MISSOURI PUBLIC SERVICE COMMISSION

Final Staff Report

Kansas City Power & Light Company
Case No. ES-2007-0458

Superheater Attemperator Spray Water Pipe Failure
Iatan Plant
Weston, Missouri
May 9, 2007

Prepared by the Staff of the
Missouri Public Service Commission
March 17, 2008

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of an Incident on May 9, 2007 at the Iatan generating plant Kansas City Power & Light operates	)))	Case No. ES-2007-0458

AFFIDAVIT OF DAVID ELLIOTT

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

David Elliott, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Electric Incident Report, and that the facts therein are true and correct to the best of his knowledge and belief.

David Elliott

David Elliott

Subscribed and sworn to before me this 17th day of March, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer

Notary Public

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Summary

This is the final report by the Staff of the Missouri Public Service Commission (Staff) on the failure of the 4-inch diameter high pressure superheater attemperator spray water pipe at the Iatan Generating Station operated by Kansas City Power & Light Company (KCPL). When the pipe ruptured near the area of the Iatan Unit 1 coal feeders on May 9, 2007, high pressure, high temperature water in the pipe flashed to steam. As a result, two KCPL employees died and another was critically injured. Four other nearby employees received no physical injuries. After the pipe ruptured, KCPL replaced the pipe, inspected other areas of potential concern based on its preliminary investigation and then returned Iatan Unit 1 to service on May 27, 2007.

Staff obtained the information in this report from documents and responses to inquiries it received from or through KCPL. Staff did not perform an independent investigation. Staff last received source information on March 10, 2008. Among Staff's sources of information is the September 28, 2007 report from KCPL's consultant, Performance Improvement International (PII) on its investigation of the root cause of the pipe rupture. As defined by PII, "A root cause is a contributing factor that if it is eliminated, the total recurrence can be prevented". Staff is not aware of other investigations or sources regarding the pipe rupture. Based on the information Staff has reviewed, Staff finds no reason to disagree with Performance Improvement International's finding that the root cause of the pipe rupture was flow accelerated corrosion (FAC).

FAC is a phenomenon where under certain water chemistry conditions, water flowing at a high velocity continually removes the protective oxide layer formed on the inside wall of steel pipe by the reaction of dissolved oxygen and the steel. Eventually, the wall thickness of the steel pipe is reduced to a point where it fails due to its loss of strength.

To address FAC at its fossil steam plants, KCPL has initiated an FAC program with procedures that should mitigate the risk of future pipe failures due to flow accelerated corrosion. The Staff makes recommendations in this report designed for the purpose of having KCPL continue to implement, monitor and improve that program.

Conclusion and Recommendations

Staff finds no reason to disagree with Performance Improvement International's root cause investigation finding that flow accelerated corrosion (FAC) was the cause of the pipe failure.

With the assistance of an outside consultant, CSI Technologies, Inc., KCPL has created an FAC program. Staff believes that this FAC program with procedures created by KCPL should mitigate the risk of future pipe failures due to FAC.

To insure that KCPL does follow and update this FAC program, Staff makes the following recommendations:

1. That the Commission order KCPL to keep all of its records relating to KCPL's FAC program, including testing results, and make them available for Staff to review upon request by Staff made with reasonable notice.

2. That the Commission order KCPL to, by June 1 of each year, provide to the Energy Utility Regulatory Manager of Staff an annual report that describes the effectiveness of the FAC program that was in effect for the preceding twelve months, including all testing results obtained during those preceding twelve months. This report shall also identify any revisions or changes made to the FAC program during the preceding twelve months.

3. That the Commission order KCPL to file a response to Staff's final incident report and staff's recommendations within thirty (30) days of a Commission Order adopting Staff's recommendations.

Damage Area

At approximately 11:45 am on May 9, 2007 a 4-inch diameter high pressure superheater attemperator spray water pipe ruptured near the area of the Iatan 1 coal feeders. A section of the pipe, approximately 9-inches in length, blew out. The water in the pipe was at 345 degrees Fahrenheit and under 2,900 psig of pressure. When the pipe ruptured the water was exposed to atmospheric pressure causing it to flash to steam.

Damage to the infrastructure of Iatan 1 plant included the rupture of the water piping, the movement of the piping supports and other sections of pipe, and damage to various sections of piping insulation and wall siding.

Personnel Injuries

The ruptured pipe site was near the area of Coal Feeder F where several KCPL employees were working to clear coal that was plugging the feeder. Three employees were waiting nearby to clean up the area after the feeder work was completed. As a result of the pipe rupturing, one employee died on site of multiple blunt force injuries, and one employee died the next day at the hospital from complications from thermal burns. A third employee was in critical condition when he arrived at the hospital and received medical treatment. Four other employees who were near the site when the pipe ruptured were taken to a hospital, but none sustained physical injuries.

KCPL Response

The failed superheater attemperator piping, as well as piping in five other Iatan plant locations, has been repaired or replaced since the incident. KCPL replaced the superheater attemperator piping with steel pipe having a higher chrome content. KCPL returned Iatan Unit 1 to service on May 27, 2007.

Based on the preliminary indication of possible FAC in the failed pipe, KCPL began investigating other pipe in the plant to determine if there were signs of FAC. Because KCPL's LaCygne Unit 2 is similar in design to the Iatan Unit 1, KCPL also inspected the superheater attemperator water spray piping on the LaCygne Unit 2 shortly after the incident at Iatan Unit 1. KCPL found no evidence of FAC in the piping at LaCygne Unit 2.

KCPL also contracted with two testing firms, Aptech, and Acuren Inspection Inc., to test certain additional areas of piping at Iatan Unit 1 as well as the piping at Hawthorn Unit 5, LaCygne Units 1 and 2, Montrose Units 1, 2, and 3, and Hawthorn Unit 9. KCPL has purchased software to use to determine where FAC might occur and as those areas are identified, they will be added to its current pipe testing program schedule. In addition, KCPL hired CSI Technologies, Inc., a consultant, which assisted in the development of KCPL's FAC program for all the fossil steam plants.

KCPL also reviewed the chemistry and treatment of the boiler water at Iatan 1, and made adjustments to the pH of the boiler water and stopped using an oxygen scavenger chemical. KCPL made these changes based on discussions and recommendations received in May 2007, from Electric Power Research Institute (EPRI).

With the assistance of an outside consultant, CSI Technologies, Inc., KCPL has created an FAC program which provides a plan for: 1) monitoring the changes in the chemical treatment of boiler water, 2) updating the FAC software, 3) updating FAC testing procedures, 4) updating plant piping drawings, 5) adding a design review procedure for plant piping modifications, 6) updating procedures with industry FAC updated standards, and 7) creating a position responsible for coordinating FAC monitoring and testing. Staff believes that this FAC program with procedures created by KCPL should mitigate the risk of future pipe failures due to FAC.

Material Reviewed

Performance Improvement International's investigation included an analysis of the wear in the pipe, the pipe material, the valve flow characteristics, the valve material, the piping arrangement, and KCPL's construction, repair, and testing procedures. See Appendix A for a copy of the summary of testing done by Performance Improvement International.

On December 19, 2007, Performance Improvement International provided KCPL an overview that summarizes the facts and Performance Improvement International's determination about the root cause of the pipe rupturing and an outline for a plan to prevent future pipe ruptures. Staff obtained a copy of this overview on January 18, 2008, and has reviewed it. Appendix B-1 is a copy of an incident summary power point presentation, and appendix B-2 is section 5.0, 5.1, and 5.2 from that overview.

OSHA investigated the incident (Inspection 310932322), and on November 5, 2007, issued a citation to KCPL identifying three violations of Section 5(a)(1) of the Occupational Safety and Health Act of 1970. The fines for these violations total $21,000. On November 26, 2007, KCPL sent a response to OSHA stating that it was contesting the citation. On January 31, 2008, U.S. Department of Labor filed a complaint against KCPL regarding the OSHA citations. KCPL told Staff it plans to file a response to the complaint by March 26, 2008. This complaint review process, which may take up to six months, is incomplete at this time.

Since the incident, KCPL has established a FAC program for all its fossil plants, called Guidelines for Flow-Accelerated Corrosion Program Activities. This program, prepared by CSI Technologies, Inc. for KCPL, has been approved by KCPL's upper level management. KCPL provided Staff a copy of this program and has reviewed it. Appendix C is a copy of KCPL's FAC program.

Staff Investigation

Staff went to visit the Iatan Plant site on May 11, 2007, and visually inspected the area where the pipe ruptured. In addition, Staff obtained information from KCPL personnel during conference calls on May 30, 2007, and July 27, 2007.

Staff reviewed the documents KCPL provided to OSHA, and reviewed the citation issued to KCPL by OSHA.

Staff reviewed the overview and root cause reports of KCPL's consultant Performance Improvement International, and sent several comments/questions based on that review to KCPL for KCPL's response. KCPL responded to those comments/questions on November 13, 2007, and on November 16, 2007, Staff had further discussions with KCPL personnel regarding those responses.

Although not specifically part of this investigation, Staff also sent a letter to the other three regulated electric utilities asking if they had any procedures/programs to identify areas of possible FAC. All three electric utilities responded that they were aware of FAC and have procedures in place to identify sites where FAC is more likely to occur.

APPENDIX A
Testing Summary
Performance Improvement International
Volume 1

VOLUME 1

Root Cause Investigation of Pipe Rupture Event at the Iatan Plant

September 28, 2007

Performance Improvement International

Kansas City Power & Light

ENERGIZING LIFE

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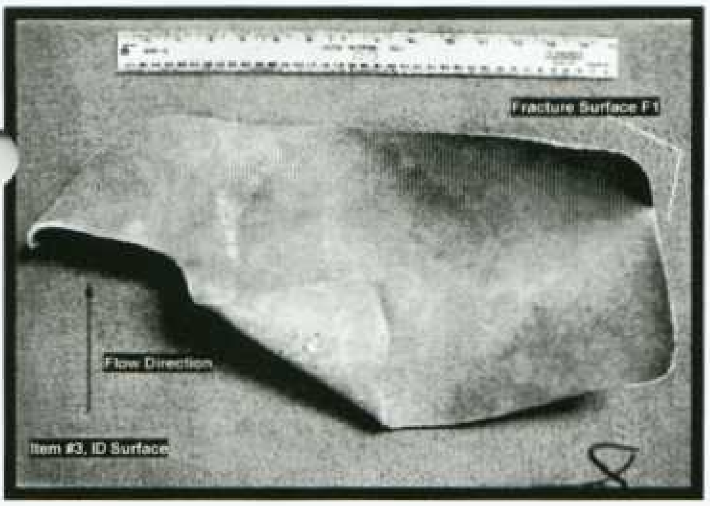
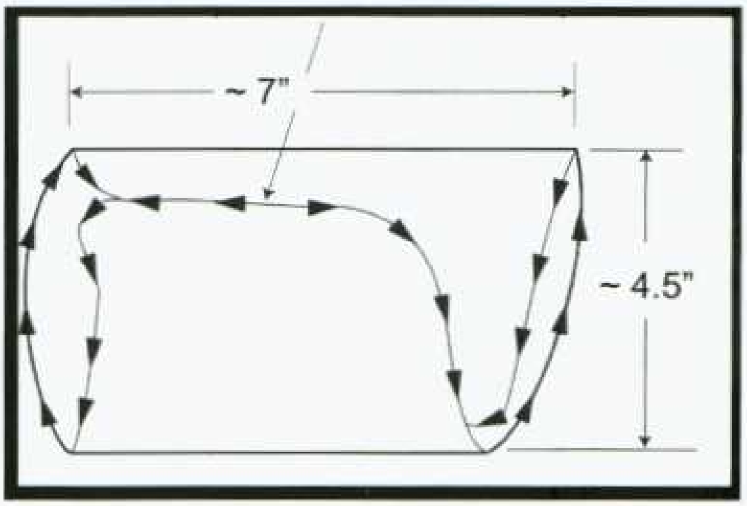
Providing a competitive advantage through research and applications

Root Cause Investigation of Pipe Rupture Event at the Iatan Plant

September 28, 2007





Lead Investigators: Dr. Chong Chiu
Mr. Michael Costen
Mr. David Dearth, PE
Mr. Andy Hon, PE
Mr. Dennis Lundy
Dr. Mostafa Mostafa

Volume 1

Root Cause Investigation of the Pipe Rupture Event at the Iatan Plant (September 28, 2007)

Root Cause Investigation of the Pipe Rupture Event at the Iatan Plant

1.1 Background

Event Description

At approximately 11:40 AM on May 9, 2007, Iatan Unit 1 experienced a catastrophic rupture of a 4 inch superheater (SH) attemperator spray line after nearly 27 years of commercial operations. At the time of the rupture, several plant personnel were in the immediate vicinity performing maintenance on a plugged coal feeder. Plant operators immediately initiated a plant shutdown. Off-site emergency responders were contacted and plant personnel were quickly dispatched to assess the impact of the rupture and attend to the injuries. This incident resulted in two fatalities and one serious injury. Subsequent examination of the ruptured line indicated significant pipe wall thinning had occurred, leading to the sudden failure of the pipe pressure boundary and the pipe rupture event. The preliminary evaluation of the failed pipe determined that flow accelerated corrosion (FAC) was the likely failure mechanism.

Following the event, Kansas City Power and Light (KCP&L) contracted with APTECH and Acuren to assess plant piping for the existence of thinned piping in the balance of the SH attemperator spray lines and other FAC susceptible plant system piping. Piping showing evidence of extensive thinning was replaced or repaired prior to returning Iatan Unit 1 to service.

Plant and SH Attemperator Spray Description

Iatan Unit 1, a Kansas City Power and Light (KCP&L) steam generating station located on the Missouri River, began commercial operation on May 27, 1980. The Missouri River is the ultimate cooling source for the once through condenser cooling.

The unit is base loaded with a 670 MWe (net) nominal continuous generating capacity and is fueled with Wyoming Powder River Basin coal, delivered by rail shipment. Nominal steam conditions are 2400 psi with 1005 F/1005 F reheat temperatures. The Iatan steam generator is a pulverized coal, balanced draft Babcock & Wilcox (B&W) water tube steam boiler. The pulverized fired boiler has an operating pressure of 2975 psi and feeds a 700 MW General Electric steam turbine and hydrogen cooled generator.

Iatan has a single 100% capacity steam driven Delaval boiler feedpump (BFP), driven by a GE feedpump turbine. Suction for the BFP is supplied by the deaerator storage tank. Condensate is supplied to the deaerator tank by the condensate system, preheated by four levels of feedwater heaters. The discharge of the BFP is preheated by two levels of high pressure heaters before entering the economizer inlet header. Reheater attemperator spray is supplied from a BFP interstage bleedoff point. The superheat (SH) attemperator spray supply is provided from the BFP discharge at ~589 Klb/hr flow rate at full load.

The SH attemperator spray design and operating temperatures are 500 F and 485 F, respectively. The SH attemperator spray design and operating pressures are 3200 psi and 2954 psi, respectively. The material specification for the feedwater piping system, including the SH attemperator spray line, is ASTM A106 Gr C.

The function of the SH attemperator spray is to maintain high temperature control of the secondary superheater with cooling spray water. The SH attemperator spray flow reaches the secondary superheater through two parallel spray lines, 1A and 1B. Total SH attemperator spray flow is generally split equally between the 1A and 1B spray lines and is controlled by four parallel control valves (two per 1A and 1B spray line). The SH attemperator spray control valve modulates spray flow to maintain a secondary superheater outlet steam temperature of 1005^0F. Spray flow is also limited to maintain steam conditions of a minimum of 10^0F above the saturation temperature. Each control valve set has an AC motor block valve and a DC motor block valve. The AC motor block valve for the 1A line is valve FW01-1032. The AC motor block valve for the 1B line is valve FW01-1025. The function of the AC motor block valve is to automatically isolate attemperator spray on a unit trip or loss of steam flow below 10% of full flow conditions, preventing thermal shock of the secondary superheater or water induction to the steam turbine.

During this investigation, KCP&L has taken many positive actions to mitigate Flow Accelerated Corrosion (FAC). The positive actions include, but limited to, the following:

(1) Changed water chemistry (increasing pH);
(2) Conducted FAC training program;
(3) Used ultrasound and other non-destructive testing to check many susceptible points at all KCP&L stations;
(4) Repaired and replaced identified thin walled pipes;
(5) Purchased and ran CHECKWORKS computer program to predict FAC susceptible areas.

1.2 Root Cause Investigation Methodology

After the pipe rupture event, KCP&L requested Performance Improvement International (PII) perform an integrated root cause investigation. The primary objective of the investigation is to understand the cause of the event and provide KCP&L recommendations to prevent recurrence of the event as well as similar events at the Iatan station and other KCP&L plants (if applicable). PII has contacted several USA leading utilities for their past experiences in similar failures of superheater attemperator spay lines. Based on their collected knowledge, this incident at the Iatan plant has not occurred in the USA fossil industry.

The root cause investigation methodology follows the nine-step process established in 1987 by Performance Improvement International, LLC. More than 10,000 utilities engineers, including TVA and AEP (two of the largest domestic utilities) have been trained about this investigation process). The nine steps in the process are:

1. Define the Failure
2. Collect Relevant Data in Operation, Maintenance, and Design
3. Determine Failure Modes (Such as Fatigue Fracture, Ductile Overload, Stress Corrosion Cracking, etc.)
4. Determine Failure Mechanisms Contributing to the Failure Modes (Such as Erosion, Flow Accelerated Corrosion, etc.)
5. Determine Sequence of Events
6. Determine Actions and Programs and Processes (P&P) that May Cause the Event
7. Determine Root Causes of the Event
8. Determine Corrective Actions to Prevent Total Recurrence
9. Establish Methods to Monitor the Progress of Corrective Actions

The investigation is divided into four major parts – failure mode investigation (Volume 2), failure mechanism investigation (Volume 3), program and processes review (Volume 4), and the root cause investigation (Volume 1).

The initial critical part of the investigation is the determination of failure modes. Without knowing the exact failure modes that were involved in the incident, failure mechanisms and their contributing factors cannot be determined.

After failure modes are determined, the second critical part of the investigation is the determination of failure mechanisms. Without knowing the failure mechanisms and their contributing factors, the human actions, programs and processes (which are under KCP&L management and organizational control) that may have contributed to the incident cannot be determined.

The third critical part of the investigation is the review of Iatan-KCP&L organizational programs, process and human actions. The purpose of this review is to determine if human actions, programs and processes are either a root or contributing cause of this incident.

The final and key part of the investigation is the assessment of the root cause(s) of the event. The definition of a root cause of an incident is as follows:

> "*A root cause is a contributing factor that if it is eliminated, the total recurrence can be prevented*".
>
> A *root cause* must meet the following conditions: (1) it is a substandard human action or a substandard industry practice and (2) it can be eliminated effectively under the control of management.

Occasionally, an event may occur without a root cause that is <u>under the control of management</u>. In these cases, PII only recommends future corrective actions to prevent event recurrence that are under management's control and no root causes are specified.

As a final conclusion of a root cause investigation, PII will define monitoring methods to determine if the corrective actions are effectively implemented and if the actions taken are effective to prevent recurrence. If the event should recur, the investigation should be reinitiated and a detailed review of the adequacy of the previous root cause investigation performed.

It is noted that in the history of root cause investigations performed by PII, no recurrences have been encountered after implementation of PII recommended corrective actions. This success is attributed primarily to the PII rigorous investigation processes.

1.3 Operation, Maintenance, and Design Data of the Failed Pipe

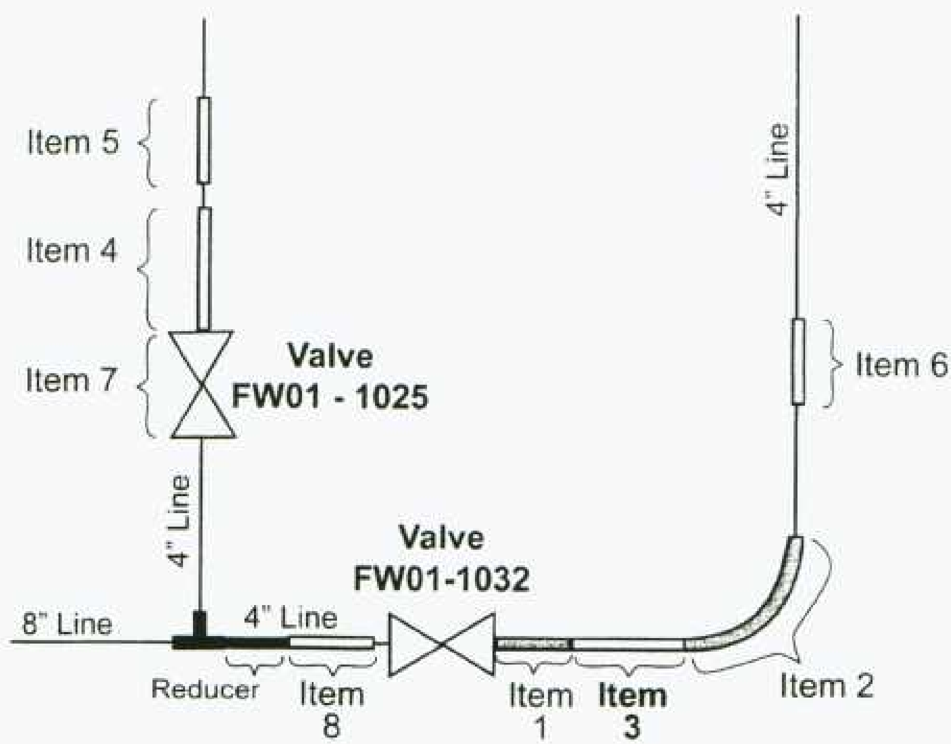
An extensive amount of Iatan plant and KCP&L corporate data and information related to operation, maintenance, and design of the Iatan plant was collected during the investigation. This data was used to refute hypothesized failure modes and failure mechanisms or was used directly to support the determination of the failure modes and failure mechanisms.

During this investigation, the investigation team made several visits to the Iatan plant and to KCP&L corporate offices to collect relevant data and information. Interviews were conducted with Iatan plant Operations, Maintenance, Engineering, Procurement, Project Management, Chemistry and Planning personnel (see Table 4.1 in Volume 4). In addition, several key KCP&L staff personnel, unavailable during plant visits, were subsequently interviewed by telephone. Data utilized in the investigation was also extracted from the various prior KCP&L OSHA submittals. At the request of the PII investigation team, information related to status of key Iatan plant and KCP&L programs and processes potentially related to this incident was provided for review and an adequacy analysis.

The data and information collected were then used to analyze the event failure modes, failure mechanisms and relevant programs and processes potentially contributing to the events. The results of the analyses and investigations are provided in Volumes 2, 3, and 4 of this investigation report.

1.4 Failure Mode Determination

The failed pipe, along with seven other items, was sent to Performance Improvement International, LLC for failure mode determination. Eight items associated with the Iatan pipe rupture event were physically provided to PII to perform a detailed failure analysis. The locations of these eight items in the plant are illustrated in Figure 1.1. Due to a lack of replacement parts, SH attemperator spray 1A block valve FW01-1032 remains in service at the Iatan plant and is not included in the failure analysis. The body and the valve seats of SH attemperator spray 1B block valve FW01-1025 are included in the failure analysis.



