UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

August 4, 2011

MEMORANDUM TO: Memo To File

FROM: Eugene F. Guthrie, Chief ***/RA/***
Reactor Projects Branch 6

SUBJECT: SUBMITTAL OF REFERENCE DOCUMENTS RELATED TO EA-11-018 FOR BROWNS FERRY NUCLEAR PLANT UNIT 1, DOCKET 50-259

This memo submits reference documents reviewed by the NRC that are to be made available for public viewing. The enclosed documents are as follows:

Enclosure 1: TVA response to NRC questions regarding the general characteristics of valve 1-FCV-074-066 (no date)
Enclosure 2: TVA response to NRC questions of April 29, 2011 regarding in service testing of 1-FCV-074-066
Enclosure 3: TVA response dated April 5, 2011 to NRC questions of March 31, 2011 regarding 1-FCV-074-66
Enclosure 4: TVA response to NRC questions from the April 4, 2011 Regulatory Conference
Enclosure 5: TVA response to NRC follow-up questions of March 31, 2011
Enclosure 6: TVA response to NRC follow-up questions of April 18, 2011
Enclosure 7: TVA response to NRC question during a site meeting on April 22, 2011
Enclosure 8: TVA response to Independent Team questions June 29, 2011
Enclosure 9: TVA response to Independent Team questions July 7, 2011
Enclosure 10: TVA response to Independent Team questions July 8, 2011
Enclosure 11: TVA response to Independent Team questions (telecon) July 11, 2011
Enclosure 12: TVA response to Independent Team questions (telecon) July 8, 2011
Enclosure 13: TVA response to Independent Team questions (telecon) July 11, 2011
Enclosure 14: TVA response to Independent Team questions July 11, 2011

Docket No.: 50-259
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Enclosures: As Stated

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X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: ☐ Yes ACCESSION NUMBER:________________________ ☐ SUNSI REVIEW COMPLETE ☐ FORM 665 ATTACHED

OFFICE	RII:DRP	RII:DRP					
SIGNATURE	JDH /RA/	EFG /RA/					
NAME	JHamman	EGuthrie					
DATE	08/04/2011	08/04/2011					
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\RPB6\BROWNS FERRY\LPCI VALVE\DOCKETING MEMO AND ENCLOSURES\DOCUMENT MEMO.DOCX

Responses to NRC Questions

Regarding Valve 1-FCV-74-066

Is the Valve 'N' stamped?
Review of the valve data sheet 1-47BD452-99 for the valve (TVA mark # 47W 452-3563),(UNID; 1MVOP-074-0066) indicates that the valve is a 24", 600# class type, Pressure Seal Angle valve by Walworth and is not 'N' stamped. (ref Calc 3-MD-Q3074-920438).

Under what classification was the valve purchased?
ASME B31.1 (ref. Calc 3-MD-Q3074-920438).

Are there markings on the valve guides from the free floating disc?
There is no evidence of galling and no markings on the valve guides that would result from interferences as a result of a cocked disc. The internal configuration of the valve includes a linear trim of sufficient length to provide stability to the valve disc and not allow cocking of the disc inside the valve body.

Are the valve guides stellite?
The valve guides are not stellite. Typically Walworth uses stellite for the valve disc, seat, and back seat only.

What NDE methods were used on the welds?
There is no record of any NDE being performed on the welds. Tack welds, being non-structural, are generally not subject to NDE.

What is the overall actuator ratio?
Review of the valve data sheet 1-47BD452-99 for the valve (TVA mark # 47W 452-3563), (UNID 1MVOP-074-0066) indicates that the overall actuator ratio is 109.78:1.

What amount of disc lift is needed for the required flow?
The amount of disc lift needed for the required flow is approximately 19" (18 15/16'' lift from drawing 3-A-12337-M3A) for the design basis flow of 20,000 gpm. The amount of lift needed for one pump flow is minimal.

When FCV-74-66 is nearly closed, more than the minimum injection flow can be achieved. The large DP across the valve demonstrates that the disk will be lifted well off the valve seat, so much more than the analysis minimum injection flow rate of 3600 gpm will occur.
(ref. Free Floating Disc Analysis)

Can we provide stroke time data?
Recorded stroke time data indicate that for a four year period (10/2006 to 08/2010) the quarterly stroke time for 1-FCV-74-066 is approximately 33 seconds (ranging from 33.1 to 33.9 seconds).
(ref. Unit 1 1-FCV-74-66 stroke time data)

What were the thrust values of the "as left" torque switch setting and the "as left" pull out thrust from the last static test?
Review of MOVATS data indicates that the "as left" torque switch trip thrust is 85,364 lb. The "as left" pullout thrust is 54,351 lb. (ref. MOVATS test results (11/12/2010)

What is the rate of friction change versus size?
See Tab XI - Performance Improvement International Report

What is the confidence factor of scaling (model to actual)?
See Tab XI - Performance Improvement International Report

If the valve disc did break free as hypothesized, what kind of mechanical shock/water hammer would be incurred by suddenly releasing the 850# valve disc with the maximum possible DP being supplied from a very large capacity pump?
Analysis was performed on the effect of a wedged disc releasing due to vibrations induced by pump flow and pressure. In order for there to be a waterhammer, there needs to be a sudden decrease in fluid velocity. When FCV-74-66 opens, the water in the pipe upstream of the valve initially has no velocity and flow will increase through the open valve and into the reactor vessel. The water in the valve above the disk will also be pushed into the reactor vessel as the disk is pushed out of the way.

Neither of these flows will experience a sudden decrease in fluid velocity on their way to the RV so there is no potential for a waterhammer to occur when FCV-74-66 suddenly opens.

(ref. Free Floating Disc Analysis)

Is a Part 21 Report being considered?
The Part 21 report is in the approval process.

References

- Valve Operator Data Sheet 1-47BD452-99
- PII Report
- U-3 Calc MD-Q3074-920438
- U-2 Calc MD-Q2074-910124 (not reviewed by me but referenced on U3 calc cover sheet)
- Walworth company drawing 3-A-12337-M-3A
- Functional Evaluation 42538 for PER 141380
- MOVATs test results (10/2006 to 08/2010)
- Unit 1 1-FCV-74-66 stroke time data
- MOVATS test results (11/12/2010)
- Unit 1 1-FCV-74-66 stroke time data
- Free Floating Disc Analysis

Inservice Testing (IST) of FCV-74-52 and FCV-74-66

Question:

On the afternoon of Friday 04/29/2011, the NRC questioned Browns Ferry Nuclear Plant (BFN) Inservice Testing (IST) Program compliance with American Society of Mechanical Engineers (ASME) Operations and Maintenance (OM) Code, Subsection ISTC 4.1 (reference SR 362156). This document was written to establish the basis for compliance.

TVA Response:

During the Unit 1 Cycle 8 refueling outage on October 23, 2010, 1-FCV-74-66 did not open while attempting to place RHR Loop 2 in service. Lights indicated open but pump discharge pressure was at maximum and no flow was indicated in the loop. This condition and the root cause are documented in PER 271338.

The BFN IST Program is implemented in accordance with ASME OM Code 1995 Edition with 1996 Addenda (1995 OMa 1996). 1995 OMa 1996, Subsection ISTC 4.1, specifies the requirements for valve position verification as follows:

> *"Valves with remote position indicators shall be observed locally at least once every 2 years to verify that valve operation is accurately indicated. Where practicable, this local observation should be supplemented by other indications such as use of flowmeters or other suitable instrumentation to verify obturator position. These observations need not be concurrent. Where local observation is not possible, other indications shall be used for verification of valve operation."*

The BFN IST Program is described in BFN Technical Instruction (TI) 0-TI-362, "Inservice Testing of Pumps and Valves." This TI lists in tabular form the ASME Class, Category, Normal and Safety Position, Surveillance Procedures, and Surveillance Frequencies. The configuration and testing of valves 1-FCV-74-52 and 1-FCV-74-66 (FCV-74-52/66) is typical for all three Units. These valves are classified as Category B valves with an active safety function. FCV-74-52/66 are normally open valves with an open safety position; however, these valves may be throttled and are therefore considered active in the IST Program. In accordance with the Code ISTC Table 3.6-1, Category B, active valves require exercising, stroke timing, and position indication verification. Exercising and stroke timing is conducted quarterly and position indication verification is conducted once per 2 years. In addition, remote position indication verification includes direct observation of stem movement.

NUREG-1482, Revision 1, "Guideline for Inservice Testing at Nuclear Power Plants," was used to develop the BFN IST Program. No specific additional guidance is provided for verification of remote position indication other than Section 4.2.7, Verification of Remote Position Indication for Valves by Methods Other Direct Observation. NRC recommendations related to this section contain some guidance applicable to FCV-74-52/66:

> *"For certain types of valves that can be observed locally, but for which stem travel does not ensure that the stem is attached to the disk, the local observation should be supplemented by observing an operating parameter as required by Subsections ISTC 4.1, 4.2, and 4.5."*

Note that ISTC Subsections 4.2 and 4.5 are not applicable to remote position indication as described by Subsection 4.1.

Neither the OM Code nor NUREG-1482 requires the use of supplemental parameters in conjunction with position verification. ASME OM Code Interpretation 99-9 confirms that it is not the intent of the ASME OM Code to require observation of stem movement to be supplemented by other indications to verify obturator position regardless of practicability.

> *"Interpretation: 99-9*
>
> *Subject: ASME/ANSI OMa-1988, Part 10, para. 4.1 and equivalent subsequent editions and addenda*
>
> *Date Issued: December 23, 1998*
>
> *File: OMI-98-20*
>
> *Question: If it is practicable, is it a requirement of OMa-1988, Part 10, para. 4.1 that local observation of stem movement be supplemented by other indication to verify obturator position?*
>
> *Reply: No."*

Contact with an OM Code committee member identified that the committee did not intend supplemental verification be performed on all IST valves during position indication testing. This position is consistent with OM Code and NUREG guidance.
Therefore, supplemental verification of the position of valves FCV-74-52 and FCV-74-66 has not been required for implementation of the OM Code at BFN, based on the OM Code itself, NUREG-1482, and Code Interpretation 99-9.

However, even though supplemental verification is not a Code requirement, it should be noted that exercise of CKV-74-68 and CKV-74-54 during performance of the surveillance procedures identified in Table 3 (see References below) provides indication that FCV-74-52 and FCV-74-66 are in the open position and passing flow. If flow was not observed during performance of these surveillance procedures, the surveillance acceptance criteria would not be met and investigation would determine any blockage of FCV-74-52 or FCV-74-66.

The requirements of the ASME OM Code are fulfilled through 0-TI-362 and the surveillance procedures listed in Appendices H, I, and J of 0-TI-362. In accordance with ISTC Table 3.6-1, Category B, active valves require exercising and position indication verification.

Inservice Testing (IST) of FCV-74-52 and FCV-74-66

Exercising of FCV-74-52/66 is conducted quarterly in accordance with the surveillance procedures listed in Table 1 (see References below). Position indication is conducted once every two years in accordance with the procedures listed in Table 2 (see References below).

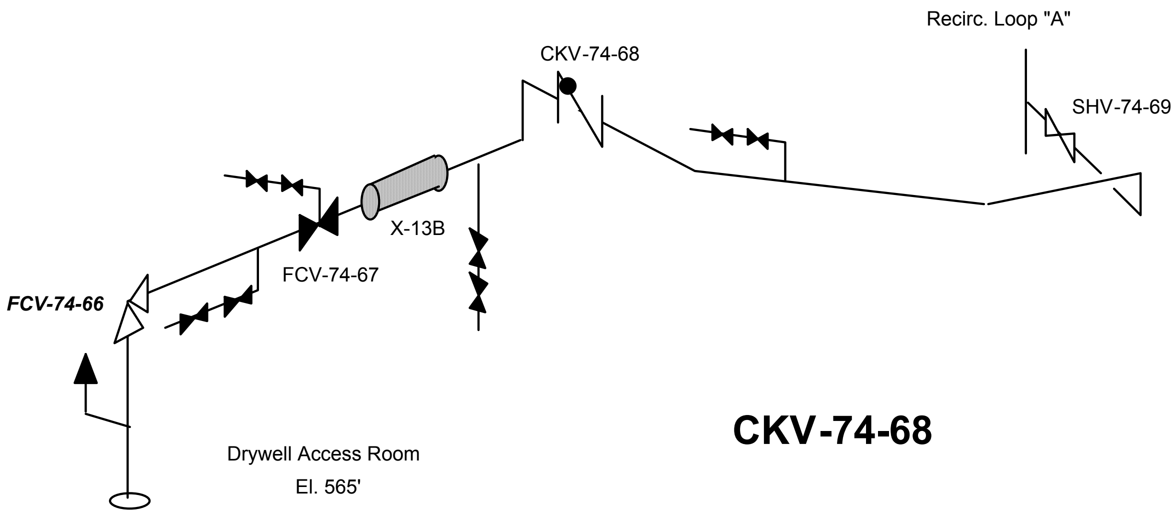


Figure 1

The configuration for RHR Loop II shown in Figure 1above illustrates the location of FCV-74-66 in relation to other IST Program valves (FCV-74-67 and CKV-74-68). RHR Loop I containing FCV-74-52 is similarly configured as shown in Figure 2 below.

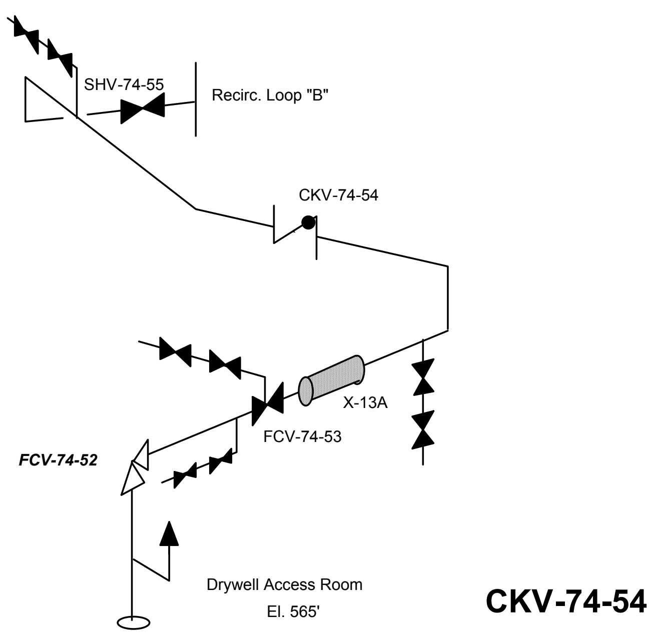


Figure 2

FCV-74-66 is normally open and is required to be open to provide flow to the reactor vessel.

IST Program implementing procedures, shown in Table 3, exercise CKV-74-68 to the open position using Shutdown Cooling flow of greater than or equal to 9000 gpm at a frequency of once per operating cycle in accordance with the BFN Condition Monitoring Program as described in 0-TI-443, “Condition Monitoring of Check Valves.” This check valve test provides supplemental indication that FCV-74-66 is in the open position. Although not specifically documented in the check valve exercise test, supplemental indication that FCV-74-66 is open is provided when the check valve exercise test is performed.

1-SI-3.2.21(II) was scheduled to be performed at Cold Shutdown during U1R8. However, upon initiation of Shutdown Cooling, no flow was observed and the issue with 1-FCV-74-66 was identified, which precluded performance of the surveillance procedure.

Conclusion:

The BFN IST Program testing specified for FCV-74-52 and FCV-74-66 is in compliance with ASME OM Code, Code Interpretation 99-9, and the guidance provided in NUREG-1482, including verification of position indication. Although supplemental position indication verification is not required by the Code or NUREG-1482 for all IST valves subject to position verification requirements, verification of flow through CKV-74-54/CKV-74-68 at BFN does provide the recommended supplemental indication as discussed in the ASME OM Code and NUREG-1482.

Inservice Testing (IST) of FCV-74-52 and FCV-74-66

References:

- ASME OM Code 1995 Edition 1996 Addenda
- 0-TI-362, Inservice Testing of Pumps and Valves
- NUREG-1482, Revision 1, Guideline for Inservice Testing at Nuclear Power Plants
- ASME OM Code Interpretation 99-9, Dated December 23, 1998 (OMI-98-20)
- BFN Surveillance Procedures:

Table 1: Quarterly Exercise of FCV-74-52/66

1-SR-3.6.1.3.5(RHR I)	2-SR-3.6.1.3.5(RHR I)	3-SR-3.6.1.3.5(RHR I)
1-SR-3.6.1.3.5(RHR II)	2-SR-3.6.1.3.5(RHR II)	3-SR-3.6.1.3.5(RHR II)

Table 2: Position Indication of FCV-74-52/66

1-SI-3.6.1.3.5(H I)	2-SI-3.6.1.3.5(H I)	3-SI-3.6.1.3.5(H I)
1-SI-3.6.1.3.5(H II)	2-SI-3.6.1.3.5(HII)	3-SI-3.6.1.3.5(H II)

Table 3: Exercise of CKV-74-68

1-SI-3.2.21(I)	2-SI-3.2.21(I)	3-SI-3.2.21(I)
1-SI-3.2.21(II)	2-SI-3.2.21(II)	3-SI-3.2.21(II)

TVA Response to NRC Questions
Dated 3/31/11 on 1-FCV-074-66

After performing an initial, preliminary review of the root cause analysis (RCA) for PER 271338, 1·FCV-074-066 RHR Outboard (Loop 2) Valve Failure, Revision 1, approved March 16, 2011, and associated analytical and test reports, the NRC staff identified the following questions and/or concerns:

1) *The root cause analysis report states that the damaged skirt with the undersized threads was compared with a new, in stock spare. The comparison noted that the new spare had undersized threads as well. However, the report failed to quantify how much the spare was undersized. Also, how would the spare thread size correlate to its strength to resist failure?*

TVA Response:

The in-stock spare was reworked by work order (WO) 11162030; thread measurements were taken to be 6.340" (major). This was compared to the dimension taken by the Westinghouse laboratory of the 1-FCV-074-66 valve skirt where the average thread dimension major was 6.33". The difference in the dimensions was concluded to be due to rolling of the thread tips as depicted in the Westinghouse report from damage caused from pullout. Thus, the spare was considered to be similar in dimension. Structural Integrity analysis of the threads bounded the condition between the as-design value of 6.3638" (major) and limiting thread dimension on the as-found disc skirt. The spare, having similar thread sizing, would have had similar strength.

2) *An evaluation was completed to determine how much force it would take for the undersized skirt threads to fail. The evaluation used the smallest measured value which was found only at one location on the skirt. This location was at the .25 inch from the bottom of the skirt which translates to the third thread on the skirt. The remaining threads were fairly consistent in their diameter although they were still undersized. The force evaluation assumed a thread engagement of 1.5 inches. Why wasn't the evaluation completed for the average diameter covering the 1.5 inches? Why weren't the values of the disc thread conditions included in the report?*

TVA Response:

Structural Integrity (SI) analysis included a comparison of the as-designed thread and the limiting case thread engagement as bounding cases. Table 2 in the "Thread Static Shear Strength Calculation" provides the as-found thread dimensions and Table 7 in the "Weld Fracture Mechanics and Stress Analysis Calculation" provides the stress intensity along the threads. The as-found limiting thread dimension is appropriate to use because this would provide a maximum capacity based on the limiting thread providing conservatism. The 1.5-inch thread length was used for conservatism in the calculation. Thread measurements were taken from 0.25 inches to 1.75 inches along the threaded surface to provide a good representative sampling as described in the Westinghouse Report STD-MCE-10-198, Table 3.1 on page 22. It should also be noted that even though small variations in thread size existed, the smallest threads would be expected to fail first with load shifting to the remaining threads leading to a domino effect. The values of the disc thread conditions were within manufacturer's tolerance (see page 12 of the Root Cause Analysis).

3) *The RCA report noted that the broken tack welds had a possible rotational aspect to the failure. The report had noted that the failed valve was reworked in 2006. A new stem was installed. It was also noted that shortly after the rework, the valve was unable to close. Investigation found a failed torque arm or anti rotational device. If the torque arm was not installed properly on the new stem, this could lead to the possible rotational aspect of the failure. Was this investigated and reviewed?*

TVA Response:

The anti-rotation device issue was thoroughly reviewed. Westinghouse provided an analysis of the weld fracture indicating the failure was in the axial direction. Regarding the rework in 2006, the failed anti-rotational device would not create additional stress on the weld or threaded connection. There is a small clearance between the disc/washer and disc skirt. This clearance allows the fit-up between the disc and disc skirt for welding and provides a separation to allow the stem to rotate independently of the disc and disc skirt. In the closed position, the valve stem would still be free to rotate (spin). Thus, no additional stresses on the weld or threads would occur because the stem was free to rotate. In the open position, the valve stem would again be free to rotate with no torsional force between the skirt and the stem since no obstruction is present. If back seating occurred, which is likely based on markings observed on the back seat, the torsional forces would be located at the contact area between the stem offset and the valve body back seat. No load would be transferred to the disc skirt weld or disc skirt threads from either torsional or axial loading. Any impact forces due to such event would not be significant based on the velocity (approximately 19 inches in 33 seconds) and associated changes in momentum while cycling of the valve open.

4) *Was the spare skirt examined under a microscope as well to determine overall health?*

TVA Response:

The spare skirt was not examined under a microscope. However, the spare skirt threads were visually inspected and measured using the three-wire thread measuring method at TVA's Power Service Shop during the weld build-up and rework of threads (Reference Work order (WO) 111620630). Measurements are provided in the answer to question 1 above.

5) *Static analysis of the thread engagement of the disc/skirt assembly determined that the measured engagement would be sufficient for loading greater than normal unseating forces. A comparison of MOVATS test data for unseating forces was completed and documented in Attachment 3 of the RCA. The data compiled in attachment 3 has no values. What assurance is there that the data supports the theory of COF being a constant and its contribution to the unseating force?*

TVA Response:

As depicted in the weak link analysis ("CVNO Report No. SR-128, Rev. 2" by Crane Nuclear, Inc. Rims R27 950913008) the normal opening thrust limit for this valve is 274,000 lbs with a required of 162,906 lbs. The Structural Integrity analysis "Thread Static Shear Strength Calculation" provides for a conservative capacity of as-found threaded connection of 313,000 lbs based on the limiting thread dimension. MPR-2524-A, Joint Owners Group (JOG) Motor Operated Valve Periodic Verification Program Summary is approved by the NRC. MPR-2524-A provides guidance that new and rebuilt valves COF and VF are on a slope until it plateaus over a period of time and remains constant unless disturbed by stroking. The INEEL report demonstrates this concept by testing and natural aging. The MOVATs data determined in 2010 provides sufficient assurance that the design values COFs are within the design basis for the MOV.

6) *The valve that failed (1-FCV-074-066) was reworked in 2006 and had no unseating force. The valve was tested again in 2008 and had no unseating force. However, the valve was rebuilt in 2010 and now has an unseating value of 51,893 #. How does this agree with the theory of COF starting out low on a new installation and/or rework and gradually increasing in value until it plateaus out?*

TVA Response:

TVA concurs with the principle of "coefficient of friction (COF) starting out low on a new installation and/or rework and gradually increasing in value until it plateaus out." Because of the effective seat cleaning capability from the high contact stresses associated with stroking globe valves (see answer to question 22) the COF may be reduced below the tangent of the seat angle (0.268 for 15 degrees) and not show any unseating force.

Although the cleaning affect from stroking globe valves may reduce the COF below that which would show unseating like 3-FCV-74-52, all other current unseating traces on the four remaining valves showed unseating consistent with the aged stellite INEEL report. The 2010 full MOVATs trace performed on the 1-FCV-74-66 aged stellite seats demonstrates that it will show unseating similar to the other four valves after stroking.

