME Code Case OMN-1.

With respect to MOV qualification, the Subcommittee on Qualification of Valve Assemblies (SC-QV) of the ASME Committee on Qualification of Mechanical Equipment used in Nuclear Facilities has prepared a proposed revision to Section QV, "Functional Qualification Requirements for Active Valve Assemblies for Nuclear Power Plants," of the ASME Standard QME-1, "Qualification of Active Mechanical Equipment used in Nuclear Power Plants." The proposed revision to Section QV to QME-1 reflects valve performance information obtained from nuclear industry programs and NRC-sponsored research since development of the QME-1 standard in the 1980s. At a meeting on February 23, 2004, SC-QV completed its resolution of comments on the proposed revision to Section QV, and planned to forward the proposed revision to Section QV to the QME main committee for balloting.

V. PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES

One typical method that "pressure locking" can occur in flexible-wedge and double-disk gate valves is when pressure in the bonnet is higher than the line pressure on both sides of a closed disk and the valve actuator is not capable of overcoming the additional thrust required as a result of the differential pressure. Thermal binding is generally associated with a solid- or flexible-wedge gate valve that is closed at high temperature and is allowed to cool before reopening is attempted such that mechanical interference occurs because of contraction of the valve body on the disk wedge. On August 17, 1995, the NRC issued GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," to request that licensees perform, or confirm that they had previously performed, (1) evaluations of the operational configurations of safety-related, power-operated (including motor-, air-, and hydraulically operated) gate valves for susceptibility to pressure locking and thermal binding; and (2) further analyses, and any needed corrective actions, to ensure that safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding are capable of performing their safety functions within the current licensing basis of the facility.

NUREG/CR-6611 (May 1998), "Results of Pressure Locking and Thermal Binding Tests of Gate Valves," describes testing sponsored by the NRC Office of Nuclear Regulatory Research at INEEL to study pressure locking and thermal binding of gate valves in support of GL 95-07.

The NRC staff has completed its review of licensee responses to GL 95-07 through issuance of an SE addressing each active U.S. nuclear power plant.

VI. CONCLUSIONS

As a result of problems identified in the 1980s with MOV performance at nuclear power plants, the NRC issued GLs 89-10 and 96-05 requesting that licensees verify initially and periodically the design-basis capability of MOVs in safety-related systems at nuclear power plants. In response to GL 96-05, the nuclear power plant owners groups developed an industry-wide JOG program for periodic verification of the design-basis capability of safety-related MOVs. The NRC accepted the JOG program as an industry-wide response to GL 96-05 with respect to age-related valve degradation. The NRC issued GL 95-07 requesting that licensees ensure that safety-related power-operated gate valves susceptible to pressure locking or thermal binding are capable of performing their safety functions. Licensees of all active U.S. operating reactor units have completed their programs to verify initially the design-basis capability of safety-related MOVs in response to GL 89-10, and to address potential pressure locking and thermal binding of safety-related power-operated valves in response to GL 95-07. Licensees are currently implementing their long-term MOV programs in response to GL 96-05. The NRC staff has completed its review of GL 96-05 programs established at individual nuclear plants through significant reliance on licensee commitments to implement the JOG program on MOV periodic verification. The NRC staff is reviewing the JOG final topical report that describes the long-term periodic verification of the design-basis capability of MOVs for use by licensees as part of their commitments to GL 96-05. In its regulations, the NRC has directed licensees implementing the ASME OM Code to supplement the quarterly MOV stroke-time testing in their IST programs with a program to periodically verify MOV design-basis capability. The NRC staff has granted requests from licensees to apply performance-based ASME Code Case OMN-1 as an alternative to the quarterly MOV stroke-time testing in their ASME Code of record. The NRC has accepted generic use of ASME Code Case OMN-1 as an alternative to MOV stroke-time testing in RG 1.192. The NRC continues to monitor licensee activities related to the performance of safety-related MOVs through the reactor oversight program.

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RULEMAKING ACTIVITIES ON INSERVICE TESTING

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Abstract

Section 50.55a of Title 10 of the Code of Federal Regulations (10 CFR 50.55a) establishes requirements for the application of codes and standards in the performance of inservice testing of components used in nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) periodically updates 10 CFR 50.55a to incorporate by reference recent editions and addenda to the American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Plants (OM Code) for inservice testing (IST) of pumps and valves used in nuclear power plants. The NRC is currently updating 10 CFR 50.55a to incorporate by reference the 2001 Edition through 2003 Addenda of the ASME OM Code. This proposed action will accord the provisions in the 2001 Edition and the 2002 and 2003 Addenda to the ASME OM Code the same legal status as the earlier editions and addenda of the ASME OM Code that have been incorporated by reference in 10 CFR 50.55a. This paper will present the status of this rulemaking and other rulemakings that are related to inservice testing of pumps and valves.

I. Incorporation By Reference of a Later Edition and Addenda of ASME Code

In Commission paper SECY-03-0078 (May 15, 2003), the NRC staff requested approval of the Commission for the initiation of a rulemaking to amend 10 CFR 50.55a to incorporate by reference the following: (1) the 2001 Edition, 2002 Addenda, and 2003 Addenda of Division 1 rules of Section III, "Rules for Construction of Nuclear Power Plant Components," of the ASME Boiler and Pressure Vessel Code (BPV Code); (2) the 2001 Edition, 2002 Addenda, and 2003 Addenda of Division 1 rules of Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the ASME BPV Code; and (3) the 2001 Edition, 2002 Addenda, and 2003 Addenda of the ASME OM Code. To improve the timeliness of NRC review and approval of new editions and addenda of the ASME Code, the staff proposed in SECY-03-0078 to conduct rulemakings to keep current the ASME Code editions and addenda incorporated by reference in 10 CFR 50.55a at approximately 2 to 3 year intervals. The Commission approved the staff's proposal in a staff requirements memorandum dated May 30, 2003.

On January 7, 2004 (69 FR 879), the NRC published a proposed rule in the Federal Register that presented an amendment to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," that would revise the requirements for construction, inservice inspection (ISI), and IST of nuclear power plant components. The proposed revision to § 50.55a(b)(3) would incorporate by reference the 2001 Edition and the 2002 and 2003 Addenda of the ASME OM Code.

The proposed amendment would revise the existing modifications and limitations for quality assurance, motor-operated valve testing, Subsection ISTD on snubbers, and exercise interval for manual valves in §§ 50.55a(b)(3)(i), 50.55a(b)(3)(ii), 50.55a(b)(3)(v), and 50.55a(b)(3)(vi), respectively, to apply to the 2001 Edition through 2003 Addenda of the ASME OM Code. The modifications and limitations in §§ 50.55a(b)(3)(i), 50.55a(b)(3)(ii), 50.55a(b)(3)(v), and 50.55a(b)(3)(vi) would continue to apply to the 2001 Edition through 2003 Addenda of ASME OM Code because the earlier Code provisions on which these regulations were based were not revised in the 2001 through 2003 Addenda of the ASME OM Code to resolve the underlying issues which led the NRC to impose the modifications and limitations on the ASME Code provisions.

The proposed amendment would revise the existing quality assurance requirements in § 50.55a(b)(3)(i) to state that paragraph ISTA-1500 of Subsection ISTA in the ASME OM Code is applicable when using the 1998 Edition and

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. NRC has neither approved nor disapproved the technical content.

later editions and addenda of the Code. Subsections of the ASME OM Code were renumbered in the 1998 Edition; therefore, § 50.55a(b)(3)(i) would be revised to account for the renumbering. The proposed revision does not change IST requirements in a substantive manner.

The proposed amendment would revise § 50.55a(b)(3)(iii) to eliminate the authorization in this paragraph to use Code Case OMN-1. Code Case OMN-1 is now authorized by Regulatory Guide 1.192, Operation and Maintenance Code Case Acceptability, ASME OM Code. Regulatory Guide 1.192 was incorporated by reference into § 50.55a in a final rule dated July 8, 2003 (68 FR 40469). Thus, it is no longer necessary to authorize the use of Code Case OMN-1 in § 50.55a(b)(3)(iii) because this code case is now included in Regulatory Guide 1.192.