Designation of Items Analyzed by PII Investigation Team (Item 3 = Failed Pipe)

Figure 1.1

SEE TABBED ATTACHMENT 1.1
FOR ALL FAILURE MECHANISMS
ANALYZED

Various types of failure analyses were performed on these eight items (see Table 1.1). The purposes of these failure analyses are stated below:

1. **Thickness Analysis** – to compare wear rates at various locations
2. **Chemical Composition analysis**- to determine the effects (if any) of material compositions on the identified failure modes
3. **Mechanical Properties Analysis**- to determine the effects (if any) of material mechanical properties on the identified failure modes
4. **Fracture Analysis**- to determine the fracture modes.
5. **Metallography Analysis**- to determine the effects of material microstructures of the identified failure modes and, in some cases, to determine original thickness.
6. **Surface Marking Analysis**- to determine the manufacturer and sources of the pipes.
7. **Weld Analysis**- to determine if any weld defects existed and contributed to the identified failure modes.
8. **Surface Crack Analysis**- to determine if thermal fatigue, water hammer, or fluid transients contributed to the identified failure modes.
9. **Surface Pitting Analysis** – to determine if cavitation pits or crevice pitting existed.

	Item 1	**Item 2**	**Item 3**	**Item 4**	**Item 5**	**Item 6**	**Item 7**	**Item 8**
Thickness Analysis	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A*
Chemical Composition Analysis	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Mechanical Properties Analysis		Yes	Yes	Yes	Yes	Yes		Yes
Fracture Analysis			Yes					
Metallography Analysis		Yes	Yes	Yes	Yes	Yes		Yes
Surface Markings		Yes	Yes	Yes		Yes	Yes	
Weld Analysis	Yes	Yes						Yes
Surface Crack Analysis via Surface Examination	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Surface Pitting Analysis	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table 1.1

As a result of these failure analyses, the failure mode of rupture was determined to be ductile overload. The thinnest area of the failed pipe was measured to be only 0.056 inches (down from the original thickness of 0.531 inches). A finite element stress analysis, using the as-found thickness of the pipe and ASTM A106

Gr C material properties, confirmed that the normal operation pressure of 2,600 psi could result in stresses was sufficient to rupture the pipe.

The detailed metallurgical evaluation identified no signs of surface micro-cracking or pitting and no evidence of strain hardening on the gains was observed. Based on these observations, failure modes related to thermal transients, water hammers, pipe fatigues due to repeat restrained movements, cavitation, or oxygen-chlorine related pitting were ruled out.

The mechanical properties and original thickness of the failed pipe were found to meet the original ASTM A106 Gr C design specification. Moreover, the microstructure of the failed pipe was determined to be adequate – acceptable inclusions, no voids, no slag, and no unknown second phase precipitations. Based on these observations, failure modes related to defective materials, fabrication defects, and inadequate original pipe thickness were ruled out.

1.5 Failure Mechanisms and Contributing Factors Determination

The failure mechanism that caused the wear of the failed pipe was determined to be high velocity Flow Accelerated Corrosion (FAC) and, to a lesser degree, erosion.

At the beginning of this investigation, twenty-nine groups of potential failure mechanisms were considered (see **Attachment 1.1** for the potential mechanisms considered). After the failure analysis (Volume 2), all except failure mechanism group 2.8 were refuted. The failure mechanism of Group 2.8 is FAC as accelerated by free vortex flow, material composition, flow reattachment, or the entrance effects.

It should be noted that the failed pipe was located downstream of 1A SH attemperator spray AC block valve FW01-1032. The wear rate in an equivalent section of pipe, located in the parallel 1B SH attemperator spray line downstream of the 1B AC block valve FW01-1025, exhibited a much lower wear rate (3.2 mils per year versus 17.3 mils per year). Operating conditions, such as flow rates, water chemistry, temperature, and pressure, of these two pipes were essential identical. The body of the FW01-1025 block valve was made of carbon steel and the body of the FW01-1032 was made of 2.25% chromium-molybdenum (Cr-Mo) F22 material.

It is noteworthy that the downstream elbow of the failed pipe has also experienced a very low wear rate although the operating conditions of the failed pipe and the downstream elbow were identical. As such, differences in water chemistry, operation temperature or pressure anomalies, and high flow rates were ruled out as contributing factors to the pipe rupture.

Using the differential analysis techniques, the team identified three possible contributing factors: (1) local flow distribution as affected by both upstream and downstream components, (2) pipe material composition and (3) entrance effects

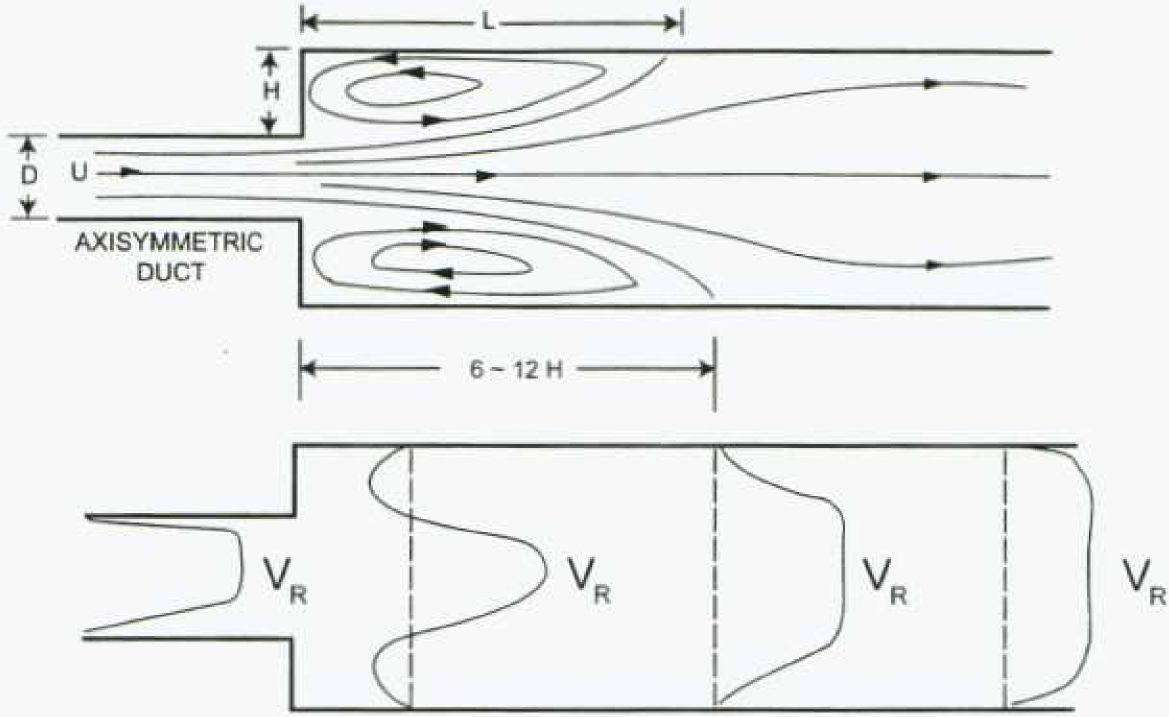
(Note: Entrance effects are the effects on the wear rates from the material composition differences of the upstream components. For example, it was found that a carbon steel pipe will typically wear at an accelerated rate when it was placed downstream of a Cr-Mo pipe of valve. See Attachment 4.32).

Entrance effects typically increase wear rates in the approximate 2.5 inch interface area downstream of the weld connecting the Cr-Mo body FW01-1032 valve to the failed carbon steel pipe. The wear rate of the failed pipe near this interface area was found substantially less than that the thinnest area of the failed pipe. The thinnest area of the failed pipe was approximately five inches downstream from the interface weld between FW01-1032 and the carbon steel failed pipe. Since the greatest piping thinning occurred outside the typical entrance effects zone, entrance effects were not considered to be a major contributing factor.

The failed pipe has a low Cr-Mo content (~0.03%). The elbow, immediately downstream of the failed pipe, had a nearly identical Cr-Mo content. Since the downstream elbow of the failed pipe has practically an identical chemical composition and a very low wear rate, the effects of pipe material composition was ruled out as a possible contributing factor. The remaining contributing factor not ruled out is *the local flow distribution*, as affected by the upstream and downstream components of the failed pipe.

The upstream component of the failed pipe is a throttled gate valve FW01-1032. A throttled gate valve is defined as a gate valve that without a smooth inlet and outlet transition to big pipe areas or a significant reduction in open area compared to open pipe areas.

The throttled gate valve has a sudden opening, producing a flow separation and re-attachment condition in the downstream pipe (as shown in **Figure 1.2** with an exaggerated sudden expansion). The re-attachment point is approximately at a distance of 6-12H from the expansion. The re-attachment point in the failed portion of piping is located between 3.9 and 7.8 inches downstream of the weld between the failed pipe and the FW01-1032 valve.



Typical Separation and Re-Attachment After a Sudden Expansion (V_R = Relative Velocity)

Figure 1.2

The component downstream of the failed pipe is a 90^0 degree standard elbow. Elbows tend to produce free-vortex flow (often called secondary flow) that result in a higher velocity at the inner radius of the elbow, starting about one pipe diameter upstream of the elbow. In the case of the failed pipe, this flow acceleration started about five inches downstream from the weld between the failed pipe and the FW01-1032 valve. The thinnest area was found to be about five inches downstream of the weld between the failed pipe and the FW01-1032 valve. **Figure 1.3** shows a typical velocity profile near and in the elbow.

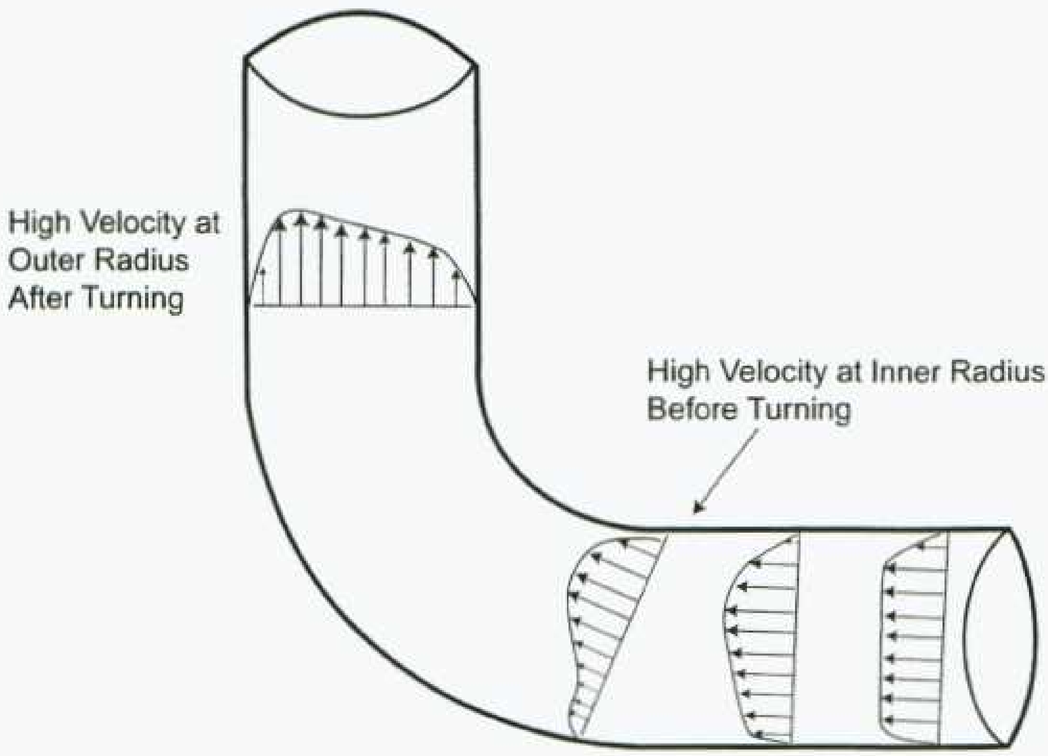


Illustration of Free-Vortex Flow Velocity Distribution

Figure 1.3

A finite element flow modeling of the failed pipe that combines both effects (free vortex flow and re-attachment) is shown in **Figure 1.4.** As can be seen in this figure, the radial velocity at the reattachment point at failed pipe near the inner radius of the elbow was very high. The investigation team believes that the radial velocity and the local high axial velocity (along the pipe line) contributed to the excessive rate of material transport, thus a high wear rate of the failed pipe.

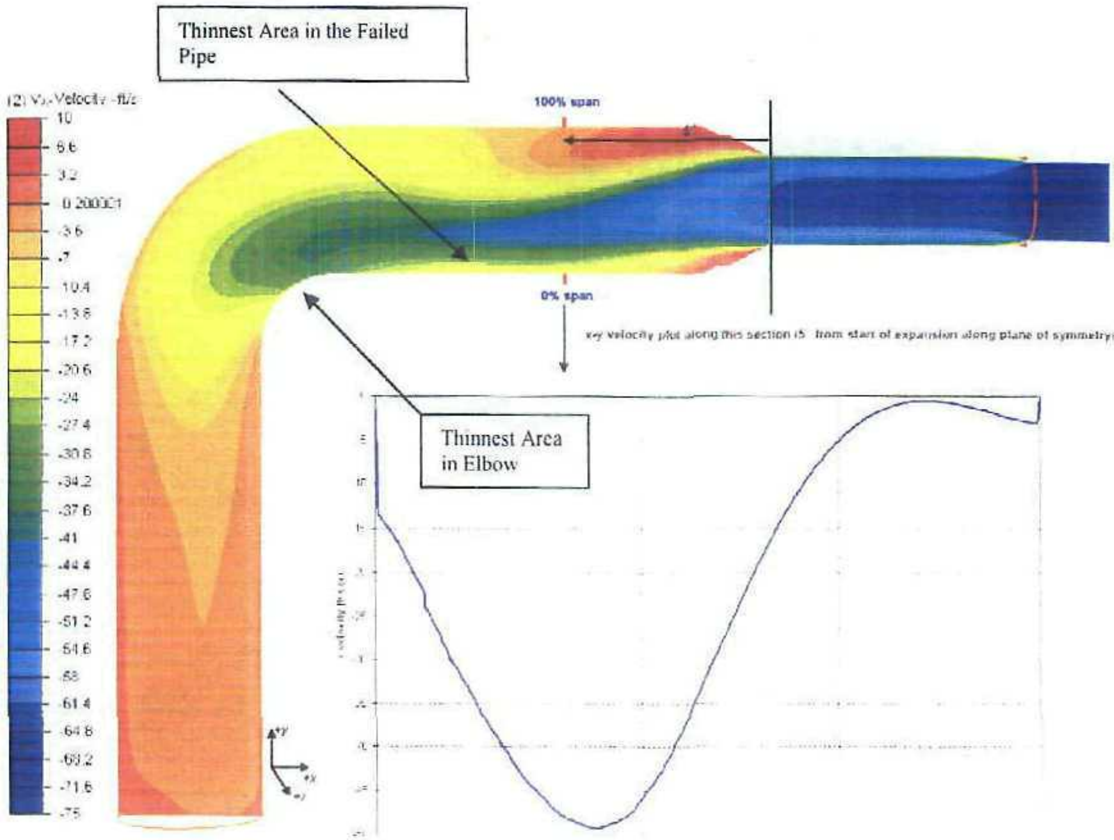


Figure 1.4

As can be seen in the above figure, the thinnest area of the pipe was located near the reattachment point. Because of effects of impingement, the wear rate was high.

At the inner radius area of the elbow, moderate wear was observed. It was caused by the acceleration of the axial velocity (without flow separation) before the turn. This area represents the highest wear rate (but much less than that in the failed pipe) in the elbow.

The following figure shows the calculational results flow patterns downstream of FW01-1025.

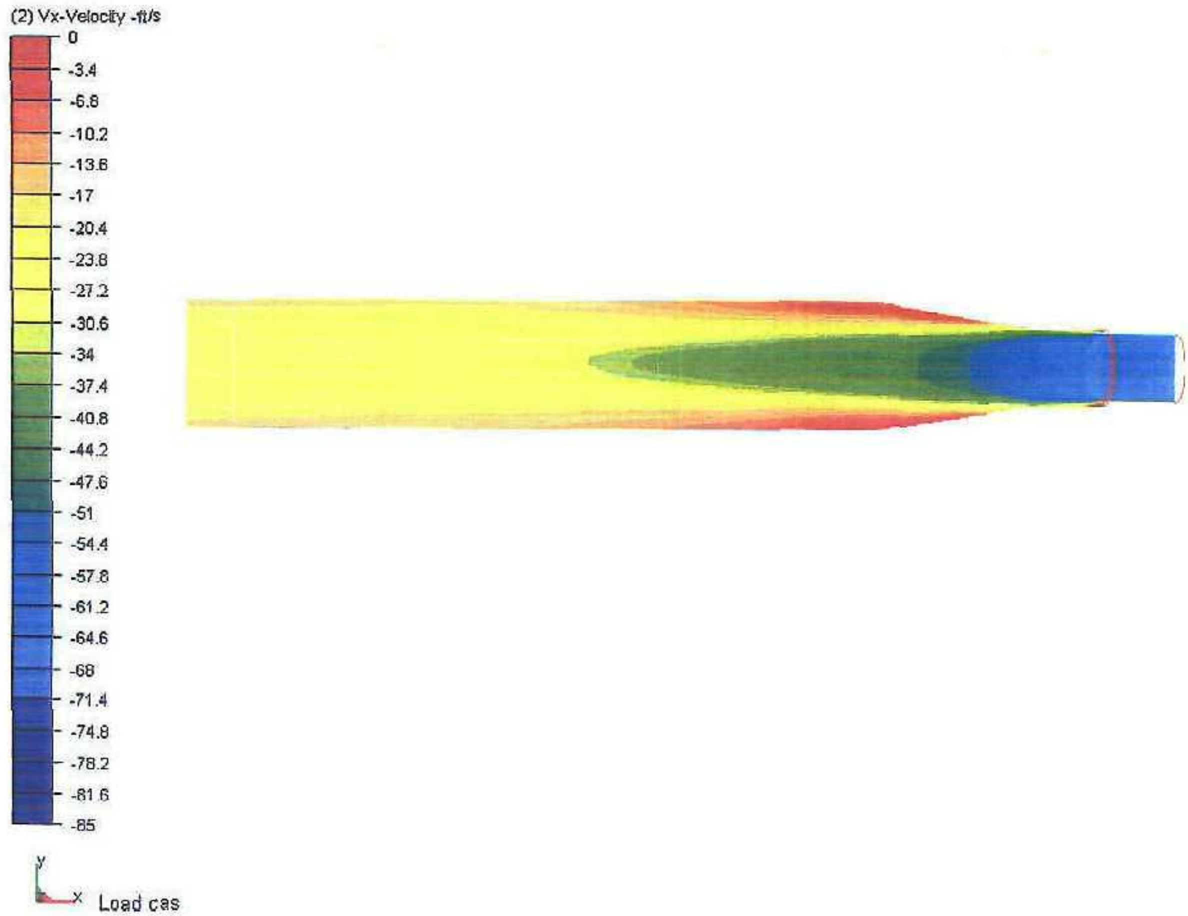


Figure 1.5 Flow Patterns (X-Direction Velocity) Downstream of FW01-1025 Valve

As can be seen in the above figure, there is little recirculation flow directly downstream of the FW01-1025. The flow was essentially attached to the pipe wall downstream of the valve without impingement. As such, the FAC rate is low.

The flow path of the FW01-1025 valve provides a venturi at the exit of the valve to prevent or minimize flow separation. Based on the significant difference in local flow distribution, the pipe downstream of FW01-1025 is predicted to have a much lower wear rate.

1.6 Sequence of Events

Based on the data and information collected through interviews and through maintenance record and purchase order searches, there were likely two human actions that may have contributed to the excessive wear rate of the failed pipe. These two actions are:

1. Prior to plant commercial operation in 1980, the location of the FW01-1032 was changed from a position downstream of the elbow to a position upstream of the elbow.

2. In September 1986, the original gate valve FW01-1032, Dewrance model P91EE100NFDB, was replaced with a Dewrance model P95KM100PFDA gate valve. The P91EE100NFDB model was a venturi gate valve and P95KM100PFDA model was a throttled gate valve.

Based on PII's analysis, elimination of either one of the two actions would have likely prolonged the rupture to a much later date. Prior to this projected much later rupture date, FAC inspections performed under the KCP&L LAMP (long term asset management program) would have provided the opportunity to identify the excessive wear rate of this pipe, permitting repair or replacement before the occurrence of failure. It is also likely that other plants would have had similar pipe ruptures, possibly triggering Iatan to perform a detailed wear rate analysis of all susceptible components (including the failed pipe) and permitting repair or replacement before the occurrence of pipe failure. A detailed description of the sequence of events related to the pipe failure is stated in Volume 4.

1.7 Programs and Processes

Among the programs and processes reviewed by the investigation team, two programs if implemented could prevent future recurrence.:

1. **Configuration Management Program**
2. **A More Structured Flow Accelerated Corrosion Program**

To understand corrective actions that need to be implemented to prevent total recurrence, a hypothetical situation is defined. Assuming the original A/E and/or Iatan plant staff possessed the knowledge about the failure mode, failure mechanisms and the contributing factors, and understood how to factor in the effects of upstream and downstream components on wear rate, the A/E and/or Iatan plant staff could have:

1. **Rejected** the configuration change that changed the location of FW01-1032 from downstream of the failed pipe (vertical position) to the upstream of the failed pipe (horizontal position).
2. **Rejected** the model P95KM100PFDA or changed back to P91EE100NFDB model after the repair of the replaced valve was completed.

To be able to reject the above two conditions for future operations, KCP&L should develop and implement a configuration management program. The program shall cover the following elements:

1. Develop a configuration control program for critical plant features and define organizational expectation for program adherence.
2. Report all proposed critical configuration changes to KCP&L's engineering department.
3. Perform engineering reviews of configuration changes for impacts to the plant design and the potential impact on the wear rate by FAC and erosion.
4. Document and record the reasons for acceptance or rejection of the proposed changes.
5. Update the drawings, procedures, and FAC monitoring programs accordingly.

A thorough, knowledge-based FAC program should also be developed by KCP&L. The program should include the following elements:

1. Develop a KCP&L program document with program ownership and plant responsibilities defined.
2. Perform a review for FAC susceptible piping and document the results in the program document.

3. Utilize the appropriate analytical-based tools to define sample inspection locations.
4. Perform inspections to assess the existence of FAC and erosion wall thinning.
5. Replace or repair pipe when the measured wall thickness is below ANSI B31.1 Code required minimum thickness.

Since the existing Configuration Control and FAC programs at KCP&L, as well as other fossil utilities, are not as robust as they could be, KCP&L should establish a policy for industry involvement and consideration of industry experience reviews. Industry involvement and knowledge will enable KCP&L to communicate upgraded improvements and key technological advances.

1.8 Root Cause Determination

In the previous section, two program improvements were identified; a configuration management program and a more structured FAC program. Also, two potentially inadequate human actions that might have contributed to this incident were identified; first, the changed location of the SH attemperator spray 1A block valve FW01-1032 and secondly, the acceptance of model P95KM100PFDA to replace model P91EE100NFDB in the FW01-1032 location.

These two programs could prevent recurrence only if KCP&L staff possessed the state-of-the-art knowledge of FAC and its computational methods.

The FAC program utilized by most of the power industry is based on Electrical Power Research Institute (EPRI) work on FAC predictions performed in the late 1980's. It is the PII team's understanding that EPRI predictions were developed from EDF (electric de France) proprietary data obtained in laboratories with test coupons in tubes. For other components that are not tubes, empirical factors were used to accommodate the difference in local flow distribution. EPRI typically recommends that its member utilities use an analytical method based on this research (called CHECWORKS) to identify sample inspections of FAC susceptible piping and to employ ultrasound (UT) methods to periodically measure susceptible piping wall thickness degradation. If piping lines inspected indicate high wear rates, an expanded inspection is recommended for lesser wear rate areas on the same line or similar configuration locations on other lines. EPRI also cautions the users of the CHECWORKS to exercise engineering judgment in selecting the areas susceptible to FAC and in the selection of sample inspection locations.