7) *There is conflicting data with respect to the history predictive monitoring data table on page 67 of the RCA report and the supplied MOVATS test data traces. For the failed valve 1-FCV-074-066 test on November 2008, it is reported in the history data as no unseating force seen. However, the MOVATS test data supplied with the overall Browns Ferry evaluation indicates otherwise. There is an open stroke spring pack deflection overlay of test data curve noted for valve 1-FCV-074-066 and valve 1-FCV-074-052. Both spring packs have a deflection thus indicating unseating force. 1-FCV-074-066 spring pack has a greater deflection than 1-FCV-074-052. Estimated force for pullout for valve 1-FCV-074-066 is well over 150,000 lbs of thrust based on Limitorque spring pack curve for the lightest pack available. The MOVATS curve date is 10/31/2008. There is also a MOVATS overlay comparison of current values for valves 1-FCV-074-052 and 1-FCV·074-066 on the same date. The current value for 1-FCV-074-052 has a spike representing the unseating but there is no spike on current trace for valve 1-FCV-074-066. Was the spring pack data taken the same stroke as the current data? If the current data was obtained after the spring pack data, it is possible that this was the point of separation. What is the measured stem factor for this valve? (MOVATS test traces show that an ETT transducer was used so torque and thrust data should be available to determine stem factor). Also, what model spring packs were installed in the actuators for 1-FCV-074-066 and 1-FCV-074-052?*

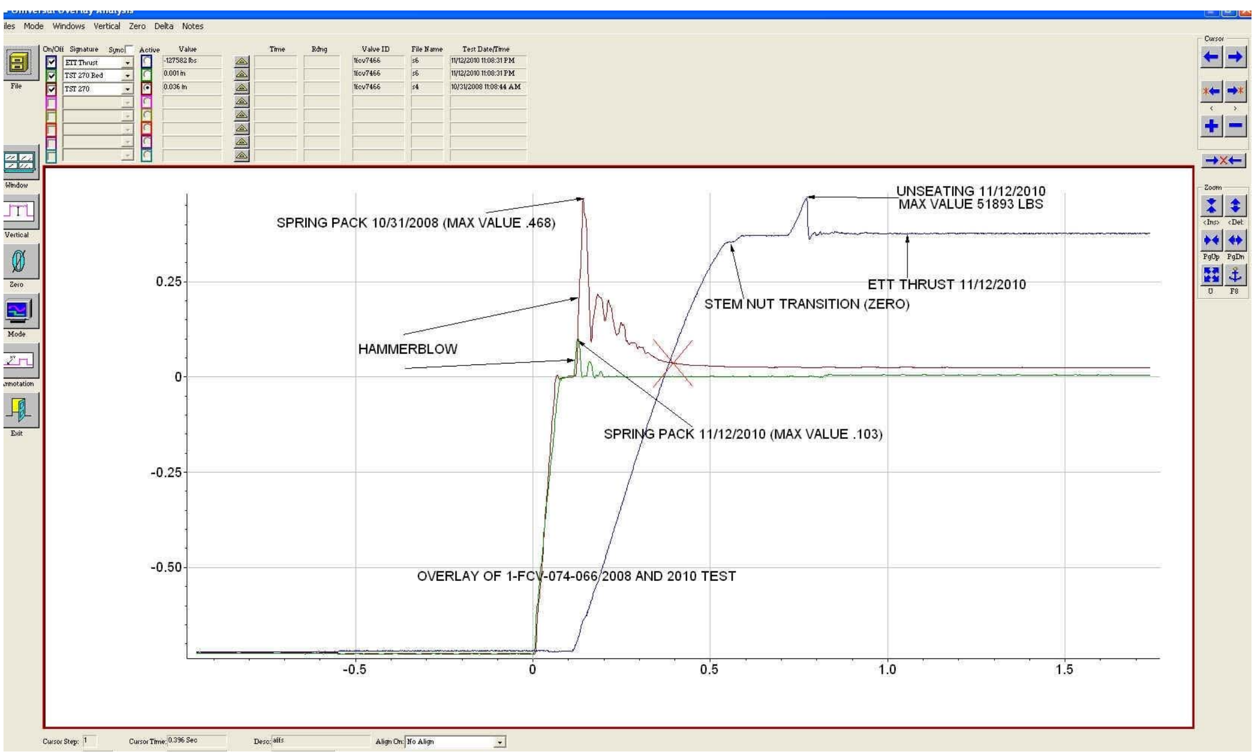
TVA Response:

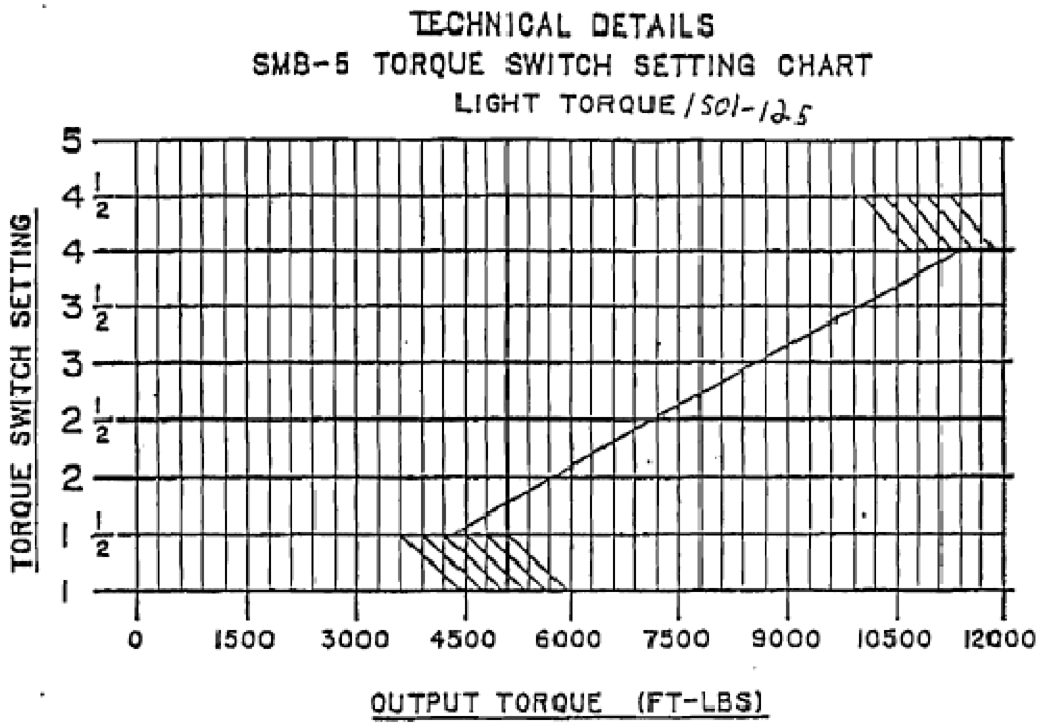
The spike (maximum deflection) on the 10/31/2008 spring pack curve is an indication of hammer blow and not unseating. Refer to the supplied overlay of test data that compared the spring pack curves between the 2008 and 2010 tests as well as the thrust curve of the 2010 test. Although the vertical axis is not the same (spring pack deflection vs. thrust), the horizontal axis is time for both curves. One can observe that the unseating is much later (well after stem nut transition) than the hammer blow event. The spring pack deflection is such a coarse measurement that one would not expect to observe unseating event. The estimated force of 150,000 lbs of thrust is associated with the hammer blow and not unseating. Therefore, this value is not expected to increase as the COF increases to a plateau over time.

Yes, the spring pack data was taken on the same stroke as the thrust data dated October 31, 2008.

Due to the location of the Easy Torque Thrust (ETT) transducer (below the anti-rotation device) the test cannot obtain the torque value. Therefore, the stem factor was not determined.

The spring pack model is Limitorque 1501-125 for both the 1-FCV-074-066 and 1-FCV-074-052 actuators.




TECHNICAL DETAILS
SMB-5 TORQUE SWITCH SETTING CHART
LIGHT TORQUE /501-125
TORQUE SWITCH SETTING
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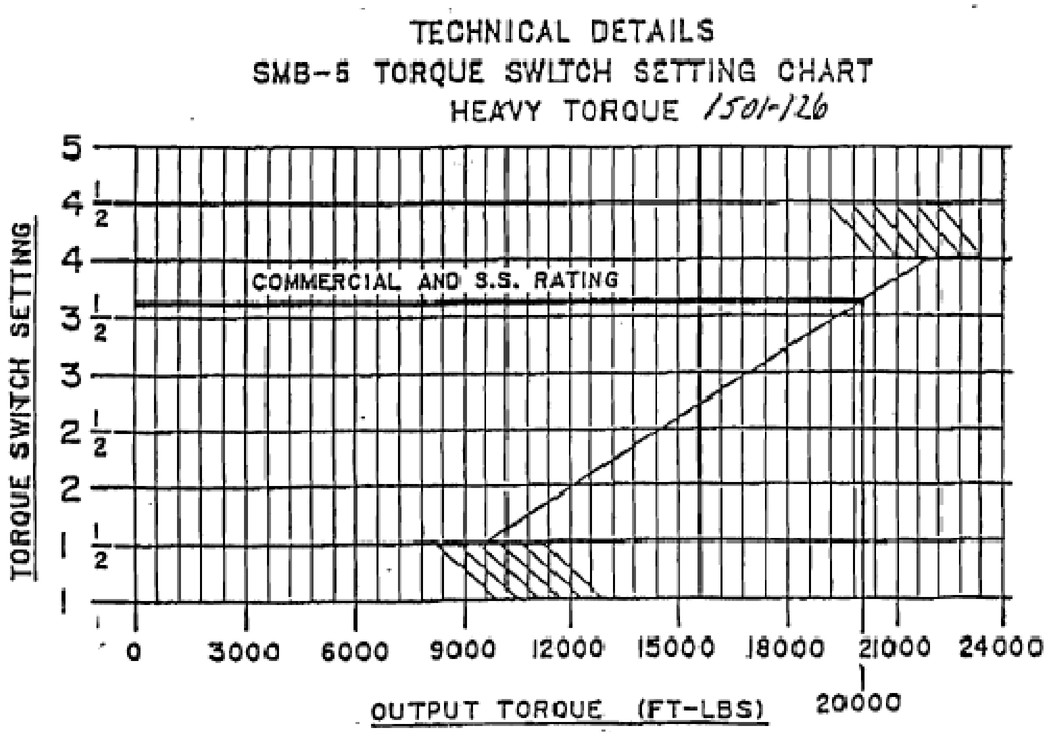
4 1/2
4
3 1/2
3
2 1/2
2
1 1/2
1
0
1500
3000
4500
6000
7500
9000
10500
12000
OUTPUT TORQUE (FT-LBS)


TECHNICAL DETAILS
SMB-5 TORQUE SWITCH SETTING CHART
HEAVY TORQUE /501-126
TORQUE SWITCH SETTING
COMMERCIAL AND S.S. RATING
5
4 1/2
4
3 1/2
3
2 1/2
2
1 1/2
1
0
3000
6000
9000
12000
15000
18000
21000
24000
20000
OUTPUT TORQUE (FT-LBS)

8) *Were the static unseating values on the other five RHR outboard injection valves consistent as compared to the total seating thrust applied? Were the unseating values on the other five valves consistent from test to test?*

TVA Response:

At this time the only accurate thrust data is the single point MOVATS data (from Table A5.2, page 68 of the Root Cause Analysis). It is supported by the current traces (qualitative data from all six valves) and other inspection technique results as identified by the Root Cause Analysis. The valves were not previously in the MOV program because they were passive valves as determined by the TVA evaluations performed for NRC Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." As an enhancement these valves have been incorporated into the MOV program to improve performance monitoring.

9) *Page 18 of the RCA report has a discussion attempting to quantify the strain normal force of the body seat that exerts on the disc. The force is estimated utilizing MOVATS calculated closing and opening thrust and static load balances. What does this mean? The discussion also attempted to correlate COF to be .33 which is close to published data for aged stellite after two strokes. A nominal value of .4 for COF is used to reflect actual conditions. This appears to be non conservative. Explain. Other studies (EPRI, INEL, JOG) involving stellite on stellite friction testing yielded higher values of COF. A nominal value of COF for materials at a 15 degree angle would be .68. Another unknown is the condition of the seat and disc edges. Were they sharp or chamfered? EPRI testing concluded that disc and seat with sharp edges can yield inconsistent friction results and be unpredictable in their performance as it relates to friction. Published data was used for justifying a nominal .4 COF value. This does not appear to be consistently applied. The published report dealt with sliding surfaces in contact simulating a gate valve. The failed valve was a globe and would not experience the same sliding action on the surface area. How were these apparent inconsistencies resolved or reconciled to achieve credible results?*

TVA Response:

The sum of the total forces acting in the vertical direction has to equal zero during seating and unseating. The two equations (seating and unseating) have two unknowns (COF and normal force). These unknowns can be solved to determine the valve body normal force and the COF (0.33) conservatively assuming the kinematic (closing) COF is 80% of the static (opening) COF.

Strain gages applied to the stem were used during the October 2010 refueling outage to accurately measure the closing force and the opening force. A value of 0.4 was chosen based on the INEEL report for aged satellite (see answer to question 22) and 2010 stain gage results rather than selecting a bounding number provided by other references and was used consistently. This globe valve disc seat does not have sharp edges since it is chamfered.

10) On page 20 of the RCS report. nonconforming conditions were identified as:

1) Disc skirt thread diameter undersized
2) Lower keyway disc locking key not installed
3) Disc washer missing
4) Damaged internal disk threads

Why weren't the undersized skirt to disc tack welds on this list? On page 26 of the RCA report, it specifically stated that the welds were identified as a nonconforming condition because they were "undersized and of poor quality". Provide a detailed explanation of why the undersized welds were not related, or contributed, to the 74-66 valve failure, or explain why the welds were not a nonconforming condition.

TVA Response:

This was an oversight; however, it is discussed on page 26 of the RCA. The undersized tack welds were considered a non-conforming condition on 1-FCV-074-0066, which was returned to the proper design configuration during the U1R8 refueling outage in November 2010. As depicted in the weak link analysis the tack weld is not credited for having any structural capacity thus was not considered as being a contributor to the failure in the RCA. The modeling of the weld fracture was important to understand the failure mechanisms and ultimate capacities combined (Weld and Threads) to bound the condition and make determinations for a failure mechanism (i.e. reactor back pressure).

The undersized welds were not considered a contributing cause since they are not credited in the design to handle axial loads. The full sized threads are designed to handle the full reactor backpressure. Additionally, threads on the other valves have not been validated to be undersized. It should also be noted that no other force can stress the undersized threads and the weld to the point of failure and the metallurgical analysis clearly demonstrates that the full length of threads were deformed and fractured due to a force in the pullout direction.

From the Structural Integrity report, the cases with thread engagement show that, if the threads and welds are assumed to share the load, the weld stresses are reduced by about a factor of 4 because the threads take the bulk of the load. However, the thread displacement at maximum weld stress was found to be on the order of 0.005 inches, while the possible thread clearance is seen from Figure 2 to be on the order of ½ the thread pitch, or 0.042 inches. So, if the threaded joint was not preloaded, or lost preload due to thread deformation, then primarily the weld would take the load, as in the zero thread engagement cases, until the weld failed, irrespective of the weld size being 0.2 or 0.5 inches. Once the weld failed, then exclusively the threads would take the load. To address this condition, and to independently check the thread shear strength calculations, finite element analyses were also performed for the case of thread engagement but no weld, with the entire load being taken by the undersized threads.

11) *Page 28 of the RCA report - MOVATS data reviewed from 1996 - 2010. A statement was made that new or refurbished stellite is not expected to show an unseating force due to low COF (< .268). This statement conflicts with the failed valve post static test. After the valve had been reworked, the data showed an unseating force of 51,893 #. Explain.*

TVA Response:

It is true that we observed unseating in the MOVATS trace of November 12, 2010. The reason we did not observe the unseating in the past (2006) is that the stellite surface was relatively new and the COF is lower. With the additional time, the stellite surface has aged and the COF is high enough to observe the unseating. It would be anticipated that the unseating forces would be observed in 2008 however, the stem and disc were already separated. The seats were not machined in 2010 when the valve was repaired and therefore the aging stellite surfaces were not disturbed.

12) *Page 28 of the RCA report - Weakness identified in the acceptance of MOVATS test data where no detection of unseating was considered. The acceptance was based on limited knowledge of aging stellite and the effects on the COF. This limited knowledge was used to provide a basis for not establishing further investigation, which could have identified the separation. Although based on industry knowledge of globe valves for a lack of unseating being shown, the justification basis for not seeing unseating was deemed to have been justified at the time. Why is this conclusion not in conflict with the maintenance data being shown in Attachment 3. If test personnel were knowledgeable on stellite aging and saw no unseating force, a questioning attitude should have challenged this test. Explain why not. Also, what has the licensee done with respect to the test data on 3-FCV-074-052? Maintenance history shows that the valve was modified in 1995. MOVATS test data show unseating in tests completed in 1998 and 2000 but has no unseating on the next tests in 2002 and 2004, but again shows unseating in 2006 and 2008 but not in 2010. The maintenance history assessment in Attachment 3 only addresses the inconsistency by stating that there was a "potential that unseating may not be observed on a globe valve trace." What assurance is there in the reliability of unseating being a constant with respect to COF?*

TVA Response:

The old maintenance data shown in Attachment 3 (Table A5.1) of the RCA, indicated that unseating events were observed for 3-FCV-074-52. However, such observations were not supported with thrust traces, rather by current traces (partial MOVATS). The Table A5.1 information was developed with the available partial MOVATS data from the past. No thrust values were available. Since these passive valves were not part of the MOV program, detailed analysis is not expected to be performed. Additionally, unseating forces are not significant for a normally open valve.

Because of the effective seat cleaning capability from the high contact stresses associated with stroking globe valves (see answer to question 22) the COF may be reduced below the tangent of the seat angle (0.268 for 15 degrees) and not show any unseating force. This valve was inspected and the results indicated the stem-disc is intact. Going forward, these valves will be maintained by the MOV Program. The program requires thrust and current data to be collected.

Additionally, operational constraints were instituted to restrict pressure differential across the valve until it can be returned to design.

MPR-2524-A, Joint Owners Group (JOG) Motor Operated Valve Periodic Verification Program Summary is approved by the NRC. MPR-2524-A provides guidance that new and rebuilt valves COF and VF are on a slope until it plateaus over a period of time and remains constant unless disturbed by stroking. The INEEL report demonstrates this concept by testing and natural aging. The MOVATs data determined in the 2010 provides sufficient assurance that the design values COFs is within the design basis for the MOV.

13) *Page 29 of the RCA report - Discussion states that performance monitoring program has a weakness in that it does not provide enough criteria for establishing anomalies with respect to aging stellite. The conclusion states "Enhancement of program knowledge should include the effects of aging stellite on the COF to establish when unseating should be seen for globe valves." What is the explanation for the inconsistent performance of 3-FCV-074-052 unseating going back and forth (seen and unseen)? How will this be addressed in the future?*

TVA Response:

Refer to question 12 for additional information regarding 3-FCV-074-52. As we transition the responsibility of this group of MOVs to the MOV Program, the performance will be monitored and trended by the MOV Program. Furthermore, due to the past history of stem separation, the thrust trace evaluation will be supplemented by the current trace evaluation. The safety function for these valves is to open. The program actions will be to ensure that they are open as required. The lessons learned from this Root Cause Analysis Report will be incorporated into those program actions.

14) *Was any attempt made by the licensee to calculate the actual force it took to "pop" the 1FCV- 74-66 valve disc loose? Did the licensee evaluate the actual force used to pull out the stuck 74-66 to validate or bound the assumptions and results of their analysis and testing? If this evaluation was accomplished what were the conclusions? If this evaluation was not accomplished, then why not? Also, provide a complete description of the lift calculations, equipment, set-up, and any additional actions (e.g., thermal stress relief) that would allow the NRC to <u>analyze</u> the actual lift forces used to break free the stuck 74-66 valve disc?*

TVA Response:

It should be noted that the mass of the valve internals and the actuator capability would be expected to lodge the disc into the seat. The lifting rig used to disassemble the valve was not instrumented to record the force required and therefore no evaluation was performed. Recording this data would not have been feasible because of the uncertainty related to suddenness of releasing the disc and inability to accurately control metal temperatures without installing thermocouples.

15) *Describe any internal or external industry operating experience (OE) regarding this phenomenon of separated valve disks that were stuck in their seats which subsequently vibrated loose after a period of time?*

TVA Response:

A similar experience provided by Performance Improvement International (PII) was at San Onofre Unit 1, 1987-1988. Dr. Chong Chiu was the Assistant Technical Manager of San Onofre Station at that time, when a temporary loss of water flow issue in the heater drain pump that caused temporary water level changes in the drain tank occurred. After a few minutes, the flow resumed. Later, the control valve stem-disc was found separated and the disc was temporarily stuck in the seat (as the only possible explanation of temporary loss of flow). This case is similar to the Browns Ferry valve stuck-and-release case experienced. However, the San Onofre event was apparently not reported as OE generally available to the industry.

16) *The root cause (i.e., under-sized upper skirt threads) would imply a 10 CFR 21 notification would be warranted. Has the vendor/supplier been notified or involved with the root cause determination? Does the vendor/supplier agree with the root cause?*

TVA Response:

TVA concurs that the undersized threads condition is 10 CFR 21 reportable and for this reason made this report via a Licensee Event Report revision.

The vendor (Crane Nuclear, current owner of Walworth Valve) was consulted during the investigation to determine specific attributes of the valve, vendor drawings, and available documentation. The Crane representative concurred with the root cause and also that the measurement of thread diameter would not be expected to be performed by the customer. The supplier (GE) was notified of the findings of the root cause and (based upon our notification to them) entered this issue in their corrective action program for evaluation as a potential 10 CFR 21 finding.

17) *What is the technical basis and empirical evidence that back-pressure conditions actually existed on the 1-FCV-74-66 valve following periodic stroke testing of the inboard RHR injection valve (1-FCV-74-67)? What is the technical basis and empirical evidence that similar back-pressure conditions did not exist to the same degree or worse for the other inboard/outboard RHR injection valves (i.e., 1/2/3-FCV-74-52/66)? What is the technical basis and empirical evidence that would explain why all the other inboard/outboard RHR injection valves were sufficiently different in design, maintenance, operation, or physical condition to not experience similar back-pressure conditions resulting in valve failure?*

TVA Response:

Note: TVA will provide the response to this question separately.

18) *In determining the maximum pressure differential of 251 psid across the closed separated FCV-74-66 valve disc (see page 16 of the RCA), the licensee assumed the associated RHR pump was started 10 minutes earlier per the safe shutdown instructions (SSI). How is this consistent with the SSI caution not to run an RHR pump greater than seven minutes without flow?*

TVA Response:

The Safe Shutdown Analysis (SSA) assumes for conservatism that the Residual Heat Removal (RHR) pump is started and rapid depressurization is initiated at 30 minutes resulting in LPCI injection at 35 minutes with peak clad temperature (PCT) remaining below 1500 degrees F for the limiting case. The Safe Shutdown Instructions (SSIs) ensure that the RHR pump is started and rapid depressurization is initiated no later than 20 minutes, which results in LPCI injection at 25 minutes. The SSI initiation is 10 minutes sooner than the SSA assumption of 30 minutes. The results of testing and analyses indicate that 1-FCV-74-66 would have opened and injection from the RHR pump would have initiated within no more than seven minutes of starting the RHR pump. Assuming it takes the seven minutes for the valve to open, injection would occur at 27 minutes, which is well within the limiting case value of 35 minutes from the SSA. The seven-minute time period is also within the time period specified in the SSI caution note for running the RHR pump without flow. The SSI caution note states, “RHR pump should NOT exceed 7 and 1/2 minutes in service without a viable flow path to prevent exceeding pump design limits.” Therefore, assurance is provided that the Appendix R peak clad temperature would have been satisfied.

19) *What is the reason for assuming the undersized threads of FCV-74-66 could not be preloaded when the upper skirt was threaded onto the valve disc? Even if the full anticipated pre-load could not be established, what is the basis for assuming the threads were not in contact and load bearing when the tack welds were made?*

TVA Response:

The models generated by Structural Integrity have assumed the skirt was in contact with the disc. The analysis considers both a pre-load and no pre-load as a method to bound the condition. The relative thread displacement was determined using the maximum load for determining the maximum stress in the weld under a no pre-load condition whether it was assembled incorrectly or due to thread deformation due to undersized threads.

20) *What is the basis for assuming the tack welds, and the undersized welds, were loaded sequentially and not concurrently? Was it possible that the FCV-74-66 tack welds and undersized threads were actually sharing the pull out load? What is the difference in the pullout load carrying capacity between FCV-74-66 (with undersized threads and undersized welds sharing the load), and another valve (e.g., 1-FCV-74-52) with undersized threads but with properly sized welds sharing the load? Would FCV-74-66, with both the undersized threads and welds sharing the load, be capable of carrying the calculated pull out load assumed during maximum back pressure conditions? What about FCV-74-52?*

TVA Response:

The potential for load sharing between the threads and the tack weld was addressed as follows. The Structural Integrity analysis concluded that the threads take the bulk of the load under that condition, and would deform under a single application of the opening thrust load with full backpressure (similar to the deformed condition observed in the threads). Once this deformation occurred; the weld would take the bulk of the load upon subsequent applications, and the undersized weld in valve 1-FCV-74-66 is predicted to fail.

From the Structural Integrity report, the cases with thread engagement show that, if the threads and welds are assumed to share the load, the weld stresses are reduced by about a factor of 4 because the threads take the bulk of the load. However, the thread displacement at maximum weld stress was found to be on the order of 0.005 inches, while the possible thread clearance is on the order of ½ the thread pitch, or 0.042 inches. So, if the threaded joint was not preloaded, or lost preload due to thread deformation, then primarily the weld would take the load, as in the zero thread engagement cases, until the weld failed, or excessively exceeds design irrespective of the weld size being 0.2 or 0.5 inches. Once the weld failed, then exclusively the threads would take the load. To address this condition, and to independently check the thread shear strength calculations, finite element analyses were also performed for the case of thread engagement but no weld, with the entire load being taken by the undersized threads.

21) *Why are single point MOVATS data comparisons sufficient to support the conclusion statements made in the RCA? Explain using the data from testing of all six valves from all three test cycles for comparison.*

TVA Response:

Not seeing unseating force during the November 2008 current trace was consistent with the metallurgical forensics analysis that determined the fractured weld existed in an oxygenated environment for a significant amount of time. Although the cleaning affect from stroking globe valves may reduce the COF below that which would show unseating like 3-FCV-74-52, all other current unseating traces on the four remaining valves showed unseating consistent with the aged stellite INEEL report. The 2010 full MOVATs trace performed on the 1-FCV-74-66 aged stellite seats demonstrates that it will show unseating similar to the other four valves after stroking.