The proposed amendment would revise the existing modification for the check valve monitoring program in § 50.55a(b)(3)(iv) to limit its application to the 1995 Edition through 2002 Addenda of the ASME OM Code. The modification in § 50.55a(b)(3)(iv) would not apply to the 2003 Addenda of the ASME OM Code because the earlier Code provisions on which this regulation was based were revised in the 2003 Addenda of the ASME OM Code to resolve the underlying issues which led the NRC to impose the modification to the ASME Code provisions. The check valve monitoring program requirements in Appendix II of the 2003 Addenda of the ASME OM Code are equivalent to the check valve monitoring program requirements in § 50.55a(b)(3)(iv).

Public Meetings

On August 25, 2003, NRC staff from the NRC Office of Nuclear Reactor Regulation held a public meeting in Scottsdale, Arizona. The purpose of the public meeting was to present, and obtain stakeholder feedback on, the proposed rulemaking to amend 10 CFR 50.55a to incorporate by reference the 2001 Edition through 2003 Addenda of Sections III and XI, Division 1, of the ASME BPV Code. These two sections of the Code provide requirements for the design and ISI of nuclear power plant components.

The NRC staff presented its issues associated with the use of 2001 Edition and 2002 and 2003 Addenda of Sections III and XI of the ASME BPV Code. The public meeting was held in the evening at the same location that ASME Sections III and XI committees were meeting to enhance stakeholder participation. Approximately 60 members of the public attended the meeting. Most of the public that attended the meeting were members of the ASME. There was a good exchange of information between the NRC staff and the public during the meeting. The staff noted, however, that the verbal feedback does not preclude the need to submit written comments when the proposed rule is issued. Members of the ASME commented on several of the issues and provided additional information for the NRC staff to consider. The NRC staff evaluated the additional information provided at the meeting and revised sections of the proposed rule based on comments received during the meeting.

On February 23, 2004, the NRC held a public meeting in St. Petersburg, Florida, to discuss NRC's proposed rule (69 FR 879) to incorporate by reference into 10 CFR 50.55a the 2001 Edition (up to and including the 2003 Addenda) of ASME Boiler and Pressure Vessel Code, Section III. Specifically, the public was invited to comment on those portions of the latest Code related to changes in the seismic design rules for piping systems. The public meeting was held in conjunction with the ASME Code committee meetings that week. Approximately 40 persons attended the public meeting. The latest changes to the Code rules represented a culmination of effort in place since 1995 when the NRC placed a restriction in 10 CFR 50.55a on the use of the revised ASME Code rules for piping seismic design that first appeared in the 1994 Addenda. In 1995, the ASME Code assigned a special task group to resolve the NRC's concerns, and the task group's effort resulted in the revised Code rules published in the 2001 Edition up to and including the 2003 Addenda. In the proposed rule, the NRC staff would accept the new ASME Code piping seismic rules with six modifications and limitations. At the public meeting, the NRC staff heard presentations by three ASME piping experts including a Japanese seismic team involved in dynamic testing of piping systems.

The NRC plans to continue to conduct meetings to obtain stakeholder feedback on future proposed rulemakings that amend 10 CFR 50.55a to incorporate by reference a later edition and addenda of the ASME Code when significant issues with the use of the later edition and addenda of the ASME BPV or OM Code are identified. The NRC staff did not identify any significant issues with the use of the 2001 Edition through 2003 Addenda of the ASME OM Code; therefore, the NRC staff did not consider a public meeting to be necessary.

II. Incorporation By Reference of "Code Case" Regulatory Guides

The ASME develops and publishes the BPV Code, which contains the Code requirements for design, construction, and ISI of nuclear power plant components, and the OM Code, which contains Code requirements for IST of nuclear power plant components. In response to Code user requests, the ASME develops Code cases for the BPV and OM Code which provide alternatives to the Code requirements under special circumstances.

The NRC staff reviews ASME Code Cases, determines their acceptability, and publishes its findings in NRC Regulatory Guides (RGs). The RGs are revised periodically as new Code cases are published by the ASME. On July 8, 2003, the NRC issued a final rule (68 FR 40469) which initiated the practice of incorporating by reference the RGs listing the acceptable and conditionally acceptable ASME Code cases in § 50.55a. Thus, NRC RG 1.84 (Revision 32), Design, Fabrication, and Materials Code Case Acceptability, ASME Section III; RG 1.147 (Revisions 0 through 13), Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1; and RG 1.192, Operation and Maintenance Code Case Acceptability, ASME Code, were incorporated into the NRC's regulations. The NRC is now proposing to incorporate by reference RG 1.84 (Revision 33) and RG 1.147 (Revision 14) to replace earlier revisions of these RGs in the NRC's regulations.

The NRC staff reviewed Code Cases OMN-1 through OMN-13 for inclusion into the version of RG 1.192 that is currently incorporated by reference in 10 CFR 50.55a. The NRC staff is not proposing a revision to RG 1.192 at this time because additional code cases have not been published by the ASME OM Code.

III. Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors

The proposed rule dated May 16, 2003 (68 FR 265110) would amend NRC regulations to provide an alternative approach for establishing the requirements for treatment of structures, systems, and components (SSCs) for nuclear power reactors using a risk-informed method of categorizing SSCs according to their safety significance. The proposed amendment would revise requirements with respect to "special treatment," that is, those requirements that provide increased assurance (beyond normal industrial practices) that SSCs perform their design basis functions. This proposed amendment is further discussed in the risk-informed IST session of this symposium.

IV. Conclusion

The final rule to update 10 CFR 50.55a to incorporate by reference the 2001 Edition through 2003 Addenda of the ASME OM Code is scheduled to be published in the Federal Register in October 2004. The final rule will become effective 30 days from date of publication in the Federal Register. Licensees of nuclear power plants would be required to use the 2001 Edition and the 2002 and 2003 Addenda of the ASME OM Code when updating IST programs in subsequent 120-month inspection intervals under § 50.55a(f)(4)(ii). The proposed rule to amend 10 CFR 50.55a to incorporate by reference the NRC's RGs that address the use of Code Cases prepared by the ASME BPV and OM Code will not include RG 1.192. The final rule that would add 10 CFR 50.69, "Risk-Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," is scheduled to be completed in mid-2004.

NUCLEAR POWER PLANT PUMP AND VALVE INSERVICE TESTING ISSUES

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Abstract

This paper summarizes a number of pump and valve inservice testing issues raised since the Seventh Nuclear Regulatory Commission (NRC)/American Society of Mechanical Engineers (ASME) Symposium on Valve and Pump Testing. The issues have generic applicability to United States nuclear power plants. Among the issues addressed are the comprehensive pump test (CPT), frequency response range of vibration measuring transducers, and online testing of check valves.

INTRODUCTION

The NRC staff has encountered a number of pump and valve inservice testing (IST) issues since the Seventh NRC/ASME Symposium on Valve and Pump Testing in 2002. This paper discusses pump issues involving the comprehensive pump test (CPT) and the frequency range of vibration-measuring transducers and valve issues involving online testing of check valves. The paper discusses the relief requests received related to these issues and the NRC safety evaluations of the requests. Some current staff positions and actions in these areas are discussed.

COMPREHENSIVE PUMP TEST ISSUES

On September 22, 1999, the staff's endorsement of the 1995 Edition of the ASME Operation and Maintenance (OM) Code up to and including the 1996 Addenda was published in the Federal Register (Vol. 64, No. 183). With this rulemaking came revised requirements for IST. The 1995 ASME OM Code includes a new set of pump testing requirements which are collectively known as the "comprehensive pump test." The CPT allows less rigorous pump testing to be performed for certain pumps on a quarterly frequency while requiring a pump test to be performed with more accurate flow instrumentation every 2 years at ±20 percent of pump design flow. The CPT was developed with the knowledge that some pumps, such as containment spray pumps, cannot be tested at the required high flow rates because of limitations of system design. All ASME OM Code editions and addenda, issued since 1995 contain CPT requirements.

Licensees have started to update their IST programs, as required by 10 CFR 50.55a, to the 1995 Edition through the 1996 Addenda of the ASME OM Code. Relief requests have been submitted to the NRC staff to propose alternative testing to the CPT pump design flow requirements because the requirements for certain pumps have been determined by the licensee to be either a burden or impractical. This paper only summarizes various issues related to the CPT in these proposed relief requests and the NRC staff's published evaluation. The intent of this paper is to summarize the current evaluations and present licensees with issues to consider if they are contemplating similar licensing actions.