It is the investigation team's opinion that EPRI model has one major drawback. The EPRI CHECWORKS model does not account for the influences of flow distribution from the upstream and downstream components. In the case of the failed pipe in this pipe rupture incident, the upstream orifice-effect of the FW01-1032 gate valve and the downstream elbow caused jet impingement at the re-attachment point, greatly accelerating the pipe wall wear rate. These effects cannot be analytically modeled in the CHECWORKS program.

In EPRI's CHECWORKS model, a straight pipe downstream a gate valve is a straight pipe downstream of a gate valve, without consideration its upstream and downstream components of a throttled gate valve and an elbow (a point-to-point model). For this reason, EPRI's CHECWORKS model prediction of the wear rate downstream of the FW01-1032 and FW01-1025 are practically identical. In reality, the wear rates were significantly different when calculated based on actual pipe wall thickness loses and when local flow distribution effects are analytically considered. FAC at a local area depends greatly on the local flow distribution. The local flow distribution is influenced highly by the upstream and down stream components. As such, good FAC prediction requires the knowledge of connected modeling (connecting the influences of upstream and downstream components).

The major contributing factors to the failure of the ruptured pipe are the upstream jetting from valve FW01-1032 and the secondary flow resulting from the existence of a downstream elbow. To have accurately predicted the wear rate in the failed pipe, KCP&L would have had to possess the knowledge of connected flow modeling of FAC. This knowledge is significantly beyond the current level of industry practice for the prediction of FAC induced pipe wall thinning.

As discussed above, it is the investigation team's conclusion that neither the KCP&L configuration management program nor the KCP&L's FAC program were the root causes of the incident. This conclusion is reached because even industry leaders with an industry standard configuration management and FAC programs may have failed to identify the excessive wear rate of the failed pipe. However, KCP&L improvements in configuration management and FAC programs are needed to reduce risk of recurrence.

By the same token, the human actions to change the location of FW01-1032 and the acceptance of P95 model as a replacement of P91 model are not contributors to this incident.

However, KCP&L staff should acquire the knowledge of the connected flow modeling of FAC to prevent recurrence.

1.9 Corrective Actions to Reduce Risk of Recurrences

To prevent recurrence of this and similar events, the PII team recommends the following actions be taken to identify other potential areas which may have similar characteristics to the failed pipe:

1. Employ the EPRI method CHECKWORKS (as has been implemented) to identify the susceptible areas.
2. Supplement the EPRI model with connected flow modeling techniques to identify additional inspection areas.
3. If the measured wall thickness is less than 30% of the minimum allowable wall thickness, replace or repair the pipe immediately.
4. If the measured wall thickness is less than the minimum allowable wall thickness (as specified by the B31.1 code), but no less than 30% of the minimum allowable, perform a safety risk assessment. If the risk is determined acceptable, replace or repair the pipe at the next planned plant outage with temporary compensatory actions (such as caution tags, leak flow blockage facilities, etc.).
5. Identify and replace all throttled gate valves and replace them as soon as practical. Until these valves are replaced, utilize NDE techniques to monitor the pipe wall thinning downstream of the valves and replace pipe based on the above criteria in 3 and 4.

The team also recommends the following long-term actions be taken:

1. Improve the configuration management program so that it would evaluate and reject changes that may cause excessive wear rates.
2. Enhance the FAC program to track all Cr-Mo pipes already put into the plant after the incident to avoid excessive pipe thinning due to entrance effects.
3. Establish an independent audit program to audit if all recommended corrective actions be taken as planned and if they are effective to prevent recurrence. Feedback the audit results to KCP&L line management to improve the deficient areas on an annual basis for at least five years.
4. Improve KCP&L's operation experience program that exchange plant operation experience with other utilities (such as TVA or AEP) so that future experience of any pipe failure from other fossil utilities can factor into KCP&L's FAC program.

ATTACHMENT 1.1

Group of Failure Mechanisms	Failure Mechanisms	Destructive Testing	Non-Destructive Test	Comments
1.1	Inadequate Original Thickness	SEM Examination of Cross-Section of the Transition Weld,	Survey of Thickness of all Four Pieces , X-ray the Transition Weld, SEM Examination of ID of the Transition Weld.	There are four failure mechanisms included in this item.
1.2	Inadequate Weld Build-up	Metallography (if visual examination finding defects)	Visual with Photo	Only the weld upstream of the failed pipe (piece 3) will be examined.
1.3	Inadequate Weld Off-set	Metallography (if visual examination finding defects)	Visual with Photo	N/A
1.4	Inadequate Welding Integrity– Hot Cracking, Lack of Fusion, Slag Inclusion, HAZ Cracking and SCC.	Metallography (if needed)	X-ray for Cracks in Welds	IF the crack origin is not in or near the welds upstream and downstream of the Piece 3, this failure mechanism is invalid.
1.5	Inadequate Pipe Fabrication Quality – Excessive Voids	Metallograpgy Examination (same as 3.1)	N/A	N/A
1.6	Inadequate Pipe Fabrication Quality- Non-Seamless Pipe	N/A	Visual with Photo	N/A
1.7	Inadequate Material Strength	Tension Testing	N/A	Two test specimens from Piece 3 will be prepared.
1.8	Inadequate Material Hardness	Micro-hardness Test	N/A	A minimum of two spots in Piece 3 will be tested . There are 5 failure mechanisms included in this item.
1.9	Inadequate Material Composition for Erosion and FAC Resistance	Chemical Quantitative Analysis of Alloys	N/A	Minimum three spots in Piece 3 and Piece 1 will be examined for composition.

2.1	Two-Phase Flashing Induced Wall Thinning	NA	Visual First with Photo	Two-phase flashing can be detected by comparing the thickness of Piece 1 and Piece 3.
2.2	Flow Accelerated Corrosion or Erosion/Corrosion	SEM Survey of Size and Depth of Scallops (or use of Impressed Molding Method)	Same as 1.1	Piece 3 and Piece 1 will be surveyed (12 points per piece)
2.3	Single Phase Erosion	Same as above		Erosion tends to make very shallow cavities or smooth ID surface.
2.4	Cavitation	Metallography (SEM) Examination of Pits (if needed)	Visual First with Photo	NA
2.5	Pitting (Chlorine Induced)	Metallography (SEM) and EDX Examination of Pits (if needed)	Visual First with Photo	NA
2.6	MIC Induced Pitting	Metallography (SEM) and EDX Examination of Pits (if needed)	Visual First with Photo	NA
2.7	Local Turbulence (such as Valve 1032 Induced) Accelerated FAC	Metallography (SEM) Survey of Size and Depth of Scallops	Same as 1.1	There are three failure mechanisms (including loose valve seats, plug separation, small valve bore) included in this item.
2.8	Free Vortex Flow (FVF), Material Compositions, Entrance Effects, and Re-attachment Accelerated FAC	Metallography (SEM) Survey of Size and Depth of Scallops (same as 2.2)	Visual First with Photo	NA
2.9	Localized Aggressive Chemistry Accelerated FAC	Magnetite Film Thickness (if possible due to the after-event oxidation)	NA	There are four failure mechanisms grouped in this item. Magnetite thickness in Piece 3 and 4 is compared. (if possible)

Group of Failure Mechanisms	Failure Mechanisms	Destructive Testing	Non-destructive Testing	Comments
3.1	Thermal Fatigue	Fracture Surface Examination (SEM Fractography) and Crack Cross Section Examination by SEM near Crack Origin	X-ray	X-ray can identify ID surface micro-cracks that might be origin of fatigue cracks
3.2	Corrosion Fatigue	Same as above	Same as above	N/A
3.3	Pressure Fluctuation Induced Fatigue	Same as above	Same as above	There are three failure mechanisms included in this item.
3.4	Over Pressure Induced Overload	Same as above	Same as above	N/A
3.5	Cracking from In-Situ Embrittlement by Hydrogen	Same as above	Same as above	N/A
3.6	Cracking from In-Situ Embrittlement by Oxygen	Same as above	Same as above	N/A
3.7	Cracking from In-Situ Embrittlement by Sulfur Based Elements	Same as above (if needed, Energy Dispersive X-ray, EDX, is performed at branched crack tips)	Same as above	N/A
3.8	Cracking from In-Situ Embrittlement by Chloride	Same as above(if needed, Energy Dispersive X-ray, EDX, at branched crack tips)	Same as above	N/A
3.9	Water Hammer and Fluid Transients (Steam Bubble Collapse, Valve Slamming, etc.)	Same as 3.1	N/A	There are 11 failure mechanisms grouped in this category.

APPENDIX B-1
Power Point Slides
Incident Summary
and Lessons Learned

Pipe Failure at KCPL Iatan Plant on May 9, 2007

and Lessons Learned

Prepared by: KCPL and PII

December 15, 2007

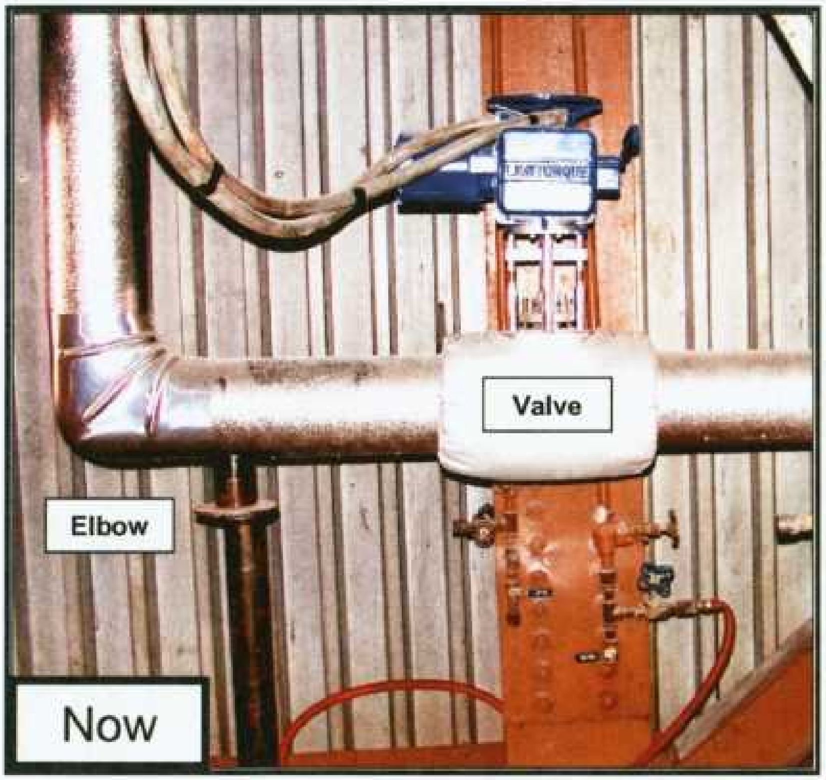
Injuries & OHSA

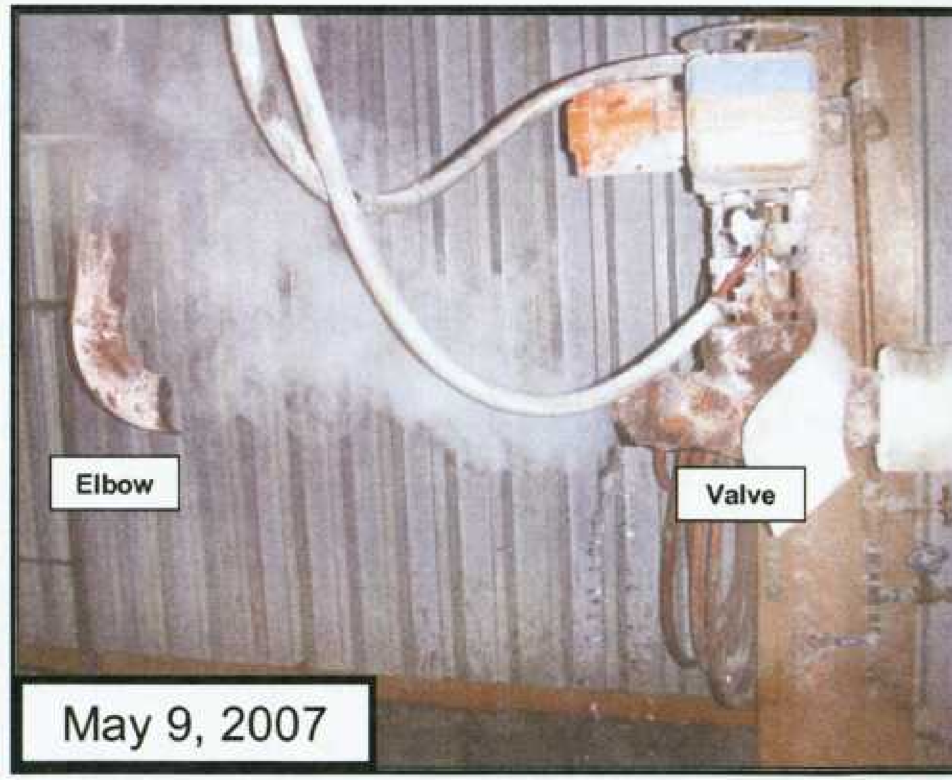
- 2 People killed
- 1 Seriously Injured
- 3 Serious citations from OHSA

Desuperheater Supply Piping Failure

Failure occurred between gate valve & elbow

THIS IS NOT A CONTROL VALVE, IT IS OPEN OR CLOSED





Iatan Station

- 670 MW (net) Station
- B&W Drum unit firing PRB coal
- Operating pressure 2975 psi at 1005F / 1005F
- In service for 27 years (1980 in service)
- Recently had run almost 3 years without accident
- Clean & reliable plant

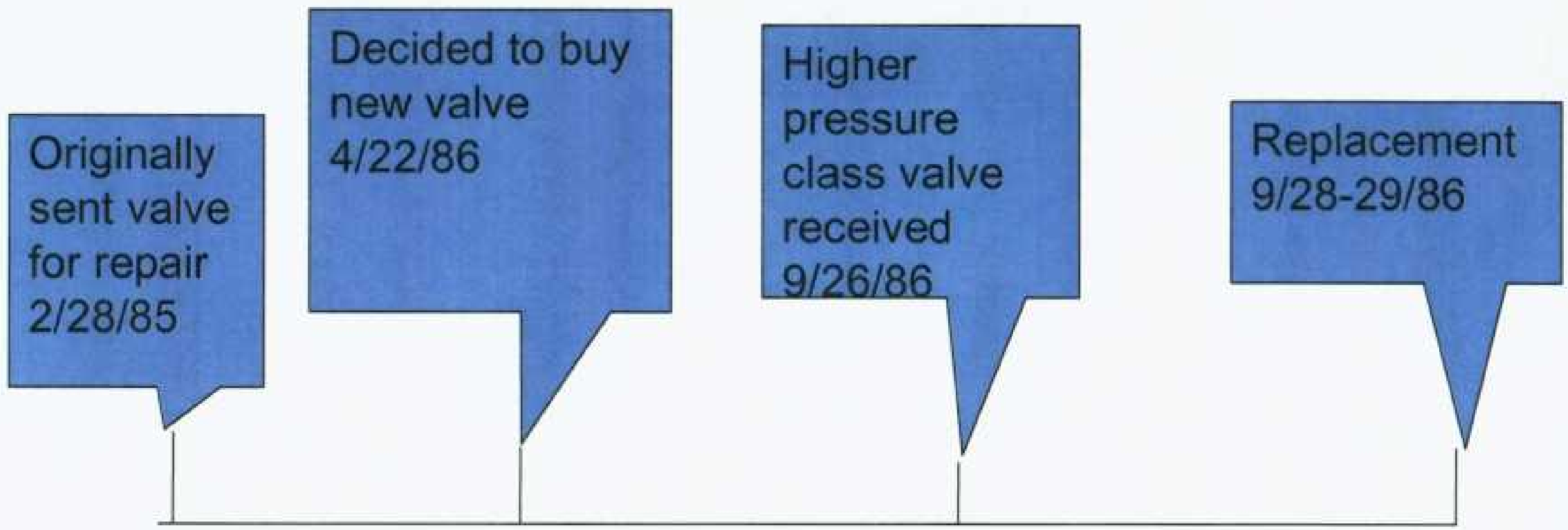
Facts Leading Up To Event

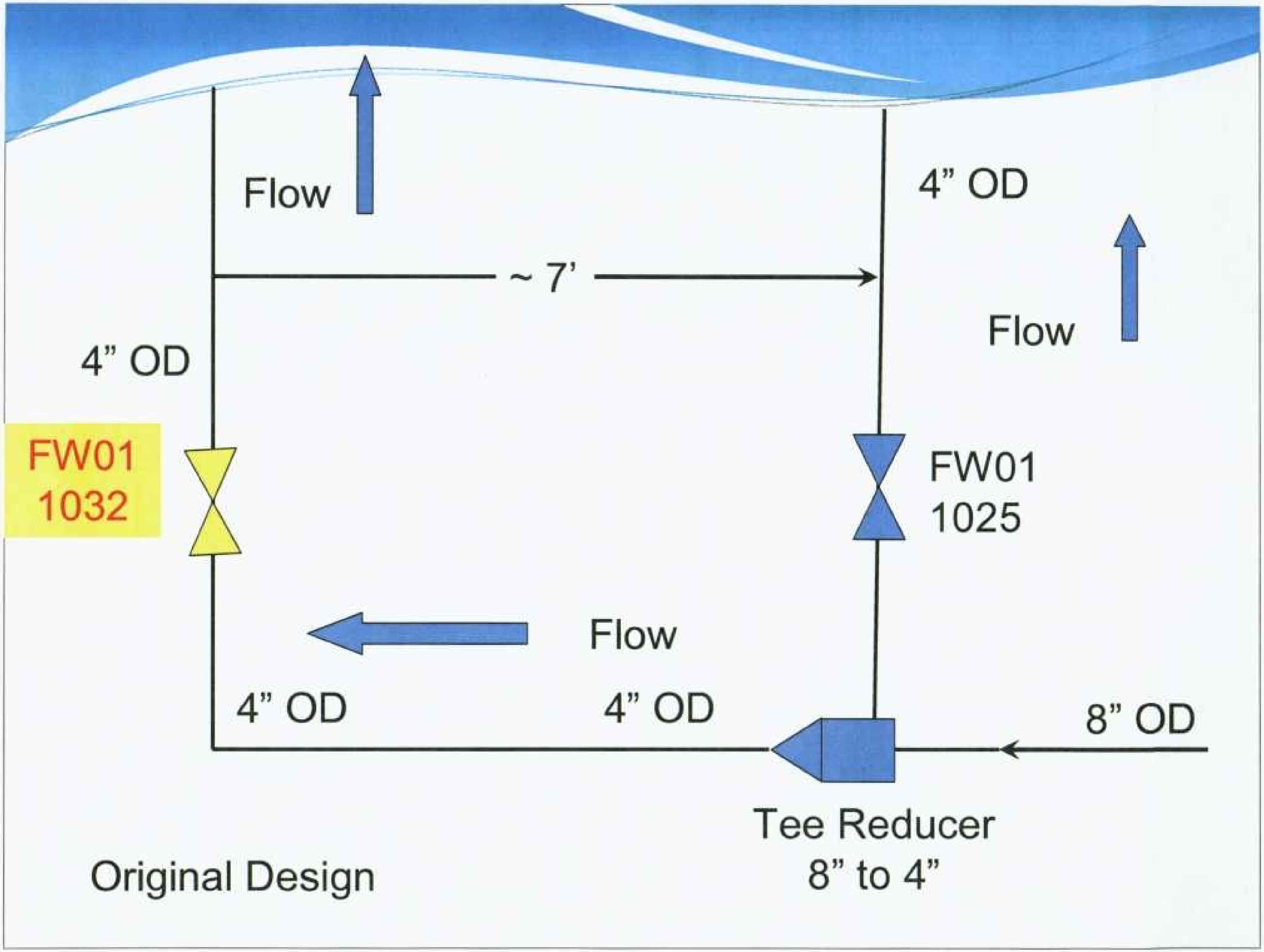
- Unit was on line but in startup
- Feeders were plugging due to wet coal
- Operators were on feeder deck
- Main steam desuperheating station is located on feeder deck
- 4" Schedule 160 A106 Gr. C desuperheater pipe ruptured
- Desuperheater piping design 500F, 3200 psi; Operating conditions 485F, 2954psi