22) *Is the determination that valve seating surfaces COF are analogous to "second stoke" COF a reasonable assumption based on the following?*
    - *Without being able to identify when the valve failure occurred, what is the basis to assume with any confidence that the valve was cycled just prior to the last closing event before it failed?*
    - *The reduction in COF shown during subsequent strokes in the INEEL report is attributed in part to the sustained relative surface motion between the samples causing plastic deformation and fracture of granular surfaces of the corrosion products. Globe valve seats do not go undergo a sustained period of relative motion between the seating surfaces.*

TVA Response:

The 1-FCV-74-66 valve disc successfully lifted when shutdown cooling began in March of 2009 effectively releasing the captured oxidation particles. The valve was then closed in accordance with the procedure after securing from shutdown cooling. Although globe valves have a shorter sliding distance on the seat, relative contact stresses are much higher based on the smaller contact surface areas offsetting the sustained relative motion. This can be seen by the relatively low industry MOVATS globe valve unseating forces. During the mockup, testing surfaces were roughened to increase the COF. Significant reductions in the COF was observed after each high compression stroke; greater change from the first stroke then getting less with each subsequent stroke moving closer to the un-roughened surface. The observed changes were much greater than those published in the INEEL report. The maximum sustained static (at the beginning of the stroke) COF before any strokes in the INEEL is 0.5 and 0.38 after one stroke. The evaluation of 1-FCV-074-66 conservatively assumes a static COF of 0.4.

23) *In 2008, the licensee attempted to vent FCV-74-66 using the bonnet vent line, but was unsuccessful. Instead of a solid stream of water, only two cups of water came out. WO 08-723813-000 was then initiated to perform the necessary maintenance to clear the presumed vent line plugging. However, subsequent maintenance during U1R8 refueling outage, did not identify any plugging (i.e., the line was determined to be clear). What opportunity did the licensee have, or miss, in recognizing that the valve bonnet vent line was not plugged but rather the FCV-74-66 valve disc was stuck in its seat preventing any flow through the vent line?*

TVA Response:

Work Order (WO) 08-723813-000 was initiated to perform the necessary maintenance to clear the vent line. The WO required the vent valves to be cut out and then verification that the vent line was clear was made back to the 1-FCV-074-066 as part of WO verification process prior to reinstalling the vent valves to ensure reliability. The obstruction was removed as previously reported in WO 08-723810-000 and corrected non-conformances identified by PER 156971. Since plugging of the vent line was the obvious cause and there was no reason to suspect the disc was lodged into the valve body, an acceptable ultrasonic (UT) method (procedure SR-1-3.5.1.1) was used to validate the piping to be full of water. It should also be noted that the lack of reliability to vent RHR Loop I was reported on October 3, 2008 and RHR Loop II on November 11, 2008.

24) *What's the basis for assuming operators would be successful in executing the SSI's given the degraded condition of the FCV-74-66 valve? Does past training and operating experience suggest operators would have waited up to seven minutes before securing the Loop II RHR due to no observed flow, especially considering operators secured RHR after less than two minutes on October 23, 2010 when procedure instructions allowed three minutes? During operation of Loop II RHR in alternate safe shutdown per the SSIs, with a degraded FCV 74-66 valve (i.e., detached from the stem), would the 120 to 215 psig pressure band for controlling reactor pressure still be appropriate for ensuring adequate RHR flow? Was this verified by analysis or testing?*

TVA Response:

The circumstances are considerably different for placing RHR in shutdown cooling versus entry into the Safe Shutdown Instructions (SSIs) due to a significant fire event. The circumstances when the valve failure was identified on October 23, 2010, involved placing RHR in shutdown cooling after a planned shutdown for a refueling outage. Under these conditions, RHR flow is expected to occur immediately upon starting of the RHR pump since reactor pressure would already be below the shutoff head of the RHR pump. The plant was not experiencing any accident, transient or external/internal event. The operators secured the pump after a reasonable amount of time and successfully placed RHR Loop I in shutdown cooling. The circumstances associated with placing RHR in alternate shutdown cooling in accordance with the SSIs during an Appendix R event are considerably different. Entry into the SSIs places the plant in a unique alignment that ensures one train is free of fire damage. The operator starts the RHR pump well before reactor pressure is below the shutoff head of the pump. The operator is trained and knows that injection flow will not be seen until reactor pressure drops to a sufficient value (e.g., below the shutoff head of the RHR pump). The typical time between RHR pump start and flow initiation is approximately 5 minutes per the Safe Shutdown Analysis. Additionally, in this situation, the operator's priority is protection of the reactor core. Therefore, the operator would not secure the running RHR pump. Instead, another operator would be dispatched to the field to determine the reason for lack of flow. It is reasonable to assume the operator would allow the RHR pump to run for the full seven and a half minutes per the caution note in the SSIs.

With respect to the pressure band for controlling reactor pressure to ensure adequate RHR flow; the pressure band for controlling reactor pressure would still be appropriate for ensuring adequate RHR flow. Based on analysis, the differential pressure required to lift the disk is small (i.e., 2.45 psi) compared to the differential pressure across the disk (i.e., a minimum of 60 psi) when the minimum required RHR injection flow is being supplied in accordance with SSI alternate shutdown cooling.

25) *Was it possible for operators to exceed the SSI timelines while they attempted to execute the SSIs given that the degraded FCV-74-66 valve would have caused an unexpected delay in the initiation of RHR flow?*

TVA Response:

The results of testing and analyses indicate that 1-FCV-74-66 would have opened and injection from the RHR pump would have been initiated within no more than seven minutes. Initiating flow within the seven-minute time period fully complies with 10 CFR 50 Appendix R Safe Shutdown Analysis and the Safe Shutdown Instructions. As discussed in the response to question 18, even with the potential delay in the opening of valve 1-FCV-74-66, RHR flow would have been established within 27 minutes versus the analyzed time of 35 minutes contained in the SSA.

Browns Ferry Unit 1 FCV-074-066
RHR Outboard Injection Valve Failure
NRC Questions (#2)

During the TVA/NRC Regulatory Conference in Atlanta, GA on April 4, 2011, the NRC staff requested TVA to address the following questions and/or provide additional information regarding their presentation and the root cause analysis (RCA) for PER 271338, 1-FCV-074-066 RHR Outboard (Loop 2) Valve Failure:

1) *Provide detailed fire modeling information (e.g., ignition frequencies, fire propagation, severity factors, suppression, etc.) from the licensee's NFPA-805 transition work for the scenarios identified in NRC's Phase 3 Significance Determination Process issued March 2, 2011. Also, provide cable routing information on the post-fire availability of alternate systems (e.g., core spray, the opposite loop of RHR/LPCI, HPCI, RCIC, etc.)?*

TVA Response

The work on the Browns Ferry Nuclear Plant (BFN) Fire Probabilistic Risk Assessment (PRA) to support transition to NFPA-805 is still ongoing. The detailed fire modeling of BFN plant-specific configurations for fire scenarios considered in the NRC Significance Determination Process (SDP) evaluation has not yet started. However, as part of the transition to 10 CFR 50.48(c), the NRC has communicated to the industry that its expectations are very high for justifications of treatment outside of the methods provided in NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities," dated September 2005. As an example, the FAQ process demonstrated that even strong technical work done by the Electric Power Research Institute (EPRI) was insufficient to convince the staff to allow relaxation of conservative assumptions documented in NUREG/CR-6850 in favor of more realistic assumptions. As a result, the Browns Ferry Fire PRA is being performed using the guidance provided in NUREG/CR-6850 and related FAQs. In addition, fire modeling performed to support the BFN transition to NFPA-805 will be in accordance with NRC guidance. Therefore, the conservatism inherent in the NUREG/CR-6850 methodology and related FAQs will bias the calculated results.

The complexity of the Fire PRA (FPRA) process is addressed in NUREG/CR-6850 by establishing a structured set of 17 technical tasks that comprise the systematic evaluation of the fire hazards and risks. Due to practical difficulties, no integrated pilot was ever performed for the process addressed in NUREG/CR-6850. Instead, the pilots tested only individual tasks. Despite the incremental enhancements documented in the FAQ resolutions, the simplifications and bounding assumptions of the methods and data in NUREG/CR-6850 remain obstacles to the goal of plant specific Fire PRAs that realistically reflect fire risks; therefore, it is difficult to use FPRAs in risk-informed decision-making. Following the completion of several FPRAs using the NUREG/CR-6850 methodology, the calculated risk numbers appear to be much higher than those associated with internal events. The Nuclear Energy Institute (NEI), experienced industry fire PRA practitioners, NRC staff, and NRC FPRA contractors met with the NRC Advisory Committee on Reactor Safeguards (ACRS) Reliability and PRA Subcommittee to discuss concerns associated with FPRAs on November 16, 2010, and again on December 13 and 14, 2010. On December 6, 2010, NEI submitted an NEI report, "Roadmap to Attaining Realism in Fire PRAs - December 2010," to the ACRS. The NEI report documents the industry's basis for concern that FPRAs are not providing results that comport with plant operating experience, and provides a roadmap for areas of FPRA requiring further improvement in order to achieve enhanced realism in FPRA methods.

The NEI report provides evidence based on results from current FPRAs that support the observation that the results of the FPRAs are conservative with respect to operating experience. The primary source of the conservatisms is the simplified approach taken in defining fire hazards and the bounding assumptions made in characterizing fire events. The net result is that FPRAs (and Fire SDPs) based on NUREG/CR-6850 are not realistic. The NEI report provides evidence that supports the following:

- Fire characterization does not conform with operating experience
  - Over-prediction of number of severe fires
  - Assumed rate of fire growth and severity, e.g., 12 minutes in electrical cabinets, oil fire severity
  - No credit for control of fires
- The level of risk is overstated
  - Fire PRAs based on NUREG/CR-6850 predict high frequency of fires, but NRC's Accident Sequence Precursor (ASP) has not demonstrated this result
  - Predicted frequency of spurious operations not consistent with operating experience
- Uneven level of conservatism can mask key risk insights and lead to inappropriate decision-making
  - Simplifications result in bounding treatment
  - Assumes plant challenge for all fires, e.g., plant trip
  - No credit for administrative controls

Many of the current FPRAs have used detailed fire modeling, cable and circuit analysis and Human Reliability Analyses (HRA) to improve the calculated results. However, even with such detailed analyses, the calculated results are estimated to be conservative by a factor in the range of 5 to 10 (or perhaps higher) overall (taken from "Achieving Realism in Fire PRA, Insights and Challenges based on Damage States and Associated Frequencies," presented by J. R. Chapman at PSA-2011 - International Topical Meeting on Probabilistic Safety Assessment and Analysis). This estimation is based on comparison of calculated results, such as the frequency of fire damage states to operating experience, as provided by the NRC's ASP program (e.g., based on calculated results, more significant fires should be occurring in the industry than are actually being experienced). The current fire PRA methods would predict that a fire designated as a "significant precursor" would be expected to occur every one to ten years across the industry. However, there has not been a significant precursor involving a fire since implementation of fire protection programs across the industry.

Identified areas of conservatism in current FPRA methodology include the following.

- Fire event data characterization
- Fire severity characterization
- Credit for incipient detection
- Credit for suppression and detection
- Switchgear zone of influence, fire growth assumptions (e.g., incipient fire growth in electrical cabinets)
- Ignition frequency treatment of standby components
- Fire growth assumptions

- Peak heat release rates
- Damage assessment
- Fire modeling
- Treatment of hot shorts
- Human reliability

The degree of conservatism for each of the above areas is not readily quantifiable until EPRI/NRC research is completed and applied.

However, as an example of the degree of conservatism that may be expected for an electrical cabinet fire, the TVA PRA group has performed a sensitivity study of refined heat release rate distribution and fire growth assumptions based on ideas discussed with the ACRS Reliability and PRA Subcommittee during the meeting in December 2010. The results indicate that the fire non-suppression probability may be reduced by a factor of 10 or more if more realistic characterization of an electrical cabinet fire is applied in fire risk estimates.

Other conservatisms exist as a result of BFN plant-specific non-quantifiable factors. Defense-in-depth measures and compensatory actions (such as the dedicated On-Site Fire Department and the roving fire watches) are not currently explicitly quantified in the FPRA methodology addressed in NUREG/CR-6850. Other non-quantifiable factors, under the current FPRA methodology, that will reduce the fire risk include the existence of fire retardant on the cable, the presence of cable tray covers, and the fact that almost 100% of BFN power cables have thermoset material jackets (currently self-ignited cable fires are required to be assumed for plant configurations with partial thermoplastic cables). Thermoset cables use a cross link polymer chain material that does not melt and is much more resistant to fire damage.

In conclusion, current FPRA and SDP methodology using NUREG/CR-6850 and related FAQs contain significant conservatism. As a result, the quantification of fire risk using this methodology can bias the SDP results substantially and result in over-prediction of fire risk associated with a finding for which the significance is dominated by fire. As such, TVA considers that it is more appropriate to use Inspection Manual Chapter 0609, Appendix M to evaluate the significance associated with the failure of valve 1-FCV-74-66.

With respect to cable routing information on the post-fire availability of alternate fire safe shutdown systems, the current level of cable routing and associated data entry being performed for the BFN NFPA-805 transition does not support providing, in a timely manner, more detailed information than the information that was gathered and provided to the NRC during the Appendix R Operator Manual Action SDP evaluation. The following information on the post-fire availability of alternate fire safe shutdown systems is provided consistent with the approach taken during the Appendix R Operator Manual Action SDP evaluation.

- To better understand the scenarios that had been proposed for the previous Appendix R Operator Manual Action SDP, detailed evaluations of individual scenarios were undertaken at BFN by Site Engineering and Operations. Initially, the individual scenarios were walked down to determine target sets and begin data analysis. Electrical Design personnel evaluated each target set to determine what equipment is impacted by the fire ignition source and assumed damage. Complete detailed circuit review was not completed. Many cables that are included in the analysis may not cause failure of the associated equipment. However, further evaluation was not performed for every cable. For these cables, the associated equipment was assumed to be impacted by the fire and made unavailable. Therefore this approach is conservative.

- The list of equipment impacted for each scenario was then reviewed by licensed individuals in the BFN Operations organization. An initial assessment was completed to determine if any normal equipment used to achieve and maintain fire safe shutdown was impacted. The results are provided in the Attachment 1 tables for each applicable scenario/fire area. Only those results applicable to the proposed SDP for the valve 1-FCV-74-66 failure have been provided. Components in the tables highlighted in red are impacted and therefore considered to be unavailable due to the fire.

Browns Ferry Unit 1 FCV-074-066
RHR Outboard Injection Valve Failure
NRC Questions (#2)

NRC Scenario from Appendix R Operator Manual Action SDP (Highlighted in orange in Tables)	Heading/Description in Tables	Fire Area
7 & 8	SCENARIO 8 & 9 (AHU Above 4KV SDBD RM)	1-3
2	SCENARIO 2 & 3 (480V RMOV BD 1C)	1-1
41	SCENARIO 33 & 34 (480V RMOV BD 1A)	5
1	SCENARIO 1 (250V RMOV BD 1C)	1-1
19	SCENARIO 24 (3-FCV-74-67)	3-1
21	SCENARIO 26 & 27 (480V RMOV BD 3D)	3-3
22	SCENARIO 28 (3-ACU-031-7205)	3-3
42	SCENARIO 35 (250V RMOV BD 1A)	5
43	SCENARIO 36 & 37 (4KV SD BD A)	5
106A	SCENARIO 115A (Cable Tunnel Intake)	25
44, 45, 46	SCENARIO 38, 39 & 40 (480V SD BD 1A)	6
9 & 10	SCENARIO 10 & 11 (1-XFA-231-TS1A)	1-5
11	SCENARIO 12 & 13 (RPT 1-BDAA-068-0001-II)	1-5
23	SCENARIO 29 (RWCU cabinet)	3-4
24	SCENARIO 30 & 31 (3-BDAA-068-0003I)	3-4
25	SCENARIO 32 (0-XFA-266-0THB)	3-4
69	SCENARIO 82 (U1 GEN BKR AIR COMPRESSOR 1-CMP-35-460B)	25
73	SCENARIO 84 (U2 EXCITER CUBICLE)	25
76	SCENARIO 87 (4160V UNIT BD 2C)	25
77	SCENARIO 88 (4160V COMMON BD B)	25
95	SCENARIO 106 (Cable Trays - 480V TB MOV BD 1C)	25
101	SCENARIO 111 (4KV UNIT BD 3B)	25
102	SCENARIO 112 (480V TMOV BD 3C)	25
103	SCENARIO 113A (North TB U1 & U2 (Bus Duct))	25
103	SCENARIO 113B (North Turbine Building U3)	25
104	SCENARIO 114A (North TB U1 & U2 (Cable Tray))	25
104	SCENARIO 114B (North TB U3 (Cable Tray))	25
105	SCENARIO 116 (Cable Tunnel to XFMR Yard)	25
106 & 106C	SCENARIO 115B (TB Cable Tunnel Tray Horizontal and Vertical)	25
61 & 62	SCENARIO 74 & 75 (4160 UNIT BD 1A)	25
63 & 64	SCENARIO 76 & 77 (4Kv RECIRC BD 1)	25
67 & 68	SCENARIO 80 & 81 (480V LTG BD 1)	25
70, 71, 72	SCENARIO 83 (480V COMMON BD 2)	25
74 & 75	SCENARIO 85 & 86 (4160 UNIT BD 2A)	25
79, 80, 81	SCENARIO 90, 91 & 92 (480V UNIT BD 2B)	25
84 & 85	SCENARIO 95 & 96 (4KV RECIRC BD 3)	25
86 & 87	SCENARIO 97 & 98 (4KV Unit BD 3A)	25
93 & 94	SCENARIO 104 & 105 (480V Common Bd 3)	25
96 & 97	SCENARIO 107 & 108 (4160V UNIT BD 2B)	25
99, 100	SCENARIO 109 & 110 (480V TMOV BD 2C)	25

2) *The Structural Integrity Associates report on the strength of the threaded joint was calculated for shear strength. This calculation was used as the basis for the postulated event that caused the failure. However, actual thread conditions from the Westinghouse report show the following:*

   - *The failure mechanism was a yielding failure causing plastic deformation (beaking) and not thread shearing.*
   - *Only a minority of the threads are documented as having plastic deformation.*
   - *The top thread and most of the second thread (which would have the most thread engagement) do not indicate any deformation.*
   - *There is virtually no deformation to two complete vertical axes of the threads.*

   The actual analysis of the failed joint appears to contradict the assumption that it took a force greater than the joints calculated shear strength to fail the joint. How does this affect the RCA, postulated failure scenario, and other report conclusions?

TVA Response:

As listed in bullet #1 above regarding the failure mechanism, the stress results illustrated in Figure 1 below are based on membrane stress averaged through critical paths in the threads, not shear stress, and are therefore consistent with the deformation pattern observed (beaking). The evidence strongly supports the predominant failure mechanism as pullout. Beaking (plastic deformation) damage to the threads was clearly caused from a shear loading condition because they were undersized, resulting in the pullout. The Westinghouse report (Ref. 1) indicates that a significant number of the threads exhibited plastic deformation, and that the most significant deformation was at the top of the threaded joint (bottom of the figures since they are upside down). Measurements were taken at the 20 degree, 110 degree, 200 degree and 290 degree azimuth locations around the skirt over a total of twenty threads. The beaking phenomenon was most notably observed at the 290 degree location starting at thread number 3 and extending over the next nine threads. Little or no evidence of beaking was observed at the other azimuth locations. Due to the undersized threads, loading would not expect to be uniformly distributed. This observation is very consistent with, and would be expected from undersized threads subjected to asymmetrical or "ratcheting" type loading conditions. This also accounts for no deformation being observed on two completed vertical axes of the threads. Because the threads were undersized leading to asymmetrical loading, this evidence pattern occurred.

Dr. Pete Riccardella (one of the founders of Structural Integrity) reviewed Structural Integrity's supporting analysis regarding this NRC question. His response is provided below.

Response from Structural Integrity (also see original reports (Refs. 2, 3, and 4))

"We disagree with observations (bullets) #2 and #3 above. Figures 2 and 3 below, taken from the Westinghouse Failure Analysis Report, indicate that a significant number of the threads exhibited plastic deformation, and that the most significant deformation was at the top of the threaded joint (bottom of the figures since they are upside down). This is consistent with the loading distribution predicted in Figure 1 below.

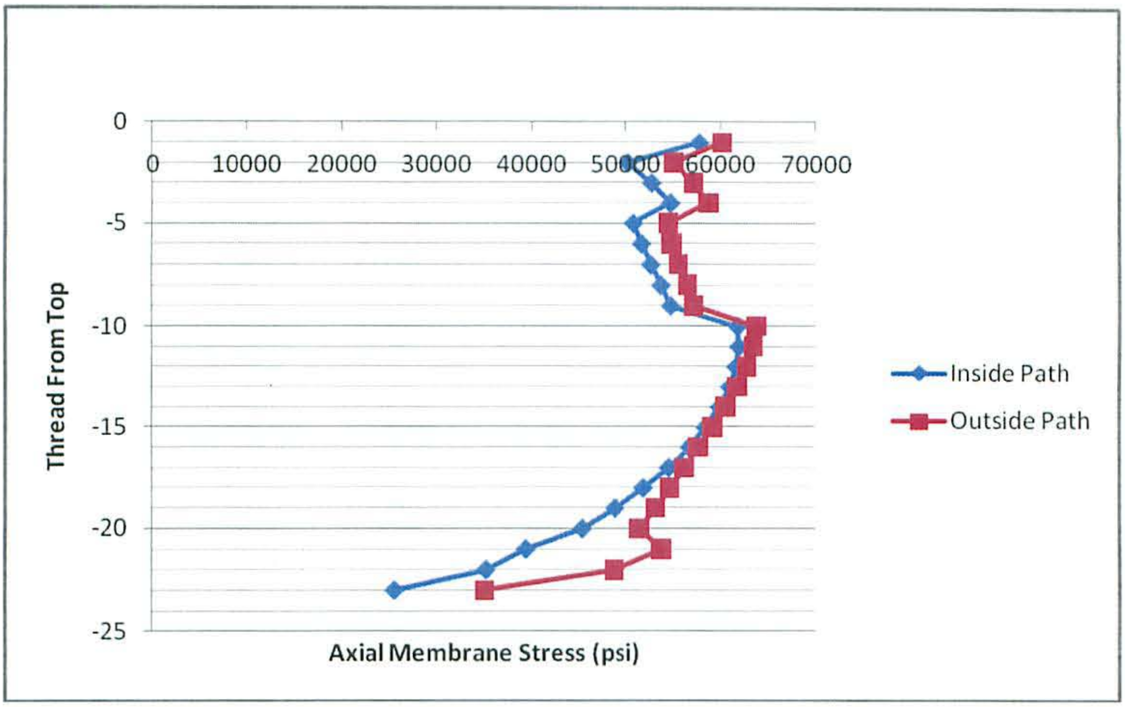


Figure 1 – Finite Element Thread Stress Results at 314 kip Axial Load

The inside path and outside path as well as axial membrane are discussed in Reference 3.