OM Code Subsection ISTB-1995 introduces a new approach to pump testing by dividing pumps into two basic groups. The pump grouping criteria of ISTB are based on the way the pumps are operated at the plant. There are two groups: normally or routinely operated pumps (group A) and standby pumps (group B). The Code identifies four type of tests: preservice test, Group A test, Group B test, and comprehensive test. All pumps receive a preservice test followed quarterly by the test associated with the pump category (Group A test for Group A pump, etc.). A comprehensive test may be substituted for a Group A test or

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Group B test. A Group A test may be substituted for a Group B test. A preservice test may be substituted for any inservice test.

As a point of information, the OM-6 pump testing standard was issued in October 1990 as OM Code-1990, Subsection ISTB (ASME, 1990). The CPT change was written against the 1990 Subsection ISTB. The 1995 OM Code, ISTB 4.3(e)(1), requires that reference values be established within ±20% of design flow for the comprehensive test.

The staff authorized or denied alternatives proposed in the following relief requests, as documented in their NRC safety evaluation:

- Seabrook Station, Unit 1
- North Anna Power Station, Units 1 and 2
- Calvert Cliffs Nuclear Power Plant, Units 1 and 2
- H. B. Robinson Steam Electric Plant, Unit 2
- Vermont Yankee
- Sequoyah, Units 1 and 2
- Monticello Nuclear Generating Plant

This paper only summarizes the various relief requests and the safety evaluation results. Licensees can review the details of a particular relief request safety evaluation in the publicly available NRC Agency wide Documents Access and Management System (ADAMS). The NRC ADAMS number associated with the relief request is shown in the Remarks column of the attached summary table.

Seabrook Station, Unit 1

The licensee of Seabrook Station submitted relief request PR-1 on March 21, 2000. The proposed alternative to the Code reference value requirements of ISTB 4.3.e(1) for the containment spray pumps CBS-P-9A and CBS-P-9B was authorized pursuant to 10 CFR 50.55a(a)(3)(i) on the basis that the alternative provided an acceptable level of quality and safety for an interim period of 2 years.

During the interim period, the licensee was requested to reevaluate the current testing to assess the ability to detect degradation as was intended by the OM Code-1995 pump test strategy. The NRC safety evaluation stated: "This may entail more detailed analysis of the IST data, consultation with the manufacturer, or running additional tests as appropriate. If the licensee cannot further demonstrate that the proposed testing is an acceptable alternative, then appropriate compensatory actions should be proposed to supplement the alternative testing. Possible strategies or combinations of strategies include: 1) testing at the best efficiency point (BEP) on a much longer interval; 2) commitment to perform additional performance monitoring on the containment spray pumps; 3) adjustment of acceptance criteria; and/or 4) continuation of the current Code testing, including taking overall vibration data quarterly."

The licensee resubmitted a revised relief request PR-1 on October 28, 2002, with additional information and proposed compensatory actions. The NRC staff concluded that meeting the requirements of ISTB 4.3.e(1) for the containment spray pumps CBS-P-9A and CBS-P-9B was impractical at that time. The staff also concluded that testing the containment spray pumps at 63 percent of the pump best efficiency point using the recirculation flow lines, together with the proposed compensatory actions, provided reasonable assurance of the operational readiness of the containment spray pumps.

Based on a review of the information provided by the licensee, the NRC staff granted the licensee's request for relief and the proposed alternatives to the Code requirements of ISTB 4.3.e(1) for the containment spray pumps pursuant to 10 CFR 50.55a(f)((6)(i) on the basis that the Code requirements were impractical.

North Anna Power Station, Units 1 and 2

The licensee of North Anna Station submitted relief request P-6 on June 4, 2001. Based on a review of the information provided by the licensee, the NRC staff concluded that the licensee's proposed alternative to the Code-required number of data points on pump test curves and to the reference value requirements of Table ISTB 4.1(a) and paragraph ISTB 4.3(e) for recirculation spray pumps 1-RS-P-2A and 2B, and 2-RS-P-2A and 2B was authorized pursuant to 10 CFR 50.55a(a)(3)(ii) on the basis that compliance with the specified requirement resulted in a hardship without a compensating increase in the level of quality and safety. The NRC staff further concluded that the alternative provided reasonable assurance of the operational readiness of the pump.

The licensee committed to include all the outside recirculating pumps in the North Anna Predictive Maintenance Program. Under this program, if the measured parameters are outside the normal operating range or are determined by the analysis to be trending towards an unacceptable degraded state, the licensee will take appropriate actions, including monitoring additional parameters, reviewing component-specific information to identify the cause, and removing the pump from service to perform maintenance.

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

The licensee of Calvert Cliffs Nuclear Power Plant submitted relief request PR-12 on January 4, 2002. The NRC staff concluded that the use of the OM Code, Subsection ISTB, 1995 Edition with 1996 Addenda (instead of OM-6, 1987/88) for the pump testing for the Calvert Cliffs Nuclear Power Plant was acceptable and approved the request pursuant to 10 CFR 50.55a(f)(4)(iv). This relief request was for only for high-pressure coolant injection (HPCI), low- pressure coolant injection (LPCI), and the containment spray pumps.

H. B. Robinson Steam Electric, Plant Unit 2

The licensee of H. B. Robinson submitted relief request IST-RR-3 on August 24, 2001. The licensee proposed an alternative to perform a reduced-flow comprehensive test for containment spray pumps A and B in lieu of a full-flow comprehensive test as required by OM Code, paragraph ISTB 4.3(e)(1). This relief was authorized pursuant to 10 CFR 50.55a(f)(6), for an interim period of 2 years on the basis that the Code-required test was impractical to perform without significant plant modification, that the interim alternative otherwise met the criteria of 10 CFR 50.55a(f)(6)(i), and that the interim relief would allow time for the licensee to explore other alternatives, make necessary plant modifications for performing the required test, or submit a revised relief request.

The licensee of H. B. Robinson submitted revised relief request IST-RR-3 on April 15, 2003, with additional information. The NRC staff concluded that the licensee's proposed alternative did not provide an acceptable level of quality and safety and did not explain why compliance with Code requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality or safety; therefore, the request was denied. The licensee subsequently modified the system's design to install a full-flow test line to allow comprehensive pump testing in accordance with the Code requirements.

Vermont Yankee

The licensee of Vermont Yankee submitted relief request RR-P01 on January 22, 2003, for the service water (SW) pumps. The staff concluded that compliance with the Code-required Group A quarterly flow test (and associated differential pressure testing) of the SW pumps would require significant redesign of the SW system. Relief was granted pursuant to 10 CFR 50.55a(f)(6)(i) on the basis of the impracticality of performing inservice testing in accordance with ASME OM Code requirements. The Code-specified comprehensive pump test shall be performed on the SW pumps on a refueling outage frequency (every 18 months). Vibration measurements, including full spectral analyses, will be performed quarterly with vibration measurements assessed in accordance with the Code (using quarterly differential pressure measurements to establish a variable reference value). The licensee's proposed alternative testing and analyses provided reasonable assurance of the pumps' operational readiness.

Sequoyah, Units 1 and 2

The licensee of Sequoyah, Units 1 and 2, submitted relief requests RP-09 and RP-10 on April 17, 2002, for the turbine driven auxiliary feedwater (TDAFW) pumps. On the basis that the NRC incorporated by reference in 10 CFR 50.55a(b) the 1995 Edition through 1996 Addenda of the OM Code, the use of the OM Code, Subsection ISTB, 1995 Edition with 1996 Addenda, for the CPT for the Sequoyah, Units 1 and 2, TDAFW pumps was approved pursuant to 10 CFR 50.55a(f)(4)(iv).

Monticello Nuclear Generating Plant

The licensee of Monticello submitted relief request PR-06 on May 6, 2003, for the HPCI pumps. The NRC staff concluded that the licensee's methodology to establish and use reference curves in the performance of the Group B and comprehensive tests of HPCI pump P-209 at Monticello Nuclear Generating Plant (MNGP) provided an acceptable level of quality and safety because MNGP used the method approved by the NRC staff in Code Case OMN-9 to establish a reference value curve for pump differential pressure and flow rate, and the requirement for conducting pump IST within ±20 percent of the pump design flow rate was not affected.