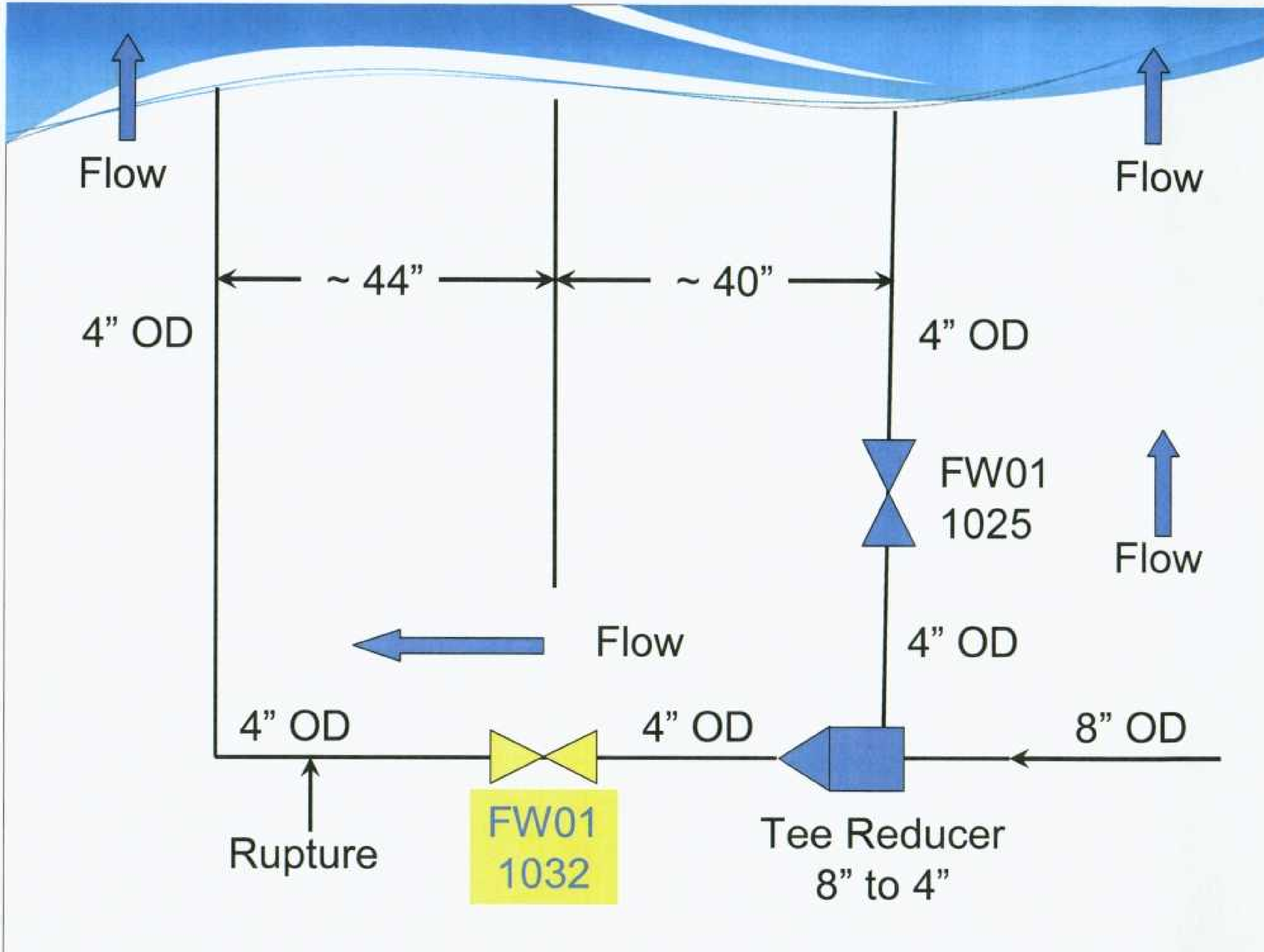
Failure Mechanisms

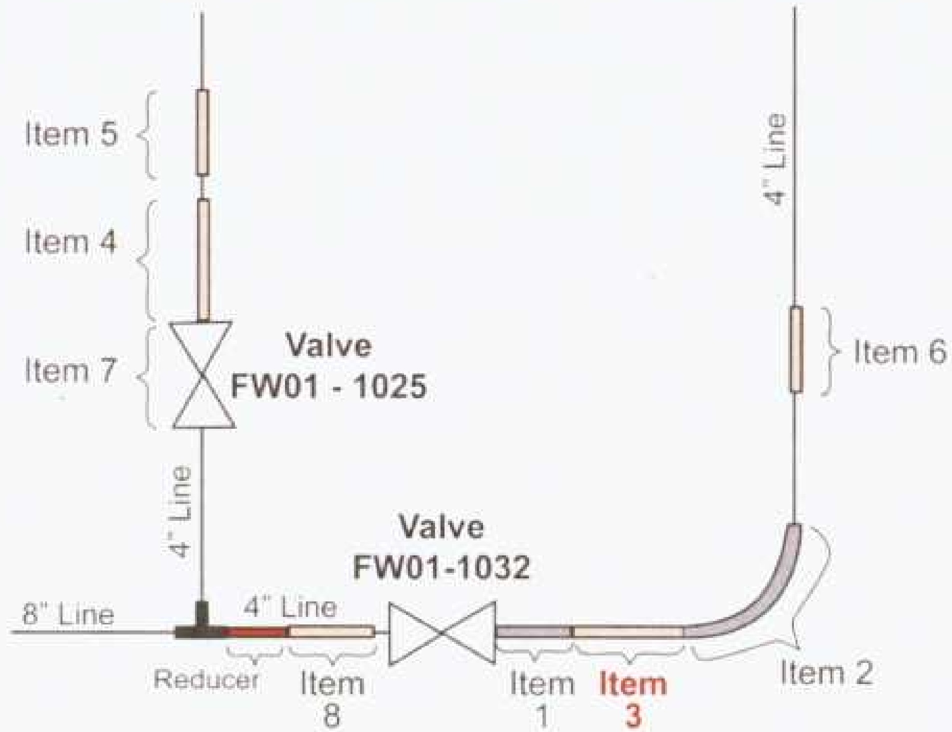
- FAC induced by "Throttling Valve" defined as:
  - Low Ao/Ap
  - Abrupt step changes on outlet
- Localized high velocity at inner radius of upstream elbow

Valve Replacement Chronological Events




Flow
4" OD
~ 7'
Flow
4" OD
FW01
1032
FW01
1025
Flow
4" OD
4" OD
8" OD
Tee Reducer
8" to 4"
Original Design


Flow
Flow
~ 44"
~ 40"
4" OD
4" OD
FW01
1025
Flow
Flow
4" OD
4" OD
4" OD
8" OD
Rupture
FW01
1032
Tee Reducer
8" to 4"



Designation of Items Analyzed by PII Investigation Team (Item 3 = Failed Pipe)

Figure 1

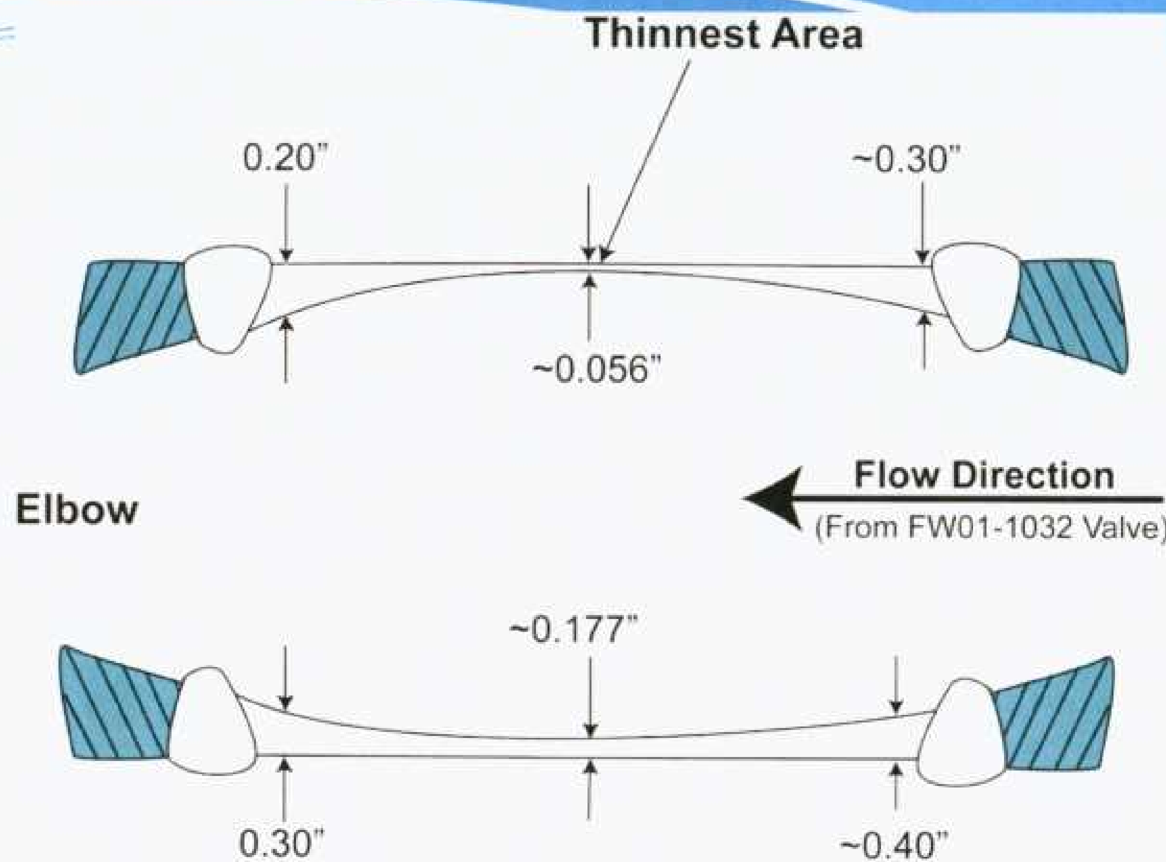
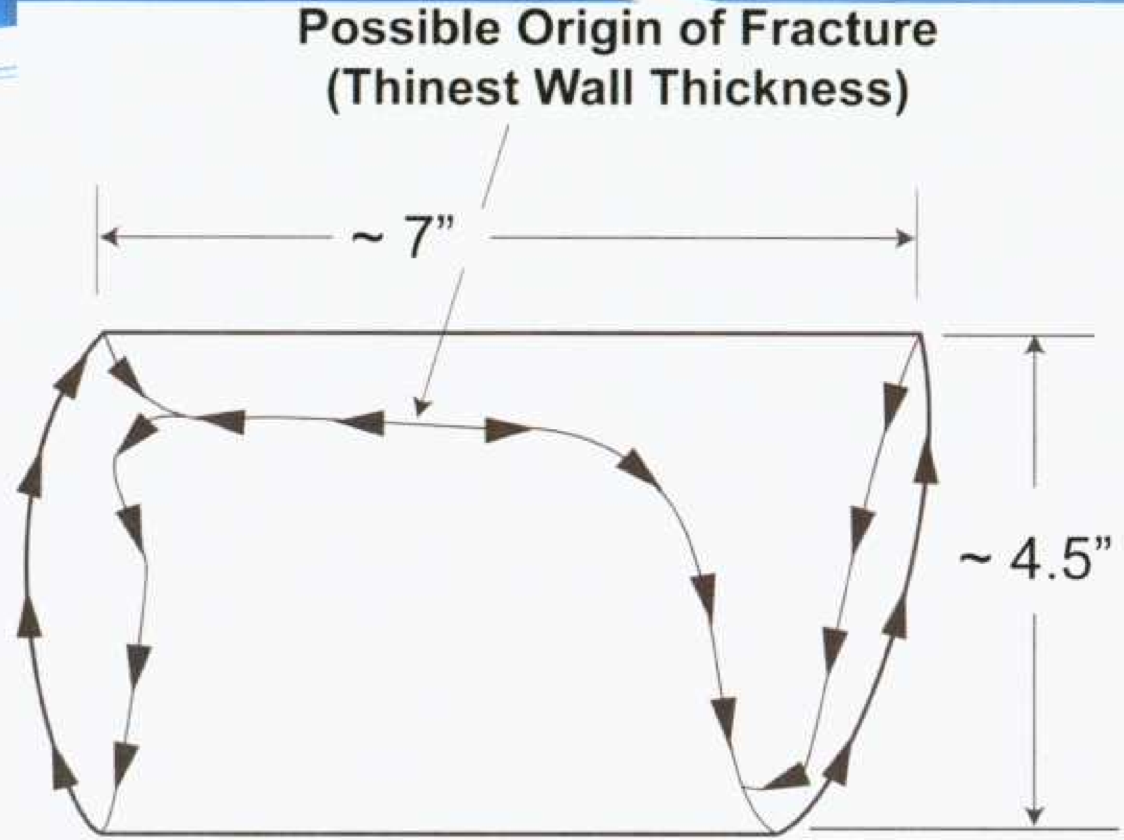


Illustration of Wall Thickness Pattern at the Time of Rupture

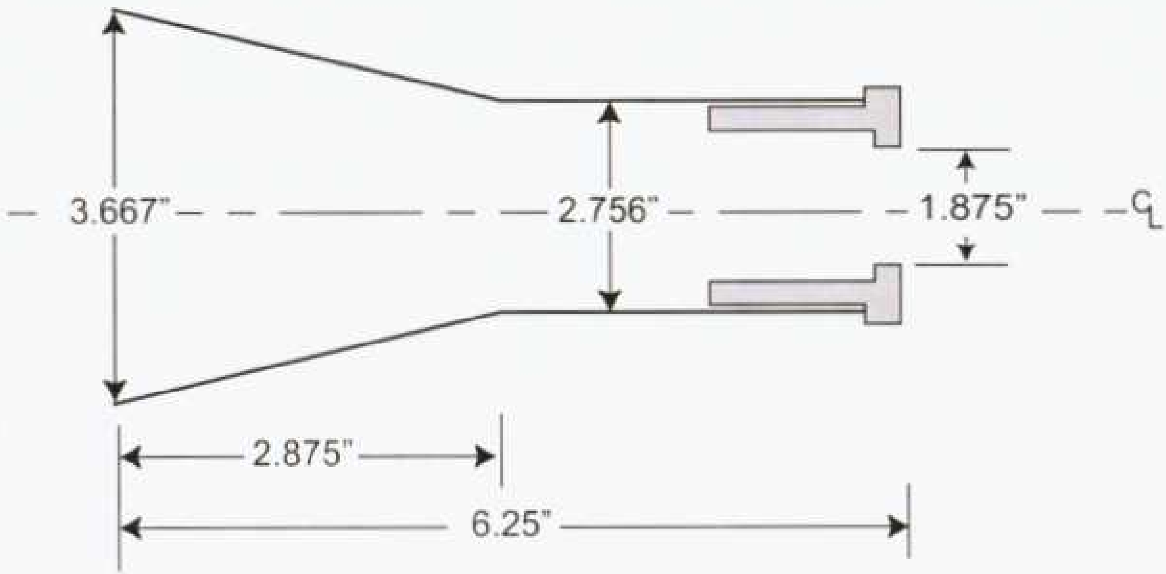
Figure 2.9



Overload Fracture Origin & Propogation

Figure 2.10

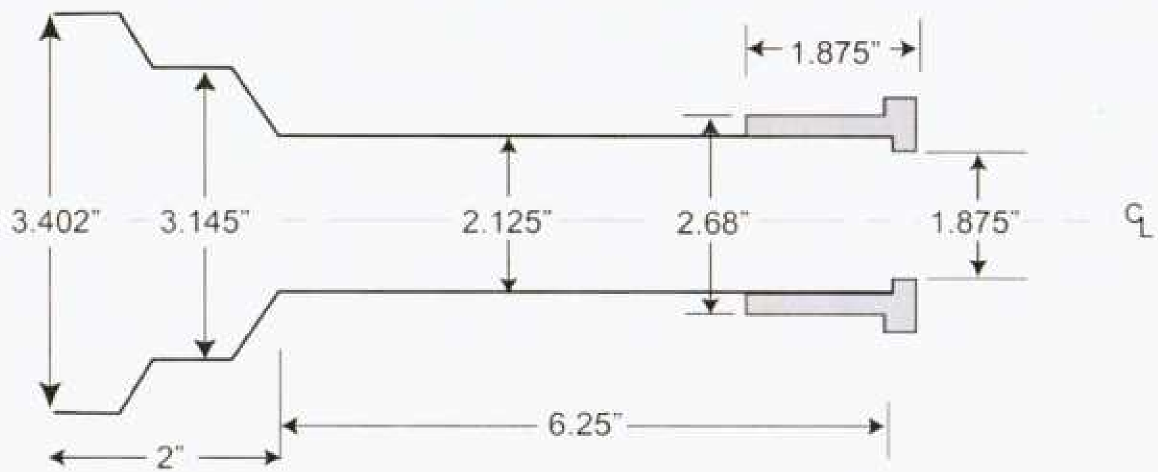
FW-1025 Original Valve



FW01 - 1025

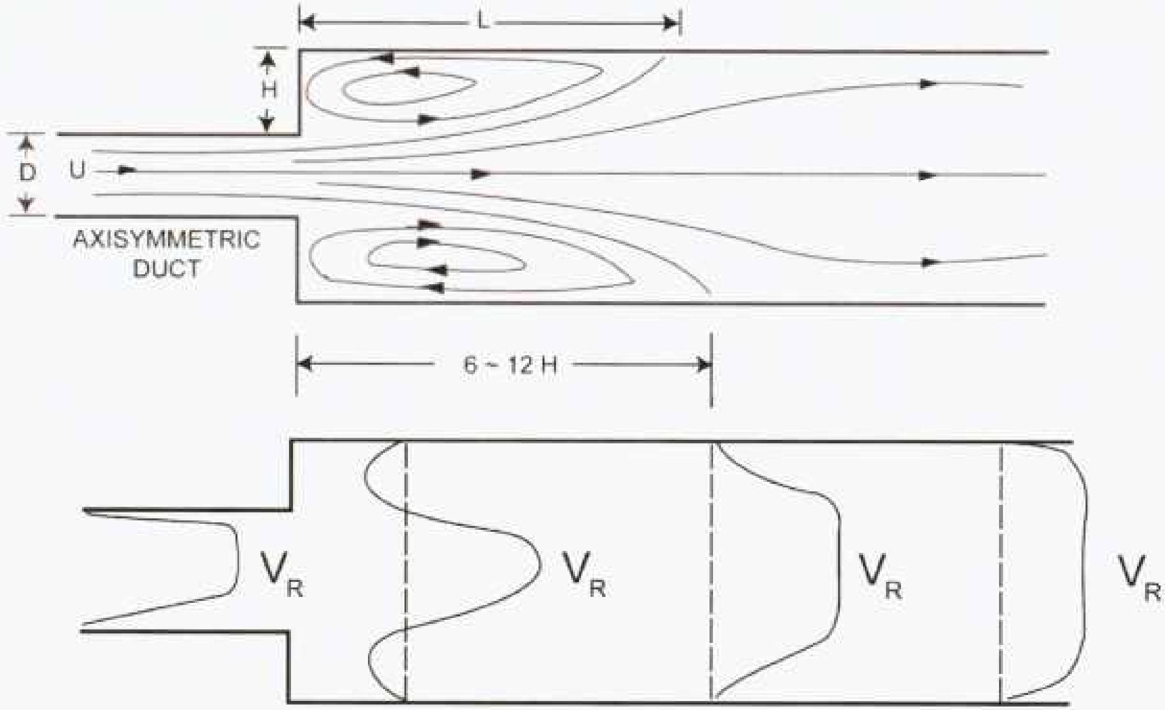
Figure 2.12

FW01-1032 Replacement Valve



FW01 - 1032

Figure 2.11



Typical Separation and Re-Attachment After a Sudden Expansion (V_R = Relative Velocity)

Figure 2

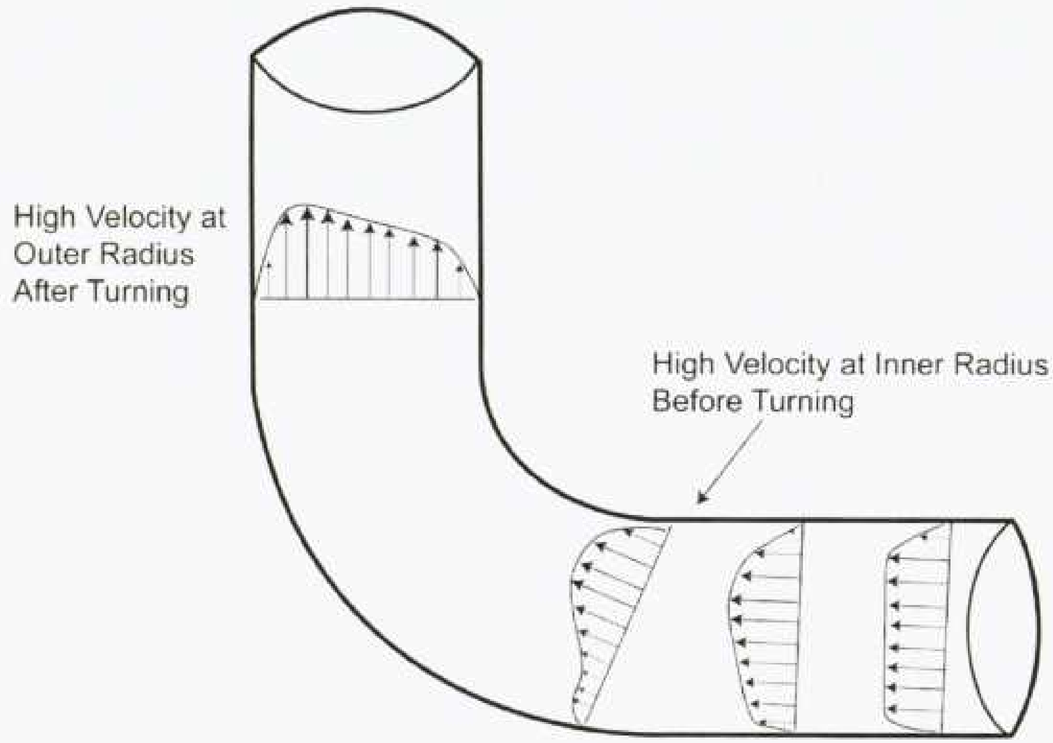


Illustration of Free-Vortex Flow Velocity Distribution

Figure 3

Comparison of Calculation Results

	EPRI	Connected Flow Modeling	Actual Data
Failed Pipe	7.9 mils per year	19.1 mils per year after 1986	17.6 mil/year (average)
Elbow	17.6 mils per year	4.3 mils per year	3.2 mils per year
Downstream of 1025	7.9 mils per year	4.2 mils per year	4.3 mils per year

Factors Impacting FAC

- Velocities of flow: Increased velocity increased wear
- Temperature : 200-500F
- Geometries of piping :Elbows, Reducers, Valves, etc.
- Piping materials: <0.1% alloy content, <0.5% 2 phase flow
- Water chemistry: Table

Comparison of Normal Feedwater Cycle Chemistry Limits for AVT And OT as a Function of Feedwater Metallurgy

Parameter	AVT(R) Mixed-Metallurgy	AVT(R) All-Ferrous	AVT(O) All-Ferrous	OT All-Ferrous
pH	9 – 9.3	9.2 – 9.6	9.2 – 9.6	D. 9 – 9.4 O. 8 – 8.5
Cation Conductivity (μS/cm)	<0.2	<0.2	<0.2	<0.15
Fe (ppb) at EI	<5 <2	<2	<2 (<1)	<2 (<0.5)
Cu (ppb) at EI	<2	<2*	<2*	<2*
O_2 (ppb) at EI	<5 (<2)	<5 (<2)	<10	D. 30 – 50 O. 30 – 150
O_2 (ppb) at CPD	<10	<10	<10	<10
Reducing Agent	Yes	Yes	No	No
ORP (mV) at DAI	-300 to -350+	-300 to -350+	Oxidizing	Oxidizing

Notes:
EI - economizer inlet, CPD - condensate pump discharge, DAI - deaerator inlet, D - drum unit, O - once-through unit
* - Copper alloys may be present in condenser.
\+ - These ORP values are meant to be indicative of a reducing treatment where a reducing agent is added to the feedwater, after the CPD, and oxygen levels are less than 10 ppb at the CPD. However, ORP is a sensitive function of many variables and may under these conditions be as high as -80 mV.