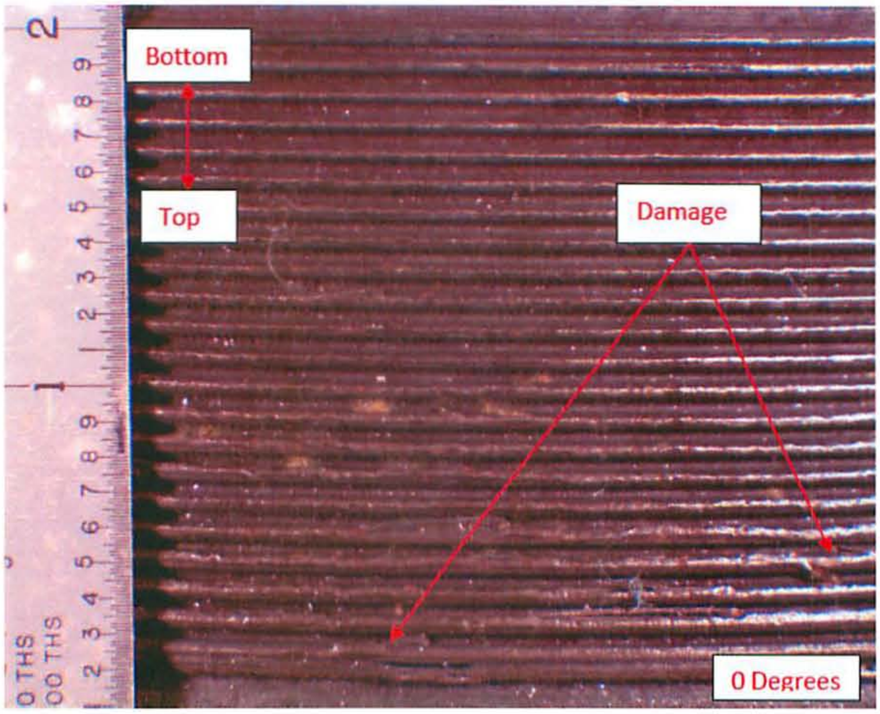


Figure 2 Close-up Macrograph of Skirt Threads, Showing Thread Damage (Fig. 3.3 from Ref. 1)

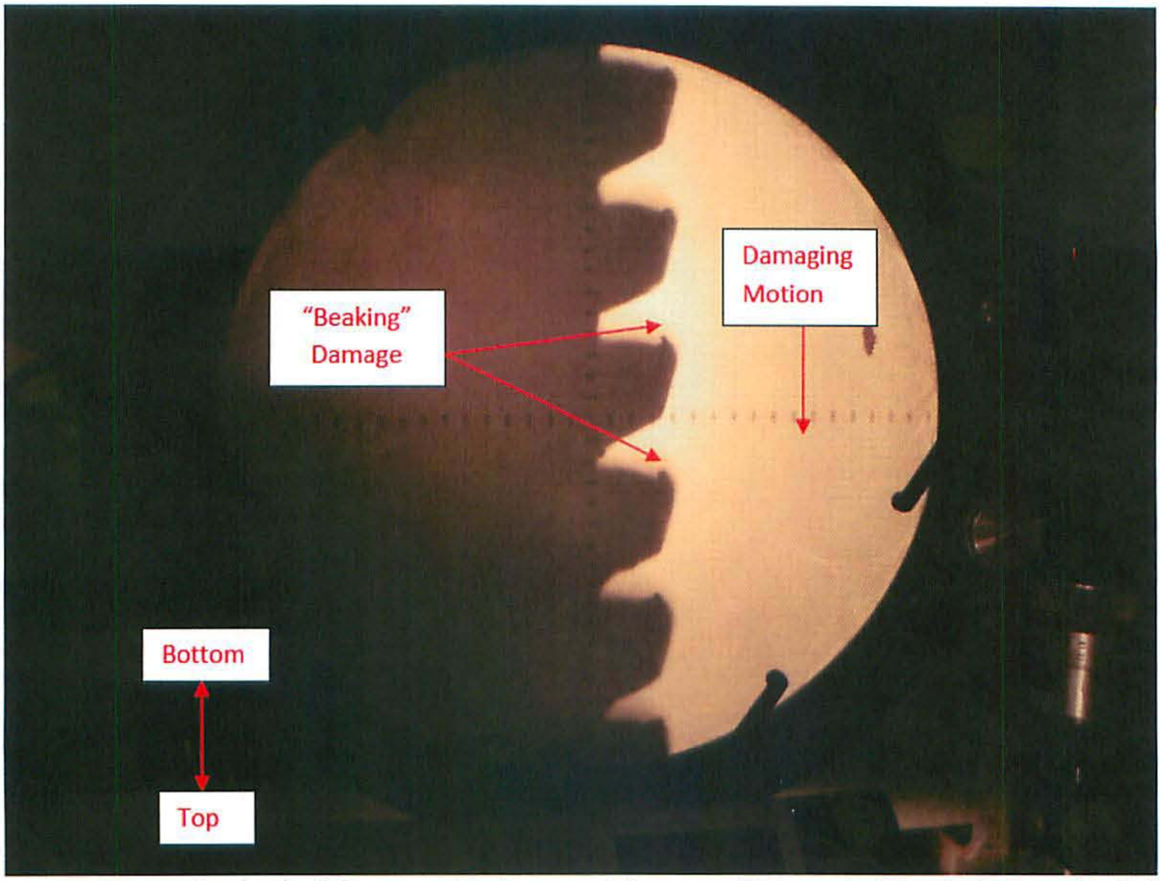


Figure 3 - Optical Comparator Image of Damaged Threads (Fig. 3-10 from Ref. 1)

As listed in bullet #1 above regarding the failure mechanism, the stress results illustrated in Figure 1 above are based on membrane stress averaged through critical paths in the threads, not shear stress, and are therefore consistent with the deformation pattern observed (beaking). Clearly the deformation in Figure 3 is more severe in the threads near the bottom of the figure (top of the joint), although all of the threads appear to be significantly deformed, which is easily visualized if one were to superimpose a symmetrical thread pattern over the thread pattern in the figure. Also, while there might be some undamaged thread regions, it must be recognized that significant clearances (slop) existed in the threaded joint due to the undersized thread condition, such that there may have been a departure from concentric alignment between the skirt and the disc, and thus some amount of rocking may have helped dislodge the two parts.

On the basis of the above, we do not believe that the metallurgical observations of the failed joint contradict the assumptions in our analysis. To the contrary, our analysis is consistent with one of the main conclusions in the Westinghouse Failure Analysis Report, that "The mixed damage forms suggest that the threads were probably not unscrewed but rather were removed by an asymmetrical force or were the result of an inconsistent mating surface in the base."

3) *No quantitative value was presented for the licensee's "high confidence" level of assurance that the 1-FCV-74-66 valve would have performed its safety function for alternate safe shutdown. What is this value? Provide an explanation of the results and methodology of the uncertainty analysis used to justify the licensee's "high confidence" that within seven minutes of RHR pump operation the 1-FCV-74-66 valve would have opened? How ma[n]y scale model tests were actually performed to demonstrate the repeatability of the two initial scale model tests? What were the results?*

TVA Response:

The TVA investigation of the valve skirt/disc separation (i.e., as-found condition) included additional literature reviews which show that friction reduction due to pressure pulsations produced from a running Residual Heat Removal (RHR) pump would have been capable of releasing the lodged disc from the seat. Rather than reach a conclusion based solely upon application of industry research, a highly recognized expert team (Performance Improvement International (PII)) was consulted to design a laboratory mock-up and perform extensive testing to determine if the valve would have functioned in the as-found condition. Actual plant data was collected from RHR Loop II with one RHR pump running to support realistic modeling of pressure pulsation amplitude and frequency. Extensive calibration testing of the laboratory mockup was performed to minimize uncertainties and improve repeatability (over 30 tests) prior to the performance of the actual vibration test using the mock-up.

Section 6.2 in the PII report, "Analysis of the October 23, 2010 BFN-1-FCV-074-066 Shut-Down Cooling Event," dated March 22, 2011, discusses experiment uncertainty. The following calculations provide the design-stage uncertainty associated with the experiment.

Design-Stage Uncertainty

Substituting values from Table 6.9 into Equation 6.3 (both in the PII report), the design-stage uncertainty of strain gauges 1 and 2 and the hydraulic press are 12 με, 20 με, and 0.02 kip respectively. The combined design-stage uncertainty of the strain gauges is

$$u_{d\_sg} = \sqrt{u^2_{d\_sg1} + u^2_{d\_sg2}} \quad (1)$$

where u_{d_sg1} and u_{d_sg2} are the design-stage uncertainty of strain gauges 1 and 2, respectively. Therefore, u_{d_sg} was 23 με throughout calibration testing. Valve body strain throughout calibration testing with the 83 degree set remained at values of 219-277 με both immediately after loading and before being pulled out (open the valve). Strain measurement error was, at most, 8.3-10.5% during these tests. Valve body strain throughout calibration testing with the 75 degree valve set ranged between 353-393 με and 241-268 με immediately after loading and before being pulled out, respectively. Valve body strain measurement errors were, at most, 5.9-6.5% and 8.6-9.5%, respectively after loading and before pullout, during these tests.

University of California San Diego (UCSD), where the tests were performed, laboratory personnel suggested that strain gauge deviation is often much greater (~100 με) than resultant values for $u_{d,sg}$ during testing with similar loading patterns. Section 6.3 of the PII report discusses the time-dependent relationship between friction reduction and valve body release. The 75 degree valve disc was released from its wedged position almost immediately after surface abrasion was reduced significantly at the contacting surface.

Propagation of Error During Vibration Testing

Equation 6.4 of the PII report conveys the interdependence of strain and force variation within the testing sample set and predicts the lower bound of strain measurement error during vibration testing. PII considers that valve body oscillation during testing may have caused strain readings to be significantly lower than their true values. Therefore, only the lower bound of error propagation is of interest. The $\delta\epsilon$ limit is believed to have been -50 to -80 με throughout testing. Variation in $u_{d,sg}$ may have approached this range of values.

Statistical Analysis of Uncertainty

PII is confident in the validity of its test results based on the following. Statistical analysis was performed to verify the likelihood that the 74-66 valve disc would have liberated from its wedged position in less than seven minutes. The percent change in static COF and time required to liberate the valve disc were determined by vibration experiments with the 83 degree and 75 degree valve sets, respectively. Therefore, the accuracy of both parameters was evaluated.

Three vibration tests were performed with the 83 degree valve set. The sample size is very small and no population mean or variance exists for the set. It is therefore appropriate to use a one-sample *t*-interval procedure. This test evaluates the likelihood that the valve disc would have been freed of its wedged position with a static COF change greater than or equal to 18.2% (required under Appendix R operating conditions). A *t*-value is established to determine the probability that disc liberation at this value would not have been possible

$$t_{\alpha/2} = \frac{\bar{x} - \mu_o}{\frac{s}{\sqrt{n}}} \qquad (2)$$

where $\bar{x}$, μ_o, s, and n are the sample mean, value of interest (limiting case), sample standard deviation, and sample size, respectively (Ref. 5, 381-2). The *t*-value is an α/2 quantity since only outliers lower than μ_o are of interest. The sample standard deviation is

$$s = \sqrt{\frac{\Sigma(x - \bar{x})^2}{n - 1}} \qquad (3)$$

where x and $\bar{x}$ are sample values and the sample mean, respectively (Ref. 5, 109). The mean of the three test values provided in Table 6.4 of the PII report is 26.3%. Therefore, s and $t_{\alpha/2}$ are 1.11 and 12.6, respectively. A *t*-table is used to determine the confidence interval associated with the $t_{\alpha/2}$ value. The sample set has

$$df = n - 1 \tag{4}$$

degrees of freedom. Therefore, *df* equals 2. Evaluating *df* in the standard *t*-table and extrapolating yields an $\alpha/2$ value of 0.003 (Ref. 5, A-10). The probability that the maximum change in the 74-66 valve could have overcome normal forces associated with an 18.2% reduction in the static COF is

$$P = 100 * \left(1 - \frac{\alpha}{2}\right) \tag{5}$$

Thus, *P* equals 99.7% and there is very reasonable assurance that the valve disc would have liberated with at least an 18.2% reduction in the static COF.

Two tests were also conducted with the 75 degree valve set to determine the amount of time required to fully abrade the seating surfaces. The 75 degree valve disc was liberated in less than seven minutes in both vibration tests. PII observed no evidence suggesting disc liberation would have required additional time.

Therefore, the laboratory mock-up testing is very credible and provides high confidence (99.7%) that the valve would have provided functional flow within seven minutes.

PII's conclusion is quoted verbatim below:

"...Therefore, PII has assurance that the valve disc would have been released from its wedged position within seven minutes.....A number of conservative measures were applied in both the calculations and the experiment conducted. As a result, PII has a very high confidence in the credibility of its findings. PII has found no safety concerns associated with the October 23, 2010 SDCE [shutdown cooling event]."

4) *The significant force needed to release the stuck FCV-74-66 valve disc from the valve seat indicated that the disc might have been in a thermally bound condition, which was not addressed by the mock-up tests. What was the technical basis that thermal binding was not a factor in the 74-66 disc being stuck in its seat?*

TVA Response:

The outboard injection valve (1-FCV-074-66) is normally open and is in a line maintained full of ambient temperature (<100°F) water by the plant keep-fill system. In the event of excessive leakage past the interlocked closed inboard valve, the water temperature could rise (experience on Unit 2 shows water temperature can get as high as 250°F). However, the normally open outboard valve would only be closed for a short period of time during quarterly operability stroking. The developed temperature gradient across the valve while the valve is being stroked is expected to be minimal since steady state conditions have already been developed while the valve is open and the amount of time during stroking is minimal. Additionally, the history of periodic temperature recording (see table below) demonstrates a negligible amount of heating from leakage past the closed inboard valve. The inboard valve is also stroked while aligning for shutdown cooling at relatively low Reactor Pressure Vessel (RPV) coolant saturation conditions (~80 psig and 325 °F). The thermal gradient developed during this shutdown cooling stroke would also be minimal because of the short stroke duration and the much longer amount of time needed to heat the keep-fill water and the valve. Heating from the bottom was not possible since it was found to not pass flow as soon as the pump was started and secured within 110 seconds. Therefore, thermal binding does not contribute to the disc being lodged in to the seat. See the following paragraph concerning higher temperature gradients from the reactor pressure vessel.

In the hypothetical event that the outlet of the valve is exposed to high temperatures while the valve is closed (or the disc is separated and resting in the valve body seat) the temperature gradient would tend to relieve the body strain rather than increase it. In this event, the inlet disc surface area and large disc trim mass, approximately equal to the disc itself, would be exposed to cool keep-full water including just a small portion of the valve surface area. The top of the disc and the majority of the valve surface area would be exposed to the higher temperature water with a lower density and associated thermal conductivity. Therefore, the insulated valve body would thermally expand more than the disc and relieve the body seating strain; both are carbon steel with the same thermal expansion coefficient. A temperature gradient event from higher inlet temperatures is not considered feasible because of the large volume of cool keep-full water required to be heated during the short time the valve is in the closed position.

The pressure suppression chamber (PSC), keep-fill system is designed to maintain a hydrostatic overpressure on the RHR discharge lines. The RHR system discharge lines are maintained full at all times to prevent the possibility of water-hammer. The RHR System is filled from the PSC head tank, which has ties to the PSC water-transfer pumps for pumping power, or from the condensate transfer system. The PSC head tank pump(s) will start and stop automatically to control the tank level. Both PSC head tank pumps take suction indirectly from the suppression pool via a connection to a Core Spray (CS) pump suction line from the PSC upstream of the pump suction isolation valve. The PSC head tank pump suction line contains two normally open isolation valves. The closed loop (PSC head tank to Emergency Core Cooling System (ECCS) to suppression pool to the PSC transfer pumps back to PSC head tank) assures that the proper suppression pool water level is maintained. Two check valves exist between the ECCS and the PSC head tank and between the ECCS and the Condensate Storage and Supply System to prevent loss of ECCS flow. The PSC transfer pumps are redundant and have separate power supplies. The instrumentation associated with the PSC keep-fill system is redundant. Also, the discharge piping of the RHR system is periodically vented from the high point of the system and water flow determined in accordance with Technical Specifications Surveillance Requirements. Verification that the systems are vented and filled is also required by plant procedures following periods of inoperability or maintenance on these systems as required demonstrating system operability. Temperature of the keep-fill system varies depending on source (Suppression Pool or Condensate). The PSC keep-fill system temperature when the source is the suppression pool is consistent with the temperature of the suppression pool, while the PSC keep-fill system temperature when the source is condensate is more dependent on the ambient temperatures of the environment. Typical temperatures of the keep-fill system are provided below which are taken in proximity to the valve. As can be seen clearly from the discussion and the temperature profiles of the keep-fill system, thermal binding was not was an issue with the 1-FCV-074-66 valve.

Pipe	Pipe temp (F)	Date Reviewed/Calibration Date	Pipe	Pipe temp (F)	Date Reviewed/Calibration Date
RHR Loop I	88.7	10/22/2008	RHR Loop II	<100	11/12/2008
RHR Loop I	<100	11/20/2008	RHR Loop II	<100	12/09/2008
RHR Loop I	<100	12/29/2008	RHR Loop II	<100	01/02/2009
RHR Loop I	84.7	01/26/2009	RHR Loop II	74	01/30/2009
RHR Loop I	102.3	02/26/2009	RHR Loop II	87.3	03/02/2009
RHR Loop I	89.7	03/09/2009	RHR Loop II	90.5	03/09/2009
RHR Loop I	92.4	03/10/2009	RHR Loop II	72.5	03/24/2009
RHR Loop I	71.2	03/20/2009	RHR Loop II	79.3	04/24/2009
RHR Loop I	73.4	04/20/2009	RHR Loop II	91.1	06/29/2009
RHR Loop I	74.4	05/14/2009	RHR Loop II	<100	10/16/2009
RHR Loop I	90.3	06/15/2009	RHR Loop II	<100	11/13/2009
RHR Loop I	93.2	07/14/2009	RHR Loop II	<100	12/08/2009
RHR Loop I	92.4	08/06/2009	RHR Loop II	<100	01/15/2010
RHR Loop I	<100	09/18/2009	RHR Loop II	<100	02/12/2010
RHR Loop I	<100	10/08/2009	RHR Loop II	<100	02/13/2010
RHR Loop I	<100	11/06/2009	RHR Loop II	<100	04/16/2010
RHR Loop I	<100	12/04/2009	RHR Loop II	<100	05/14/2010
RHR Loop I	<100	12/23/2009	RHR Loop II	<100	06/11/2010
RHR Loop I	<100	01/09/2010	RHR Loop II	<100	07/16/2010
RHR Loop I	<100	02/04/2010	RHR Loop II	<100	08/15/2010
RHR Loop I	<100	03/05/2010	RHR Loop II	<100	09/10/2010
RHR Loop I	<100	04/10/2010	RHR Loop II	<100	10/15/2010
RHR Loop I	<100	05/07/2010	RHR Loop II	<100	11/14/2010
RHR Loop I	<100	06/04/2010	RHR Loop II	<100	11/14/2010
RHR Loop I	<100	07/11/2010	RHR Loop II	<100	12/10/2010
RHR Loop I	<100	08/06/2010	RHR Loop II	<100	01/11/2011
RHR Loop I	<100	09/03/2010	RHR Loop II	<100	02/11/2011
RHR Loop I	<100	10/08/2010			
RHR Loop I	<100	11/08/2010			
RHR Loop I	<100	11/09/2010			
RHR Loop I	<100	12/03/2010			
RHR Loop I	<100	01/07/2011			
RHR Loop I	<100	02/04/2011			
RHR Loop I	<100	03/04/2011			

5) *Did the licensee conduct any licensed operator training (e.g., simulator) specifically involving implementation of the safe shutdown instructions (SSI) in which the operators were trained to seek and pursue alternate sources of coolant injection to compensate for the loss of RHR? If so, describe and provide the applicable simulator exercise guides and/or lesson guides? Did the licensee provide any licensed operator training that involved implementation of the SSIs in which the RHR pump would run for up to seven minutes without any indication of flow? If so, describe provide the applicable simulator exercise guides and/or lesson guides?*

TVA Response:

Browns Ferry Nuclear Plant (BFN) Operators are trained in the skills, knowledge and behaviors required to execute Emergency Operating Instructions (EOIs), Severe Accident Management Guidelines (SAMG), Radiological Emergency Plan (REP), and Safe Shutdown Instructions (SSIs). As discussed below, operators are also trained on recognition and decision making processes necessary to address a scenario which is outside the bounds of rule-based procedure compliance.

SSI training scenarios include fires in plant locations and the associated equipment failures that require operators to respond in order to maintain the plant in a safe condition and to complete the SSI actions. Once in the SSIs, operators are taught that the SSI actions are the only credible path for success and operators are trained to complete them accordingly. Specific technical training regarding alternate path solutions within SSI is not provided due to the design of the SSIs. Consistent with the SSIs and the BFN licensing basis, additional malfunctions after SSI entry are not part of the training since additional equipment malfunctions would remove the success path once in the SSI.

To ensure operator awareness and expectations when confronted with issues outside of rule-based procedure guidance, applicable behavioral training is provided to operators. The cumulative effect of the behavioral training ensures operator understanding of the expectations for maintaining the reactor in a safe condition and ensuring the safety and welfare of the public during all plant conditions. These expectations apply regardless of whether the operator actions are driven by rule-based response within established procedure guidelines or knowledge-based response when outside of established procedure guidelines.

Operators are trained to recognize conditions that are outside the procedure bounds. Success paths in these circumstances rely on application of behaviors supported by teamwork, collaboration and other organizational actions.

Examples of approved training materials in place at BFN to address behavioral aspects of plant operation include:

- Procedure OPDP-1, "Conduct of Operations," training to emphasize role and responsibilities for core and public safety
- Multiple complex casualties during EOI training to drive "a protect the core" mind-set
- Multiple complex scenarios leading to execution of SAMG strategies
- Multiple complex scenarios requiring REP guideline execution to protect core and the public.

When plant conditions or events are outside the bounds of applicable procedures, the operators are able, based on the combined technical and behavioral aspects of the operating training program, to recognize that they are in knowledge-based mode. They will use all means possible to ensure nuclear and public safety.

Additional training details are noted below.

- As part of the licensed operator initial and continuing training programs, TVA provides simulator scenarios which contain complex casualties with multiple system failures. One example of this is OPL171I029 (initial training), which combines High Pressure Coolant Injection (HPCI) System out of service with a loss of off-site power and failure of one diesel generator to start with a failure of the Reactor Core Isolation Cooling (RCIC) injection valve to open, which results in emergency depressurization as required by the EOIs. To further complicate this event, three Safety Relief Valves (SRVs) fail to open, which will result in the operator having to use alternate SRVs to attain six SRVs open.

- Shift Manager and Shift Technical Advisor (STA) programs include training on roles and responsibilities for core and public safety commensurate with the position as follows.

    - Shift Manager Responsibilities (from OPDP-1, Duties and Responsibilities of the Shift Manager (Rev. 19, Page 35 of 69))

      Duties and responsibilities of the Shift Manager (SM) related to maintaining adequate core cooling include the following:

        - *As the senior management representative on shift, the SM is in direct charge of plant operations and is responsible through the Operations Superintendent and Operations Manager to the Plant Manager for safe and reliable operation of the nuclear plant.*
        - *The SM is responsible for on shift management and oversight in the control room and all plant group activities.*
        - *The SM has the authority to take action necessary to ensure compliance with Technical Specifications, operating license requirements, and approved plant procedures to protect the health and safety of employees and the public, to ensure adequate security, and to protect the plant from damage.*

- Shift Manager Training

Training Material	Purpose	Relevant Objective(s)
OPL199.LM4 OPERATING PHILOSOPHY	The purpose of this module is to instill TVA's operating philosophy to the Shift Manager candidate. The Shift Manager is the first and foremost example of the operating philosophy in all situations. As such, it is critical that the Shift Manager be fully cognizant of TVA's and plant management's attitudes towards operation of the plant	1. Describe the authority and responsibility of the Shift Manager. 2. In a variety of circumstances, advocate the operating philosophy of TVA in accordance with plant policies and procedures and the operators' code of professionalism. This may include the following: a. Enforcing standards of operating performance. b. Advocating an overriding attitude of conservatism for reactor core safety, particularly in regard to reactivity control, reactor coolant inventory, core cooling, heat sink availability, primary system integrity, and containment integrity. c. Applying prudent judgment based on training, experience, and management expectations. 3. When presented with a scenario or a plant situation that requires corrective actions by operators, explain how the operating philosophy of TVA governs actions in response to the scenario/situation. **4. Given an operating condition that is not addressed in procedures, direct conservative actions designed to protect the plant and public health and safety.** 5. Given an action or condition that reduces the reliability of safety-related equipment, develop a plan to mitigate the situation and restore the equipment to full reliability in a timely manner. 6. Given a choice of two or more alternatives for a given plant operational situation, select the one that provides the greater margin of reactor safety consistent with operating requirements. 7. Using the operational situations as examples, explain how foregoing a short-term benefit to prevent sacrificing long-term component integrity is applied to managing plant operations.

<table>
<tr><th>Training Material</th><th>Purpose</th><th>Relevant Objective(s)</th></tr>
<tr><td>OPL199.AC1

TRANSIENT AND ACCIDENT ANALYSIS</td><td>The purpose of this module is to reinforce the knowledge the individual has gained with their experience as a Unit Supervisor/SRO. The focus of this module should be on how this knowledge can be used to predict the consequences of actions, both positive and negative.</td><td>1. Given a set of accident data, evaluate parameters to determine if natural circulation is occurring following a loss of forced coolant flow prior to equipment or core damage.

2. During simulated conditions, demonstrate a thorough understanding of, and the skills needed to maintain and restore, the following safety functions:

Reactivity control

Reactor coolant inventory

Core cooling

Heat sink availability

Primary system integrity

Containment integrity

3. For a given plant operational condition and the plant probabilistic risk assessment, identify and discuss failure mechanisms, human or equipment, that would provide risk of core damage.

4. List the parameters used and identify the indications of a degraded core.

5. State the potential problems of cooling a degraded core and discuss policies and procedures that are used to diagnose and mitigate the situation.</td></tr>
<tr><td>OPL199.AC2

EMERGENCY OPERATING INSTRUCTIONS (EOIs)</td><td>The purpose of this module is to ensure that the candidate has a full understanding of the bases for the Emergency Operating Instructions. As a Shift Manager, the individual may face situations which require deviation from the instructions. To recognize these situations and respond appropriately, the individual must be fully cognizant of the bases and assumptions used to develop the Emergency Operating Instructions.</td><td>Apply the bases of the EOIs to accident events that may require deviation from the instructions.

Enabling Learning Objectives

1. Explain the methods of verifying proper implementation of the EOIs in accordance with plant operating philosophy.

2. Given an accident scenario, predict the plant response to the recommended actions by applying knowledge of EOI bases.

3. Describe and discuss example situations that allow for deviation from EOIs in accordance with plant administrative procedures.