The NRC staff concluded that Monticello's request to use reference curves as part of an alternative testing methodology to satisfy the provisions in paragraphs ISTB 5.2.2(a) and ISTB 5.2.3(a) of the ASME OM Code for the Group B and comprehensive tests, respectively, of the HPCI pump provided an acceptable level of quality and safety. On this basis, the NRC staff authorized Monticello's proposed alternative in accordance with 10 CFR 50.55a(a)(3)(i).

Summary of Nuclear Power Plants Requesting Relief related to Comprehensive Pump Test

Plant	Relief Request	OM Code Section (year)	Comprehensive Test		Reason	Remark
			Flow (% of design)	TDH-Flow (total dynamic head flow) curve		
Seabrook, Unit 1 (50-443) Cont. spray pumps	PR-1, March 21, 2000 (2nd 10-year IST)	ISTB 4.3.e.1 1995/96	1900 gpm (63%)	Approx. Flat	The licensee proposed only recirculation line flow for comprehensive test.	Authorized for 2 years, interim ML003760787
	Revised PR-1, October 28, 2002	ISTB 4.3.e.1 1995/96	1900 gpm (63%)	Approx. Flat	(1) Repeatable results (2) Spray pumps are included in Predictive Maintenance Monitoring Equipment Program, which will enhance vibration monitoring and analysis and periodic lube oil analysis. (3) Corrective action required, if unacceptable degraded condition found	Relief granted, 10 CFR 50.55a(f)(6)(i) ML031070510
Calvert Cliffs, Units 1 and 2 (50-317) (50-318) HPCI, LPCI, spray pumps	PR-12 Jan 4, 2002 (3nd 10-year IST)	Use of ISTB 1995/96 instead of OM-6 1987/88	N/A	N/A	The licensee proposed to use OM Code 1995 through 1996 Addenda, Subsection ISTB, which allows to use of comprehensive pump test.	Approved pursuant to 10 CFR 50.55a(f)(4)(iv) ML021000690
North Anna, Units 1 & 2 (50-338) (50-339) Spray Pumps	P-6, June 4, 2001 (3nd 10-year IST)	ISTB 4.3.e.1 1995/96	1500 gpm (40%)	Flow varies with TDH	(1) Full-flow test was performed in Unit 2 during construction phase. (2) Flow increases with lower TDH. (3) Spray pumps are included in Predictive Maintenance Program for additional testing, trending, and diagnostic analysis. (3) Corrective action required if unacceptable degraded condition found. (4) More restrictive differential pressure requirement than Table ISTB 5.2.3-1 to ensure pumps can deliver required accident flow.	Authorized 10 CFR 50.55a(3)(ii) ML020280439

Summary of Nuclear Power Plants Requesting Relief related to Comprehensive Pump Test

Plant	Relief Request	OM Code Section (year)	Comprehensive Test		Reason	Remark
			Flow (% of design)	TDH-Flow (total dynamic head flow) curve		
Sequoyah, Units 1 & 2 (50-327) (50-328) AFW (aux. feedwater) pumps	RP-09 & RP-10, April 17, 2002 (2nd 10-year IST)	Use of ISTB 1995/96 instead of OM-6 1987/88	N/A	N/A	The licensee proposed to use OM Code 1995 through 1996 Addenda, Subsection ISTB, which allows to use of comprehensive pump test.	Approved pursuant to 10 CFR 50.55a(f)(4)(iv) ML021970279
H.B. Robinson, Unit 2 (50-261) Spray pumps	IST-RR-3 August 24, 2001 (4th 10-year IST)	ISTB 4.3.e.1 1995/96	240 gpm (20%)	N/A	The licensee proposed only recirculation line flow (20% of maximum flow) for comprehensive pump test. Pump was never tested at design flow in installed condition.	Authorized for 2 years, interim ML040700790
	Revised IST-RR-3 April 15, 2003	ISTB 4.3.e.1 1995/96	Test at 33%	N/A	The licensee proposed (1) test at 33% maximum flow (2) vibration monitoring quarterly (3) $220,000 required for design modification to meet the code.	Relief denied. ML031780245
Vermont Yankee (50-271) Service water pumps	RR-P01 Jan 22, 2003 (4th 10-year IST)	ISTB3400 and Table ISTB-3400-1 OM-1998 2000 Add.	Full design flow	N/A	Service water pumps are Group A pumps. Licensee will perform CPT every refueling outage at full flow, but cannot perform Group A flow test quarterly due to existing SW system limitation. The licensee will measure vibration and differential pressure every quarter, plot flow-head curve quarterly to provide additional information, and perform lube analysis.	Relief granted due to impracticality per 10 CFR 50.55a(f)(6)(i) ML032020388
Monticello (50-263) HPCI pumps	PR-06 May6, 2003 (4th 10-year IST)	ISTB 5.2.2(a) and 5.2.3(a) OM-1995 1996 Add.	For details see relief request and OMN-9 guidelines	For details see relief request and OMN-9 guidelines	The licensee stated that use of an accurate reference value is very important for accurate trending and analysis. The licensee stated that the complexities of the flow control system for the HPCI pump make it difficult to exactly duplicate the reference points. The licensee proposed an alternative test method for the Group B and comprehensive tests of the HPCI pump. The alternative testing used the methodology of the Code Case OMN-9, "Use of a Pump Curve for Testing."	Authorized 10 CFR 50.55a(3)(ii) ML032060580

PUMP'S VIBRATION MEASURING INSTRUMENTS (TRANSDUCERS) ISSUE

The NRC has received relief requests from various licensees for relief from the provisions of ISTB 4.7.1(f) of the ASME OM Code for pumps with low pump shaft rotational speeds. Paragraph ISTB 4.7.1(f), "Frequency Response Range," requires that 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 1000 hertz (Hz).

Most of the licensees stated that procurement and calibration of instruments to cover the lower end of the Code-specified range was impractical due to the limited number of vendors supplying such equipment, the level of equipment sophistication required, and the equipment cost. Therefore, past relief requests were typically authorized pursuant to 10 CFR 50.55a(a)(3)(ii) on the basis that compliance with the specified Code requirement would result in hardship without a compensating increase in the level of quality and safety. The NRC provided detailed safety evaluations authorizing these relief requests.

The NRC has learned that, due to technology advancement and research work performed in the field of instrumentation, vibration-measuring transducers meeting the Code requirements can be easily procured from various suppliers at a reasonably low cost.

Therefore, licensees are requested to carefully examine the availability, procurement, and related cost of the Code-required instruments (vibration-measuring transducers) before submitting a relief request to the NRC.

Recently, a similar relief request was received from the licensee of the Pilgrim Nuclear Power Station. After review, requests for additional information, and followup discussion by the NRC, the licensee withdrew the relief request and decided to install a new transducer, that met the Code requirements.

ONLINE TESTING OF CHECK VALVES ISSUES

In an effort to shorten refueling outages, many licensees are performing as much maintenance and testing, and as many other surveillance activities, as possible with the nuclear power plant online. For example, several licensees have submitted relief requests to the NRC to conduct inservice testing once per refueling cycle, rather than during a refueling outage as prescribed by the Code. Several factors should be taken into consideration in preparing (and evaluating) such relief requests to ensure that the proposed alternative provides an acceptable level of quality and safety.

If a licensee is testing a particular valve during refueling outages, it may be because the licensee determined that it was impractical to test the valve quarterly during operation or during cold shutdown. The inservice testing program should document the basis for deferring the testing from quarterly (and during cold shutdown) to refueling outages. Relief requests to perform testing with the nuclear plant online should be prepared in light of the refueling outage justification for each valve or group of valves affected. If necessary, the refueling outage justification should be revised to be consistent with the relief request.

Consideration should be given to whether the testing can be readily accomplished within the allowed outage time permitted by any applicable technical specification. In general, the time necessary to complete the testing should be significantly less than the allowed outage time. This general consideration is intended to avoid technical specification violations or the need to issue exigent technical specification amendments or notices of enforcement discretion.