From: EPRI Report #1008082

Alloy Content of Pieces

Item Number	% Cr +% Mo	Wear Rate – Thinnest Area (Mils/Year)
Item 1 (Part of Valve FW01-1032)	3.03%	Negligible (Machine Marks are Still Visible)
Item 2 (Vertical Section of the Elbow, Downstream of the Failed Pipe, Item 3)	0.14%	3.4 mils/Year
Item 2 (Round Section of the Elbow)	0.03%	3.2 mils/Year
Item 3 (Failed Pipe, Downstream of FW01-1032)	**0.03%**	**17.6 mils/Year**
Item 4 (Downstream of FW01-1025)	0.14%	4.3 mils/Year
Item 5 (Downstream of Item 4)	0.13%	1.1 mils/Year
Item 6 (Downstream of Item 2)	0.03%	4.3 mils/Year
Item 7 (Part of FW01-1025)	0.20%	N/A
Item 8 (Downstream of Reducer)	0.21%	10.0 mils/Year

Attributes of Good FAC Program

- Extensive checking of piping using UT or Eddy Current testing
- Utilize CHECWORKS or CHECUP to identify potential high wear areas
- Use engineering judgment and lessons learned to supplement CHECKWORKS or CHECUP
- Modify water treatment program to increase PH and minimize oxygen scavenger
- Train everyone to recognize FAC
- Executive support and dedicated person(s) to FAC

Configuration Management

- Provides a formal procedure for reviewing changes
- Documents what has been installed for later use after people have retired and files destroyed
- Saves time because accurate information is available

Lessons Learned

- Design
  - Valves:
    - Bigger is not always better particularly with higher pressure class valves
    - Low Ao (valve exit)/Ap (pipe ID) ratios adversely impact FAC
    - Specify "C" dimension on valve outlet to match pipe
    - Eliminate sudden dimension changes on valve outlets
  - Piping
    - Two phase flow best addressed with =>1.25% chromium material
    - Higher than expected spray flow rates on units burning PRB make desuperheater spray supply lines susceptible to FAC
    - Limit flow velocities to 10 to 15 fps, if practical

Lessons Learned (Continued)

- Design (continued)
  - Material
    - A106 piping alloy content varies and is crucial to resisting FAC
    - Be aware of localized erosion from "entrance-effects" (alloy piping followed by carbon steel piping)
    - Input all valves as carbon steel in CHECWORKS, regardless of actual material

Lessons Learned (Continued)

- A Structured FAC Program
  - Define a corporate policy and organizational responsibilities
  - Develop a FAC implementation procedure
  - Utilize industry predictive computer codes as a supplement to engineering judgment in prioritizing inspections
  - Ensure inspections are performed downstream of components causing flow separation and reattachment
  - Utilize oxygenated/oxidized feedwater chemical control for all ferrous-systems
  - Once you change to an all ferrous system, chemical clean ASAP so you can move to higher PH

Lessons Learned (Continued)

- A Structured FAC Program (continued)
  - Check high energy piping in high traffic areas, regardless of indicated susceptibility
  - Control alloy content of A106 pipe or location that it is installed in new plants
  - Checking high wear areas as indication of status of other areas is not guarantee
  - Be aware that similar geometries and process conditions can have widely different wear rates

Lessons Learned (Continued)

- Other Programs to Reduce FAC Risk
  - Experience Review – participate in industry forums and periodically benchmark programs against high performing peer stations
  - Configuration Control – utilizing accurate configuration information in analytical models is essential
  - Root Cause – carefully evaluate root causes of through-wall pipe leaks including consideration of programmatic causes and take broad improvement actions

Vendors Providing Support to KCPL

- Aptech – Eddy Current Testing on line (Marvin Cohn 408/636-5360)
- CSI – CHECWORKS support and written program (Robert Aleksick 847/836-3000)
- EPRI – Report # 1008082, Training Programs
- Performance Improvement International (PII)– Root Cause Analysis and Lessons Learned from Past Industry Events (Dr. Chiu 760/722-0202)

Conclusion

- Have a formal FAC program with executive support
- Configuration Management and Root Cause Analysis are proactive approaches to identifying issues and do not rely on vendor to determine what is equivalent or acceptable
- Industry standards need to be raised and maintained
- You do not want to have an FAC incident!

APPENDIX B-2
Section 5.0 Executive Summary
Section 5.1 Lessons Learned
Section 5.2 Iatan Events Summary (pages 8-14)
Performance Improvement International
Volume 5

<u>Volume 5</u>

Lessons Learned from the Iatan Pipe Rupture Event

Dedicated to:

The Jones and the McCool families, who lost their loved ones,

Ronald D. Jones and Thomas A. McCool, in this tragic event

5.0 Executive Summary

On May 9, 2007, Iatan Unit 1 fossil power plant, owned by Kansas City Power and Light (KCP&L), experienced a catastrophic rupture of a 4 inch superheater (SH) attemperator spray line (2954 psi/485^{o}F operating conditions), resulting in two fatalities of personnel working in the vicinity on a plugged coal feeder. The SH attemperator spray line takes suction downstream of the boiler feedpump and upstream of the high pressure heaters. Preliminary inspection of the failed piping indicated significant thinning (~0.06 inches remaining wall) of the Schedule 160 pipe, likely caused by flow-accelerated corrosion (FAC). Inspection of other FAC-susceptible piping identified a small number of locations with pipe wall thinning requiring attention. Piping replacements were implemented as required and Iatan Unit 1 was returned to service.

FAC is a process whereby the normally protective magnetite layer on the internal wall of carbon steel pipe "dissolves" in a stream of flowing water or wet steam. The reduction or elimination of the protective layer results in loss of the base material.

Following the event, KCP&L contracted with Performance Improvement International, LLC (PII) to perform a root-cause analysis (RCA) of the event and a programs and processes review. PII (previously called FPI International) was founded by Dr. Chong Chiu in 1987, and has solved several thousand complex engineering cases without recurrence. Dr. Chiu, a MIT engineering PhD in 1977, was designated to lead the investigation team to investigate the Iatan pipe rupture event. Dr. Chiu is a world-renowned expert in root-cause investigation of complex engineering issues. During his career, Dr. Chiu has investigated more than 300 major events, including Three Mile Island nuclear accident, San Francisco blackout, Texas A&M bonfire collapse, and many other complex accidents internationally.

A brief description and the summary results of the PII team analysis, presented in five major categories of review, are provided below:

Root-Cause Investigation (Volume 1): The PII root-cause analysis methodology was employed to determine the cause of the event as well as identify corrective actions to prevent recurrence. Volumes 2, 3 and 4 provided the analyses and reviews necessary to complete the cause investigation. Results are provided in the following paragraphs.

Failure Analysis (Volume 2): Detailed laboratory visual and microscopic inspections were performed on the failed pipe section and selected adjacent piping and components. Chemical and mechanical properties were determined as well as a fracture and metallographic analysis. In addition, surface markings, cracking and pitting were analyzed. From these analyses, factors contributing to the pipe rupture were determined including (1) flow distribution effects from up and downstream components and the geometry of the piping system, (2) material chromium content, and (3) process chemistry.

Determination of Relative Significance of Contributing Factors (Volume 3): To determine the relative significance of contributing factors, sensitivity analyses (based on Kastner and Riedle (1986) empirical correlations) and finite element flow models were used to predict pipe wall wear rates. The magnitude of the wear rate was then used to determine contributing factor significance. The throttled configuration and sudden expansion of the outlet of the upstream gate valve was determined to have the greatest impact on predicted wear rate.

Programs and Processes Review (Volume 4): A historic sequence of events leading up to the pipe rupture event was developed. Each event with a consequential impact on the pipe rupture event was analyzed to determine if either an Iatan or industry standard program or process should have prevented the event.

Areas for improvement were identified in the Iatan FAC and configuration control programs. A weakness was also identified in the industry standard FAC analysis software program models.

Lessons Learned (Volume 5): From the analysis and reviews performed for this event, ten “lessons learned” with recommendations were developed and are provided for the power industry’s use.

The investigation team analysis determined the pipe failure occurred due to the unique connected flow effects from the upstream gate valve and the downstream elbow. The narrow throat and abrupt exit expansion of the gate valve just upstream of the failure created flow separation and reattachment near the failure point. A flow-modeling analysis revealed that a valve with a venturi exit of less than 15 degrees is most likely immune to flow separation. Secondary flow from the downstream elbow also began near the failure point. These effects, combined to increase the localized velocity at the failure location, greatly accelerated the flow-accelerated corrosion (erosion-corrosion) mechanism. ***Note: This type of unique interaction is not typically well-understood in the industry and is not definitively predictable with the current EPRI CHECWORKS or CHECUP analysis modeling software.***

Minor contributing causes or factors in the event included (1) the reducing feedwater chemistry in an all-ferrous feedwater system, (2) low trace amount of chromium in the failed pipe and the (3) lack of maturity in the FAC and configuration-management programs at KCP&L.

The following lessons learned from this event were developed by KCP&L and the PII investigation team:

- *Actively **participate** in industry FAC forums and periodically **benchmark** programs and performance against high performing peer stations.*
- ***Define** a corporate policy and organizational responsibilities for FAC and other organizationally- significant programs.*
- ***Develop** a FAC implementation procedure, including documented susceptibility analysis, sample selection prioritization techniques, periodic inspections with sample expansion, structural analysis and remedial methods and chemistry program integration.*
- ***Utilize** industry predictive computer codes (such as CHECWORKS or CHECUP) as a supplemental tool in prioritizing FAC inspections in conjunction with engineering judgment, industry experience, industry guidance documents and sound configuration knowledge and documentation.*
- ***Ensure** FAC baseline and follow-up inspections are performed downstream of components whose configuration causes flow separation and re-attachment; particular attention should be given when these components or piping, which are upstream of other piping features (such as elbows), cause entry-flow acceleration ("connected effects").*
- ***Select** piping and components in the original piping design or subsequent modifications to limit flow velocities to less than15 fps, if practical. **Consider** the impact of the internal geometry of in-line components on flow velocities and pipe wall/component wall erosion.*
- ***Ensure** that feedwater chemical control is optimized to limit FAC, consistent with industry (EPRI) guidelines. The implications and risk associated with AVT(R) control must be carefully assessed and balanced against benefits.*

- ***Utilize*** *.1% (or greater) chromium material (including P11 1.25% and P22 2.25%) in piping and components should be considered if optimized feedwater chemical control methods are not effective in controlling FAC. For two phase flow, a minimum of 0.5% chromium material should be used and P11 or P22 should be considered.*

- ***Maintain*** *configuration documentation and utilize the "as-built" configuration in analytical models, which are essential to the health of a FAC program.*

- *Carefully* ***evaluate*** *the root cause of piping/components experiencing significant thinning or pressure boundary loss. Programmatic causes should be explored and broad improvement actions should be taken.*

5.1 Lessons Learned – Introduction

The purpose of this volume is to provide the owners and operators of fossil power plants a comprehensive review of the lessons learned from the investigation of the pipe rupture event at KCP&L's Iatan I plant. All appendices quoted in this volume will be provided with a written request to KCP&L. During the investigation, the investigation team noted that Iatan was typical of the US fossil generation fleet and the observations would have broad applicability. As such, the team would like to summarize its lessons learned in this volume, Volume 5, with a goal to help all fossil power plants to reduce their risks of future pipe rupture events.

Defining and applying "Lessons Learned" experiences are a primary learning component in a company culture devoted to continuous improvement and knowledge management. Developing and sharing "Lessons Learned" knowledge from the root-cause investigation of the Iatan Pipe rupture event and the associated KCP&L programs and processes review provides a fundamental benefit to the Iatan Plant, KCP&L and those in the industry with similar plant process conditions as experienced at Iatan. Adaptation of knowledge gained from these lessons learned will enable others in the industry to avoid the unsuccessful outcomes experienced at KCP&L's Iatan Plant when they are confronted with similar physical process conditions, program limitations and organizational issues.

The "Lessons Learned" provided in this report were developed by Performance Improvement International (PII) in conjunction with the KCP&L management team. The PII team has more than 100 years of combined experience working for more than 70 utilities (domestic and international) in the area of component reliability (including piping systems) programs. This report presents the combined team observations, assessments and recommendations to assist KCP&L and the industry in preventing future pipe failures similar to the Iatan Plant event.

To aid a reader without access to the total event investigation documentation in understanding the Iatan pipe rupture event, a brief summary is provided of the event along with a plant description, the failure mechanism and the causes and contributors determined by the PII root cause investigation team. Comprehensive documentation of the event description, sequence of events, failure analysis, failure mechanism investigation, programs and processes review, root cause investigation and corrective actions are provided in **Volumes 1 through 4** of the root cause analysis report.

Each "Lesson Learned" is first stated with the related general observations of the investigation team. A team assessment of the observation is then performed, followed by a recommendation to KCP&L and the industry (see **Volumes 1 through 4** for more in-depth treatments of the facts and circumstances associated with these "Lessons Learned"). Although the focus of this section primarily addresses experiences with negative outcomes, many positive observations of KCP&L's Iatan plant and personnel were identified during this review. Foremost among these observations was an intense desire of the KCP&L organization and management to broadly understand the significant Iatan event and effect physical, programmatic and organizational changes to prevent future similar occurrences.

5.2 Iatan Event Summaries

Event Description: On May 9, 2007, Iatan Unit 1 fossil power plant, owned by KCP&L, experienced a catastrophic rupture of a 4 inch Schedule 160 superheater (SH) attemperator spray line, resulting in two fatalities of personnel working in the immediate vicinity on a plugged coal feeder. The rupture occurred in a short spool piece (Item 3 in **Figure 5.1 and Figure 5.2**) immediately downstream (~5 inches from the valve to pipe weld) of the AC motor operated stop valve (FW01-1032) in the "A" leg of a dual train attemperator spray line and just upstream of a 90 degree elbow. The stop valve was a gate valve design. The valve had been installed a vertical position rather than a horizontal position, deviating from its original designed layout, prior to commission in 1980. In 1986, the original valve was replaced with a valve of a different internal design, having an abrupt opening at the valve exit and a reduced throat diameter (**See figure 5.1a**). Subsequent investigation revealed significant thinning (< 0.06 inches – see **Figure 5.3**) at the rupture initiation site from an active flow-accelerated corrosion (FAC) mechanism. The wear rate in the pipe downstream of the initial stop valve in the parallel "B" leg piping (FW01-1025) was less than 25% of the wear rate found in the "A" leg. The "B" stop valve employed a gate-valve design with a similar seat opening, but with a smooth "venturi-type" transition to the entrance and exit piping.

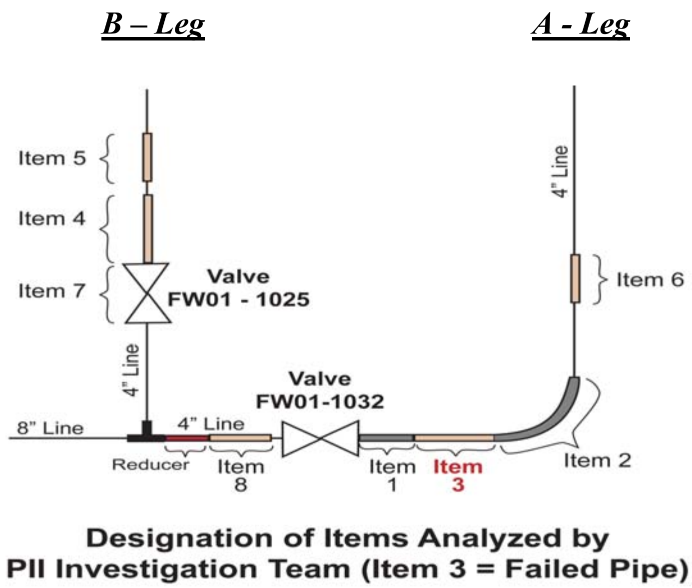

B – Leg
A - Leg
Item 5
Item 4
Item 7
Valve
FW01 - 1025
4" Line
4" Line
Item 6
Valve
FW01-1032
8" Line
4" Line
Reducer
Item
8
Item
1
Item
3
Item 2
Designation of Items Analyzed by
PII Investigation Team (Item 3 = Failed Pipe)

Figure 5.1

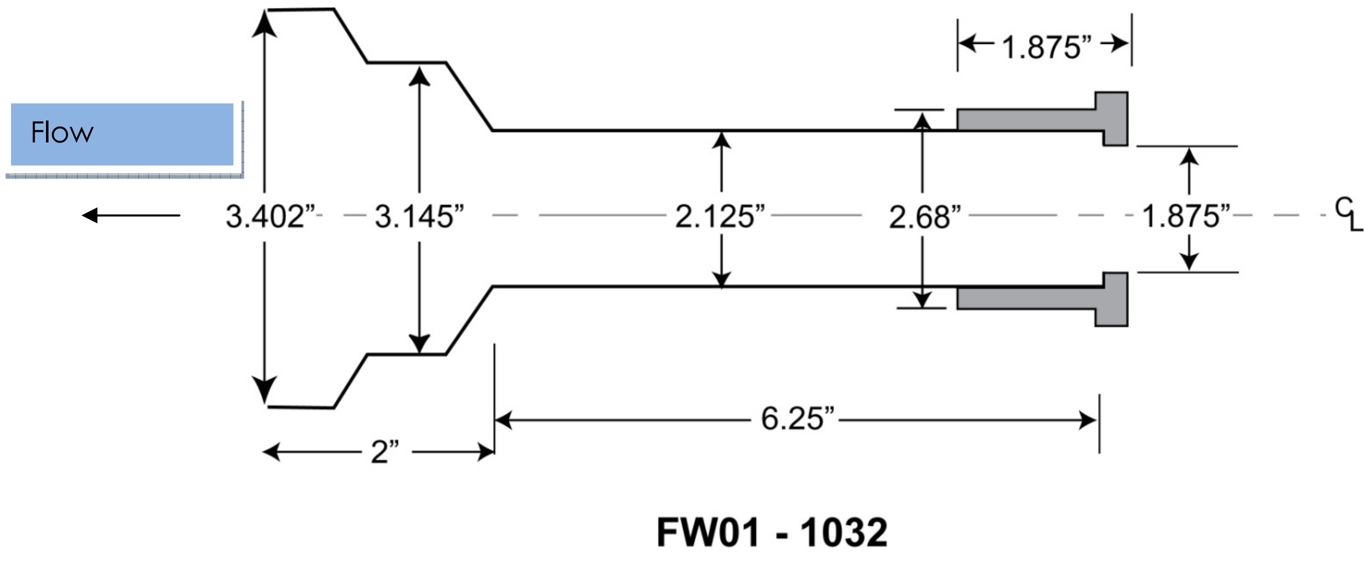


Figure 5.1a (Valve Exit Countour)

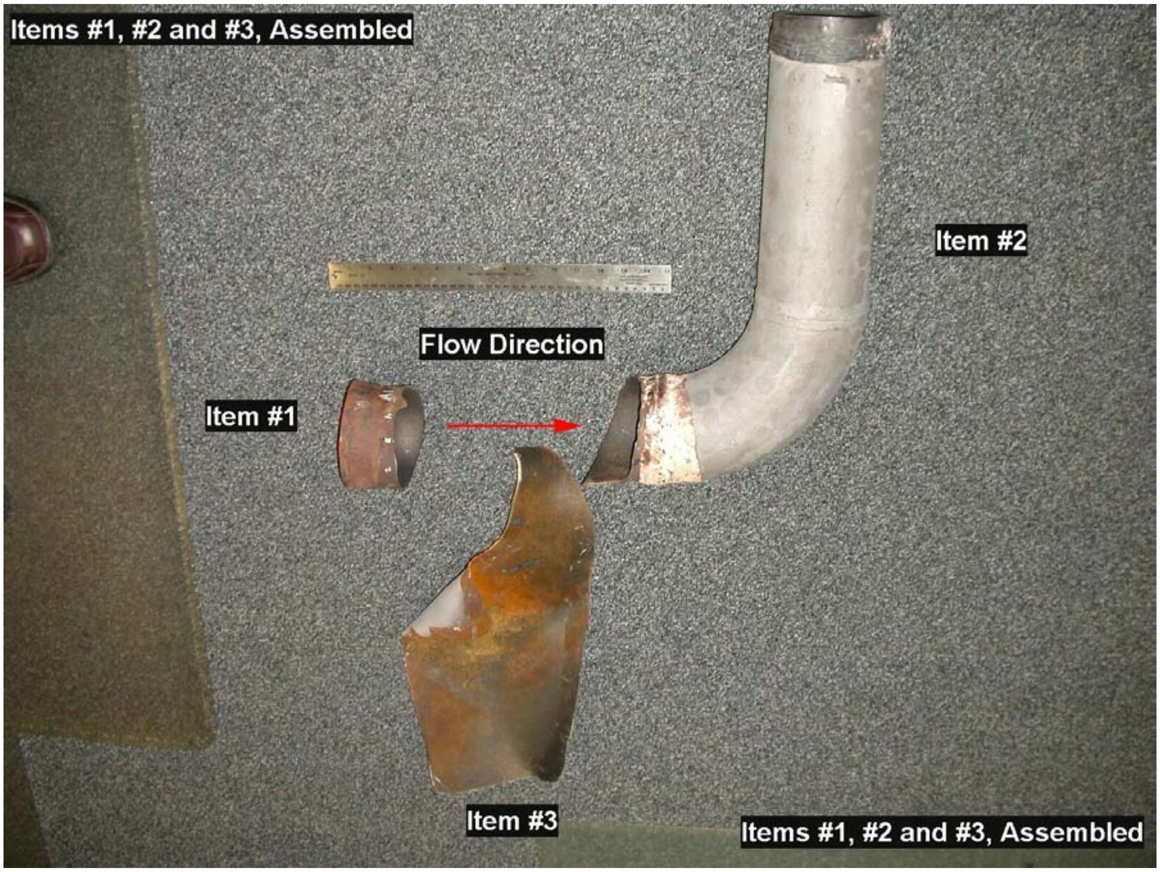


Figure 5.2 – Failed 4 inch SH Attemperator Spray A-Line

Plant Description: Beginning operation in May 1980, the Iatan Unit 1 plant is a pulverized coal plant located on the Missouri River, fueled with Wyoming Powder River Basin coal. The balanced draft Babcock & Wilcox design consists of a wall-fired boiler with a maximum operating pressure of 2975 psi and a nominal 700 MW General Electric steam turbine and hydrogen-cooled generator.

SH attemperator spray flow is provided at a full-load nominal flow rate of approximately 530 Klb/hr from the discharge of the boiler feedpump and upstream of the high pressure feedwater heaters. The SH attemperator spray flow reaches the secondary superheater through two parallel spray lines, 1A and 1B. The operating pressure and temperature conditions of the SH spray flow are 2954 psi and 485°F, respectively. Control valves modulate attemperator spray flow to maintain a secondary superheater outlet steam temperature of 1005°F. Spray flow is also limited to maintain a minimum of 10°F above the saturation temperature. Each SH attemperator control valve set has an AC motor operated stop valve. FW01-1032 (see **Figure 5.1**) is the AC motor operated stop valve for the 1A spray line. FW01-1025 (see **Figure 5.1**) is the AC motor stop valve for the 1B spray line.

The SH attemperator spray piping was designed, fabricated and constructed to the requirements of ANSI B31.1-1973. The piping material was ASTM A106, Schedule 160, Grade C carbon steel.

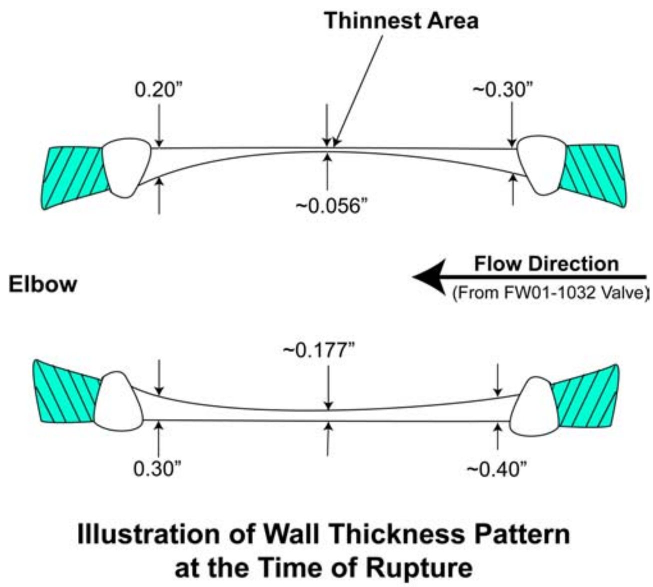

Thinnest Area
0.20"
~0.30"
~0.056"
Elbow
Flow Direction
(From FW01-1032 Valve)
~0.177"
0.30"
~0.40"
Illustration of Wall Thickness Pattern
at the Time of Rupture

Figure 5.3

Pipe Thinning Mechanism: Laboratory microscopic inspection of the piping at the point of rupture identified flow-accelerated corrosion (FAC) as the mechanism causing the significant thinning shown in **Figure 5.3**. This thinning resulted in a ductile failure of the pipe wall pressure boundary due to ductile overload stresses.

FAC is a process whereby iron is continuously oxidized and removed from piping systems. The normally protective magnetite layer on the internal wall of carbon steel pipe "dissolves" in a stream of flowing water or wet steam. The reduction or elimination of the protective layer results in loss of the base material. The process, which generally occurs slowly over design life, can be accelerated and lead to premature pipe wall thinning. Especially vulnerable are turbulent, high-velocity areas in high-purity water boiler feedwater systems, auxiliary equipment, and areas with two-phase flows. The FAC process is affected by a number of variables, including hydrodynamics (velocity, geometry, water content in steam, temperature, and mass transfer), water chemistry (oxygen content, reducing agent, and pH) and piping/component material composition (percent of chromium, copper and molybdenum). Changes in any one of these variables may affect the susceptibility of a system or a component to FAC damage.