4. Given situations that allow for deviation from EOIs, discuss the benefits of the deviation and potential problems if improperly applied.</td></tr>
</table>

Training Material	Purpose	Relevant Objective(s)
OPL199.EP1 EMERGENCY PLANS	The purpose of this module is to ensure that the candidate has a full understanding of the bases for the Emergency Plans. As a Shift Manager, the individual may face situations which require implementation of the site Emergency Plans. To recognize these situations and respond appropriately, the individual must be fully cognizant of the bases and assumptions used to develop the Emergency Plans.	Enabling Learning Objectives 1. Describe the responsibilities of the shift manager to manage an emergency event while implementing the emergency plan. 2. Given an emergency event condition, describe the typical decisions with priorities that a shift manager must make in transitioning from normal operations to coping with an emergency event and implementation of the emergency plan. 3. Given an emergency event condition, assign priorities to activities to ensure resources are appropriately directed to manage the plant condition and implement the emergency plan in accordance with plant procedures. 4. Describe conservative protective action recommendations based on core/containment status or unverified radioactive release information. 5. Given emergency conditions, identify constraints or impediments that may adversely impact timely protection of the general public. 6. Identify organizations available to offer equipment or assistance for mitigating an emergency. 7. Given emergency conditions, determine additional resources needed for mitigating the event.

Browns Ferry Unit 1 FCV-074-066
RHR Outboard Injection Valve Failure
NRC Questions (#2)

Training Material	Purpose	Relevant Objective(s)
OPL199.TE1 APPLYING DESIGN BASES TO OPERATIONS	The purpose of this module is to provide the Shift Manager candidate with an understanding of how the design bases apply to operational situations.	1. Given various plant conditions, determine if operation is outside plant design bases. 2. In the presence of conditions outside the normal operating limits, identify any safety concerns associated with plant operations. 3. In the presence of conditions outside the design bases, identify the safety concerns associated with plant operations. 4. Given a situation where the plant is known to be outside the design bases, determine the appropriate course of action to return the plant to within design limits. 5. Explain the design basis for environmental qualification of instrumentation. 6. Given a plant-specific event that has the potential for putting the plant outside the design bases (such as a loss of the residual heat removal system while in mid-loop operations, and improper surveillance or maintenance), evaluate the effect of the event on plant safety using appropriate design bases. 7. Given a specific plant condition coupled with an on-line maintenance request, determine the effects on PSA and if the request should be approved and work allowed to proceed. 8. Given a plant condition and information on planned activities, determine the plant parameters that define the basis of the operating envelope and how they might be affected by the planned activities. 9. Explain factors considered in determining availability and operability of structures, components, and systems important to plant safety.

- STA Responsibilities (from OPDP-1, Duties and Responsibilities of the STA (Rev. 19, Page 37 of 69))

  Duties and responsibilities of the STA related to maintaining adequate core cooling include the following:

  - *Assists in oversight providing an <u>independent perspective of critical safety functions</u>, using redundant and diverse plant indications during transients and emergencies.*
  - *<u>Immediately reporting any abnormalities or plant condition that may represent a challenge to the critical safety functions</u> or that could result in a degradation of the safety level.*
  - *Assessing plant parameters during and following an accident in order to ascertain whether core damage has occurred or appears imminent.*
  - *<u>Providing recommendations on appropriate corrective actions</u> to restore plant parameters to acceptable values.*
  - *<u>Investigating the causes of abnormal or unusual events that occur and assess any adverse effects</u>.*
  - *<u>Evaluating the effectiveness of procedures in terms of terminating or mitigating accidents and make recommendations when changes are needed</u>.*

- STA Training

  - This material is trained as part of OPL175.001, Duties and Responsibilities of the STA, as part of initial STA training. The goal of the training is as follows:

    "Upon completion of this lesson, the STA will demonstrate satisfactory knowledge of the duties and responsibilities assigned to the on-shift STA"

    - Tasks associated with this training material include the following
      - Verify critical safety functions during transients by using redundant and diverse indication.
      - Assess plant parameters during and following an accident to ascertain whether or not core damage has occurred.
      - **Recommend appropriate corrective action to restore plant parameters to acceptable values.**
      - Recognize and report to the Shift Manager events which may affect plant safety.
      - **Recommend appropriate corrective actions to terminate or mitigate an accident.**

- The training material also addresses the importance of during transients and accidents, comparing existing critical parameters to plant-specific critical safety function limiting values, and providing an independent verification of critical safety functions to the shift supervisor. The training material defines a critical safety function as a "function needed to control reactivity, remove core heat, provide an ultimate heat sink, or contain radioactivity."

With respect to licensed operator training that involved implementation of the SSIs in which the RHR pump would run up to seven minutes without any indication of flow, the following information is provided.

The circumstances associated with placing the RHR System in alternate shutdown cooling in accordance with the SSIs during a 10 CFR 50 Appendix R event support keeping the RHR pump running. Entry into the SSIs places the plant in a unique alignment that ensures one train is free of fire damage. The operator starts the RHR pump well before reactor pressure is below the shutoff head of the pump. The minimum flow valves are normally open such that there is a flow path available when the RHR pumps are started. The operator is trained and knows that injection flow will not be seen until reactor pressure drops to a sufficient value (e.g., below the shutoff head of the RHR pump). The typical time between RHR pump start and flow initiation is approximately five minutes per the Safe Shutdown Analysis. Additionally, in this situation, the operator's priority is protection of the reactor core. Therefore, the operator would not secure the running RHR pump during an emergency situation if there was no indication of RHR flow. Instead, another operator would be dispatched to the field to determine the reason for lack of flow and take appropriate action to attempt to establish flow locally. It is reasonable to assume the operator would allow the RHR pump to run at least for the full seven and a half minutes per the caution note in the SSIs.

TVA has found evidence that supports this position. Operators ran RHR Loop I and Loop II pumps for approximately 110 minutes and approximately 55 minutes, respectively, during a simulator exercise performed to support the development of an REP scenario in 2010. The RHR pumps automatically started in response to an accident signal and the operators were unable to perform rapid depressurization due to loss of drywell control air. The operators were unaware at the time that drywell control air would be lost and that the rapid depressurization would not function. Operators were in the EOIs at this point in the scenario. While the EOIs do not contain a caution note relative to running an RHR pump without a flow path, the operators are trained and aware of the cautionary note relative to running an RHR pump without a flow path in the Operating Instruction for the RHR System. The RHR minimum flow valves are normally open and provide a flow path upon the starting of the RHR pump. RHR Loop II flow was established at approximately 55 minutes after the pumps started. The RHR Loop I pumps were secured at approximately 110 minutes after starting and no flow path was available and RHR Loop II flow had been established. Allowing the RHR pumps to run for these periods of time would be not considered a deficiency during the actual REP drill.

6) *Does the NSSS vendor agree with the licensee's Part 21 report regarding under-sized threads? What kind of feedback has the vendor provided to substantiate or unsubstantiate[d] the conclusions in the licensee's Part 21 report dated April 1, 2011?*

TVA Response:

General Electric (GE), the Nuclear Steam Supply System (NSSS) vendor, agrees that there is merit to the notification report and has entered it into their corrective action program and is evaluating the failure of the 24" globe valve at Browns Ferry per the attached GE corrective action document. The final Part 21 determination will be contained in a document identified as PRC 11-21. At this time, General Electric is investigating and has provided no additional feedback on the TVA conclusions.

Additionally, the valve vendor (Crane Nuclear, current owner of Walworth Valve) was consulted during the investigation to determine specific attributes of the valve, vendor drawings, and available documentation. The Crane representative concurred with the root cause and also that the critical measurements of valve components would not be expected to be performed by the customer (TVA). The representative (David Dwyer, Manager of Engineering) stated "There are no maintenance based requirements to verify critical dimensions of parts. That being said, during any refurbishment the goal is to bring wear surfaces within spec limits." The skirt threads are not considered a "wear surface."

Commitment Tracking System

Welcome: Schwan, James

Quick CAR Report

Close

[Print]

CAR Information

CAR:	54578
CAR Type:	External
Entry Date:	March 27, 2011
Priority:	B - Condition Adverse to Quality
Generated By:	Customer Complaint
Internal Audit #:	
Cust. CAR #:	None Identified
Customer Site:	BROWNS FERRY 1-3
Supplier / Vendor:	
Supplier/Vendor Contact:	
Initiator:	Porter, Dale
Process Owner:	Watford, Glen
Responsible Person:	Schwan, James
CAR Status:	Pending Response Completion

Problem

Problem Description:	-External Contact Name: Richard Steed -Phone Number: 256-729-2552 -Email: rwsteed@tva.gov Failed Valve - General Electric (GE) provided the valve as the Nuclear Steam Supply System Supplier via TVA/GE Contract No. 66C60-90744 (Units 1 and 2) and 67C60-91750 (Unit 3) as meeting all requirements of GE Co. Specification No. 21A1047 and GE Purchase Specification 21A1047AS, Rev. 5 - Globe Valves - Motor Operated (GE Parts List No. 10-154). This valve is the RHR Loop II LPCI flow control valve, 1-FCV-074-066, and was manufactured by the Walworth Company as Part No. 531,543 (Figure 5509), Drawing Nos. 0-A-12337-M-1E, C-12337-3A, C-12337-8-1, and a vendor-provided sketch. The valve is a 24-inch No. 5297PS, 600-lb MSS SP-66 Rating cast carbon steel, butt welded, pressure-seal angle globe valve operated by a Limitorque SMB-5T-350 motor operator. The root cause analysis identified the failure mechanism was due to opening thrust exceeding the threaded connection between the disc skirt and disc due to a manufacture's defect in which the threads were undersized. Comparisons of the as-found disc skirt (TIIC # AEJ982E) and the in-stock disc skirt (TIIC # BWF455P) were made by the Root Cause team and similar thread dimensions were found.
Proposed Resolution:	Evaluate original documentation (design and manufacturing records) and evaluate impact of identified failure on plant safety performance. Potentially Reportable Condition will be issued with supplemental customer information.
Keywords:	Original Design; Original Manufacture; Hardware

Response Analysis

Causal Factors:

Cause Analysis:

Effects and Extents:

Action(s)

Response Acceptance

Responsible Acceptance:

Original Acceptance Date:

Acceptance Date:

Process Owner Acceptance:

Original Acceptance Date:

Acceptance Date:

Initiator Acceptance:

Original Acceptance Date:

Acceptance Date:

Closure

Responsible Closure:

Original Closure Date:

Closure Date:

Process Owner Closure:

Original Closure Date:

Closure Date:

Initiator Closure:

Original Closure Date:

Closure Date:

Effectiveness Review

Effectiveness Reviewer:

E/R Due Date:

E/R Completion Date:

E/R Notes:

CAR Critique Review

CAR Critique Actions:

CAR Critique Notes:

Trend Codes

Severity:

Trend Codes:

7) *How many periodic surveillance tests of the Loop II LPCI inboard injection valve occurred on Unit 1 between May 2007 and November 2008 that could have resulted in back-pressure conditions on the Loop II LPCI outboard injection valves? Also how many times and when has similar surveillance testing been accomplished that could have created back-pressure conditions on the other five Unit 1, 2, and 3 LPCI outboard injection valves?*

17) *(question from March 31, 2011) What is the technical basis and empirical evidence that back-pressure conditions actually existed on the 1-FCV-74-66 valve following periodic stroke testing of the inboard RHR injection valve (1-FCV-74-67)? What is the technical basis and empirical evidence that similar back-pressure conditions did not exist to the same degree or worse for the other inboard/outboard RHR injection valves (i.e., 1/2/3-FCV-74-52/66)? What is the technical basis and empirical evidence that would explain why all the other inboard/outboard RHR injection valves were sufficiently different in design, maintenance, operation, or physical condition to not experience similar back-pressure conditions resulting in valve failure?*

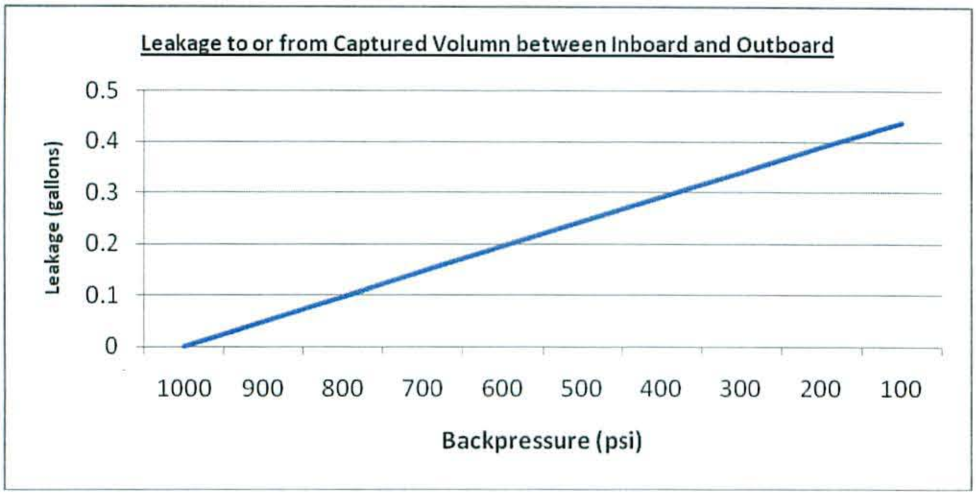
TVA Response:

The original Question 17 from the NRC Questions dated March 31, 2011, and Question 7 received at the Regulatory Conference on April 4, 2011, are similar, with respect to additional information requested. We have included the response to both as a combined answer below.

The table below provides the data associated with the periodic surveillance tests of the valves in question during this time frame.

Strokes at Pressure between May 2007 and November 2008					
1-FCV-74-53 (impacts 1-FCV-74-52)	1-FCV-74-67 (impacts 1-FCV-74-66)	2-FCV-74-53 (impacts 2-FCV-74-52)	2-FCV-74-67 (impacts 2-FCV-74-66)	3-FCV-74-53 (impacts 3-FCV-74-52)	3-FCV-74-67 (impacts 3-FCV-74-66)
5	4	7	6	5	5
06/13/2008	03/28/2008	07/03/2008	04/26/2008	07/13/2008	06/27/2008
03/21/2008	01/04/2008	04/11/2008	02/01/2008	01/25/2008	02/08/2008
12/27/2007	10/12/2007	01/17/2008	11/09/2007	11/02/2007	10/19/2007
09/28/2007	07/19/2007	10/26/2007	08/21/2007	08/10/2007	07/27/2007
07/11/2007		08/03/2007	09/11/2007	05/18/2007	05/04/2007
		07/31/2007	05/25/2007		
		05/11/2007			

The backpressure force can vary based on the leak tightness of the FCV-74-66 and 52 flow control valves (FCVs). The figure below demonstrates the effect of leakage either into the volume above the disc (i.e., between the inboard and outboard valves) (raising the pressure) or out of the volume (reducing the pressure). This figure charts the change in specific volume as the pressure in a controlled volume is changed converting the change in mass to gallons. All the outboard valves are the same 24" angled globe valve manufactured by Walworth.



The applied backpressure could be significantly different depending on the relative leak tightness of the three in-line valves (injection check, inboard, and FCV). If the FCV is relatively leak tight, pressure would build-up during the cycling of the inboard valve. All the Units 2 and 3 available as-found leak rate results from 1993 until current for the injection check valve (36 tests) and the inboard injection gate valve (38 tests) were collected to determine the mean leakage (1.15 and 0.29, SCFH respectively) and standard deviation (1.36 and 1.08, respectively). The as-found October 28, 2008, leak rate results for the Unit 1 RHR Loop II injection check valve and the inboard injection gate valve were 13.5 (9 standard deviations above the mean) and 12.46 (11 standard deviations above the mean) SCFH respectively. The leakage rate past the check valve is more than enough to pressurize the volume of 21.2 ft^3 (Δ of ~0.06 ft^3) needed to pressurize to reactor pressure) during stroking of the inboard injection valve as long as leakage past the FCV (74-66) is relatively lower. This backpressure will not decrease if leakage past the inboard valve is higher than the FCV after the inboard valve is closed and the FCV (74-66) is given a signal to open as is done during logic surveillance testing. The leak tightness of the Unit 1 FCV-74-66 valve was demonstrated while troubleshooting the October 23, 2010 separated disc. A pressure gage was placed between the closed inboard injection valve and closed FCV. The FCV was given an open signal and while the stem moved open the pressure decreased well below atmospheric pressure indicating leak tightness. Therefore the backpressure on the Unit 1 74-66 valve had the potential to be significantly higher than that experienced the comparable Unit 2 and 3 valves. The Unit 1 RHR Loop I injection check valve and inboard injection gate valve also exhibited high leakage similar to RHR Loop II. However, based on the results of inspection of the 1-FCV-74-52 valve (i.e., disc and skirt not separated and welds intact), it is concluded that either relative leakage past the outboard valve (1-FCV-74-

52) was high not allowing backpressure to build or the threads on 1-FCV-74-52 were not undersized to the extent found on 1-FCV-74-66.

The 1 FCV-74-66 tack welds between the skirt and disc were not considered to be a contributing cause since they are not credited in the design to handle axial loads. The properly sized threads are designed to handle the full reactor backpressure. However, threads on the other valves have not been validated to be undersized. Inspections of all similar nonconforming valves on Units 1, 2, and 3 have been completed and found to have the discs attached and the welds intact. It should also be noted that no force (other than that resulting from applied backpressure) can stress the undersized threads and the weld to the point of failure and the metallurgical analysis clearly demonstrates that the full length of threads on the 1-FCV-74-66 valve were deformed and fractured due to a force in the pullout direction. A force in the seating direction would simply push the disc further into the body without any stress on the threads and the welds since the threads and welds move with the disc. Excessive force on the backseat would also have a negligible effect on the thread and weld stresses since the stem velocity and associated change in momentum is relatively low.

As discussed in the Crane weak link analysis (Ref. 6), the axial loading comes from testing the 1-FCV-074-67 downstream valve with the 1-FCV-074-66 in the closed position. The corresponding valves in the other loop (Loop I) would be pressurized due to testing the FCV-074-53 valve with the FCV-074-52 valve closed. By removing the FCV-074-67 (and FCV-074-53) from testing except under refueling conditions when the backpressure does not exist, the axial loading mechanism has been minimized. Additionally, operational constraints have been put in place to limit the backpressure on all remaining valves that have not been modified or returned to design configuration.

In addition, the Unit 2 RHR valves (2-FCV-74-66 and 2-FCV-74-52) have been repaired by applying 8 structural gussets between the skirt and the disc capable of resisting maximum backpressure and rotational forces.

In summary, based on plastic deformation of the threads, the tack welds of 1-FCV-74-66 took the full load resulting from backpressure and failed. The magnitude of the force would fail a full size ½" thick weld after the threads plastically deformed. The threads of valve 1-FCV-74-66 were significantly damaged after one event (backpressure applying axial force) and continued to degrade with each subsequent event until failure. The threads were so damaged by the first event that each subsequent event would continue to damage the threads until failure with a much lesser force such as normal unseating. A common cause failure mechanism does did not exist for the following reasons: 1) since the welds are the first to fail, inspection of the tack welds demonstrated that all other valves were not subjected to forces of this magnitude or that the threads are not undersized, 2) relative leakage rates between the injection check, inboard, and flow control (FCV-74-66 or 52) valves played a dominant role in the magnitude of force applied, 3) the FCV-74-66 and 52 valves are normally open and remain open during a design basis event, including shutdown during an Appendix R fire event, and 4) backpressures and corresponding stresses on the threads and welds during a design basis event are well within the capability of undersized threads and welds in the hypothetical event that it is required to open after being closed given the historical leakage record of the other similar valves.

8) Was a root cause determination conducted for an event involving failure of the 2-FCV-74-66 valve in December 1974 as reported by Abnormal Occurrence Report BFAO-50-260/7432W? If so what was the results?

TVA Response:

A review of BFN historical data revealed the Abnormal Occurrence Report BFAO-50-260/7432W was documented in Abnormal Occurrence Report (AOR) 2607432W. No cause investigation was documented in the TVA system for this occurrence. A TVA trouble ticket was identified for tack welds being broken and the disc being rotated partially counterclockwise for both the 1-FCV-74-66 valve and 1-FCV-74-52 valve. However, with respect to the AOR and valve 2-FCV-74-66, the AOR indicated that the disc and skirt came unscrewed and separated, with the disc lodged in the seat. Repairs were made per MMI 15.3.1.5-N- 2/8/1975 (Welding Instruction for FCV-74-52 and FCV-74-66 Disc to Disc Skirt). The welding instruction was included in the work procedure (WP3896 R1 - 1977 timeframe) for Engineering Change Notice (ECN) L1473 which installed the V-Notch Disc Trim.

It would have been normal for investigations of this nature to be performed by the Supplier (GE) as an FDDR (Field Deviation Disposition Report) and thus TVA has requested GE to investigate their Design Record Files (DRF). Subsequent to this event ECN L1473 (1975) was initiated for the incorporation of the V-Notch Disc Trim modifications to the FCV-074-052/066 valves correcting rotational issues due to flow induced vibration.

References

1. Westinghouse Report No. STD-MCE-10-198, "Browns Ferry 1 RHR Angle Valve Destructive Evaluation," Westinghouse Proprietary Information, December 2010.

2. Structural Integrity Associates Letter Report 1001572.401,"Browns Ferry LPCI Injection Valve Evaluation", Revision 0, January 2011.

3. Structural Integrity Associates Calculation No. 1001572.302, Revision 0, "Weld Fracture Mechanics and Stress Analysis of LPCI Injection Valve (1-FCV-74-66)," February 2011.

4. Structural Integrity Associates Calculation No. 1001572.301, Revision 0, "LPCI Injection Valve (1-FCV-74-66) Thread Static Shear Strength Calculation," February 2011.

5. "Introductory Statistics," N. A. Weiss, 7th Edition, Peason Educacion, 2005.