Sometimes there is a tradeoff between testing these valves at power and testing them during outages (e.g., when there may be greater reliance on shutdown cooling or when other necessary equipment is out of service). Licensees should provide a risk-informed justification, either quantitative or qualitative, for why testing online is appropriate instead of testing during the refueling outage. Licensees should identify any compensatory measures to be established as a risk management action to reduce the risk impact of testing with the nuclear power plant at power. If relevant, licensees should provide information on how testing at power versus testing during refueling outages will affect scheduled maintenance work windows for the applicable system. Can this testing be done within these work windows or does this testing extend either the shutdown or at-power work windows? In calculating the difference in risk between testing at power and testing during refueling outages, a new estimate of the maintenance unavailabilities may need to be developed that will reflect the increased maintenance activities at power and the basis for the estimate should be documented.

At times, testing (or the disassembly and inspection of valves) during refueling outages can be more advantageous from a worker safety perspective when, for example, the system is cold and depressurized. Licensees should consider worker safety and discuss whether the valve or valves can be adequately isolated (e.g., leakage) when requesting that testing be performed with the nuclear plant online.

Several licensees have submitted relief requests to the NRC to take credit for maintenance activities performed to meet the requirements of 10 CFR 50.65 for inservice testing of components. The inservice testing requirements of 10 CFR 50.55a and the maintenance rule requirements of the 10 CFR 50.65 rules are two separate activities. Therefore, inservice testing activities and maintenance activities as required by 10 CFR Part 50 cannot be interchanged. The staff requests licensees not to submit relief requests to interchange maintenance rules activities with the inservice testing requirements.

CONCLUSION

The purpose of this paper is to make licensees aware of a number of pump and valve issues that the staff has encountered since the Seventh NRC/ASME Symposium on Valve and Pump Testing in 2002. Licensees who believe that some of the items discussed are applicable to their facilities may wish to review their current IST program and modify their program as appropriate.

REFERENCES:

NUREG Reports

NUREG/CP-0152, Vol. 4, "Proceedings of the Seventh NRC/ASME Symposium on Valve and Pump Testing," July 2002.

NUREG/CR-6396, "Examples, Clarifications, and Guidance on Preparing Requests for Relief From Pump and Valve Inservice Testing Requirements."

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

Generic Letters

GL 89-04, "Guidance on Developing Acceptable Inservice Testing Programs."

Correspondence

March 21, 2000, letter from T. C. Feigenbaum of North Atlantic Energy Service Corporation to NRC, "Safety Evaluation of Relief Requests for the Second 10-year Interval Inservice Test Program Plan, Seabrook Station, Unit No. 1" (TAC No. A8532).

October 28, 2002, letter from J. M. Vargas, North Atlantic Energy Service Corporation, to Nuclear Regulatory Commission, "Seabrook Station, Inservice Testing Program for Pumps and Valves for Second 10-year Interval, Revision to Relief Request PR-1" (TAC No. MB6676).

June 4, 2001, letter from Virginia Electric and Power Company (Dominion) to NRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2 Inservice Testing Program for Pumps and Valves for Third 10-year Interval" (TAC Nos. MB2221 and MB2222).

January 4, 2002, letter from C.H. Cruse, The Constellation Energy Group, to NRC, "Calvert Cliffs Nuclear Power Plant Units 1 and 2, Request for Relief from ASME Code Requirements for ECCS and AFW Pump Testing Requirements; PR-12" (TAC Nos. MB3782 and MB3783).

April 17, 2002, letter from P. Salas, Tennessee Valley Authority, to NRC, "Sequoyah Nuclear Power Plant Units 1 and 2, Request for Relief from ASME Section XI Code Requirements, Inservice Testing (IST) Program - Turbine Driven Auxiliary Feedwater Pumps" (TAC Nos. MB4930 and MB4931).

January 22, 2003, letter from M. A. Balduzzi, Entergy to NRC, "Fourth 10-Year Interval Inservice Testing Program and Request for Approval of IST Relief Requests for Pumps and Valves for Vermont Yankee Nuclear Power Station" (TAC No. MB7489).

August 24, 2001, letter from Carolina Power & Light Company to NRC, "Relief Request for Fourth 10-Year Pump and Valve Inservice Testing Program for H. B. Robinson Steam Electric Plant Unit 2" (TAC No. MB2798).

April 15, 2003, letter from Progress Energy to NRC, "Revision to Inservice Testing Program Relief Request IST-RR-3 for Containment Spray Pump Comprehensive Pump Test Requirements for H. B. Robinson Steam Electric Plant Unit 2" (TAC No. MB8447).

United States Code of Federal Regulations, Title 10, Part 50: Domestic Licensing of Production and Utilization Facilities

10 CFR 50.55a, "Codes and standards."

Federal Register

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

Codes and Standards

ASME/American National Standards Institute (ASME/ANSI), *Operations and Maintenance Standards*, New York, 1987

Part 6 (OM-6), "Inservice Testing of Pumps in Light-Water Reactor Power Plants"

ASME/ANSI, *Code for Operation and Maintenance of Nuclear Power Plants*, 1995 Edition and 1996 Addenda:

Subsection ISTB, "Inservice Testing of Pumps in Light-Water Reactor Power Plants"

Subsection ISTC, "Inservice Testing of Valves in Light-Water Reactor Power Plants"

Code Case OMN-9, "Use of a Pump Curve for Testing"

OVERVIEW OF NRC NUREG-1482, REVISION 1,
Guidelines for Inservice Testing at Nuclear Power Plants

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Abstract

The NRC staff is issuing Revision 1 to NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plant," for use by nuclear power plant licensees. Since the initial issuance of NUREG-1482, certain tests and measurements required by earlier editions and addenda of the American Society of Mechanical Engineers (ASME) Code have been clarified, revised or eliminated. The revision to NUREG-1482 incorporates and addresses those changes. The revised guidance incorporates lessons learned and experience gained since the initial issue. This paper provides an overview those changes and discusses how they affect NRC guidance on implementing pump and valve inservice testing (IST) programs. This paper highlights important changes to NUREG-1482, but is not intended to provide a complete record of all changes to the document. Since the issuance of Generic Letter (GL) 89-04, the NRC has improved and clarified its guidance for performing inservice testing of pumps and valves. The NRC intends to continue to develop and improve its guidance on IST methods through active participation in the ASME Code consensus process, interactions with various technical organizations, and through periodic updates of NRC-published guidance and issuance of generic communications as the need arises. Revision 1 to NUREG-1482 incorporates regulatory guidance applicable to the 1998 Edition up to and including the 2000 Addenda to the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code). It supplements the guidance and positions in GL 89-04. The 1998 Edition up to and including the 2000 Addenda to the ASME OM Code was incorporated by reference into Title 10 of the Code of Federal Regulations (10 CFR) Section 50.55a(b) and became effective on October 28, 2002 (67 FR 60520). The NUREG document reflects the applicable changes to the paragraph numbering format in the latest OM Code. Revision 0 to NUREG-1482 is still valid and may continue to be used by those licensees who have not been required to update their IST program to the 1995 (or later) Edition of the OM Code. The guidance provided in many sections herein may be used for requesting relief from or alternatives to Code requirements. However, licensees may also request relief or authorization of an alternative that is not in conformance with the guidance. In evaluating such requested relief or alternatives, the NRC uses the recommendations of the NUREG, where applicable. The NRC may reference a recommendation from the NUREG in safety evaluations and grant relief or authorize the alternative if the licensee has addressed all of the aspects included in the applicable section.

Introduction

The U.S. Nuclear Regulatory Commission (NRC) provides licensees guidelines and recommendations for developing and implementing programs for the inservice testing of pumps and valves at commercial nuclear power plants. In NUREG-1482, the staff discusses the regulations; the components to be included in an inservice testing program; and the preparation and content of cold shutdown justifications, refueling outage justifications, and requests for relief from the ASME Code requirements. The staff also gives specific guidance on relief acceptable to the NRC and advises licensees in the use of this information at their facilities. The staff discusses the revised standard technical specifications (TS) for the inservice testing program requirements and gives guidance on the process a licensee may follow upon finding an instance of noncompliance with the Code.

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. NRC has neither approved nor disapproved the technical content.