APPENDIX C
Kansas City Power & Light
Guidelines for
Flow-Accelerated Corrosion
Program Activities

Kansas City Power & Light

Guidelines for Flow-Accelerated Corrosion (FAC) Program Activities

Revision 0
January 16, 2008

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Table of Contents

1. Purpose

1.1. The purpose of this program guideline is to define the process to establish, control, update, and document an effective Flow-Accelerated Corrosion (FAC) Program at Kansas City Power & Light (KCPL) fossil plants.

1.2. The objective of the FAC Program is to predict, detect, monitor, and mitigate FAC degradation in plant piping in order to prevent failures while enhancing plant safety and reliability.

2. Responsibilities

2.1. Corporate Engineering Director

2.1.1. Provide management oversight to ensure the implementation and maintenance of the site FAC Program.

2.1.2. Provide adequate resources to ensure that the FAC Program is maintained current and meets industry standards.

2.1.3. Ensure that an engineer will be dedicated to FAC; however, this individual can perform other duties as time allows.

2.1.4. Ensure that adequate and formal communication exists between responsible departments.

2.2. Corporate FAC Program Coordinator

2.2.1. Maintain this program guideline.

2.2.2. Ensure all FAC Program activities are performed in accordance with the program guideline and applicable industry standards, governing documents, and references.

2.2.3. Maintain and update key FAC program elements including the Susceptibility Evaluation, CHECWORKS Steam/Feedwater Application (SFA) model, Susceptible Non-Modeled (SNM) Evaluation, FAC Program isometric drawings, and inspected components database.

2.2.4. Maintain awareness of changes in plant chemistry, operation, and design and review these changes for impact on the FAC Program.

2.2.5. Maintain awareness of FAC-related industry experiences and practices and share corporate/site FAC experience with the industry.

2.2.6. Prepare outage inspection and repair/replacement scopes and coordinate inspection and repair/replacement activities with applicable departments (i.e. scaffold erection, insulation removal, surface preparation, extent of replacement, etc.).

2.2.7. Coordinate with non-destructive examination (NDE) personnel to ensure FAC inspections are performed in accordance with the program guideline and applicable industry standards, governing documents, and references.

2.2.8. Perform fitness for service evaluations to determine if components are acceptable for continued service; record inspection results in the inspection database; perform inspection scope sample expansion as required; and recommend components for repair/replacement as needed.

2.2.9. Determine minimum allowed thickness for inspected components.

2.2.10. Maintain replacement records for all components in FAC-susceptible lines.

2.2.11. Report on FAC Program status, health, and effectiveness to senior staff.

2.2.12. Develop a long-term FAC Program plan as directed by this guideline.

2.3. Corporate Chemistry Department

2.3.1. Promote and implement an optimized plant chemistry treatment to mitigate the effects of FAC.

2.3.2. Communicate plant chemistry conditions and changes to the FAC Program Coordinator, when requested.

2.4. Plant Operations

2.4.1. Provide information to the FAC Program Coordinator regarding operational changes.

2.5. Plant Engineering

2.5.1. Provide information to the FAC Program Coordinator regarding system design changes.

2.5.2. Consult with the FAC Program Coordinator on design change options for potential impact on the FAC Program, as appropriate.

2.6. Plant Maintenance Department/Construction Service Administrators

2.6.1. Prepare locations for inspection (i.e. scaffold erection, insulation removal, etc.).

2.6.2. Perform component and line repair and replacement activities and provide marked-up drawings indicating the replacements to the FAC Program Coordinator.

3. FAC Susceptibility Evaluation

3.1. FAC Program Scope

3.1.1. The scope of the FAC Program shall consist of all piping that cannot be determined to be non-susceptible to FAC. EPRI Flow-Accelerated Corrosion reports will be used as KCPL guidelines.

3.1.2. Systems and lines can be considered non-susceptible to FAC and can be excluded from the FAC Program scope if they meet one or more of the following exclusion criteria:

- Stainless steel or low alloy steel with chromium content 1.25% or greater. NOTE: This criterion only applies if all components in a system or line are constructed with this material including equipment nozzles, valves, fittings, and pipe.
- Superheated steam with no moisture content. NOTE: Drains from superheated systems should not be automatically excluded.
- High dissolved oxygen concentrations such as raw water or service water systems.
- Single phase with temperature below 200°F.
- No flow or operation less than 2% of the plant operating time.
- Systems not containing water or steam.
- The existence of plant experience or industry experience on a system or line should override the above exclusion criteria.
- NOTE: Additional information on the above exclusion criteria can be found in EPRI resources [17.1].

3.1.3. Each plant system should be listed and categorized as susceptible to FAC or not susceptible to FAC. Each excluded system should have an exclusion criteria clearly identified and a reference specified.

3.1.4. Each susceptible plant system should be further divided into lines and/or subsystems. A separate list should be prepared for each plant unit. Each line and/or subsystem from FAC susceptible systems should be listed and categorized as susceptible to FAC or not susceptible to FAC. Each excluded line and/or subsystem should have an exclusion criteria clearly identified and a reference specified. In addition, a set of color-coded P&IDs should be created that identify FAC susceptibility.

3.1.5. The Susceptibility Evaluation should also classify FAC susceptible lines as CHECWORKS SFA modeled or non-modeled. Lines cannot be modeled in CHECWORKS SFA if any of following conditions are true:

- Lines containing socket-welded fittings.
- Lines with unknown operating conditions.
- Conditions outside CHECWORKS SFA modeling capabilities, such as lines with entrained moisture or vent lines with non-condensable gasses.
- Lines with localized FAC susceptibility (such as the presence of a carbon steel valve in an alloy line).
- Lines with low moisture content, but non-superheated (steam quality above 95%).
- Visually inspected lines may be modeled, but do not require modeling.
- NOTE: Additional information on the above model exclusion criteria can be found in EPRI guidelines [17.2].

3.1.6. Each susceptible line from FAC susceptible systems should be listed and categorized as modeled in CHECWORKS SFA or non-modeled. A separate list should be prepared for each plant unit. Each non-modeled line should have a non-modeled exclusion criteria clearly identified and a reference specified.

3.2. Documentation

3.2.1. The Susceptibility Evaluation should be documented in an Engineering Report. The report should be updated and maintained to reflect modified plant design, plant operation, and new industry and plant operating experience. At a minimum, the Susceptibility Evaluation should be reviewed prior to selecting the next inspection scope, approximately once every two years. This review should be documented in a revision to the Susceptibility Evaluation Engineering Report.

- Possible updates to the Susceptibility Evaluation include a newly installed line, a line updated with FAC resistant material, or a bypass line being utilized during normal operation.

- If no modifications were made since the previous revision, a statement of "no changes were made" or similar is sufficient.

3.2.2. Lines and/or subsystems may be labeled on plant piping an instrumentation diagrams (flow diagrams) and color-coded as CHECWORKS SFA modeled, Susceptible Non-Modeled, and non-susceptible as a visual aide in recording the Susceptibility Evaluation.

4. FAC-Predictive Modeling

4.1. FAC-Predictive Model Scope

4.1.1. A CHECWORKS Steam/Feedwater Application (SFA) model will be utilized on all coal units.

4.1.2. The scope of the CHECWORKS SFA model should be based on the Susceptibility Evaluation. The CHECWORKS SFA model scope shall consist of piping susceptible to FAC that can be accurately modeled in the CHECWORKS SFA model.

- In general, CHECWORKS SFA is the preferred method for addressing FAC susceptible piping.

4.1.3. The CHECWORKS SFA model should include all parallel trains in multiple train systems.

4.1.4. Within a line, all components should be modeled including fittings, pipe, valves, equipment nozzles, etc. Each component shall be given a unique name for identification purposes.

4.2. CHECWORKS SFA Modeling

4.2.1. A CHECWORKS SFA model should be created for each unit containing all necessary information to accurately predict FAC wear rates and time to critical thickness for components in the model scope. This includes plant global data such as the heat balance diagram, steam cycle data, chemistry data, and plant period data; component design data such as location, material, pipe size, design conditions, and geometry; and line operating conditions such as global duty factors, flow rates, and thermodynamic data.

- Detailed steps to create a CHECWORKS SFA model is beyond the scope of this guideline. The CHECWORKS SFA Guidelines for Plant Modeling and Evaluation of Component Inspection Data [17.2] and CHECWORKS SFA User Guide [17.6] are good resources for detailed instructions on creating a model.

4.2.2. The CHECWORKS SFA model should be calibrated using inspection data. This calibration process is commonly called a Pass 2 Analysis.

4.2.3. CHECWORKS SFA lines should be grouped into Wear Rate Analysis (WRA) runs for calibration. WRA run definitions should include lines of similar operation, chemistry, and thermodynamic data. WRA runs may be further refined based on inspection data to obtain the best possible calibration.

4.2.4. Routine updates to the CHECWORKS SFA model should be performed to account for the latest operation, chemistry, replacement, and inspection data. This should occur prior to selecting the next inspection scope, approximately once every two years. This includes the following tasks:

- **Update Plant Period**: including dates and online hours for the latest operating cycle and maintenance outage
- **Input Water Treatment**: including dissolved oxygen concentration, amine type and concentration, etc. The CHECWORKS SFA User Guide [17.6] should be used to determine the chemistry parameters required by the model.
- **Perform Water Chemistry Analysis (WCA)**: WCA should be performed for the most recent water treatment and power level and any errors resolved.
- **Revise Component Configuration Data**: The model should be revised to account for any design changes or other configuration changes that have occurred since the model was last updated.
- **Model Replacements**: The model should be revised to account for any pipe replacements that have occurred since the model was last updated.
- **Perform Network Flow Analysis (NFA)**: NFA should be performed in the model and any errors resolved.
- **Import UT Data**: Inspection data should be imported and partitioned appropriately for every examined component in the model.
- **Perform UT Analysis**: For every component for which UT data was imported, UT analysis should be run to determine the wear and minimum measured thickness on that component.
- **Identify Inspection Data for Model Calibration**: For every component for which UT analysis was performed, a decision should be made whether or not to use the data in model calibration. The CHECWORKS SFA Guidelines for Plant Modeling and Evaluation of Component Inspection Data [17.2] provides many reasons why data should be excluded from model calibration.

- **Perform Wear Rate Analysis (WRA)**: WRA should be performed to calculate predicted wear rates and predicted time to critical thicknes.
- **Review WRA Results**: The WRA results should be reviewed to ensure they are reasonable. In particular, the Line Correction Factors (LCF) and the scatter plots should be reviewed for inspection points outside the 20% and 50% bounding lines.
- **Refine WRA Input**: If the review of the WRA indicates that the calibration could be refined, then the analyst should exclude points as appropriate, re-define runs, and refine the input as necessary to achieve the best calibration possible.

4.2.5. Some plant events require greater effort to accurately model in the CHECWORKS SFA model than the routine tasks listed above. In general, these updates are infrequent. Examples of non-routine model update events are:

- Modeling new lines.
- Power uprates
- Extended operation at reduced power (approximately one year or more)
- Major plant equipment replacements such as turbine replacement or multiple feedwater heater replacement. Note: the impact of this would be significant changes in flow rate and thermodynamic values.

4.3. *Documentation*

4.3.1. The CHECWORKS SFA modeling activities, modeling decisions, input data and output results should be documented in an Engineering Report. The Engineering report should be revised prior to selection of the next inspection scope, approximately every two years, with the latest operation, chemistry, replacement, inspection data, and revised Pass 2 Analysis.

4.3.2. The official plant CHECWORKS SFA model should be modified by a controlled process and the backups of the model should be created frequently.

5. Susceptible-Non Modeled (SNM) Evaluation

5.1. *Susceptible Non-Modeled (SNM) Scope*

5.1.1. The scope of the Susceptible Non-Modeled (SNM) Evaluation should be based on the Susceptibility Evaluation. The Susceptible Non-Modeled (SNM) scope shall consist of piping susceptible to FAC that cannot be accurately modeled in the CHECWORKS SFA model.

5.1.2. The SNM Evaluation should be line based and need not list individual components.

5.2. *Prioritization of SNM Locations*

5.2.1. An SNM Evaluation should be performed to evaluate all SNM lines for consequence of failure and level of susceptibility.

- EPRI guidelines provide additional instruction on all aspects of a SNM program [17.3] and [17.4].

5.2.2. SNM lines should be categorized as either high consequence of failure (F1) or low consequence of failure (F2).

5.2.3. High consequence of failure (F1) lines exhibit the following characteristics:

- Large bore (nominal diameter greater than two inches). There is potentially greater significance of failure in large bore piping than small bore piping; therefore, large bore piping should be given the highest priority.
- High energy small bore piping that is part of a critical system, failure will likely result in personnel injury, and/or failure will result in plant shutdown.

5.2.4. Low consequence of failure (F2) lines exhibit the following characteristics:

- Small bore (nominal diameter less than two inches).
- Low energy lines NOT part of a critical system, failure will NOT likely result in personnel injury, and failure will NOT result in plant shutdown.

5.2.5. A relative susceptibility ranking of high consequence of failure (F1) lines should be performed. The relative susceptibility ranking categories should be high (S1), moderate (S2), and low (S3). A line should be categorized as S1, S2, or S3 based on the following criteria:

- Steam quality
- Temperature
- Operating frequency
- Flow rate
- Plant experience
- Industry experience

5.2.6. Low consequence of failure (F2) lines need not be further evaluated. These lines can be considered "maintenance items" and either run to failure or progressively replaced.

5.2.7. Based on the results of the consequence of failure and susceptibility rankings, initial inspections should be conducted to identify degraded lines, and also to confirm the integrity of lines, as some may not be degraded. The priority of inspections should be based on consequence of failure and relative susceptibility ranking: F1S1, F2S2, F1S3, and then F2 and engineering judgment.

5.2.8. Following initial inspections, a prioritized course of action should be determined for SNM lines consisting of additional inspections, progressive replacement strategies, or no further analysis needed (no degradation found). For many small-bore lines it may be more economical to replace the line with FAC resistant material than perform inspections.

5.3. Documentation

5.3.1. The Susceptible Non-Modeled (SNM) Evaluation should be documented in an Engineering Report. The Engineering Report should be updated and maintained to reflect the latest Susceptibility Evaluation, operating conditions, new plant and industry operating experience, and inspection data. At a minimum, the SNM Evaluation should be reviewed prior to selecting the next inspection scope, approximately once every two years. This review should be documented in a revision to the SNM Evaluation Engineering Report.

- Possible updates to the SNM Evaluation include a new SNM lines in the Susceptibility Evaluation, new operating conditions like temperature or steam quality changes, new plant or industry operating experience, and the results of FAC inspections
- If no significant modifications were made since the previous revision, a statement of "no changes were made" or similar is sufficient.

5.3.2. SNM lines may be labeled on plant piping an instrumentation diagrams (flow diagrams) and color-coded based on consequence of failure and relative FAC susceptibility as a visual aide in recording the SNM Evaluation.

- These drawings may be combined with the Susceptibility Evaluation drawings mentioned previously.

6. FAC Program Isometric Drawings

6.1. Isometric Drawing Scope

6.1.1. FAC Program isometric drawings will be updated or developed for all lines modeled in CHECWORKS SFA.

6.1.2. It may be beneficial to create isometrics for SNM lines to aide in inspection selection.

6.1.3. It is not necessary to create isometrics for non-susceptible systems and lines.

6.1.4. A set of isometrics should be prepared for each unit as piping configuration differences do exist even for similar units.

6.2. Isometric Drawing Format and Documentation

6.2.1. FAC Program isometrics should indicate, at a minimum, piping configuration, size, FAC Program component labels, equipment labels, and rough dimensions. The isometrics need not supply the level of detail associated with design or construction isometrics.

6.2.2. It is acceptable to use pre-existing plant isometrics and overlay FAC Program component labels on them.

6.2.3. FAC Program isometrics should be updated to reflect the updates in line design and configuration. FAC Program isometrics need not be updated on a cyclic basis. Instead, revisions should be made when design and configuration changes are made. Routine updates to the Susceptibility Evaluation and CHECWORKS SFA model should indicate when FAC Program isometric updates are needed.

7. Inspection Selection

7.1. Minimum Inspections

7.1.1. Fifty inspection points will be required at least every 2 years for a unit which has a planned outage lasting at least 14 days.

7.2. Inspection Selection Sources

7.2.1. Selection of inspection locations should be based on the results of key FAC Program elements and operating experience. The following should be reviewed when selecting an inspection scope:

- CHECWORKS SFA model
- Reinspections based on past fitness for service evaluations
- SNM Evaluation
- Plant operating experience
- Industry operating experience
- Engineering judgment

7.2.2. The CHECWORKS SFA model should be used to select modeled components that have not been previously inspected. Selection of components from the CHECWORKS SFA model should primarily be based on predicted wear rate and predicted time to critical thickness. The following items should be considered when selecting CHECWORKS SFA modeled components:

- Components with the highest predicted wear rates. NOTE: inspection of valves, orifices, and flow elements should be scheduled based on their respective predictions. When performing the inspection, wear in the valve, orifice, or flow element should be gauged by the wear in the downstream pipe.
- Components with the shortest time to critical thickness.
- Components of varied geometry.
- Components from different trains.
- Components from different lines in two-phase systems.
- Components downstream of orifices and valves especially control valves.
- If a CHECWORKS SFA wear rate analysis run is calibrated, components need not be inspected if CHECWORKS SFA predictions indicate sufficient time to critical thickness. NOTE:

Occasional inspections should be made to ensure that conditions have not changed and that component wear rate is increasing.

7.2.3. Previously inspected components should be reinspected based on the results of past fitness for service evaluations. This approach is also called trending of inspection data.

7.2.4. Susceptible Non-Modeled locations should be selected based on line prioritization by consequence of failure, relative FAC susceptibility, and recommended course of action (inspect, replace, or ignore). Engineering judgment and operating experience should be used to select which component(s) to inspect in an SNM line.

7.2.5. Plant operating experiences should be considered when selecting inspection locations such as:

- Suspect geometries.
- Components downstream of replaced areas. (Upstream if the replaced component was an expander or expanding elbow).
- Repaired or replaced components will be reinspected within 4 years of the repair or replacement date.
- Locations similar to past problem areas at the plant or at similar plants.
- Piping downstream of valves known to be leaking or valves not being operated according to design. This includes components in lines considered non-susceptible due to being isolated, if it is the isolation valve that is leaking.

7.2.6. Industry operating experiences should be considered when selecting inspection locations such as:

- Reported industry failures and observations.
- Susceptible piping and components immediately downstream of stainless steel heaters; such locations may be particularly susceptible to the entrance effect.
- Known industry generic problem areas such as unusual geometries, downstream of orifices, flow elements, and control valves, downstream of leaking traps and valves, etc.

7.2.7. Engineering judgment should be applied when selecting locations from any of the above areas.

7.3. Inspection Scope Sample Expansion

7.3.1. FAC is not a random phenomenon; if a degraded component (fitting or section of pipe) is detected, it is likely that there are additional degraded components in the same line, as well as in similar lines (sister trains). Under these circumstances, it is essential that the inspection sample be expanded in order to detect all degraded components.

7.3.2. The inspection scope sample expansion analysis and subsequent recommended additional inspections should be performed during the current inspection outage.

7.3.3. If any component is determined to have a wall thickness below the minimum acceptable wall thickness or if significant and unexpected FAC damage is detected, then additional inspections should be performed to bound the thinning. The additional inspections should consist of the following:

- Any component within two pipe diameters downstream of the degraded component or within two diameters upstream if that component is an expander or expanding elbow.
- A minimum of the next two highest ranked components from the CHECWORKS SFA results from the train in which the degraded component is modeled. If the line is not modeled in CHECWORKS SFA, engineering judgment should be used to identify the most-susceptible locations.
- Components of similar geometry in sister trains.

7.3.4. If sample expansion inspections detect additional degradation, then the sample should continue to be expanded per the criteria above until no additional components with significant FAC damage are detected.

7.3.5. Inspections of components from the current outage or past outages may satisfy the sample expansion criteria; therefore, sample expansion requirements may be met without performing additional inspections.

7.4. Inspection Scope Documentation

7.4.1. The Inspection Scope Plan for each inspection outage should be documented in an Engineering Report, plan, letter, or other suitable record. Each inspection location should be listed along with a reason and justification for inclusion clearly identified.

- Examples of reasons and justifications for inclusion in the inspection scope include: CHECWORKS – highest wear, shortest time to critical thickness, varied geometry coverage; SNM – F1S1 ranking; Operating Experience – name and/or description of the industry or plant event that triggered inspection; etc.

7.4.2. Inspection scope sample expansion decisions should be documented in a suitable record (letter, form, spreadsheet, etc.). Each scope sample expansion location should list the additional components to be inspected and provide a reason and justification for not selecting a location for inspection (i.e. the downstream component has previously been inspected and shows little to no wear, etc.).

8. Examination of Piping

8.1. Inspection Methods

8.1.1. Components may be inspected by ultrasonic testing (UT) techniques, radiographic testing (RT) techniques, visual inspection techniques, or pulsed eddy current (PEC) test, or other accepted inspection methods.

8.1.2. UT inspections are the preferred method for large bore piping. Other techniques should supplement the UT inspections.

8.1.3. Preparation of piping for inspection is the responsibility of the site Maintenance Department. Pipe preparation activities, such as scaffold erection, insulation removal, and pipe surface preparation should be documented in a maintenance procedure. The FAC Program Coordinator should review this procedure.

8.1.4. The site department or external organization that performs inspections (UT, PEC, RT, etc.) should provide the inspection procedure. The FAC Program Coordinator should review this procedure.

8.2. Ultrasonic Testing (UT) Technique (A scan equipment required)

8.2.1. Attachment B provides UT grid layout examples based on geometry type.

8.2.2. The ultrasonic testing (UT) technique should consist of gridding a component and taking wall thickness measurements at grid intersection points to determine wall thickness. For nominal pipe size of 2" diameter and less, it is acceptable to scan the inspection location in lieu of gridding, identifying the minimum and maximum thicknesses. Any inspected wall thickness below the minimum allowed thickness should be characterized to determine size of degradation.

8.2.3. Grid lines should be parallel and perpendicular to flow. For elbows, the grid lines perpendicular to flow are radial lines focused on the center of curvature. This results in an equal number of measurements on the intrados and extrados of an elbow.

8.2.4. The grid should be labeled alpha-numerically so that a grid intersection can be identified by a specific alpha-numeric designation.

8.2.5. UT readings should be taken at each intersecting grid point and recorded. If a thin area or wear pattern is observed, the examiner should scan and map the area to ensure that the minimum wall thickness is recorded.

8.2.6. Maximum spacing between grid lines should be based on the table below:

Pipe Size (in.)	Number of grid lines around component circumference	Axial distance between circumferential grid line bands (in.)
2	8	1
2.5	8	1
3	10	1
4	12	1.5
6	12	2
8	12	2.5
10	12	2.5
12	14	3.5
14	14	3.5
16	14	4
18	14	4.5
20	16	5
24	16	6
>24	18	6

8.2.7. When inspecting reducers, expanders, reducing elbows, and expanding elbows, the grid size should be selected so that an equal number of radial readings appear on the large and small ends and both sides do not exceed the maximum spacing between grid lines.