6. CVNO Report No. SR-128, Revision 2, "Seismic Weak Link Report," Crane Nuclear, Inc., August 1995.

Attachment 1

BFN Scenario Equipment Availability Results Tables

SCENARIO 1(250V RMOV BD 1C)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	1	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 2 & 3(480V RMOV BD 1C)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	2	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 8 & 9(AHU Above 4KV SDBD RM)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	7 & 8	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 10 & 11 (1-XFA-231-TS1A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	9 & 10	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 12&13(RPT 1-BDAA-068-0001-II)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	11	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 24(3-FCV-74-67)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	19	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 26 & 27(480V RMOV BD 3D)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	21	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 28(3-ACU-031-7205)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	22	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

Enclosure 4

SCENARIO 29(RWCU cabinet)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	23	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 30 & 31(3-BDAA-068-0003I)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	24	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C		CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI	U1 HPCI	RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A			480V SD BD 1B	
	480V RMOV BD 1A		U1 RCIC	480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C		CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI	U2 HPCI	RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A			480V SD BD 2B	
	480V RMOV BD 2A		U2 RCIC	480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C		CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI	U3 HPCI	RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A			480V SD BD 3B	
	480V RMOV BD 3A		U3 RCIC	480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 32(0-XFA-266-0THB)

<table>
<tr><th></th><th colspan="2">DIVISION I</th><th></th><th colspan="2">DIVISION II</th></tr>
<tr><td rowspan="7">UNIT 0</td><td>DG A</td><td>DG B</td><td rowspan="7">25</td><td>DG C</td><td>DG D</td></tr>
<tr><td>4KV SD BD A</td><td>4KV SD BD B</td><td>4KV SD BD C</td><td>4KV SD BD D</td></tr>
<tr><td>DG 3A</td><td>DG 3B</td><td>DG 3C</td><td>DG 3D</td></tr>
<tr><td>4KV SD BD 3EA</td><td>4KV SD BD 3EB</td><td>4KV SD BD 3EC</td><td>4KV SD BD 3ED</td></tr>
<tr><td>A1 RHRSW</td><td>C1 RHRSW</td><td>B1 RHRSW</td><td>D1 RHRSW</td></tr>
<tr><td>A2 RHRSW</td><td>C2 RHRSW</td><td>B2 RHRSW</td><td>D2 RHRSW</td></tr>
<tr><td>A3 RHRSW</td><td>C3 RHRSW</td><td>B3 RHRSW</td><td>D3 RHRSW</td></tr>
<tr><td rowspan="8">UNIT 1</td><td>CS 1A</td><td>CS 1C</td><td rowspan="3">U1 HPCI</td><td>CS 1B</td><td>CS 1D</td></tr>
<tr><td>RHR 1A LPCI</td><td>RHR 1C LPCI</td><td>RHR 1B LPCI</td><td>RHR 1D LPCI</td></tr>
<tr><td>RHR 1A HX</td><td>RHR 1C HX</td><td>RHR 1B HX</td><td>RHR 1D HX</td></tr>
<tr><td colspan="2">480V SD BD 1A</td><td rowspan="3">U1 RCIC</td><td colspan="2">480V SD BD 1B</td></tr>
<tr><td colspan="2">480V RMOV BD 1A</td><td colspan="2">480V RMOV BD 1B</td></tr>
<tr><td colspan="2">U1 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 1C</td></tr>
<tr><td colspan="2">250V RMOV BD 1B</td><td rowspan="2">U1 SRVs</td><td colspan="2">250V RMOV BD 1A</td></tr>
<tr><td colspan="2">U1 DIV I ECCS INV</td><td colspan="2">U1 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 2</td><td>CS 2A</td><td>CS 2C</td><td rowspan="3">U2 HPCI</td><td>CS 2B</td><td>CS 2D</td></tr>
<tr><td>RHR 2A LPCI</td><td>RHR 2C LPCI</td><td>RHR 2B LPCI</td><td>RHR 2D LPCI</td></tr>
<tr><td>RHR 2A HX</td><td>RHR 2C HX</td><td>RHR 2B HX</td><td>RHR 2D HX</td></tr>
<tr><td colspan="2">480V SD BD 2A</td><td rowspan="3">U2 RCIC</td><td colspan="2">480V SD BD 2B</td></tr>
<tr><td colspan="2">480V RMOV BD 2A</td><td colspan="2">480V RMOV BD 2B</td></tr>
<tr><td colspan="2">U2 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 2C</td></tr>
<tr><td colspan="2">250V RMOV BD 2B</td><td rowspan="2">U2 SRVs</td><td colspan="2">250V RMOV BD 2A</td></tr>
<tr><td colspan="2">U2 DIV I ECCS INV</td><td colspan="2">U2 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 3</td><td>CS 3A</td><td>CS 3C</td><td rowspan="3">U3 HPCI</td><td>CS 3B</td><td>CS 3D</td></tr>
<tr><td>RHR 3A LPCI</td><td>RHR 3C LPCI</td><td>RHR 3B LPCI</td><td>RHR 3D LPCI</td></tr>
<tr><td>RHR 3A HX</td><td>RHR3C HX</td><td>RHR 3B HX</td><td>RHR 3D HX</td></tr>
<tr><td colspan="2">480V SD BD 3A</td><td rowspan="3">U3 RCIC</td><td colspan="2">480V SD BD 3B</td></tr>
<tr><td colspan="2">480V RMOV BD 3A</td><td colspan="2">480V RMOV BD 3B</td></tr>
<tr><td colspan="2">U3 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 3C</td></tr>
<tr><td colspan="2">250V RMOV BD 3B</td><td rowspan="2">U3 SRVs</td><td colspan="2">250V RMOV BD 3A</td></tr>
<tr><td colspan="2">U3 DIV I ECCS INV</td><td colspan="2">U3 DIV II ECCS INV</td></tr>
</table>

SCENARIO 33 & 34 (480V RMOV BD 1A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	41	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 35(250V RMOV BD 1A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	42	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 36 & 37 (4KV SD BD A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	43	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 38, 39 & 40 (480V SD BD 1A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	44, 45, 46	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 74 & 75 (4160 UNIT BD 1A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	61 & 62	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 76 & 77 (4Kv RECIRC BD 1)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	63 & 64	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C		CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI	U1 HPCI	RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A			480V SD BD 1B	
	480V RMOV BD 1A		U1 RCIC	480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C		CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI	U2 HPCI	RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A			480V SD BD 2B	
	480V RMOV BD 2A		U2 RCIC	480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C		CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI	U3 HPCI	RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A			480V SD BD 3B	
	480V RMOV BD 3A		U3 RCIC	480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

Enclosure 4

SCENARIO 80 & 81 (480V LTG BD 1)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	67 & 68	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 82 (U1 GEN BKR AIR COMPRESSOR 1-CMP-35-460B)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	69	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 83 (480V COMMON BD 2)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	70, 71, 72	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 84 (U2 EXCITER CUBICLE)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	73	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 85 & 86 (4160 UNIT BD 2A)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	74 & 75	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

Enclosure 4

SCENARIO 87 (4160V UNIT BD 2C)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	76	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 88 (4160V COMMON BD B)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	77	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 90, 91 & 92(480V UNIT BD 2B)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	79, 80, 81	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 95 & 96(4KV RECIRC BD 3)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	84 & 85	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 97 & 98(4KV Unit BD 3A)

<table>
<tr><th></th><th colspan="2">DIVISION I</th><th></th><th colspan="2">DIVISION II</th></tr>
<tr><td rowspan="7">UNIT 0</td><td>DG A</td><td>DG B</td><td rowspan="7"></td><td>DG C</td><td>DG D</td></tr>
<tr><td>4KV SD BD A</td><td>4KV SD BD B</td><td>4KV SD BD C</td><td>4KV SD BD D</td></tr>
<tr><td>DG 3A</td><td>DG 3B</td><td>DG 3C</td><td>DG 3D</td></tr>
<tr><td>4KV SD BD 3EA</td><td>4KV SD BD 3EB</td><td>4KV SD BD 3EC</td><td>4KV SD BD 3ED</td></tr>
<tr><td>A1 RHRSW</td><td>C1 RHRSW</td><td>B1 RHRSW</td><td>D1 RHRSW</td></tr>
<tr><td>A2 RHRSW</td><td>C2 RHRSW</td><td>B2 RHRSW</td><td>D2 RHRSW</td></tr>
<tr><td>A3 RHRSW</td><td>C3 RHRSW</td><td>B3 RHRSW</td><td>D3 RHRSW</td></tr>
<tr><td rowspan="8">UNIT 1</td><td>CS 1A</td><td>CS 1C</td><td rowspan="3">U1 HPCI</td><td>CS 1B</td><td>CS 1D</td></tr>
<tr><td>RHR 1A LPCI</td><td>RHR 1C LPCI</td><td>RHR 1B LPCI</td><td>RHR 1D LPCI</td></tr>
<tr><td>RHR 1A HX</td><td>RHR 1C HX</td><td>RHR 1B HX</td><td>RHR 1D HX</td></tr>
<tr><td colspan="2">480V SD BD 1A</td><td rowspan="3">U1 RCIC</td><td colspan="2">480V SD BD 1B</td></tr>
<tr><td colspan="2">480V RMOV BD 1A</td><td colspan="2">480V RMOV BD 1B</td></tr>
<tr><td colspan="2">U1 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 1C</td></tr>
<tr><td colspan="2">250V RMOV BD 1B</td><td rowspan="2">U1 SRVs</td><td colspan="2">250V RMOV BD 1A</td></tr>
<tr><td colspan="2">U1 DIV I ECCS INV</td><td colspan="2">U1 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 2</td><td>CS 2A</td><td>CS 2C</td><td rowspan="3">U2 HPCI</td><td>CS 2B</td><td>CS 2D</td></tr>
<tr><td>RHR 2A LPCI</td><td>RHR 2C LPCI</td><td>RHR 2B LPCI</td><td>RHR 2D LPCI</td></tr>
<tr><td>RHR 2A HX</td><td>RHR 2C HX</td><td>RHR 2B HX</td><td>RHR 2D HX</td></tr>
<tr><td colspan="2">480V SD BD 2A</td><td rowspan="3">U2 RCIC</td><td colspan="2">480V SD BD 2B</td></tr>
<tr><td colspan="2">480V RMOV BD 2A</td><td colspan="2">480V RMOV BD 2B</td></tr>
<tr><td colspan="2">U2 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 2C</td></tr>
<tr><td colspan="2">250V RMOV BD 2B</td><td rowspan="2">U2 SRVs</td><td colspan="2">250V RMOV BD 2A</td></tr>
<tr><td colspan="2">U2 DIV I ECCS INV</td><td colspan="2">U2 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 3</td><td>CS 3A</td><td>CS 3C</td><td rowspan="3">U3 HPCI</td><td>CS 3B</td><td>CS 3D</td></tr>
<tr><td>RHR 3A LPCI</td><td>RHR 3C LPCI</td><td>RHR 3B LPCI</td><td>RHR 3D LPCI</td></tr>
<tr><td>RHR 3A HX</td><td>RHR3C HX</td><td>RHR 3B HX</td><td>RHR 3D HX</td></tr>
<tr><td colspan="2">480V SD BD 3A</td><td rowspan="3">U3 RCIC</td><td colspan="2">480V SD BD 3B</td></tr>
<tr><td colspan="2">480V RMOV BD 3A</td><td colspan="2">480V RMOV BD 3B</td></tr>
<tr><td colspan="2">U3 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 3C</td></tr>
<tr><td colspan="2">250V RMOV BD 3B</td><td rowspan="2">U3 SRVs</td><td colspan="2">250V RMOV BD 3A</td></tr>
<tr><td colspan="2">U3 DIV I ECCS INV</td><td colspan="2">U3 DIV II ECCS INV</td></tr>
</table>

SCENARIO 104 & 105(480V Common Bd 3)

<table>
<tr><th></th><th colspan="2">DIVISION I</th><th></th><th colspan="2">DIVISION II</th></tr>
<tr><td rowspan="7">UNIT 0</td><td>DG A</td><td>DG B</td><td rowspan="7">93 & 94</td><td>DG C</td><td>DG D</td></tr>
<tr><td>4KV SD BD A</td><td>4KV SD BD B</td><td>4KV SD BD C</td><td>4KV SD BD D</td></tr>
<tr><td>DG 3A</td><td>DG 3B</td><td>DG 3C</td><td>DG 3D</td></tr>
<tr><td>4KV SD BD 3EA</td><td>4KV SD BD 3EB</td><td>4KV SD BD 3EC</td><td>4KV SD BD 3ED</td></tr>
<tr><td>A1 RHRSW</td><td>C1 RHRSW</td><td>B1 RHRSW</td><td>D1 RHRSW</td></tr>
<tr><td>A2 RHRSW</td><td>C2 RHRSW</td><td>B2 RHRSW</td><td>D2 RHRSW</td></tr>
<tr><td>A3 RHRSW</td><td>C3 RHRSW</td><td>B3 RHRSW</td><td>D3 RHRSW</td></tr>
<tr><td rowspan="8">UNIT 1</td><td>CS 1A</td><td>CS 1C</td><td rowspan="3">U1 HPCI</td><td>CS 1B</td><td>CS 1D</td></tr>
<tr><td>RHR 1A LPCI</td><td>RHR 1C LPCI</td><td>RHR 1B LPCI</td><td>RHR 1D LPCI</td></tr>
<tr><td>RHR 1A HX</td><td>RHR 1C HX</td><td>RHR 1B HX</td><td>RHR 1D HX</td></tr>
<tr><td colspan="2">480V SD BD 1A</td><td rowspan="3">U1 RCIC</td><td colspan="2">480V SD BD 1B</td></tr>
<tr><td colspan="2">480V RMOV BD 1A</td><td colspan="2">480V RMOV BD 1B</td></tr>
<tr><td colspan="2">U1 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 1C</td></tr>
<tr><td colspan="2">250V RMOV BD 1B</td><td rowspan="2">U1 SRVs</td><td colspan="2">250V RMOV BD 1A</td></tr>
<tr><td colspan="2">U1 DIV I ECCS INV</td><td colspan="2">U1 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 2</td><td>CS 2A</td><td>CS 2C</td><td rowspan="3">U2 HPCI</td><td>CS 2B</td><td>CS 2D</td></tr>
<tr><td>RHR 2A LPCI</td><td>RHR 2C LPCI</td><td>RHR 2B LPCI</td><td>RHR 2D LPCI</td></tr>
<tr><td>RHR 2A HX</td><td>RHR 2C HX</td><td>RHR 2B HX</td><td>RHR 2D HX</td></tr>
<tr><td colspan="2">480V SD BD 2A</td><td rowspan="3">U2 RCIC</td><td colspan="2">480V SD BD 2B</td></tr>
<tr><td colspan="2">480V RMOV BD 2A</td><td colspan="2">480V RMOV BD 2B</td></tr>
<tr><td colspan="2">U2 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 2C</td></tr>
<tr><td colspan="2">250V RMOV BD 2B</td><td rowspan="2">U2 SRVs</td><td colspan="2">250V RMOV BD 2A</td></tr>
<tr><td colspan="2">U2 DIV I ECCS INV</td><td colspan="2">U2 DIV II ECCS INV</td></tr>
<tr><td rowspan="8">UNIT 3</td><td>CS 3A</td><td>CS 3C</td><td rowspan="3">U3 HPCI</td><td>CS 3B</td><td>CS 3D</td></tr>
<tr><td>RHR 3A LPCI</td><td>RHR 3C LPCI</td><td>RHR 3B LPCI</td><td>RHR 3D LPCI</td></tr>
<tr><td>RHR 3A HX</td><td>RHR3C HX</td><td>RHR 3B HX</td><td>RHR 3D HX</td></tr>
<tr><td colspan="2">480V SD BD 3A</td><td rowspan="3">U3 RCIC</td><td colspan="2">480V SD BD 3B</td></tr>
<tr><td colspan="2">480V RMOV BD 3A</td><td colspan="2">480V RMOV BD 3B</td></tr>
<tr><td colspan="2">U3 UNIT PREFERRED</td><td colspan="2">480V RMOV BD 3C</td></tr>
<tr><td colspan="2">250V RMOV BD 3B</td><td rowspan="2">U3 SRVs</td><td colspan="2">250V RMOV BD 3A</td></tr>
<tr><td colspan="2">U3 DIV I ECCS INV</td><td colspan="2">U3 DIV II ECCS INV</td></tr>
</table>

SCENARIO 106 Cable Trays - 480V TB MOV BD 1C

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	95	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 107 & 108(4160V UNIT BD 2B)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	96 & 97	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 109 & 110(480V TMOV BD 2C)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	99, 100	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 111(4KV UNIT BD 3B)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	101	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 112(480V TMOV BD 3C)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	102	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 113A North TB U1 & U2 (Bus Duct)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	103	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 113B North Turbine Building U3

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	103	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 114A North TB U1 & U2 (Cable Tray)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	104	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 114B North TB U3 (Cable Tray)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	104	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 115A Cable Tunnel Intake

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	106A	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 115B TB Cable Tunnel Tray Horizontal and Vertical

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	106 & 106C	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

SCENARIO 116(Cable Tunnel to XFMR Yard)

	DIVISION I			DIVISION II	
UNIT 0	DG A	DG B	105	DG C	DG D
	4KV SD BD A	4KV SD BD B		4KV SD BD C	4KV SD BD D
	DG 3A	DG 3B		DG 3C	DG 3D
	4KV SD BD 3EA	4KV SD BD 3EB		4KV SD BD 3EC	4KV SD BD 3ED
	A1 RHRSW	C1 RHRSW		B1 RHRSW	D1 RHRSW
	A2 RHRSW	C2 RHRSW		B2 RHRSW	D2 RHRSW
	A3 RHRSW	C3 RHRSW		B3 RHRSW	D3 RHRSW
UNIT 1	CS 1A	CS 1C	U1 HPCI	CS 1B	CS 1D
	RHR 1A LPCI	RHR 1C LPCI		RHR 1B LPCI	RHR 1D LPCI
	RHR 1A HX	RHR 1C HX		RHR 1B HX	RHR 1D HX
	480V SD BD 1A		U1 RCIC	480V SD BD 1B	
	480V RMOV BD 1A			480V RMOV BD 1B	
	U1 UNIT PREFERRED			480V RMOV BD 1C	
	250V RMOV BD 1B		U1 SRVs	250V RMOV BD 1A	
	U1 DIV I ECCS INV			U1 DIV II ECCS INV	
UNIT 2	CS 2A	CS 2C	U2 HPCI	CS 2B	CS 2D
	RHR 2A LPCI	RHR 2C LPCI		RHR 2B LPCI	RHR 2D LPCI
	RHR 2A HX	RHR 2C HX		RHR 2B HX	RHR 2D HX
	480V SD BD 2A		U2 RCIC	480V SD BD 2B	
	480V RMOV BD 2A			480V RMOV BD 2B	
	U2 UNIT PREFERRED			480V RMOV BD 2C	
	250V RMOV BD 2B		U2 SRVs	250V RMOV BD 2A	
	U2 DIV I ECCS INV			U2 DIV II ECCS INV	
UNIT 3	CS 3A	CS 3C	U3 HPCI	CS 3B	CS 3D
	RHR 3A LPCI	RHR 3C LPCI		RHR 3B LPCI	RHR 3D LPCI
	RHR 3A HX	RHR3C HX		RHR 3B HX	RHR 3D HX
	480V SD BD 3A		U3 RCIC	480V SD BD 3B	
	480V RMOV BD 3A			480V RMOV BD 3B	
	U3 UNIT PREFERRED			480V RMOV BD 3C	
	250V RMOV BD 3B		U3 SRVs	250V RMOV BD 3A	
	U3 DIV I ECCS INV			U3 DIV II ECCS INV	

Browns Ferry Unit 1 FCV-074-066
RHR Outboard Injection Valve Failure
NRC Questions (#3)

After reviewing TVA's response to the NRC staff questions provided to TVA on March 31, 2011, regarding the root cause analysis (RCA) for PER 271338, 1-FCV-074-066 RHR Outboard (Loop 2) Valve Failure, and related supporting documentation, the NRC staff has identified a number of follow-up questions as follows:

1) *Explain the basis for the statements in your response to question #23, and provide any necessary supporting documentation. Ensure the following discrepancies/questions are addressed at a minimum:*

   a. *WO 08-723813-000 stated that the vent valves were replaced with new valves and the original valves were not reinstalled.*
   b. *There was no documentation in WO 08-723810-000 that indicated an obstruction was removed or indicated that the venting was successful.*
   c. *In direct contrast to your response, PER 156971 specifically stated that WO 08-723810-000 was <u>unsuccessful</u>:*

      Ops was unable to vent loop II RHR per I-SR-3.5.1.1 (RHR II) section 7.2 [6] which vents the RHR shutdown cooling return line at the bonnet vent of I-FCV-74-66. Venting was attempted per the SR as written and per WO# 08-723810-000 (troubleshooting WO to stroke 1-FCV-74-6610 mid position and then vent as written). Neither attempt yielded a continuous vent for 4 minutes as prescribed in the SR. WO# 08-723813-000 initiated to troubleshoot vent valves for the bonnet of 1-FCV-74-66.

   d. *What is the basis for stating that WO 08-723810-000 corrected the non-conformances identified by PER 156971, when PER 156971 was initiated <u>after</u> WO 08-723810-000 was performed and appears to still be open?*

   e. *With plugging of the line possibly not being the "obvious cause" as stated in your response, readdresses the original question.*

   What opportunity did the licensee have, or miss, in recognizing that the valve bonnet vent line was not plugged, but rather the FCV-74-66 valve disc was stuck in its seat preventing any flow through the vent line?

   TVA Response:

   a) The vent line with the valves (1-VTV-074-0626B and 0627B) was replaced by Work Order (WO) 08-72813-000 for valve 1-FCV-074-066 and similar work was performed by WO 08-722217-000 for valve 1-FCV-074-052. WO 08-72813-000 was written to perform troubleshooting and venting of the line or to replace the valve and line to re-establish the vent path if troubleshooting venting was unsuccessful. Browns Ferry Nuclear Plant, Unit 1, was laid up for several years and these bonnet vents were not refurbished or tested as a part of restart. Therefore, it was reasonable to determine the vent lines/vent valves were clogged. Both RHR Loop I and RHR Loop II valves in this location appeared to be clogged. In order to reduce dose, the vent line including valves was replaced with a new prefabricated assembly to reduce the amount of time in a radiation field. Further examination was not considered necessary at the time since the obstruction was removed. The blockage could have been either between the valves or between the valves in the vent line.

b) We concur that the WO 08-723810-000 provided no documentation that indicated an obstruction was removed or indicated that venting was successful. The vent lines are bonnet vents for 1-FCV-74-66 and 1-FCV-74-52. WO 08-723810-000 throttled 1-FCV-74-66 to a mid-travel position and attempted to vent to verify there was no blockage in the bonnet with the valve in the full open position. This attempt to vent was unsuccessful so it was assumed the blockage was in the vent line/vent valves. WO 08-72813-000 was then written to troubleshoot and vent the line or replace the line and valve if unsuccessful at venting under WO 08-72810-000.

c) We agree that PER 156971 states that WO 08-723810-000 was unsuccessful. WO 08-723810-000 was unsuccessful at clearing the line and the obstruction was removed by WO 08-723813-000 for 1-FCV-74-66. See PER corrective action 156971-002 which states "This condition was corrected by the completion of WO 08-723813-000 during the U1R8 RFO. Therefore, this PER action can be closed."

d) WO 08-0723810-00 did not correct the non-conformances identified in PER 156971. PER 156971 was created to develop a WO (i.e., WO 08-723813-000) to correct this condition. All PER 156971 corrective actions have been completed and are either "closed" or in "waiting for approval" status.

e) The evidence indicates the bonnet vent was plugged with an obstruction blocking flow and was corrected by WO 08-723813-000. Venting is performed monthly per 1/2/3-SR-3.5.1.1(RHR I) and (RHR II) to ensure that the lines are full of water in accordance with the requirements specified in Technical Specifications (TS) Surveillance Requirement (SR) 3.5.1.1 and SR 3.5.2.2. The procedure was revised with an acceptable ultrasonic testing method to validate the piping to be full of water for meeting the TS SRs since the vent lines had proven to be unreliable. Functional Evaluation (FE) 42924 and FE 43012 provide the technical justification for the non-conforming condition associated with venting and required a revision to 1-SR-3.5.1.1 (RHR I and RHR II) to perform ultrasonic testing monthly until such a time as these obstructions were cleared. It should be noted that the RHR Loop I lack of venting was reported on 10/3/2008, and lack of venting in RHR Loop II was reported on 11/11/2008. Valve 1-FCV-074-052, in RHR Loop I, was determined not to be separated or lodged in the seat even though similar conditions (lack of venting) were present obstructing the associated vent line.

It also should be noted that the 1-FCV-74-66 valve was opened and throttled three days later when RHR Loop II was successfully placed in shutdown cooling.

Without the current knowledge of the non-conforming undersized thread condition, the sensitivity to the disc being separated and acting as a stop check valve was reasonably not heightened especially in light of previous unreliable venting of RHR Loop I, successful performance of shutdown cooling three days later, and venting having an unrelated mission (water hammer prevention). Therefore, it is not reasonable to expect a correlation to have been made between the lack of vent capability and the occurrence of the separation of the disc and the skirt on valve 1-FCV-74-66.

2) *With regard to question #9, assuming that Browns Ferry Unit 1 is testing their valves in accordance with ASME 1995 Edition, 1996 Addenda, then Section ISTC 4.2 specifies the in service exercising test requirements. In particular, ISTC 4.2.3 "Valve Obturator Movement" states: "The necessary valve obturator movement shall be determined by exercising the valve while observing an appropriate indicator, such as indicating lights that signal the required change of obturator position, or by observing other evidence such as changes in system pressure, flow rate, level, or temperature, that reflects change in obturator position." Does the licensee supplement indicating lights with other evidence of obturator movement and if not, please explain why?*

TVA Response:

BFN, Unit 1, is committed to implement the ASME 1995 Edition, 1996 Addenda, of the OMa Code, including section ISTC 4.2.3 as stated above. In order to meet the requirements of ISTC 4.2.3, when indicating lights are available, BFN, Unit 1, determines obturator movement when exercising a valve by observing those lights. This meets the requirements of the OMa Code and is consistent with industry practices. In addition to the quarterly stroke time test of 1-FCV-74-66, a remote position indication verification test is performed once every 2 years in accordance with ISTC-4.1. Specifically, ISTC-4.1 states:

> "Valves with remote position indicator shall be observed locally at least once every 2 years to verify that valve operation is accurately indicated. Where practicable, this local observation should be supplemented by other indications such as the use of flowmeters or other suitable instrumentation to verify obturator position. These observations need not be concurrent. Where local observation is not possible, other indications shall be used for verification of valve operation."

BFN procedure 1-SR-3.3.1.4(H II) performs the remote position indication verification test of 1-FCV-74-66.

An excerpt from procedure 1-SR-3.3.3.1.4(H II), Section 6.0, Acceptance Criteria, states:

"B. Visual verification of valve position (open/closed) is accurately indicated by its remote position indicators (red, green lights) at the Main Control Room panels.

Local valve position verification can make use of limit switches, position indicators on the valve, valve stem travel, etc. to determine valve position."

3) *With regard to question #10, what was the difference in loading capacity in the pullout direction between the 1-FCV-74-66 valve (with undersized welds and undersized threads) and any other LPCI outboard injection valve (e.g., 1-FCV-74-52) with undersized threads but properly sized welds? What would have been the maximum backpressure against the 1-FCV-74-66 valve disc that could have occurred and yet still allow the valve to cycle open without significant damage to the undersized welds? In comparison, what would have been the maximum backpressure against the disc of any other LPCI outboard injection valve (e.g., 1-FCV-74-52) before significant damage to the properly sized welds would have occurred? [Note, in answering these questions, consider both cases of sequential loading and shared loading between the welds and threads.] Is there a range of back pressures where the 1-FCV-74-66 valve would have been expected to fail but not the other LPCI outboard injection valves?*

TVA Response:

Assuming linear behavior, the stress results in Table 1 of Reference 1 and the associated thread pullout load calculations can be scaled to respond to the above questions (See Table 2 below). The response also requires one to assume a reasonable material flow stress to determine limit load of the welds. The pullout load calculated for the 1-FCV-74-66 was 314 kips. At this load, which corresponds to ~729 psi back pressure, the 0.2" weld would also fail once the threads have deformed and are no longer able to share load, because the predicted weld stress is 122.6 ksi, which is well above the skirt material flow stress of 57.5 ksi. However, at this load, the 0.5" weld is still slightly below the flow stress and therefore could sustain additional loading. From Table 2 below, it is seen that the 0.5" weld would have failed at a load of 334.7 kips, which corresponds to a back pressure of ~778 psi. Note from the last two columns of Table 2 that both the 0.2" and 0.5" weld sizes are predicted to fail at the load level corresponding to valve opening against full reactor back pressure (999 psi). So in response to the final question, valve 1-FCV-74-66 would be expected to fail at the pullout capability of the threads, which corresponds to ~729 psi back pressure. Other valves, with 0.5" welds could withstand a little higher back pressure, ~778 psi. But none of these valves could withstand full reactor back pressure with the undersized threads regardless of tack weld size. If the valve threads were machined properly, the valves could have withstood full reactor back pressure with comfortable safety margins, regardless of weld size. The tack welds have not been considered or credited in the weak link analysis (Ref. 3) since the threaded connection is the design feature for axial loading. In addition, TVA has contracted with Structural Integrity to perform additional elasticplastic analysis of the threaded connection to further demonstrate connection behavior which is expected to be available by April 22, 2011.