The NRC staff is issuing this NUREG to assist the industry in eliminating unnecessary requests for relief and to provide guidelines and examples acceptable to the staff that might be useful to a licensee considering an alternative IST method to that required in the ASME Code. It is hoped that the guidance in NUREG-1482 will assist the industry in establishing a consistent IST approach. Implementation of the guidance is strictly voluntary and may change depending on advancements in technology or IST techniques. The NUREG also discusses some examples of the use of portions of later OM Code Editions and Addenda that licensees may implement if the related requirements stated in the applicable recommendations are met.

Specifically, the NRC staff is issuing Revision 1 to NUREG-1482 for the following reasons:

(1) To provide guidance on the use of portions of the 1998 OM Code up to and including the 2000 Addenda that the staff has determined are acceptable to implement pursuant to 10 CFR 50.55a(f)(4)(iv). This guidance is generally applicable to the 1995 OM Code including the 1996 Addenda requirements and any differences in guidance are discussed where the Code requirements differ.

(2) To provide guidance on information to be included in relief requests or alternatives in order to ensure a more efficient and effective review and approval by the NRC staff.

(3) To clarify common IST issues that have been identified as a result of NRC inspections, licensees' telephone calls or meetings, public meetings, and NRC staff participation on ASME OM committees.

(4) To indicate the NRC staff's views on the acceptability of or the need for caution in applying certain ASME OM interpretations.

(5) To consolidate references to various documents that apply to IST.

(6) To clarify the information to be included in an IST program, the format for relief requests, alternatives, cold shutdown/refueling outage justifications, and the scope of IST programs.

(7) To clarify the staff's views on certain ASME Code requirements or NRC regulatory positions.

The requirement governing the use of specific ASME OM Code Editions and Addenda is provided in 10 CFR 50.55a. As later Editions and Addenda to the ASME OM Code are incorporated by reference into 10 CFR 50.55a, the NRC staff plans to update NUREG-1482 as needed to reflect the changes in Code requirements or other regulatory positions and criteria.

Background

On April 3, 1989, the NRC issued Generic Letter (GL) 89-04, "Guidance on Developing Acceptable Inservice Testing Programs." It addressed frequently encountered issues such as relief requests, procedural implementation, and technical specification provisions for operability and included 11 technical positions used by the staff in reviewing IST program relief requests and described acceptable alternatives to the Code requirements. The positions in GL 89-04 were not for voluntary implementation in all cases, since the staff requested certain licensees implement the positions of the generic letter.

Since the issuance of GL 89-04, the NRC has recognized the need for more focused regulatory initiatives regarding IST by revising 10 CFR 50.55a and separating the IST and inservice inspection (ISI) programs in paragraphs (f) and (g) of Section 50.55a, issuing specific IST guidance such as NUREG-1482, creating a new regulatory guide for approving OM Code cases, and coordinating with ASME to sponsor periodic symposia on pump and valve issues.

On October 28, 2002, the NRC incorporated by reference into paragraph 50.55a(b)(3), the 1998 Edition up to and including the 2000 Addenda of the ASME OM Code. The OM Code in Subsections ISTB and ISTC specify the IST requirements for pumps and valves, respectively. NUREG-1482, Revision 1 is an update incorporating regulatory changes up to and including the ASME OM Code, 1998 Edition with 2000 Addenda.

When using the ASME OM Code (1995 Edition including the 1996 and 1997 Addenda as well as the 1998 Edition up to and including the 2000 Addenda), the recommendations and guidance in NUREG-1482, Revision 1 essentially replaces the positions in GL 89-04. This document discusses the use of these later Editions and Addenda to the OM Code, which may be implemented by licensees pursuant to 10 CFR 50.55a(f)(4)(iv) and gives guidance for obtaining approval pursuant to 10 CFR 50.55a(f)(4)(iv) when updating an IST program (or portion of the program) to the requirements of a later OM Code.

Discussion

The format of the revised NUREG follows the format of a typical IST program plan (i.e., Development and Implementation, General Guidance, Valves, Pumps, Technical Specifications, Code Non-Compliance, and Risk-Informed Inservice Testing). The Appendices contain a copy of the Nuclear Energy Institute (NEI) White Paper, "Standard Format for Requests from Commercial Reactor Licensees Pursuant to 10 CFR 50.55a," dated September 30, 2002, and a copy of GL 89-04 Supplement 1. The NEI White Paper provides guidance for determining the appropriate regulatory requirement under which a request is submitted to the NRC for approval and sample templates containing the appropriate form and content for preparing a relief request.

Throughout the General Guidance, Valves, and Pumps sections, IST requirements for which licensees have requested relief or proposed alternatives are discussed, and guidance is provided on the type of information that should typically (or in some cases must) be included. They also discuss Code and regulatory issues and provide recommendations and guidance as needed. The discussions of issues and recommendations are not intended to impose additional requirements beyond that required by the Code or the regulations, and, as such, do not represent backfits. Rather, these discussions are intended to clarify existing requirements of the Code or the regulations and may provide recommendations to ensure that Code and other regulatory requirements continue to be met.

Section 2 of NUREG-1482 discusses the development and implementation of an IST program. It describes existing requirements for IST, discusses the scope of an IST program, and provides guidance for presenting information in IST programs, including cold shutdown justifications, refueling outage justifications, and relief requests. The section includes a sample list of plant systems for boiling-water reactors (BWRs) and pressurized-water reactors (PWRs) that typically (but not necessarily) contain Code pumps or valves that perform a safety function. The section also includes information needed for licensees to establish the tests and test frequencies proposed for pumps and valves in an IST program.

Two of the more significant changes to this document are the discussion of the use of OM Code cases and the use of the NEI White Paper in the development and submittal of IST programs.

With the incorporation by reference of the OM Code into 10 CFR 50.55a, the NRC staff recognized the need for a new regulatory guide that would approve OM Code cases. This regulatory guide would provide a function similar to that of existing Regulatory Guide 1.147 which approves ASME Code cases applicable to Section XI of the ASME Boiler and Pressure Vessel Code. Accordingly, the NRC staff developed Regulatory Guide (RG) 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM Code." At the same time, the NRC staff also developed a new Regulatory Guide (RG) 1.193, "ASME Code Cases not Approved for Use." Both of these two new regulatory guides were issued for the first time in June 2003. In Revision 1 to NUREG-1482 the NRC states, "The licensee may implement the Code cases listed in RG 1.192 without obtaining further NRC review, if the Code cases are used in their entirety, with any supplemental conditions specified in the regulatory guide." The following Code cases are listed in RG 1.192 as acceptable to the NRC for application in licensees' OM IST programs:

OMN-2, "Thermal Relief Valve Code Case."

OMN-5, "Testing of Liquid Service Relief Valves Without Insulation."

OMN-6, "Alternate Rules for Digital Instruments."

OMN-7, "Alternative Requirements for Pump Testing."

OMN-8, "Alternative Rules for Preservice and Inservice Testing of Power-Operated Valves That Are Used for System Control and Have a Safety Function per OM-10."

OMN-13, "Requirements for Extending Snubber Inservice Visual Examination Interval at LWR Power Plants."

In addition, the following OM Code cases are listed in RG 1.192 as "conditionally acceptable." These Code cases are acceptable to the NRC for application in licensees' OM IST programs within the limitations described in RG 1.192:

OMN-1, "Alternative Rules for Pre-service and Inservice Testing of Certain Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants."

OMN-3, "Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants."

OMN-4, "Requirements for Risk Insights for Inservice Testing of Check Valves at LWR Power Plants."

OMN-9, "Use of a Pump Curve for Testing."

OMN-11, "Motor Operated Valve Risk-Based Inspection Code Case."

OMN-12, "Alternative Requirements for Inservice Testing Using Risk Insights for Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants."