8.2.8. Grid lines should begin approximately ¼ inch from the toe of welds or as close as practical to the toe of welds.

8.2.9. Minimum grid coverage for fittings should include an extension of three circumferential grid bands upstream of the upstream weld and an extension two pipe diameters downstream of the downstream weld. For expanders and expanding elbows the upstream extension should be two pipe diameters and the downstream extension should be three circumferential grid bands.

8.2.10. Valves and orifices cannot be accurately inspected by UT techniques. Instead FAC wear in these components can be gauged from wear in the pipe immediately downstream. If significant wear is detected in the downstream pipe, the valve or orifice should also be inspected. A valve or orifice inspection grid need not include an upstream pipe extension.

8.2.11. The origin location (A1) and reference line (A column) should conform to the UT grid layout examples in Attachment B.

8.2.12. Each location should be gridded in a way that facilitates repeatability for future inspections. To document each inspection location a grid map sketch should be created indicating, at a minimum:

- Component identification number
- Size and adequate dimensions
- Flow direction
- Reference point (A1) and reference line location
- Radial measurement direction (clockwise or counterclockwise)
- Axial and radial grid line naming convention
- Weld locations
- Location of adjacent components

8.3. *Radiographic Testing Technique*

8.3.1. Due to the qualitative nature of radiographic testing (RT) techniques, it may not provide the minimum measured wall thickness. Therefore, engineering judgment should be used to determine if the component requires replacement, re-inspection at a future date or can be returned to service without restriction. UT inspection may be used as a supplement to RT in cases where RT provides uncertain results

8.3.2. At the discretion of the FAC Program Engineer, component inspections may be performed using RT. RT is generally an excellent choice for small-bore lines, and may also be useful on certain large-bore lines.

8.4. *Visual Inspection Technique*

8.4.1. Visual detection of FAC damage can be difficult, especially if using video equipment. The damage can be spread over a large area and have a smooth transition between thinned and normal sections. The presence of oxide films tends to mask the transition between normal and worn areas. The use of multiple light sources can help to create shadows or to distinguish changes in surface boundary locations. In the case of two-phase systems, the damaged surface often takes the appearance of "tiger striping" which is more visibly evident and can enhance the detection of degraded areas. In these cases the degraded areas have a polished metallic appearance.

8.4.2. Visual exams can consist of direct observation or be performed using remote capabilities such as bore-scopes, cameras, mirrors, and remote crawlers equipped with cameras. Since FAC can be difficult to see with the naked eye, it is even more difficult to see with these remote devices. Extreme care must be used when evaluating areas for FAC wear while performing a remote visual exam.

8.4.3. Visual inspections enable a rapid examination of large areas to determine if wall degradation is present. Visual inspection should be used in areas where personnel access is possible (e.g. large diameter piping, vessel shells, etc.).

- The FAC Program Coordinator should determine when visual inspection techniques are used.
- When a component (e.g., a valve) is disassembled or removed from a FAC susceptible line, and wear patterns are detected, the FAC Program Coordinator should visually inspect the component interior and the area adjacent to the opening to determine if FAC damage is present.
- In cases where wear is detected or suspected, the visual inspections should be supplemented with UT measurements to quantify the wall loss that has occurred.

8.5. Pulsed Eddy Current (PEC) Testing

8.5.1. The benefit of pulsed eddy current (PEC) testing is that it can be performed without removing insulation. This is especially useful for components with asbestos insulation. The drawback is that the data is not as accurate as UT inspections.

- The FAC Program Coordinator should determine when PEC testing is used.
- In cases where wear is detected or suspected, the PEC test should be supplemented with UT measurements to quantify the wall loss that has occurred.
- PEC testing results should not be used in fitness for service evaluations without an increase in safety factor.

9. Evaluation of Piping Examinations

9.1. Inspection Tracking

9.1.1. FAC inspections should be documented by the inspection location grid map sketch and the inspection thickness measurements in its' native file format.

9.1.2. Inspections should be recorded in an inspection database with component properties and inspection results. At a minimum, the inspection database should include:

- Component name (the name may be equivalent to the CHECWORKS SFA component name)
- Geometry
- Location
- Diameter
- Nominal thickness and pipe schedule
- Minimum allowed thickness
- Material
- Installation date or time in service
- Inspection date
- Measured wear
- Measured wear rate
- Minimum measured thickness
- Remaining service life
- Next scheduled inspection
- Component pass/fail status

9.1.3. The inspection database should be distinct from the CHECWORKS SFA model. This is because the CHECWORKS SFA model does not have the capability to perform trending calculations including calculation of measured wear rate, remaining service life, next scheduled inspection, and component pass/fail status. In addition, the CHECWORKS SFA model does not contain SNM components. The inspection database should be able to manage inspection data, analyze inspection data, and provide streamlined methods for retrieval of past inspection results.

9.2. Minimum Allowed Thickness

9.2.1. Design minimum allowed thickness is based on the minimum wall thickness stipulated for initial plant design. This value should primarily be determined by the calculation of hoop stress thickness per ASME B31.1 [17.9]. Hoop stress thickness should be calculated for each inspected component by the following formula:

$$Thoop = (P \times D) / [2(SE + P \times \gamma)] + A$$

where:

Thoop = Minimum allowed thickness by hoop stress

P = Design pressure (psig)

D = Outside diameter

SE = Maximum allowable stress of material at design temperature

γ = Material coefficient (usually 0.4; for steel below 900°F)

A = Additional thickness (A = 0 for most pipe where D $\geq$ 4", A = 0.065 for most pipe where D < 4")

9.2.2. An administrative lower limit of 0.100" should be used for the minimum allowed thickness.

9.2.3. Minimum allowed thickness is calculated as the greatest of 75% of the design minimum allowed thickness (per hoop stress thickness calculation) or the administrative limit per the following formula:

$$Tminallow = Max\ (75\%\ Thoop\ ,\ 0.100")$$

where:

Tminallow = Minimum allowed thickness

Thoop = Design minimum allowed thickness by hoop stress (the Thoop calculation includes a safety factor of 4; therefore, 75% of the Thoop calculation includes a safety factor of 3)

0.100" = Administrative lower limit

9.2.4. It is possible to revise the minimum allowed thickness based on more elaborate design/stress calculations. If required, the FAC Program Coordinator should seek assistance from a design/stress Engineering Specialist to calculate such revised minimum allowed thickness values.

9.3. Fitness for Service Evaluation

9.3.1. Inspection data should be analyzed to determine if a component has experienced wear; to ascertain the location, extent, and depth of wall thinning; and to evaluate the wear rate and wear pattern to identify trends.

9.3.2. The FAC Program Coordinator is responsible for performing fitness for service evaluations to determine the need for pipe or component repair and/or replacement. Fitness for service evaluations should be performed as soon as possible after the receipt of the inspection results and prior to plant restart after the outage.

9.3.3. The process of evaluating inspection data is complicated by several factors, including:

- Unknown initial wall thickness
- Variations in as-built wall thickness along the axis and around the circumference of the component
- Uncertainties and inaccuracies in UT measurements
- Counterbore and other component misalignment or fit-up
- Obstructions
- Data recording or transfer errors

9.3.4. Measured wear should be calculated for each inspection. The selection of which wear calculation method to use should be determined by EPRI guidance [17.2]. The acceptable methods used to quantify FAC wear are:

- Area Method (per engineering judgment)
- Band Method (for pipe, concentric reducers and expanders, nozzles, tees)
- Moving Blanket Method (for elbows, reducing/expanding elbows, tees)
- Point-to-Point Methods (for multiple outage inspection data)
- Max-Min Methods (for scan values)
- NOTE: These methods have been defined by EPRI in many resources such as [17.1], [17.2], and [17.3].

9.3.5. Fitness for Service Evaluations involve the calculation of wear, wear rate, and remaining service life based on measured wall thickness. The process and formulas used to calculate these values are introduced by EPRI in the "Evaluating Worn Components" section of [17.1] and [17.3].

9.3.6. Measured wear rate should be calculated for each inspection by the following formula:

WR = W / t

where:

WR = Wear rate

W = Wear

t = Time in service (or time between two inspections for point-to-point)

9.3.7. Remaining service life should be calculated for each inspection by the following formula:

RSL = (Tminmeas - Tminallow) / (WR × SF)

where:

RSL = Remaining service life in operating hours

Tminmeas = Minimum measured wall thickness

Tminallow = Minimum allowed thickness

WR = Wear rate

SF = Safety factor (industry standard default value of 1.1; a higher value may be used per engineering judgment; EPRI provides guidance on determining the appropriate safety factor in [17.3])

9.3.8. Next scheduled inspection should be calculated based on remaining service life and estimated future operating times. In general, remaining service life should be greater than two years. It may be necessary to update next scheduled inspection based on actual plant operation.

9.3.9. A component should be accepted for continued service (Pass) if the minimum measured wall thickness is greater than the minimum allowed thickness AND the component is not projected to degrade below the minimum allowed thickness before the next scheduled outage. If this is not true, the component is not acceptable for continued service (Fail).

10. Repair and Replacement

10.1. Guidelines for Repair/Replacement Urgency

10.1.1. KCPL is researching best practice on determining urgency for replacements.

10.1.2. Guidelines for replacement urgency are:

- Piping below 75% of design minimum allowed thickness (factor of safety of 3) requires replacement rather than repair.
- Piping below 75% of design minimum allowed thickness (factor of safety of 3) will be replaced at next forced outage if parts are available.
- Piping below 50% design minimum allowed thickness (factor of safety of 2) will be replaced immediately.
- Approval from the Vice President will be required to operate beyond these time frames.

10.2. Selecting Repair/Replacement Locations

10.2.1. The need to repair or replace a component should be determined by the following:

- Forecasting. Previous inspection results may indicate that the component wall thickness is nearing the minimum allowed thickness. This may trigger component replacement, or if this is an indication of a more wide-spread problem, line or segment replacement.
- Fitness for Service Evaluations. The component should be repaired or replaced if the component is not acceptable for continued service (Fail).

10.3. Performing and Tracking Repairs and Replacements

10.3.1. Consideration should be given for non-susceptible material for replacements.

10.3.2. Replacing individual components may be less expensive in the short term; however, in the long term it may be more cost effective to perform entire line replacement with FAC resistant materials.

10.3.3. As planned replacements are implemented, visual inspections should be conducted in adjacent piping for signs of degradation.

10.3.4. It is recommended that a baseline UT inspection be performed on all new carbon steel components prior to service. This inspection should be captured in the inspected components database.

10.3.5. In most cases, repairs should be considered temporary and followed by a permanent replacement at the first available opportunity.

10.4. Root Cause

10.4.1. When a severely degraded pipe is found or a rupture occurs a root cause analysis will be conducted and documented.

11. Chemistry

11.1. Optimizing the cycle chemistry can significantly assist in controlling FAC. The Corporate Chemistry Department should implement an optimized plant chemistry treatment to mitigate the effects of FAC.

11.2. Detailed guidelines for FAC-optimized water chemistry are contained in EPRI TR 1008082 Guidelines for Controlling Flow-Accelerated Corrosion in Fossil and Combined Cycle Plants [17.1].

12. Training and Qualifications

12.1. The FAC Program Coordinator should posses the following qualifications and training (as a minimum):

12.1.1. A knowledge base normally associated with a graduate engineer.

12.1.2. Familiarity with this program guideline and industry standard references.

12.1.3. Formal training in Flow-Accelerated Corrosion and CHECWORKS SFA.

12.1.4. Familiarity with applicable piping codes.

12.1.5. Regular participation in applicable industry conferences and seminars (or similar events).

12.1.6. Contact and communication with industry peers.

12.2. FAC Program backup and support personnel should also be familiar with this program guideline, receive training in FAC, and receive training in CHECWORKS SFA (if they will be working with the model).

12.3. Basic FAC training should be provided to Operations, Systems Engineers, Maintenance personnel, and Chemistry personnel so that they are made aware of conditions that impact FAC and their role in contributing to a successful FAC Program.

13. Performance Indicators, Health Reports, and Assessments

13.1. Performance Indicators

13.1.1. Performance indicators are used to quantify and trend FAC Program effectiveness over time, thus enabling comparisons of current FAC Program health with the past, and determining if the program is improving or worsening.

13.1.2. Performance indicators that are quantifiable allow for a mathematical approach to trending program effectiveness over time. Examples of quantifiable performance indicators are:

- Number of unplanned failures.
- Number of sample expansions required per outage.
- Number of inspections per outage over time.
- Percent of CHECWORKS SFA components in WRA runs considered calibrated.
- Projected number of future repairs and replacements.

13.1.3. Performance indicators that are qualitative allow a subject approach to trending program effectiveness over time. Examples of qualitative performance indicators are:

- Adherence to the FAC Program guidelines.
- Last revision/update to key FAC Program elements.
- FAC Program Coordinator staffing, experience, and training.
- Fulfillment/status of assessment action items.

13.1.4. The FAC Program Coordinator and Corporate Engineering Director should mutually agree upon applicable performance indicators.

13.2. Annual FAC Report

13.2.1. A FAC Program Health Report should be prepared once per year at a minimum. The Health Report should be transmitted to senior staff.

13.2.2. The Health Report should include the following items, at a minimum:

- Overall FAC Program health rating.
- Discussion of performance indicators.
- Conclusions from FAC Program assessments.
- FAC Program continuous improvements from the past year.
- FAC Program deficiencies.

13.3. Assessments

13.3.1. Assessments of the FAC Program provide the opportunity to compare the current FAC Program with this guideline, management expectations, performance indicators, and industry standards.

- Assessments may be performed by KCPL personnel during self-assessments.
- Assessments may also be performed by external industry experts as an independent party or as a member of the internal self-assessment team.

13.3.2. There are numerous ways to conduct an assessment of the FAC Program. Each assessment should define the purpose, define assessment criteria, list the action plan and scope, record observations, and list action items. Action items should be tracked until fulfilled.

- CHUG Position Paper No. 7 Self Assessment Guidance to Support Flow-Accelerated Corrosion Programs [17.7] provides guidance on assessment types and sample assessment questions and checklists.

13.3.3. Commencing in 2009 and occurring at least once every four years thereafter, a formal assessment of the FAC Program shall be conducted. The assessment should be led by an external industry expert.

14. Quality Assurance

14.1. Key FAC Program elements such as the Susceptibility Evaluation, CHECWORKS SFA model, SNM Evaluation, and Fitness for Service Evaluations should be independently prepared, verified, and approved by persons knowledgeable in FAC.

14.2. Any future revisions to the Susceptibility Evaluation, CHECWORKS SFA model, SNM Evaluation should also be independently prepared, verified, and approved by persons knowledgeable in FAC.

15. Long-Term FAC Program Strategy

15.1. The long-term goal of the Flow-Accelerated Corrosion Program is not merely the detection and replacement of FAC-degraded pipe, but the mitigation of FAC throughout the entire plant. Therefore, the FAC Program should continue to explore methods for accomplishing this. Many different approaches are possible. Changes in chemistry treatments, upgraded materials, and design changes are all possible methods of reducing or eliminating FAC.

15.2. The CHECWORKS SFA model is a key element in the plant FAC Program. After each outage, the CHECWORKS SFA model should be calibrated with the latest UT data (Pass 2 analysis) and chemistry information.

15.3. Any changes in the physical or chemical state of the plant that may impact the Flow-Accelerated Corrosion rates should be communicated to the FAC Program Coordinator for evaluation. In addition, any significant or long-term changes in operating practice should also be communicated. For example, plant modifications, new chemistry treatments, power uprates, and changes in valve lineups can all impact FAC rates.

15.4. Improvements in water chemistry are among the most powerful tools available to reduce FAC rates. The FAC Program Coordinator should coordinate with Chemistry personnel as appropriate to ensure that FAC is considered when decisions on water treatment are made.

15.5. Replacement of degraded piping and fittings with steel containing chromium reduces the rate of FAC significantly. The presence of molybdenum or copper also reduces the rate of FAC. Replacement with steels containing 1.25% chromium or greater will reduce susceptibility to the point where the component may be eliminated from further consideration within the FAC Program. The use of upgraded materials is practical and cost-efficient under some circumstances, and should be considered as one way to reduce or eliminate future degradation of the replaced component.

15.6. When possible, material analysis should be performed on components to determine trace alloy content. As even small amounts of chromium (0.1%) reduce FAC rates, inspections on chromium containing components can be scheduled with less frequency in favor of those with lower chromium content. See CHUG Position Paper No. 5 [17.8] concerning chromium sampling for further discussion.

15.7. The FAC Program Coordinator should consider planned programmatic replacement of high wear lines with a FAC resistant material, especially small bore, on a multiple component or line basis as an alternative to replacement of individual components. Line or segment replacement often provides greater long-term benefits by reducing overall FAC Program costs.

15.8. Some FAC problems may be best solved by minor design changes. Such design changes might involve rerouting piping to reduce turbulence, resizing valves or replacing valve trims to reduce flashing, or installing moisture removal equipment to increase local steam quality.

16. Definitions

16.1. BASELINE INSPECTIONS - Involve new or replacement components which have not previously been involved in plant operations.

16.2. CHECWORKS STEAM/FEEDWATER APPLICATION - EPRI computer modeling program used to predict rates of wall thinning and remaining lives of components degraded by FAC.

16.3. CORROSION – The degradation of a material by chemical reactions with the environment.

16.4. DESIGN MINIMUM ALLOWED THICKNESS - Required minimum wall thickness for initial plant design.

16.5. ENTRANCE EFFECT - A phenomena where FAC susceptible piping downstream of FAC resistant piping has a higher FAC wear rate.

16.6. EPRI – Electric Power Research Institute.

16.7. EROSION – The degradation of a material by mechanical methods.

16.8. FLOW-ACCELERATED CORROSION (FAC) - A form of material degradation that results in thinning of the inside wall in carbon steel piping and fittings under certain flow, temperature, and chemistry conditions. Also known as FAC. Previously known as Erosion/Corrosion or E/C.

16.9. GRID MAP SKETCH – Paperwork to document the results of inspections.

16.10. INITIAL THICKNESS (Tinit) – The wall thickness of a component prior to its being placed in service. Tinit may be either measured or assumed to be Tnom.

16.11. LARGE BORE PIPING - All piping greater than 2" NPS (nominal pipe size).

16.12. MINIMUM ALLOWED THICKNESS (Tminallow) - Required minimum wall thickness for a component to remain in operation.

16.13. MINIMUM MEASURED THICKNESS (Tminmeas) – The wall thickness that is representative of the wear that has occurred in a component at a given time. In most cases, Tminmeas will be the lowest wall thickness measured on that component for a particular set of inspection data.

16.14. NDE – Non destructive examination.

16.15. NEXT SCHEDULED INSPECTION (NSI) - The time at which an inspection will be performed on a given component.

16.16. NOMINAL THICKNESS (Tnom) - The components nominal wall dimension as supplied by the manufacturer.

16.17. PASS 2 ANALYSIS - The process of calibrating the CHECWORKS SFA computer model by importing UT inspection data thickness measurements and re-running the wear rate analysis.

16.18. PERFORMANCE INDICATORS – Measurements used to quantify program health and compare program effectiveness over time.

16.19. REMAINING SERVICE LIFE (RSL) - The time for the wall thickness to reach minimum allowed thickness based on the measured wear rate.

16.20. RUN/LINE CALIBRATION – See Pass 2 Analysis.

16.21. SINGLE PHASE – Flow is entirely water.

16.22. SMALL BORE PIPING - All piping 2" NPS and less.

16.23. SUSCEPTIBLE NON-MODELED (SNM) EVALUATION – A subset of the FAC Program that addresses FAC susceptible lines that cannot be modeled using the EPRI CHECWORKS SFA software.

16.24. TRAIN - Loops within subsystems that perform the same function and have similar geometries, flow rates and temperatures and which, would have similar FAC risk.

16.25. TWO PHASE – Flow is a mixture of steam and water.

16.26. WEAR (W) – The amount of material removed from component wall thickness since the baseline conditions.

16.27. WEAR RATE (WR) – Wall loss per unit time. Not necessarily constant from cycle to cycle if chemistry or operating conditions change.

17. Resources

17.1. Guidelines for Controlling Flow-Accelerated Corrosion in Fossil and Combined Cycle Plants, EPRI, Palo Alto, CA: 2005. 1008082.

17.2. CHECWORKS Steam/Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data, Doc. No. 1009599, Final Report, September 2004.

17.3. Recommendations for an Effective Flow-Accelerated Corrosion Program, EPRI NSAC-202L-R3, TR 1011838, May 2006.

17.4. Recommendations for an Effective Flow-Accelerated Corrosion Program for Small-Bore Piping: Augmentation of Appendix A, NSAC-202L-R3 (EPRI Report 1011838), CHUG Position Paper Number 6, October 2007, Revision 0.

17.5. Flow Accelerated Corrosion in Power Plants, EPRI TR-106611-R1, Revision 1, 1998.

17.6. CHECWORKS Steam/Feedwater Application Version 2.2 User Guide, EPRI, Palo Alto, CA: 2006. EPRI Product 1013375.

17.7. Self Assessment Guidance to Support Flow-Accelerated Corrosion Programs, CHUG Position Paper No. 7, June 2007.

17.8. Chromium Sampling: Material Analysis of Carbon Steel in Steam Cycle Piping to Support Flow-Accelerated Corrosion Programs, CHUG Position Paper No. 5, September 2006.

17.9. ASME Standard Code for Pressure Piping, Power Piping USAS B31.1.0.

Attachment A

FAC Program Documentation Matrix

Program Element	Type	Section	Quantity	Update Frequency
FAC Program Guideline	Program Guideline	All	1	no set cycle
FAC Susceptibility Evaluation	Engineering Report	3	1/(plant or unit)	once per cycle
CHECWORKS SFA Model	SFA Database	4	1/unit	once per cycle
CHECWORKS SFA Model Report	Engineering Report	4	1/unit	once per cycle
SNM Evaluation	Engineering Report	5	1/(plant or unit)	once per cycle
Isometrics	Drawings	6	many/unit	no set cycle
Inspection Scope Plan	Engineering Report (or similar)	7	1/unit/outage	no further updates once completed for that outage
Sample Expansion Evaluations	Letter/form	7	Varying/unit/outage	no further updates once completed for that outage
Inspection Location Grid Maps	Form	8	Varying/unit/outage	no further updates once completed for that outage
Native Format Inspection Files	Text files	8	Varying/unit/outage	no further updates once completed for that outage
Inspection Database	Database	9	1/(unit or plant)	once per cycle
Health Report	Letter/form	13	1/unit	once per year
Assessment	Engineering Report	13	1/unit	once per four years

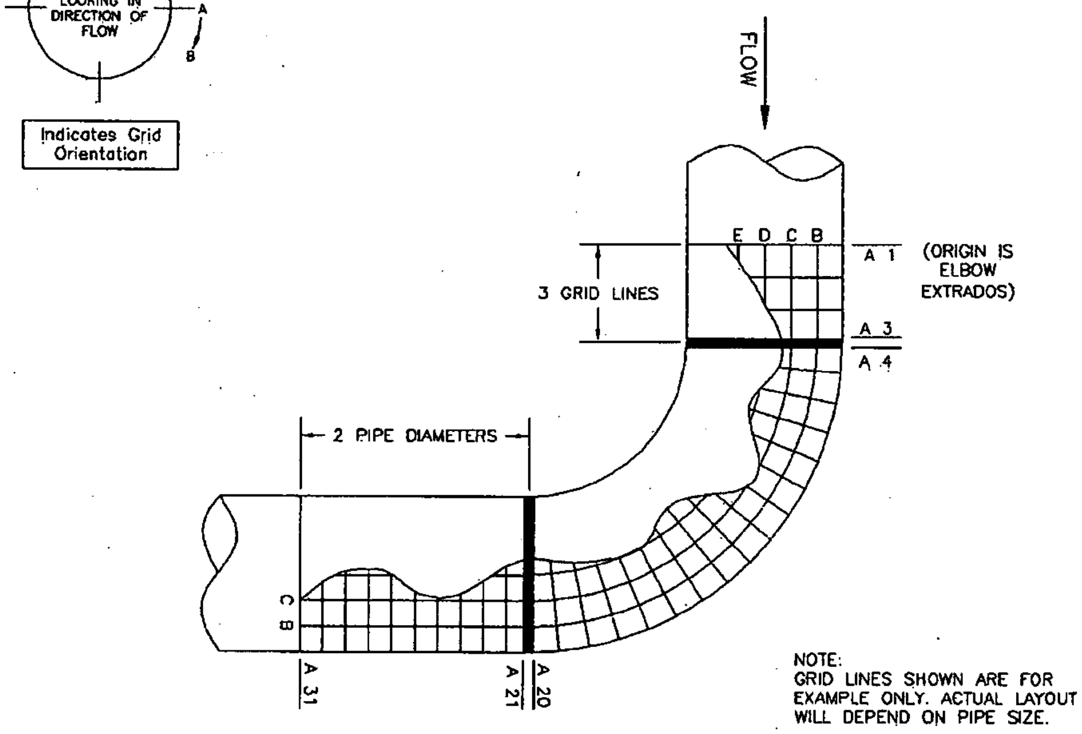
-An update frequency of "once per cycle" indicates an update prior to each inspection scope selection, approximately once every two years.