Table 2 – Stress Results from Table 1 of Reference 1, Scaled to Determine Pullout Loads and Back Pressure for Other Valves

Opening Load (kips)	Back Pressure (psi)	Weld Membrane Stress (ksi)*			
		Threads Engaged		Threads Not Engaged	
		0.5" Weld	0.2" Weld	0.5" Weld	0.2" Weld
313.6	728.7	13.36	29.92	53.88	122.55
334.7	777.7	14.26	31.93	57.5	130.78
429.9	999	18.31	41.02	73.86	168

*Flow Stress = 57.5 ksi

4) *Question #3 was answered from the perspective of how the failed anti-rotation device may have impacted the weld and/or threaded connection, instead of addressing how the misapplied force that failed/damaged the anti-rotation device may have directly caused damage to the undersized welds and skirt threads. This 2006 event was not thoroughly discussed. There were indications from discussion with the root cause team that during the resetting of MOV parameters following the event in 2006, craftsmen may have manually over-thrusted the valve on both the seat and backseat. An over-thrust condition by the manual handwheel can develop tremendous forces on the valve seats and body. Provide a detailed explanation of the 2006 anti-rotation device event, subsequent evaluation, and corrective actions with specific as-found and as-left MOV parameters?*

TVA Response:

A review of the maintenance history since applying the V-notch trim on the disc for all six valves found only one occasion on the 1-FCV-74-66 valve (manually operated by a millwright while adjusting limit switches) where the valve could have been inappropriately seated; this happened during the BFN, Unit 1, restart effort in 2006. The limit switches were inappropriately adjusted causing the Anti-rotation device (Stem Key) to run out against the yoke's keyway preventing the valve from fully closing and resulted in inappropriate back seating of the valve and the damage to the upper anti-rotation device. As-left partial MOVATS was performed (see figures below) after the limits were set using the millwrights (10/09/2006). No partial MOVATS was performed after repairing the anti-rotation devise. The next MOVATS test was performed on 10/31/2008. During the associated work activities, manual operation by the hand wheel was performed. The manual operation of the hand wheel was originally believed to be a possible cause of damage to the tack welds. The Structural Integrity analysis (Ref. 2) of the threaded connection and tack welds provided additional information to better understand the effects of the over-thrusting the disc in either the open or closed direction. Based on the applied force required to manually seat the disc, the force required to establish a normal unseating force (without backpressure) required to fail the threaded connection would exceed human capabilities (see Attachment 1). In the opening direction, no impact to skirt threads or weld would occur due to the lack of contact between the disc skirt and back seat during such event. This was discussed in our previous response. Operating experience (OE) regarding such instances was discussed during the root cause analysis and determined to be related to much smaller valve sizes and not applicable to this event. Thus, no additional stresses on the skirt tack weld or threads due to the over-thrust or back seating would occur and this was concluded not to be a contributor to the failure. (see Attachment 4 for the October 2006 MOV parameters)

5) *The response to question #22 states, "The evaluation of 1-FCV-074-66 conservatively assumes a static COF of 0.4." What is the technical basis for this statement, and where is it discussed or referenced in the RCA?*

TVA Response:

A coefficient of friction (COF) of 0.4 is considered the appropriate value for the following reasons:

- Stroking data performed in 2010 demonstrated a seating COF of approximately 0.32 on 1-FCV-074-66 after reassembly and testing.

- The INEEL Report (Ref. 6) shows a static COF of 0.38 after one stroke for aged stellite.
    - The disc was lifted from the seat then lodged back into the seat representing one stroke during shutdown cooling in March of 2009.
    - The 1-FCV-74-66 valve disc successfully lifted when shutdown cooling began in March of 2009 effectively releasing the captured oxidation particles on the seat and chamfered edge of the disc. The valve was then closed in accordance with the procedure after securing from shutdown cooling.

- Typically the COF for new dry stellite on stellite is less than 0.2. (See Attachment 2)

- Globe valve strokes with large actuators SMB-5T (actuator on the 1-FCV-74-66 valve) are effective at cleaning the seats of oxidation.

  Although globe valves have a shorter sliding distance on the seat, relative contact stresses are much higher based on the smaller contact surface areas offsetting the sustained relative motion. This can be seen by the relatively low industry MOVATS globe valve unseating forces.

  The technical basis is discussed in RCA section 3.0 and the Performance Improvement International Report, Ref. 5.

6) *With regard to question #18, the maximum DP across the separated 1- FCV-74-66 valve disc during execution of the SSIs was calculated to be 251 psid. Was this maximum DP used [to] simulate RHR system conditions for the mock-up testing? If no, what DP was used? During implementation of the SSIs, operators will start the designated RHR pump prior to initiating a rapid depressurization using MSRVs. Once reactor pressure reaches 450 psig, operators are instructed to open the associated LPCI inboard injection valve (e.g., 1-FCV-74-67). Operators are to then continue depressurizing until a reactor pressure band of 100 to 215 psig. Considering this scenario, is it possible that the 74-66 valve disc might initially become more embedded while reactor pressure exceeds RHR pump discharge pressure and pump vibrations cause a relaxation the coefficient of friction (COF) of the valve seating surface? Also, if operators only depressurize to approx. 215 psig as allowed by the SSIs, the maximum DP across the stuck disc could be much less than assumed (i.e., instead of 251 psid, it might be as low as 160 psid). Was a range of DP values across the disc considered in the mock-up testing or analysis? If so, what was the minimum DP used and what were the results? If not, why not?*

TVA Response:

The mock-up testing was performed to determine the limiting change in the coefficient of friction (COF) subjected to pump vane passing vibration impulses. The limiting change in COF was determined to be 27.3% which corresponds to a pressure differential of approximately 100 psi, well within the lowest available differential pressure during the Appendix R event; a pressure differential of 251 psi corresponds to a needed change in COF of 18.9%.

The assumed total closing thrust load from the motor actuator is greater than the load applied by differential pressure associated with total normal operating reactor pressure (1030 psig). This thrust load approaches a limiting sudden load of twice the gradually applied load after approximately four strokes. Differential pressure with the high side being downstream (reactor side) is gradually applied as the inboard valve is opened. Since the pressure differential is gradually applied and less than the normal motor operator thrust it is not expected to further lodge the disc into the seat. Even if the differential pressure was assumed to be suddenly applied it would have a negligible effect on the deflection of the disc into the valve body since the deflection is approaching its limit after already being impacted by the actual maximum of 13 strokes by a higher stem force.

7) *With regard to question 21, provide the test data for all 6 valves from 2006 until present (raw data in addition to printouts if possible).*

TVA Response:

Attachment 3 provides copies of the traces of the valves listed in Table A5.1 from the Root Cause Analysis (RCA) report from 2006 until present. The raw data files are very large and contain significantly more data than is requested; it is hard to separate the specific raw data requested from the whole file. Additionally, the software used for the data analysis is proprietary. We will make the data available on-site at BFN for any requested reviews.

8) *What is the licensee's reason for limiting the extent of cause to the manufacturing defect in LPCI valves (e.g., 1-FCV-74-66) in light of the identified maintenance deficiencies and surveillance inadequacies that could be present in other safety-related valves?*

TVA Response:

Maintenance history of all six BFN FCV-74-66/-52 valves was reviewed and relevant items are included in Attachment 3 of the RCA report. Work activities reviewed for the respective valves did not require direct manipulation of the disc skirt threads and there is no requirement to verify dimensional requirements of a disassembled threaded connection. A weakness was identified in the area of configuration control relative to other non-conforming conditions identified as part of this root cause. Based on evaluation of other observations included in Section 11.0 of the RCA report, the current level of performance with respect to maintenance practices provides reasonable assurance that equipment discrepancies are identified and resolved using the corrective action program and equipment is being restored to a high level of fidelity with respect to design configuration. Therefore, maintenance practices would be excluded from the extent of cause. There are no maintenance practices that could lead to the failure of the threads. As previously stated, the practice of performing surveillance on 1-FCV-074-67 with 1-FCV-074-66 in the closed position with undersized threads at full reactor pressure will create the conditions necessary for axial pullout. Therefore, maintenance deficiencies and surveillance inadequacies had no effect on the disc separation as the failure mechanism is related to the undersized threads provided by the manufacturer.

9) *The licensee's RCA concluded on pages 16 and 17, which pressure locking and thermal binding were not contributors to the failure of 1-FCV-74-66. Has TVA analyzed whether LPCI Valves 1-FCV-74-66 and 1-FCV-74-67 might have been closed for a sufficient period of time for a temperature-induced pressure increase to occur between the two valves and cause pressure locking forces when these valves were later opened? Has TVA analyzed whether LPCI Valve 1-FCV-74-66 might have been closed when hot during specific surveillance tests and opened at a lower temperature condition such that the required opening force was increased by partial thermal binding of the valve disc in the seat? In light of the significant effort needed to extract the disc from the seating area following the valve failure, has TVA analyzed whether the valve disc of 1-FCV-74-66 was thermally bound in the valve seating area in the as-found condition?*

TVA Response:

Pressure locking typically occurs in flexible-wedge and double-disc gate valves when fluid becomes pressurized within the valve bonnet, and the actuator is not capable of overcoming the additional thrust requirements resulting from the differential pressure created across both valve discs by the pressurized fluid in the valve bonnet. In the case of the 1-FCV-074-66 valve, the pressure created during testing with the 1-FCV-074-67 open created sufficient backpressure to develop axial loading conditions. This condition combined with the undersized threads resulted in sufficient force to create the stem to disc separation as discussed in the root cause analysis. The 1-FCV-074-66 angled globe valve in not capable of a pressure lock condition because the skirt has drilled holes to allow for a pressure relief pathway. Additionally pressure built up between the disc skirt and valve bonnet will not stress the disk to skirt threads or the disk tack welds because the disk is free to move with the skirt. While opening, the disc is well off its seat before the top of the skirt enters the potential pressure binding compartment leading to the valve bonnet; reaction loads would only compress the skirt since the pressure differential across the disc and associated force separating the disc from the skirt is negligible in this position.

The outboard injection valve (1-FCV-074-66) is normally open and is in a line maintained full of ambient temperature (<100°F) water by the plant keep-fill system. In the event of excessive leakage past the interlocked closed inboard valve, the water temperature could rise (experience on Unit 2 shows water temperature can get as high as 250°F). However, the normally open outboard valve would only be closed for a short period of time during quarterly operability stroking. The developed temperature gradient across the valve while the valve is being stroked is expected to be minimal since steady state conditions have already been developed while the valve is open and the amount of time during stroking is minimal. Additionally, the history of periodic temperature recording (see table below) demonstrates a negligible amount of heating from leakage past the closed inboard valve. The inboard valve is also stroked while aligning for shutdown cooling at relatively low Reactor Pressure Vessel (RPV) coolant saturation conditions (~80 psig and 325 °F). The thermal gradient developed during this shutdown cooling stroke would also be minimal because of the short stroke duration and the much longer amount of time needed to heat the keep-fill water and the valve. Heating from the bottom was not possible since it was found to not pass flow as soon as the pump was started and secured within 110 seconds. Therefore, thermal binding does not contribute to the disc being lodged in to the seat. See the following paragraph concerning higher temperature gradients from the reactor pressure vessel.

In the hypothetical event that the outlet of the valve is exposed to high temperatures while the valve is closed (or the disc is separated and resting in the valve body seat) the temperature gradient would tend to relieve the body strain rather than increase it. In this event, the inlet disc surface area and large V-notch disc trim mass, approximately equal to the disc itself, would be exposed to cool keep-full water including just a small portion of the valve surface area. The top of the disc and the majority of the valve surface area would be exposed to the higher temperature water with a lower density and associated thermal conductivity. Therefore, the insulated valve body would thermally expand more than the disc and relieve the body seating strain; both are carbon steel with the same thermal expansion coefficient. A temperature gradient event from higher inlet temperatures is not considered feasible because of the large volume of cool keep-full water required to be heated during the short time the valve is in the closed position.

The pressure suppression chamber (PSC), keep-fill system is designed to maintain a hydrostatic overpressure on the RHR discharge lines. The RHR system discharge lines are maintained full at all times to prevent the possibility of water-hammer. The RHR System is filled from the PSC head tank, which has ties to the PSC water-transfer pumps for pumping power, or from the condensate transfer system. The PSC head tank pump(s) will start and stop automatically to control the tank level. Both PSC head tank pumps take suction indirectly from the suppression pool via a connection to a Core Spray (CS) pump suction line from the PSC upstream of the pump suction isolation valve. The PSC head tank pump suction line contains two normally open isolation valves. The closed loop (PSC head tank to Emergency Core Cooling System (ECCS) to suppression pool to the PSC transfer pumps back to PSC head tank) assures that the proper suppression pool water level is maintained. Two check valves exist between the ECCS and the PSC head tank and between the ECCS and the Condensate Storage and Supply System to prevent loss of ECCS flow. The PSC transfer pumps are redundant and have separate power supplies. The instrumentation associated with the PSC keep-fill system is redundant. Also, the discharge piping of the RHR system is periodically vented from the high point of the system and water flow determined in accordance with Technical Specifications Surveillance Requirements. Verification that the systems are vented and filled is also required by plant procedures following periods of inoperability or maintenance on these systems as required demonstrating system operability. Temperature of the keep-fill system varies depending on source (Suppression Pool or Condensate). The PSC keep-fill system temperature when the source is the suppression pool is consistent with the temperature of the suppression pool, while the PSC keep-fill system temperature when the source is condensate is more dependent on the ambient temperatures of the environment. Typical temperatures of the keep-fill system are provided below which are taken in proximity to the valve. As can be seen clearly from the discussion and the temperature profiles of the keep-fill system, thermal binding was not was an issue with the 1-FCV-074-66 valve.

Pipe	Pipe temp (F)	Date Reviewed/Calibration Date	Pipe	Pipe temp (F)	Date Reviewed/Calibration Date
RHR Loop I	88.7	10/22/2008	RHR Loop II	<100	11/12/2008
RHR Loop I	<100	11/20/2008	RHR Loop II	<100	12/09/2008
RHR Loop I	<100	12/29/2008	RHR Loop II	<100	01/02/2009
RHR Loop I	84.7	01/26/2009	RHR Loop II	74	01/30/2009
RHR Loop I	102.3	02/26/2009	RHR Loop II	87.3	03/02/2009
RHR Loop I	89.7	03/09/2009	RHR Loop II	90.5	03/09/2009
RHR Loop I	92.4	03/10/2009	RHR Loop II	72.5	03/24/2009
RHR Loop I	71.2	03/20/2009	RHR Loop II	79.3	04/24/2009
RHR Loop I	73.4	04/20/2009	RHR Loop II	91.1	06/29/2009
RHR Loop I	74.4	05/14/2009	RHR Loop II	<100	10/16/2009
RHR Loop I	90.3	06/15/2009	RHR Loop II	<100	11/13/2009
RHR Loop I	93.2	07/14/2009	RHR Loop II	<100	12/08/2009
RHR Loop I	92.4	08/06/2009	RHR Loop II	<100	01/15/2010
RHR Loop I	<100	09/18/2009	RHR Loop II	<100	02/12/2010
RHR Loop I	<100	10/08/2009	RHR Loop II	<100	02/13/2010
RHR Loop I	<100	11/06/2009	RHR Loop II	<100	04/16/2010
RHR Loop I	<100	12/04/2009	RHR Loop II	<100	05/14/2010
RHR Loop I	<100	12/23/2009	RHR Loop II	<100	06/11/2010
RHR Loop I	<100	01/09/2010	RHR Loop II	<100	07/16/2010
RHR Loop I	<100	02/04/2010	RHR Loop II	<100	08/15/2010
RHR Loop I	<100	03/05/2010	RHR Loop II	<100	09/10/2010
RHR Loop I	<100	04/10/2010	RHR Loop II	<100	10/15/2010
RHR Loop I	<100	05/07/2010	RHR Loop II	<100	11/14/2010
RHR Loop I	<100	06/04/2010	RHR Loop II	<100	11/14/2010
RHR Loop I	<100	07/11/2010	RHR Loop II	<100	12/10/2010
RHR Loop I	<100	08/06/2010	RHR Loop II	<100	01/11/2011
RHR Loop I	<100	09/03/2010	RHR Loop II	<100	02/11/2011
RHR Loop I	<100	10/08/2010			
RHR Loop I	<100	11/08/2010			
RHR Loop I	<100	11/09/2010			
RHR Loop I	<100	12/03/2010			
RHR Loop I	<100	01/07/2011			
RHR Loop I	<100	02/04/2011			
RHR Loop I	<100	03/04/2011			

10) *On page 19 of the RCA, it described mock-up tests for evaluating the effect of vibration on the COF of the valve disc after it became bound in the valve seat. The Performance Improvement International (PII) report dated March 22, 2011, stated on page 18 that the two scaled valve body and disc sets were scaled at a 1:16 ratio except the valve disc/seat contacting area height and the valve disc height. Based on these mock-up tests, TVA concluded on page 20 of the RCA that the separated disc would be released from the valve body in time (within 7 minutes according to the PII report on page 31) to allow sufficient flow to the reactor pressure vessel to prevent fuel temperatures from exceeding 1500°F during an Appendix R event. Describe the*

determination that the mock-up testing was consistent with the specific parameters and conditions associated with the actual 1-FCV-74-66, such as the valve design, size, disc and seating surface conditions, seating area size based on valve temperature, specific valve vibration acceleration and applicable axes, applied force in closing the valve (including the amount, method of application and number of actuations), and force needed to remove the failed valve disc from its seat. Discuss the applicability of a friction-based study in light of the actions necessary to release the valve disc of 1-FCV-74-66 that might reflect a thermally bound condition. Assuming that a friction-based study is applicable, discuss the uncertainty based on two standard deviations in the length of time predicted for the disc to be released from the valve body considering the test results and limited number of tests?

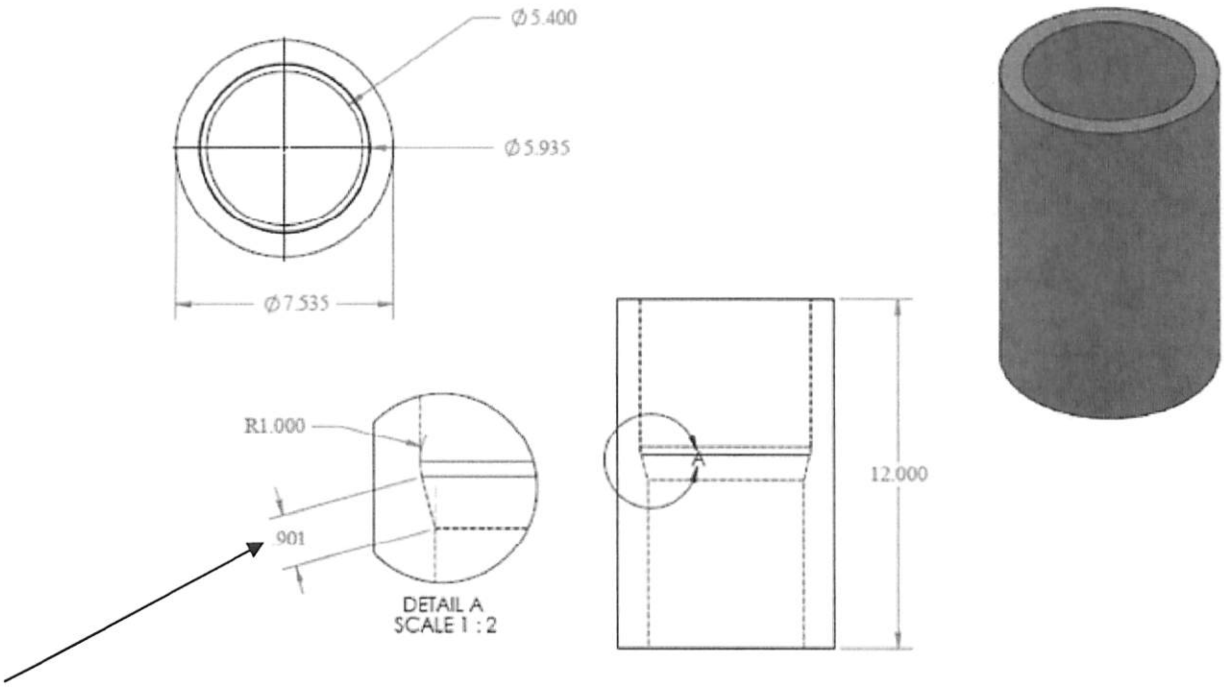
TVA Response:

All geometry affecting the normal and frictional forces acting on the experiment valve disc set were either maintained from the 74-66 valve or proportionately scaled. The experiment valve bodies exhibited behavior similar to the long, hollow cylinder that the 74-66 valve body can be treated as. Geometry outside of the experiment valve set seating areas is not relevant to the normal or frictional forces acting on the seating surfaces.

The mock-up testing was performed to determine the limiting change in the coefficient of friction (COF) subjected to pump vane passing vibration impulses and the amount of time needed to overcome a fouled surface. The valve body force restraining the valve disc is a function of three factors 1) COF, 2) seat angle, and 3) applied seating thrust; independent of geometric scaling factors (e.g., valve design, size, and seating area). Besides the seat angle, the configuration and material strength of the valve is only important in that it is strong enough to stop movement of the disc into the valve body without significant permanent deformation. The mock-up valve body was instrumented with strain gages to ensure conditions remained elastic. The applied seating thrust strains the valve body creating a force normal to the contact surface. The product of this normal force and the COF restrains the disc in the valve body. The axial component of the developed normal force acts to release the disc from the valve body. The needed change in the COF can then be adjusted by varying these three factors (COF, seat angle, and applied seating thrust) and the applied force from the pressure differential. In the calibration stages of the mock-up testing, various combinations of these factors were used to adjust the force required to pull the disc free and corresponding needed change in the COF. Calibration testing ensured a repeatable pull out force to determine the limiting change in the coefficient of friction. A significant surface relative roughness was used to simulate the actual fouled surface during the vibration timing tests after extensive calibration to ensure appropriate frictional characteristics (e.g., COF, frictional force, applied system force).

The mock-up did not attempt to recreate impacts from the valve stem on a lodged disc because of the large uncertainties associated with duplicating successive strain energy stored by the valve body from motor actuator inertia. Rather, a strain and frictional energy analytical approach was used conservatively assuming the stem impacts approach a perfectly applied sudden load (Ref. 5).

Pump vibration vane passing impulses vertically (axial stem direction) impacts the horizontal lodged disc of the horizontally oriented angle globe valve. The mock-up appropriately applied the vibration load orthogonal to the horizontal disc. The magnitude of vibration used by the mock-up was conservatively set to be less than the force per unit length of circumference measured from the actual RHR pump test; the actual 1-FCV-74-66 seat length was used for the mock-up which was 0.901 inches.



Multi-view model of the experiment 75° valve body.

Material temperature effects are not considered significant because of the relatively low temperatures maintained by the RHR keep-fill system. Relative thermal expansion between the valve body and disc were conservatively omitted because in most cases the gradient would be negligible, and in cases where the thermal gradient is not negligible it would cause the body to expand more than the disc relieving the disc from the valve body (see thermal binding discussion below).

The outboard injection valve (1-FCV-074-66) is normally open and is in a line maintained full of ambient temperature (<100°F) water by the plant keep-fill system. In the event of excessive leakage past the interlocked closed inboard valve, the water temperature could rise (experience on Unit 2 shows water temperature can get as high as 250°F). However, the normally open outboard valve would only be closed for a short period of time during quarterly operability stroking. The developed temperature gradient across the valve while the valve is being stroked is expected to be minimal since steady state conditions have already been developed while the valve is open and the amount of time during stroking is minimal. Additionally, the history of periodic temperature recording (see table below) demonstrates a negligible amount of heating from leakage past the closed inboard valve. The inboard valve is also stroked while aligning for shutdown cooling at relatively low Reactor Pressure Vessel (RPV) coolant saturation conditions (~80 psig and 325 °F). The thermal gradient developed during this shutdown cooling stroke would also be minimal because of the short stroke duration and the much longer amount of time needed to heat the keep-fill water and the valve. Heating from the bottom was not possible since it was found to not pass flow as soon as the pump was started and secured within 110 seconds. Therefore, thermal binding does not contribute to the disc being lodged in to the seat. See the following paragraph concerning higher temperature gradients from the reactor pressure vessel.