Code Cases OMN-1, OMN-3, OMN-4, OMN-11, and OMN-12 are risk-informed Code cases. Regulatory Guide 1.175, "An Approach For Plant-Specific, Risk-Informed Decision Making: Inservice Testing," describes an acceptable alternate approach for applying risk insights from probabilistic risk assessment (PRA), in conjunction with established traditional engineering information, to make changes to a nuclear power plant's IST program. The approach described in RG 1.175 addresses the high level safety principles specified in RG 1.174 and attempts to strike a balance between defining an acceptable process for developing risk-informed IST programs without being overly prescriptive. Until such time as a risk-informed regulation is promulgated and included in the regulations, the alternative approach described in RG 1.175 must be authorized by the NRC pursuant to 10 CFR 50.55a(a)(3)(i) on a plant-specific basis prior to implementation. Because 10 CFR 50.55a(a)(3)(i) places no restrictions on the scope of alternatives that may be authorized, licensees may propose risk-informed alternatives to their entire IST program or may propose alternatives that are more limited in scope (e.g., for a particular system or group of systems, or for a particular group of components). However, with the issuance of RG 1.192, risk-informed IST methods may be used by licensees without prior NRC staff review and approval. NUREG-1482 further discusses risk-Informed IST in a later section.

NEI issued its white paper entitled, "Standard Format for Requests from Commercial Reactor Licensees Pursuant to 10 CFR 50.55a," dated September 30, 2002. The white paper provides useful guidance in determining the appropriate regulatory requirement under which a "relief request" is submitted to the NRC for approval as well as the appropriate format and content to use in the request. The term "relief request" is used loosely in this instance to denote the various types of submittals to the NRC allowed by 10 CFR 50.55a including alternatives to the regulation [10 CFR 50.55a(a)(3)], impractical relief requests [10 CFR 50.55a(f)(5)(iii)], and requests to use later Code Editions and Addenda [10 CFR 50.55a(f)(4)(iv)]. The NEI white paper has been reviewed by NRC staff, and the staff generally agrees with the format and content in the white paper and encourages its use.

Occasionally, the NRC has receives IST program submittals or partial submittals that lack the start and end dates of the 120-month IST interval or the specific Code Edition and Addenda in use. Some licensees, when developing their IST programs, were not aware that the regulations are issued or updated throughout the year through issuance of Federal Register notices. The Code of Federal Regulations is a codification of the general and permanent rules published in the Federal Register and is kept up to date by the individual issues of the Federal Register. Accordingly, these two publications must be used together to determine the latest version of any given rule. Without this understanding, some licensees mistakenly have used the revision date of the Code of Federal Regulations to determine the appropriate Code Edition and Addenda as required in 10 CFR 50.55a(b) rather than the effective date of the rule as noted in the Federal Register notice. Consequently, a more recent Code Edition and Addenda may have been incorporated by reference in 10 CFR 50.55a(b) as noticed in the Federal Register, which resulted in the program being developed to an incorrect edition of the Code.

NUREG-1482, Section 3 provides guidance and NRC recommendations for several general aspects of IST. The significant changes in clarification and guidance in this section fall into three categories; (1) inservice test intervals/frequencies, (2) testing at power/on-line testing/entry in limiting conditions for operation (LCOs), and (3) pre-conditioning. With regard to test intervals, the NRC may approve relief for extending a test interval for extenuating circumstances in which (1) compliance would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, or (2) the system design makes compliance impractical. Impractical conditions justifying test deferrals are those that could result in an unnecessary plant shutdown, cause unnecessary challenges to safety systems, place undue stress on components, cause unnecessary cycling of equipment, or unnecessarily reduce the life expectancy of the plant systems and components. Any requested relief would typically include a technical justification for the deferment. Test interval deferrals and exercise frequencies typically have applied to requests to perform IST cold shutdowns or refueling outages.

Unless accompanied by other acceptable rationale, the necessity to enter into an LCO to perform IST would not be sufficient to justify deferring testing until a cold shutdown or refueling outage. Guidance on issues regarding the applicability of LCO and surveillance requirements has been previously issued by the NRC in GL 87-09. If a licensee chooses to defer testing from quarterly to cold shutdown, or to refueling outages, other justification must be included in addition to entry into an LCO. If the deferral is not justified by additional basis, the licensee must perform tests quarterly, or during cold shutdown (as justified), with entry into the LCO for IST to be completed within the out-of-service time allowed by TS.

Pre-conditioning of structures, systems, and components (SSCs) continues to be an issue of discussion between licensees and NRC staff. In Information Notice (IN) 97-16, "Preconditioning of Plant Structures, Systems, and Components Before ASME Code Inservice Testing or Technical Specification Surveillance Testing," the NRC staff discussed the longstanding concern regarding unacceptable preconditioning of plant SSCs before testing. The staff noted that experience has demonstrated that some testing cannot be performed without disturbing or altering the equipment. The staff also indicated that any such disturbance or alteration would be expected to be limited to the minimum necessary to perform the test and to prevent damage to the equipment. The staff alerted licensees that, in certain cases, the safety benefit of some preconditioning activities might outweigh the benefits of testing in the as-found condition.

Where the ASME Code does not provide specific provisions related to as-found testing of a pump or valve in the IST program, the staff considers acceptable preconditioning to include such activities as (1) periodic venting of pumps which is not routinely scheduled directly prior to testing but may occasionally be performed before testing; (2) pump venting directly prior to testing provided the venting operation has proper controls with a technical evaluation to establish that the amount of gas vented would not adversely affect pump operation; (3) occasional lubrication of a valve stem prior to testing of the valve where stem lubrication is not typically performed prior to testing; and (4) unavoidable movement due to the set-up and connection of test equipment. In each instance of acceptable preconditioning, the licensee is expected to have a documented evaluation of the preconditioning activity and justification for continued confidence in the IST program to assess the operational readiness of the pump or valve. Unacceptable preconditioning of pumps and valves in the IST program includes such activities as (1) routine lubrication of a valve stem prior to testing the valve; (2) operation of a pump or valve shortly before a test if such operation could be avoided through plant procedures with personnel and plant safety maintained; and (3) venting a pump immediately prior to testing without proper controls and scheduling. Further clarification and guidance is provided in NUREG 1482, Section 3.5.

In an effort to shorten refueling outages, an increasing number of licensees are scheduling maintenance, testing, and surveillance activities while the nuclear power plant is on-line. Several licensees have submitted relief requests to the NRC to conduct inservice testing once per refueling cycle, as opposed to during the refueling outage as required by the Code. The NUREG describes several factors to take into consideration when preparing such requests.

One comment of note is that a risk assessment is often performed to justify taking the SSC out of service. The assessment of risk resulting from performance of maintenance activities as required by 10 CFR 50.65(a)(4) of the Maintenance Rule is not sufficient justification for testing components at power. This assessment is required for maintenance activities performed during power operations or during shutdowns. A risk assessment should address the relative merits of testing at power versus testing during refueling outages.

NUMARC 93-01, Rev. 2, Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, also provides guidance for conducting on-line maintenance and testing that may be useful in planning and conducting on-line activities.

NUREG-1482, Section 4 provides guidance and recommendations on valve issues. Revision 1 addresses check valves, power-operated valves (e.g., motor-, air-, and hydraulically-operated valves), safety and relief valves, and miscellaneous valves such as manual valves and pressure isolation valves. Since the issuance of Revision 0, there have been major changes and developments in the ASME OM Code and IST knowledge, technology, philosophy and methodology. Therefore, the NUREG section on valves was rewritten in its entirety. The complete depth and breadth of the individual changes are too numerous to mention in this paper.

Ongoing issues with regard to check valve categorization, requirements, and test methods are addressed. The current issues and guidance with regard to stroke-time testing of power operated valves are discussed in detail as well as verification of position indication. NUREG-1482, Section 4 also provides guidance on instrumentation and instrument accuracy. The section on relief valves contains only minor changes while guidance with respect to miscellaneous valves such as manual valves and pressure isolation valves should be reviewed for applicability to each plant.

As operating experience with the recent Code changes grows, issues regarding valve IST will continue to emerge and be resolved. The NRC intends to continue to update and improve its IST guidance through participation in standards development organizations and technical groups, issuance of generic communications such as information notices, regulatory issue summaries, and generic letters as well as through regular updates of NRC guidance documents (e.g., NUREG-1482) as the need arises. Revision 1 to NUREG-1482 incorporates generic communications issued up to January 1, 2004. It is recommended that a search of recent communications be performed when evaluating issues regarding valve IST.