-The FAC Susceptibility Evaluation and SNM Evaluation may be organized as one report containing all plant units or one report per unit.

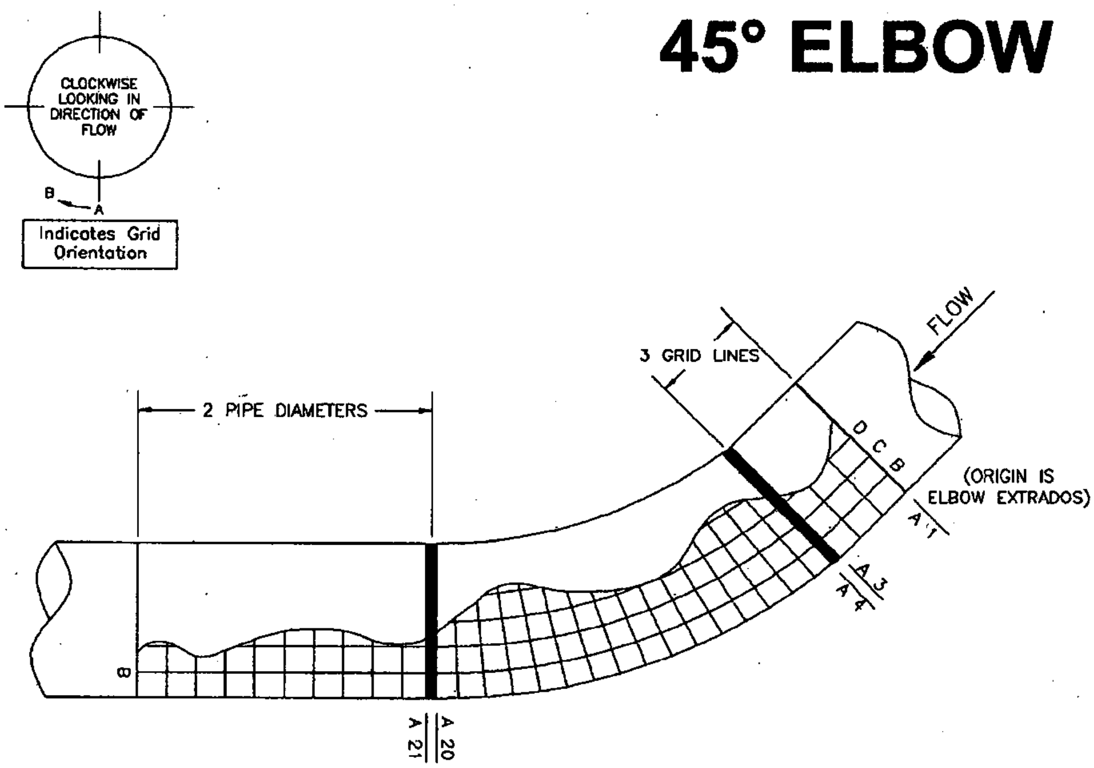
Attachment B

UT Inspection Grid Layout

90° ELBOW


CLOCKWISE LOOKING IN DIRECTION OF FLOW
A
B
Indicates Grid Orientation
FLOW
E D C B
A 1
(ORIGIN IS ELBOW EXTRADOS)
3 GRID LINES
A 3
A 4
2 PIPE DIAMETERS
C B
A 31
A 21
A 20
NOTE:
GRID LINES SHOWN ARE FOR EXAMPLE ONLY. ACTUAL LAYOUT WILL DEPEND ON PIPE SIZE.

45° ELBOW



NOTE:
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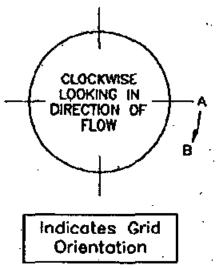
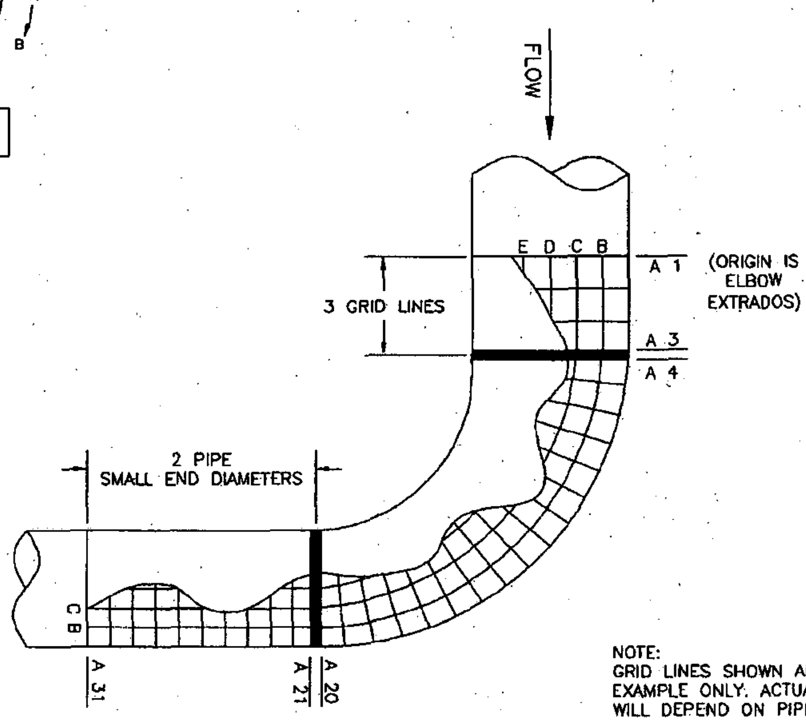
90° REDUCING ELBOW





NOTE:
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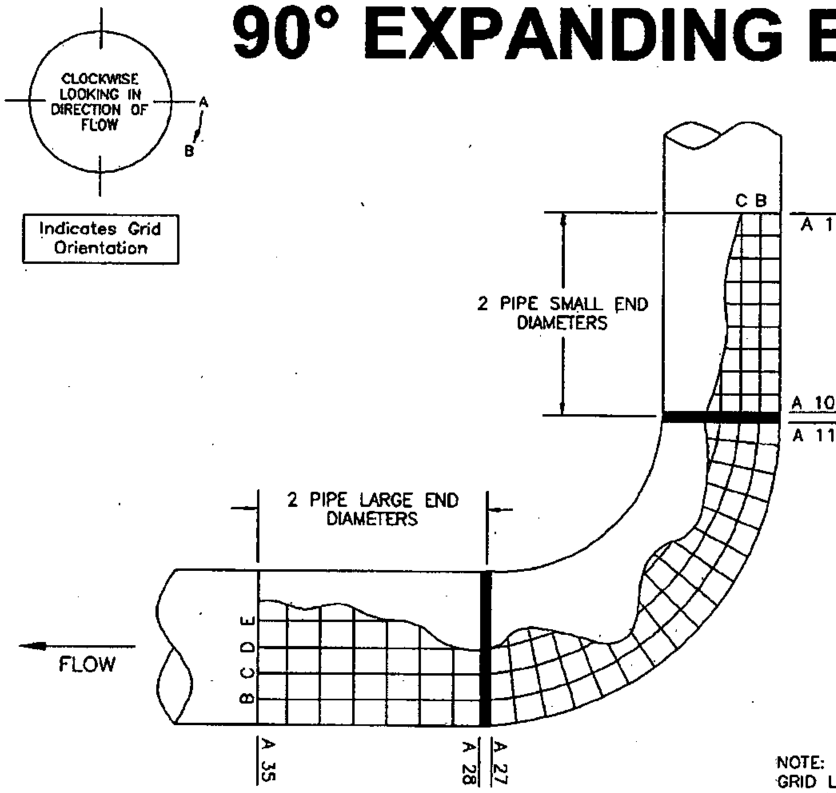
90° EXPANDING ELBOW



NOTE:
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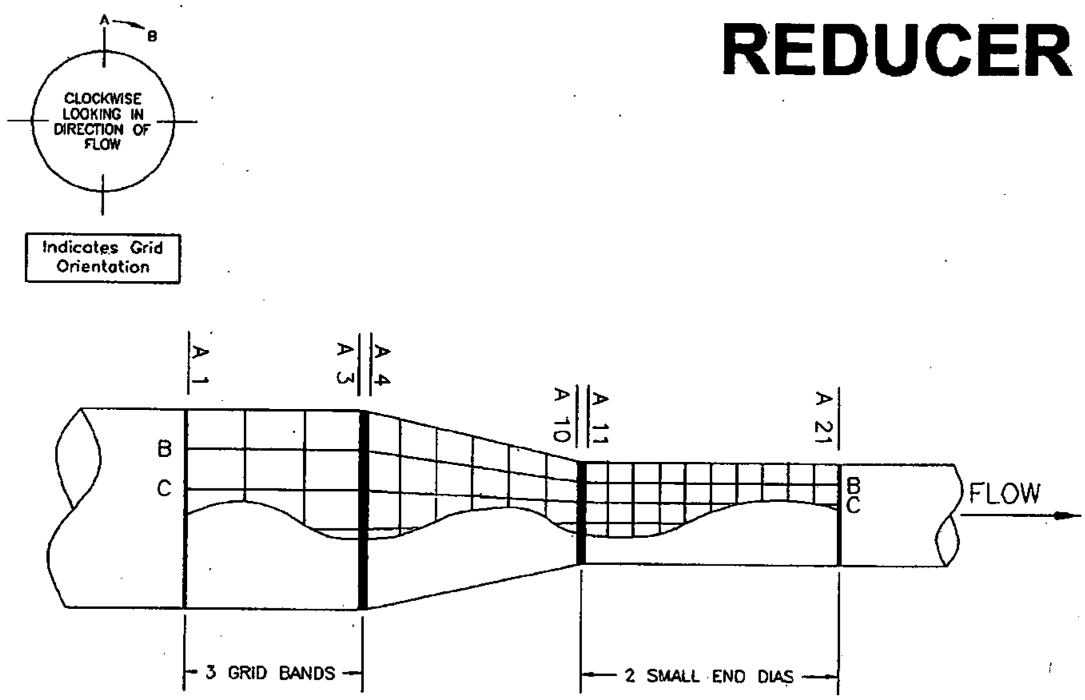
REDUCER



NOTE:
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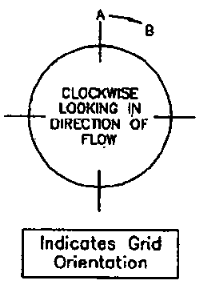
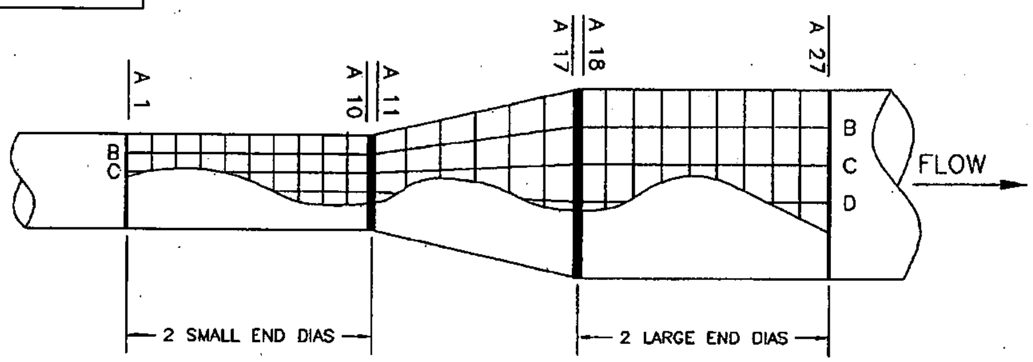
EXPANDER





NOTE:
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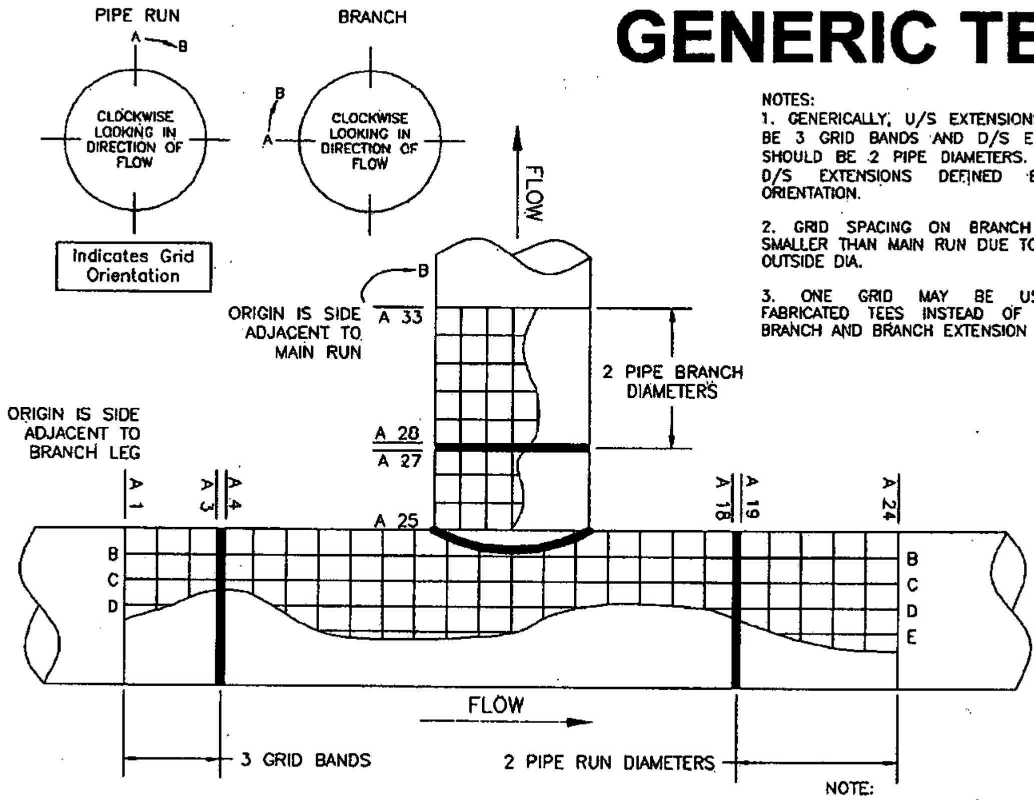
GENERIC TEE



NOTES:

1. GENERICALLY, U/S EXTENSIONS SHOULD BE 3 GRID BANDS AND D/S EXTENSIONS SHOULD BE 2 PIPE DIAMETERS. U/S AND D/S EXTENSIONS DEFINED BY FLOW ORIENTATION.
2. GRID SPACING ON BRANCH MAY BE SMALLER THAN MAIN RUN DUE TO SMALLER OUTSIDE DIA.
3. ONE GRID MAY BE USED FOR FABRICATED TEES INSTEAD OF SEPARATE BRANCH AND BRANCH EXTENSION GRIDS.

NOTE:
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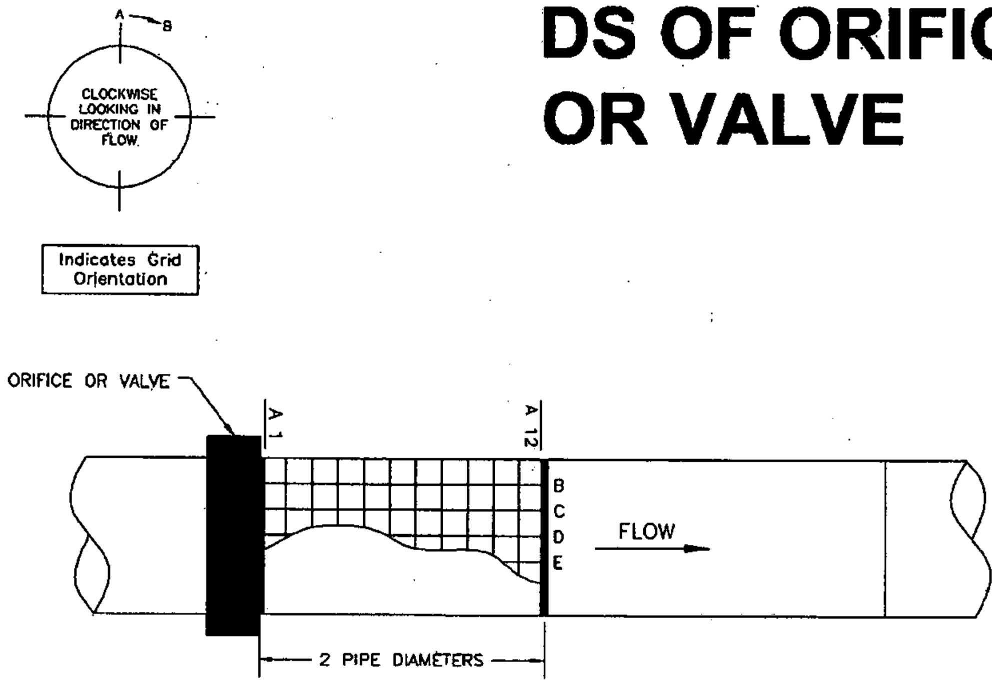
DS OF ORIFICE OR VALVE



NOTE:
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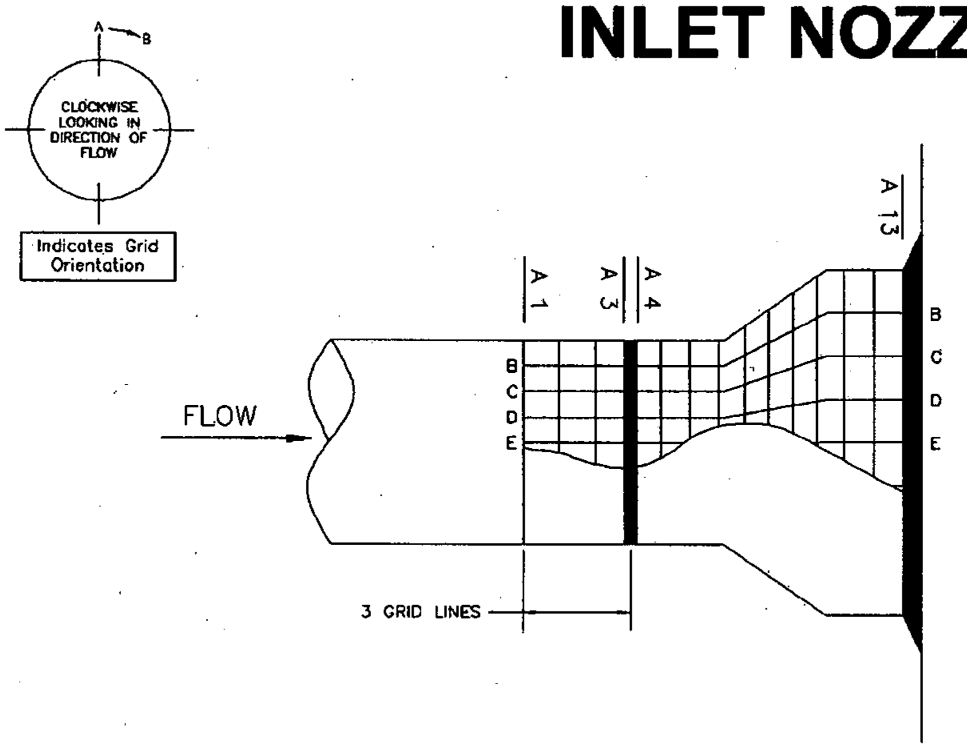
INLET NOZZLE



NOTE:
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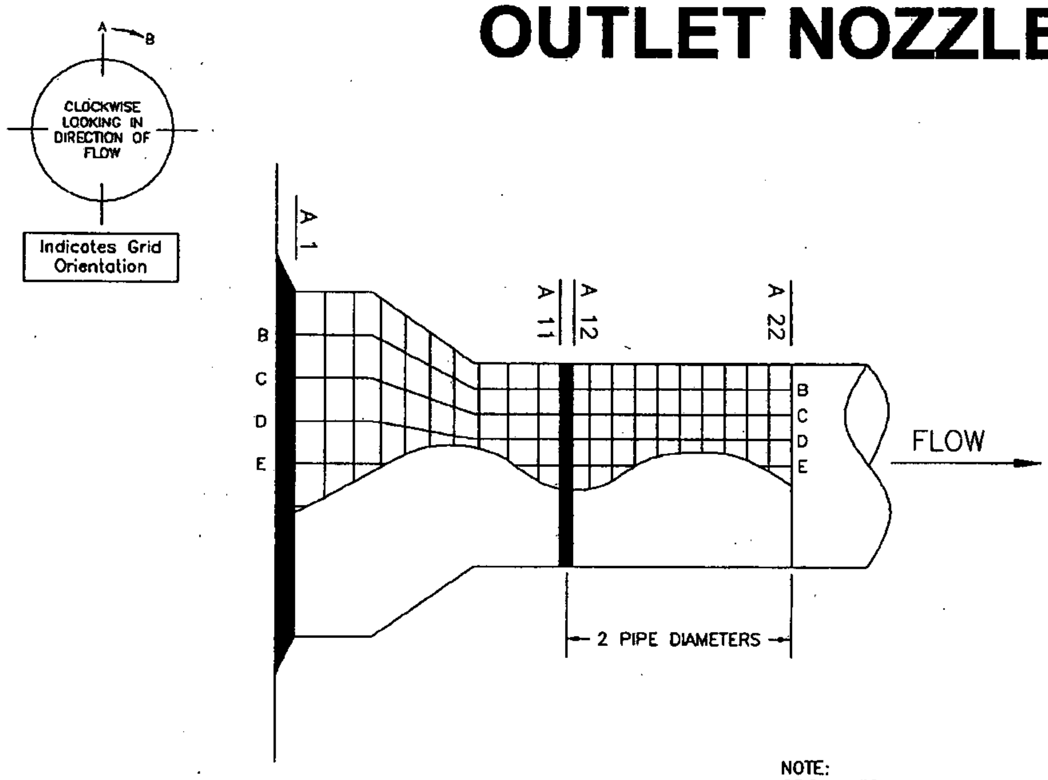
OUTLET NOZZLE



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