NUREG-1482, Section 5 provides guidance and recommendations on pump issues. Revision 1 addresses the use of reference curves, evaluation of pump vibration, the comprehensive pump test (CPT), minimum flow lines, instrument and equipment accuracy, pump drivers as well as other issues of interest in the IST of pumps. Since the issuance of Revision 0, there have been major changes and developments in the ASME OM Code and IST knowledge, technology, philosophy and methodology. Therefore, the NUREG section on pumps was rewritten in its entirety. The complete depth and breadth of the changes are beyond the limits of this paper. However, the CPT and pump drivers will be briefly discussed.

In 1995, OM Code Subsection ISTB introduced a new approach to pump testing wherein pumps were divided into two basic groups, normally or routinely operated pumps (group A) and standby pumps (group B). The Code identifies four type of tests: preservice, Group A, Group B, and Comprehensive tests. Group A and Group B are quarterly tests associated with the pump category (Group A test for Group A pump, etc.). Once every two years, each pump in the program is required to be tested to the more rigorous test requirements of the Comprehensive Pump Test (CPT).

A comprehensive test may be substituted for Group A test or Group B test. Group A test may be substituted for Group B test. A preservice test may be substituted for any inservice test. All pumps would receive a pre-service or baseline test followed by quarterly (periodic) tests. The Code allows the less rigorous pump testing to be performed for certain pumps on a quarterly frequency while requiring a pump test to be performed with more accurate flow instrumentation every 2 years at ±20 percent of pump design flow. The intent is to be able to routinely monitor for degradation using the quarterly test and to verify design capability using the CPT.

The OM Code, ISTB-3300(e)(1) requires that reference values be established within ±20% of the design flow for the CPT. The CPT was developed with the knowledge that there are some pumps, such as containment spray pumps, that cannot be tested at the required high flow rates due to original system design configuration. In these cases, it may be necessary to use the pump's recirculation line for IST. However, recirculation lines are not typically designed ±20% of the design flow.

The NRC may accept the use of a lower flow (reference values less than ±20% of the design flow), as required by Subsection ISTB for the comprehensive test, if the licensee demonstrates to the satisfaction of the NRC in a relief request the impracticality of establishing a reference value within ±20% of the design flow for the CPT. The proposed alternative methods to detect hydraulic degradation and trend degradation must provide reasonable assurance of the pump's operational readiness. The NRC reviews these relief requests on a case-by-case basis.

Pump drivers are outside of the scope of the ASME OM Code with the exception of vibration testing for vertical line shaft pumps where the driver is an integral part of the pump. Most of the pumps are driven by electric motors, which are connected via coupling shafts. Motor vibration due to coupling misalignment may not be realized or measured at the pump. Small changes in vibration of a motor can have significant effects on the pump operation and affect the operational readiness of the pump. While excluded from the ASME Code, the health of pump drivers should be included in a licensee's overall plan for the assessment of its pumping systems.

Issues related to motor drivers of pumps are under consideration by a Working Group Committee (WGC) of the Institute of Electrical and Electronics Engineers (IEEE). IEEE addresses issues related to operations, maintenance, aging and testing of Class 1E equipment in nuclear power plants. The WGC has the task to develop and update the IEEE Standard Criteria for the Testing of Nuclear Power Generating Station Safety Systems.

NUREG-1482, Section 6 discusses revised standard technical specifications. The purpose of a pump or valve inservice test is to assess the operational readiness of the component. Inservice tests are designed to detect component degradation by assessing component performance in relation to operating characteristics when the component was known to be operating acceptably. Thus, the data or information obtained during these tests provide insight into the ability of a component to perform its safety-related function under design-basis conditions until the next test. In contrast, technical specification surveillance requirements typically assess system capability, e.g., the ability of a system or component (e.g., pump) to deliver the flow rate assumed in an accident analysis at the time of the test.

The revised standard Technical Specifications reflect the fact that licensees are required by 10 CFR 50.55a to establish and implement an inservice testing program. Section 6 further discusses this topic and reaffirms previous guidance with respect to Code versus TS test frequencies.

NUREG-1482, Section 7 discusses the process for licensees to follow when a Code nonconformance is found. This section was revised to clarify the relationship between Code and TS noncompliance. The guidance in this section was not significantly changed with the exception of deleting a discussion on Design Bases reviews and including further clarifying guidance on starting points for time periods in TS action statements.

NUREG-1482, Section 8 discusses the development of a risk-informed IST program. This is a new section. In recent years, the potential for a risk-based or risk-informed approach to inservice testing has received much attention and study by both NRC and industry. As of the publication of this paper, only two licensees have risk-informed IST programs, Comanche Peak Steam Electric Station and San Onofre Nuclear Generating Station. The section discusses the regulatory basis for a risk-informed program, the use of risk insights for on-line inservice testing, and the use of ASME OM risk-informed Code cases.

Until such time as a risk-informed alternative to the current Code requirements is incorporated by reference into 10 CFR Part 50, the alternative approach described in Regulatory Guide 1.175 must be authorized by the NRC pursuant to 10 CFR 50.55a(a)(3)(i) on a plant-specific basis prior to implementation. Because 10 CFR 50.55a(a)(3)(i) places no restrictions on the scope of alternatives that may be authorized, licensees may propose risk-informed alternatives to their entire inservice testing program or may propose alternatives that are more limited in scope (e.g., for a particular system or group of systems, for a particular group of components). In either case, the staff expects that the licensee's proposal address the principles described in Regulatory Guide 1.175, including those related to implementation and monitoring.

In an effort to shorten refueling outages, many licensees are trying to do as much maintenance, testing, and surveillance activities as possible with the nuclear power plant on-line. For example, several licensees have submitted relief requests to the NRC to conduct inservice testing once per refueling cycle, as opposed to during the refueling outage as prescribed by the Code. Section 8 discusses several factors to be taken into consideration when preparing (and in evaluating) such relief requests to ensure that the proposed alternative provides an acceptable level of quality and safety. The list is not all inclusive but does provide a useful starting point.

Over the past several years, the ASME has developed a series of risk-informed Code cases related to testing of pumps and valves. When using the ASME's risk-informed Code cases, the testing and performance monitoring of individual components must be performed as specified in the risk-informed component Code cases (e.g., OMN-1, OMN-4, OMN-7, OMN-11, and OMN-12) as modified by any conditions specified in RG 1.192. The use of the Code cases is discussed in both Section 2 and Section 8 of NUREG-1482. The information contained in these sections is not new but, rather, combines information from previously issued sources into one common area.

The ASME Committee on Operation and Maintenance of Nuclear Power Plants (ASME OM Committee) is in the process of developing a new Subsection ISTE of the OM Code that will address risk-informed inservice testing. No guidance with respect to draft ISTE documents are provided in NUREG-1482. Later revisions will address this Code Section once it is approved.

Conclusion

Since the issuance of GL 89-04, the NRC has updated and improved its guidance on performing IST. The NRC intends to continue to revise its guidance as experience is gained and lessons are learned through participation in Code and technical organizations and through regular updates of NRC published guidance as the need arises.

Revision 1 to NUREG-1482 is an update incorporating the most recent regulatory changes including the incorporation by reference of the ASME OM Code, 1998 Edition and the 2000 Addenda. It supplements the guidance and positions in GL 89-04. To the extent practical, it reflects the applicable section, subsection, or paragraph of the appropriate documents (10 CFR Part 50, ASME OM Code, and regulatory guides).

Revision 0 is still valid and may continue to be used by those licensees who have not updated their IST program to the 1995 OM Code (or later).

The requirement for licensees to periodically update their IST programs to later ASME OM Code Editions and Addenda is governed by 10 CFR 50.55a. In the future, NUREG-1482 will be updated on an 'as-needed" basis, as Code requirements evolve or other regulatory changes in direction affect the guidance therein.

References

American Society of Mechanical Engineers/ American National Standards Institute (ASME/ANSI), Code for Operation and Maintenance of Nuclear Power Plants, New York, 1998 Edition up to and including the 2000 Addenda.

U. S. Code of Federal Regulations, Title 10, "Energy," Chapter 1, Part 50, "Domestic Licensing of Production and Utilization Facilities."

Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," April 3, 1989.

NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants, Revision 1," 2004.

NEI White Paper, "Standard Format for Requests from Commercial Reactor Licensees Pursuant to 10 CFR 50.55a," dated September 30, 2002.