In the hypothetical event that the outlet of the valve is exposed to high temperatures while the valve is closed (or the disc is separated and resting in the valve body seat) the temperature gradient would tend to relieve the body strain rather than increase it. In this event, the inlet disc surface area and large disc trim mass, approximately equal to the disc itself, would be exposed to cool keep-full water including just a small portion of the valve surface area. The top of the disc and the majority of the valve surface area would be exposed to the higher temperature water with a lower density and associated thermal conductivity. Therefore, the insulated valve body would thermally expand more than the disc and relieve the body seating strain; both are carbon steel with the same thermal expansion coefficient. A temperature gradient event from higher inlet temperatures is not considered feasible because of the large volume of cool keep-full water required to be heated during the short time the valve is in the closed position.

The TVA investigation of the valve skirt/disc separation (i.e., as-found condition) included additional literature reviews which show that friction reduction due to pressure pulsations produced from a running Residual Heat Removal (RHR) pump would have been capable of releasing the lodged disc from the seat. Rather than reach a conclusion based solely upon application of industry research, a highly recognized expert team (Performance Improvement International (PII)) was consulted to design a laboratory mock-up and perform extensive testing to determine if the valve would have functioned in the as-found condition. Actual plant data was collected from RHR Loop II with one RHR pump running to support realistic modeling of pressure pulsation amplitude and frequency. Extensive calibration testing of the laboratory mockup was performed to minimize uncertainties and improve repeatability (over 30 tests) prior to the performance of the actual vibration test using the mock-up.

Section 6.2 in the PII report, "Analysis of the October 23, 2010 BFN-1-FCV-074-066 Shut-Down Cooling Event," dated March 22, 2011, discusses experiment uncertainty. The following calculations provide the design-stage uncertainty associated with the experiment.

Design-Stage Uncertainty

Substituting values from Table 6.9 into Equation 6.3 (both in the PII report), the design-stage uncertainty of strain gauges 1 and 2 and the hydraulic press are 12 $\mu\epsilon$, 20 $\mu\epsilon$, and 0.02 kip respectively. The combined design-stage uncertainty of the strain gauges is

$$u_{d,sg} = \sqrt{u_{d,sg1}^2 + u_{d,sg2}^2} \tag{1}$$

where $u_{d,sg1}$ and $u_{d,sg2}$ are the design-stage uncertainty of strain gauges 1 and 2, respectively. Therefore, $u_{d,sg}$ was 23 $\mu\epsilon$ throughout calibration testing. Valve body strain throughout calibration testing with the 83 degree set remained at values of 219-277 $\mu\epsilon$ both immediately after loading and before being pulled out (open the valve). Strain measurement error was, at most, 8.3-10.5% during these tests. Valve body strain throughout calibration testing with the 75 degree valve set ranged between 353-393 $\mu\epsilon$ and 241-268 $\mu\epsilon$ immediately after loading and before being pulled out, respectively. Valve body strain measurement errors were, at most, 5.9-6.5% and 8.6-9.5%, respectively after loading and before pullout, during these tests.

University of California San Diego (UCSD), where the tests were performed, laboratory personnel suggested that strain gauge deviation is often much greater (~100 $\mu\epsilon$) than resultant values for $u_{d,sg}$ during testing with similar loading patterns. Section 6.3 of the PII report discusses the time-dependent relationship between friction reduction and valve body release. The 75 degree valve disc was released from its wedged position almost immediately after surface abrasion was reduced significantly at the contacting surface.

Propagation of Error During Vibration Testing

Equation 6.4 of the PII report conveys the interdependence of strain and force variation within the testing sample set and predicts the lower bound of strain measurement error during vibration testing. PII considers that valve body oscillation during testing may have caused strain readings to be significantly lower than their true values. Therefore, only the lower bound of error propagation is of interest. The $\delta\epsilon$ limit is believed to have been -50 to -80 $\mu\epsilon$ throughout testing. Variation in $u_{d,sg}$ may have approached this range of values.

Statistical Analysis of Uncertainty

PII is confident in the validity of its test results based on the following. Statistical analysis was performed to verify the likelihood that the 74-66 valve disc would have liberated from its wedged position in less than seven minutes. The percent change in static COF and time required to liberate the valve disc were determined by vibration experiments with the 83 degree and 75 degree valve sets, respectively. Therefore, the accuracy of both parameters was evaluated.

Three vibration tests were performed with the 83 degree valve set. The sample size is very small and no population mean or variance exists for the set. It is therefore appropriate to use a one-sample *t*-interval procedure. This test evaluates the likelihood that the valve disc would have been freed of its wedged position with a static COF change greater than or equal to 18.2% (required under Appendix R operating conditions). A *t*-value is established to determine the probability that disc liberation at this value would not have been possible

$$t_{\alpha/2} = \frac{\bar{x} - \mu_o}{\frac{s}{\sqrt{n}}} \qquad (2)$$

where $\bar{x}$, μ_o, s, and n are the sample mean, value of interest (limiting case), sample standard deviation, and sample size, respectively (Ref. 4, 381-2). The *t*-value is an α/2 quantity since only outliers lower than μ_o are of interest. The sample standard deviation is

$$s = \sqrt{\frac{\Sigma(x - \bar{x})^2}{n - 1}} \qquad (3)$$

where x and $\bar{x}$ are sample values and the sample mean, respectively (Ref. 4, 109). The mean of the three test values provided in Table 6.4 of the PII report is 26.3%. Therefore, *s* and $t_{\alpha/2}$ are 1.11 and 12.6, respectively. A *t*-table is used to determine the confidence interval associated with the $t_{\alpha/2}$ value. The sample set has

$$df = n - 1 \qquad (4)$$

degrees of freedom. Therefore, *df* equals 2. Evaluating *df* in the standard *t*-table and extrapolating yields an *α*/2 value of 0.003 (Ref. 4, A-10). The probability that the maximum change in the 74-66 valve could have overcome normal forces associated with an 18.2% reduction in the static COF is

$$P = 100 * \left(1 - \frac{\alpha}{2}\right) \qquad (5)$$

Thus, *P* equals 99.7% and there is very reasonable assurance that the valve disc would have liberated with at least an 18.2% reduction in the static COF.

Two tests were also conducted with the 75 degree valve set to determine the amount of time required to fully abrade the seating surfaces. The 75 degree valve disc was liberated in less than seven minutes in both vibration tests. PII observed no evidence suggesting disc liberation would have required additional time.

Therefore, the laboratory mock-up testing is very credible and provides high confidence (99.7%) that the valve would have provided functional flow within seven minutes.

PII's conclusion is quoted verbatim below:

"...Therefore, PII has assurance that the valve disc would have been released from its wedged position within seven minutes.....A number of conservative measures were applied in both the calculations and the experiment conducted. As a result, PII has a very high confidence in the credibility of its findings. PII has found no safety concerns associated with the October 23, 2010 SDCE [shutdown cooling event]."

References

1. Structural Integrity Associates Letter Report 1001572.401,"Browns Ferry LPCI Injection Valve Evaluation," Revision 0, January 2011.

2. Structural Integrity Associates Calculation No. 1001572.302, Revision 0, "Weld Fracture Mechanics and Stress Analysis of LPCI Injection Valve (1-FCV-74-66)," February 2011.

3. CVNO Report No. SR-128, Revision 2, "Seismic Weak Link Report," Crane Nuclear, Inc., August 1995.

4. "Introductory Statistics," N. A. Weiss, 7th Edition, Peason Education, 2005.

5. Performance Improvement International "TVA Browns Ferry Nuclear Power Plant Analysis of the October 23, 2010 BFN-1-FCV-074-066 Shut-Down Cooling Event." March 2011.

6. INEEL/EXT-02-01021,"Results of NRC-Sponsored Stellite 6 Aging and Friction Testing," Idaho National Engineering and Environmental Laboratory, October 2002.

Attachment 1

Handwheel Evaluation

Purpose:
Calculate what the Handwheel Input torque and handwheel rim pull to seat/unseat the valve for FCV-74-66

References:
1. MOVATS Testing During Unit 1 Outage (U1R8) - normal static seating
2. Structural Integrity Calculation (SI Calculation No. 1001572.301 Rev0 "LPCI Injection Valve (1-FCV-74-66) Thread Static Shear Strength Calculation"
3. Limitorque Document (SEL (7) - Stem Factors)
4. Limitorque Document (SEL (11) - Standard Handwheel Ratios for SMB & HMB Units)
5. Valve Drawing 0-A-12337-M-1E, R000, "Walworth Co. Pressure Seal Angle Valve with Limitorque SMB-5T Operator"
6. 1-47BD452-99-1, Rev 0, Operator Data Sheet, BFN Unit 1 Residual Heat Removal (RHR) System

Design Input:
1. Thrust (MOVATS) = 482,155 lbs (ref 1)
2. Thrust (SI - Threads) = 313,000 lbs (ref 2)
3. Stem Factor (SF) = 0.0417 (ref 3)
4. OAR (Overall Ratio) = 109.78 (ref 6)
5. HW Ratio =142.0 (ref 4)
6. HW eff = 0.25 (ref 4)
7. Handwheel radius (ft) = (dia = 30" ~ radius = 1.25 ft) (ref 5)

Assumptions:
1. Thrust value taken from the MOVATS trace is used as a normal total seating thrust
2. Actual stem factor is unavailable. The stem factor is taken from the Limitorque SELs.

Computations and Analyses:
Required Valve Torque

$$Required\ Valve\ Torque = Required\ Valve\ Thrust \times SF$$
$$Required\ Valve\ Torque = (482{,}155\ lbs)(0.0417)$$
$$Required\ Valve\ Torque = 20{,}105.9\ ft-lbs$$

Handwheel Input Torque

$$HW\ Input\ Torque = \frac{Required\ Valve\ Torque}{Handwheel\ Ratio \times eff}$$
$$HW\ Input\ Torque = \frac{20{,}105.9\ ft-lbs}{(142.0)(0.25)}$$
$$HW\ Input\ Torque = 566.36\ ft-lbs$$

Handwheel Rim Pull

$$HW\ Rim\ Pull = \frac{Handwheel\ Input\ Torque}{Radius\ of\ handwheel\ (in ft)}$$
$$HW\ Rim\ Pull = \frac{566.36 ft-lbs}{1.25\ ft}$$
$$HW\ Rim\ Pull = 453.09\ lbs$$

Attachment 2

Properties of Stellite 6B

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Wrought Products Technical Data

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Certified Mechanical Properties.

Covers **Stellite®6B** in the form of sheet and plate up to 1 inch thickness and round bar up to 3.5" diameter.

Minimum Properties of Wrought Stellite® 6B

Property	Value	
Tensile Strength	130 ksi (896 MPa)	MIN
Yield Strength at 0.2% offset	70 ksi (483 MPa)	MIN
Elongation in 4D	5%	MIN
Reduction in Area	7%	MIN
Hardness	33-43 HRC	

Properties Data

The properties listed in this booklet are typical or average values based on laboratory tests conducted by the manufacturer. They are indicative only of the results obtained in such tests and should not be considered as guaranteed maximums or minimums. Materials must be tested under actual service conditions to determine their suitability for a particular purpose. All data represent the average of four or less tests unless otherwise noted. The secondary units (metric) used in this booklet are those of the SI system.

Chemical Composition, Percent

Stellite®	Cobalt	Nickel	Silicon	Iron	Manganese	Chromium	Molybdenum	Tungsten	Carbon
6B	Bal.	3.00*	2.00*	3.00*	2.00*	28.00-32.00	1.50*	3.50-5.50	0.90-1.40
6K	Bal.	3.00*	2.00*	3.00*	2.00*	28.00-32.00	1.50*	3.50-5.50	1.40-1.90

*Maximum

Average Physical Properties

Physical Properties	Temp., degrees C	Metric Units Stellite 6B	6K	Temp., degrees F	British Units Stellite 6B	6K
Hardness Limits Typical	22	33-43 RC 36-40 RC	40-42* RC 43-47 RC	72	33-43 RC 36-40 RC	40-42* RC 43-47 RC
Density	22	Kg/m3 8387	8387	72	lb/in.3 0.303	0.303
Melting Range		1265 to 1354°C			2310 to 2470 deg. F	
Electrical Resistivity	22	microhm-m 0.91	-	72	microhm-m 36	-
Thermal Conductivity	22	watt-cm/sq. cm-deg. C 0.147	-	72	Btu-in/sq.ft.hr.-deg. F 103 (546 ohms per cil. mil. ft.)	-
Mean Coefficient of Thermal Expansion		x 10-6/m/m.K			microinches/in.-deg. F	
	0-100	13.9	13.8	32-212	7.7	7.7
	0-200	14.1	13.8	32-392	7.8	7.7
	0-300	14.5	13.8	32-572	8.0	7.7
	0-400	14.7	13.8	32-752	8.2	7.7
	0-500	15.0	13.8	32-932	8.3	7.7
	0-600	15.3	14.0	32-1112	8.5	7.8
	0-700	15.8	14.2	32-1292	8.8	7.9
	0-800	16.3	14.5	32-1472	9.1	8.1
	0-900	16.9	14.9	32-1 652	9.4	8.3
	0-1000	17.4	15.5	32-1832	9.7	8.6
Electrical Conductivity						

Enclosure 5

Compared to Copper, percent	22	1.90	-	72	1.90	-
Specific Heat (calculated)	Room	J/kg•K 423	Room -		Btu/lb-deg. F 0.101	-
Magnetic Permeability at 200 Oersteds (15.900 A/m)	22	<1.2	<1.2	72	<1.2	<1.2
Reflecting Power, percent		57-70			57-70	

*Minimum depending on gauge

Average Hot Hardness

Stellite®	Test Temp., deg. F	(deg. C)	Brinell Hardness at Temperature, Mutual Indentation Method
6B	1000	(538)	226
	1200	(649)	203
	1400	(760)	167
	1600	(871)	102

Average Compressive Strength

Stellite®	Form	Test Temp.	Average Compressive Strength Ksi (MPa)
6B	1/2-in. (12.7 mm), Plate 1	Room	347 (2392)
6K	Sheet 1	Room	325 (2241)

Average Modulus of Rupture

Stellite®	Form	Test Temp.	Average Modulus of Rupture Ksi (MPa)
6B	Sheet 1	Room	338 (2360)

Average Modulus of Elasticity

Stellite®	Form	Test Temp.	Average Modulus of Elasticity psi x 10^6 (MPa)
6B	Sheet 1	Room	30.4 (210,000)
6B	5/8-in. (15.9 mm), Bar	Room	31.1 (214,000)

Average Izod Impact Strength (un-notched)

Stellite®	Form	Test Temp.	Average Izod Impact Strength (un-notched) ft. lbs.	J
6B	1/2-in (12.7 mm), Plate 1	Room	62	84

Average Charpy Impact Strength

Stellite®	Test Temp., deg. F (deg. C)	Type of Test	Average Charpy Impact Strength, ft. lbs. (J) Longitudinal	Transverse
6B 1/2-in. (12.7 mm), Plate 1	Room	Un-notched	72 (98)	65 (88)
		notched	6 (8)	-
	1000 (538)	Un-notched	81 (110)	-
		notched	15 (20)	-
	1250 (677)	Un-notched	116 (157)	-
		notched	15 (20)	-
	1500 (816)	Un-notched	126 (171)	-
		notched	15 (20)	-

1 Solution heat-treated at 2250 deg. F (1232 deg. C), air cooled

Average Room Temperature Data - Stellite® 6B

FORM	Condition	Ultimate Tensile Strength, Ksi (MPa)	Yield Strength at 0.2% offset Ksi (MPa)	Elongation in 2 in. 50.8 mm, percent	Hardness, Rockwell C
Sheet, 0.040 in. (1.0 mm), thick	Solution Heat-treated*	145.0 (1000)a	90.1 (621)a	12a	36a
Sheet, 0.065 in. (1.7 mm), thick	Solution Heat-treated*	140.8 (971)a	86.7 (598)a	11a	36a
Sheet,	Solution Heat-				

Enclosure 5

0.125 in. (3.2 mm), thick	treated*	144.7	(998)a	89.8	(619)a	11a	37a
Sheet, 0.187 in. (4.8 mm), thick	Solution Heat-treated*	144.5	(996)a	89.3	(616)a	10a	37a

Solution heat-treated at 2250 deg. F (1232 deg. C), air cooled
a Average of 27-31 tests

Average Tensile Data 1

Stellite®	Form	Test Temp.,		Ultimate Tensile Strength		Yield Strength at 0.2% offset,		Elongation in 2 in. 50.8 mm, percent
		deg. F	(deg. C)	Ksi	(MPa)	Ksi	(MPa)	
6B	0.063 in. (1.6 mm), Sheet	Room		146.0	(1007)	91.6	(632)	11
		1500	(816)	73.9	(509)	45.4	(313)	17
		1600	(871)	55.8	(385)	39.2	(270)	18
		1800	(982)	32.6	(225)	19.8	(137)	36
		2000	(1093)	19.5	(134)	10.9	(75)	44
		2100	(1149)	13.3	(92)	7.7	(53)	22
	1/2 in. (12.7 mm), Plate	Room		148.0	(1020)	88.0	(607)	7
		1000	(538)	133.0	(917)	58.5	(403)	9
		1250	(677)	115.0	(793)	60.6	(418)	9
	5/8 in. (15.9 mm), Bar	Room		154.1	(1063)	92.6	(638)	17*
		600	(316)	147.8	(1019)	74.5	(514)	30*
		1000	(538)	129.1	(890)	67.3	(464)	28*
		1500	(816)	75.4	(520)	46.5	(321)	28
		1600	(871)	58.3	(402)	37.9	(261)	34*
6K	0.063 in. (1.6 mm), Sheet	Room		176.5	(1217)	102.7	(708)	4
		1200	(649)	146.0	(1007)	-	-	8
		1500	(816)	70.2	(484)	44.5	(307)	17
		1800	(982)	34.1	(235)	19.3	(133)	28
		2000	(1093)	17.4	(120)	8.6	(59)	53

1 Solution heat-treated at 2250 deg. F (1232 deg. C), air cooled.
*Elongation, percent in 1 in. (25.4 mm).

Average Cavitation-Erosion Data

Alloy	Test Duration, hrs.	Weight loss, mg.
Stellite® 6B	100	42.3
Type 304 Stainless Steel	7	39.9

Average Abrasive Wear Data

Alloy	Condition	Volume Loss, mm3	Hardness, Rockwell	Wear Coefficient[1]
Stellite® 6B	Mill annealed	8.2	C-38	0.471×10^{-3}
Stellite® 6K	Mill annealed	13.3	C-46	0.946×10^{-3}
Stellite® 25	Mill annealed	53.0	C-24	2.00×10^{-3}
1090 Steel	1 hr. at 1600 deg. F (871 deg. C) water quenched + 4 min, at 900 deg. F (482 deg. C)	37.2	C-55	8.00×10^{-3}
Type 316 Stainless Steel	As received sheet	81.4	B-86	2.0×10^{-3}
Type 304 Stainless Steel	As received sheet	102.1	B-92	$3.00 \times 1\ 0^{-3}$

Average Adhesive Wear Data*

Alloy	Condition	Ring Alloy	Volume Loss, mm3	Wear Coefficient1
Stellite® 6B	Mill annealed	4620 Steel	0.293	3.70×10^{-5}
Stellite® 6K	Mill annealed	4620 Steel	0.561	8.73×10^{-5}
Stellite® 25	Mill annealed	4620 Steel	0.285	2.50×10^{-5}
1090 Steel	1 hr. at 1600 deg. F (871 deg. C) water quenched + 4 min, at 900 deg. F (482 deg. C)	4620 Steel	0.293	6.00×10^{-5}

Average Coefficients Of Static Friction For Some Common Materials

Material Against	Stellite® 6B	Cast Iron	Bronze	Aluminium	Lead
Stellite® 6B	0.119	0.123	0.125	0.138	0.119
Cast Iron	0.123	0.199	0.245	0.213	0.225

Enclosure 5

Bronze	0.125	0.245	0.231	0.257	0.249
Aluminium	0.138	0.213	0.257	0.213	0.328
Lead	0.119	0.225	0.249	0.328	0.290

Coefficient represents tangent of angle of repose. Tests made on dry surface having better than 120 grit finishes. All values based on averages and are to be used comparatively and not as absolute values.
* Average of two or more tests against a case-hardened SAE 4620 steel ring (Rockwell C-63).

1 The wear coefficient (K) was calculated using the equation where V = Wear volume (mm^3)

P = Load (kg)

L = Sliding distance (mm)

h = Diamond pyramid hardness

A combination of a low wear coefficient and a high hardness is desirable for good wear resistance.

Average Corrosion Data - Stellite® 6B*

Media	Concentration, percent by Weight	Test Temp., deg F (deg. C)	Average Penetration Rate per Year** mils	mm
Acetic Acid	10	Boiling	0.08	0.002
Acetic Acid	30	Boiling	0.04	0.001
Acetic Acid	50	Boiling	0.02	<0.001
Acetic Acid	70	Boiling	0.06	<0.002
Acetic Acid	99	Boiling	0.03	<0.001
Chromic Acid	10	150 (66)	95	2.41
Formic Acid	10	Boiling	20	0.51
Formic Acid	30	Boiling	26	0.66
Formic Acid	50	Boiling	47	1.19
Formic Acid	70	Boiling	50	1.27
Formic Acid	88	Boiling	23	0.58
Hydrochloric Acid	2	Room	0.1	<0.003
Hydrochloric Acid	5	Room	63	1.60
Hydrochloric Acid	10	Room	108	2.74
Hydrochloric Acid	20	Room	93	2.36
Hydrochloric Acid	2	150 (66)	0.1	<0.003
Hydrochloric Acid	5	150 (66)	>1000	>25.4
Hydrochloric Acid	10	150 (66)	>1000	>25.4
Hydrochloric Acid	20	150 (66)	>1000	>25.4
Nitric Acid	10	Boiling	0.15	<0.004
Nitric Acid	30	Boiling	6	0.15
Nitric Acid	50	Boiling	>1000	>25.4
Nitric Acid	70	Boiling	>1000	>25.4
Phosphoric Acid	10	Boiling	Nil	Nil
Phosphoric Acid	30	Boiling	2	0.05
Phosphoric Acid	50	Boiling	19	0.48
Phosphoric Acid	70	Boiling	23	0.58
Phosphoric Acid	85	Boiling	611	15.5
Sodium Hydroxide	30	Boiling	13	0.33
Sulfuric Acid	10	Room	0.02	<0.001
Sulfuric Acid	30	Room	Nil	Nil
Sulfuric Acid	50	Room	0.4	0.01
Sulfuric Acid	77	Room	0.7	0.02
Sulfuric Acid	10	150 (66)	0.02	<0.001
Sulfuric Acid	30	150 (66)	0.09	<0.003
Sulfuric Acid	50	150 (66)	>1000	>25.4
Sulfuric Acid	77	150 (66)	176	4.5
Sulfuric Acid	2	Boiling	31	0.79
Sulfuric Acid	5	Boiling	91	2.31
Sulfuric Acid	10	Boiling	157	3.99
Sulfuric Acid	20	Boiling	360	9.14
Sulfuric Acid	50	Boiling	>1000	>25.4
Sulfuric Acid	30	Boiling	>1000	>25.4
Sulfuric Acid	77	Boiling	>1000	>25.4
Ferric Chloride (10 days without crevice)	10	Room	13	0.33***
Ferric Chloride (10 days with crevice bolt)	10	Room	9**	0.23***
Ferric Chloride + Sodium Chloride (10 days)	5 10	Room	18	0.46***
Potassium Permanganate + sodium Chloride (120 hrs)	2 2	194 (90)	8	0.20

* Determined in laboratory tests. It is recommended that samples be tested under actual plant conditions.
** Corrosion rates for all duplicate samples based on an average of 4-24 hour test periods.
*** Samples pitted during test.

Average Stress Rupture and Creep Data

Stellite®	Test Temp., deg. F	(deg. C)	Stress Ksi	(MPa)	Initial Elongation, percent	Life, hrs.	Time in hours for total Elongation, % of: 0.5	1.0	2.0	Elongation at Rupture, percent
6B 0.063 in. (1.6 mm), Sheet[2]	1000	(538)	60	(414)	0.70	192.8[1]	-	-	-	0.8
	1200	(649)	50	(345)	0.45	361.4	0.5	113.8	-	3.0
	1400	(760)	35	(241)	0.35	59.3	0.4	3.8	16.3	5.1
	1500	(816)	25	(172)	0.35	70.6	0.2	4.3	19.9	4.7
	1600	(871)	19	(131)	0.10	57.9	0.5	2.2	11.1	4.3
	1700	(927)	12	(83)	0.19	104.0	1.8	20.9	89.9	2.6
	1800	(982)	8	(55)	0.05	113.4	5.1	22.7	57.6	5.5
	2000	(1093)	2	(14)	0.004	116.7	4.4	-	-	13.3

1 Test discontinued before rupture.
2 Specimens were solution heat-treated at 2250 deg. F (1232 deg. C) and air cooled prior to testing.

Enclosure 5

Fusion Welding

Stellite® 6B (AMS 5894) and **Stellite® 6K** can be welded by gas tungsten-arc (TIG) with an argon flow of 25 CFH, gas metal-arc (MIG), shielded metal-arc (coated electrode), and oxy-acetylene in this order of preference. The oxy-acetylene method should be used with discretion and care in that Stellite will "boil" during welding which may cause porosity. Use a 3x reducing flame to minimize oxidation, penetration, and inter-alloying.

Stellite® 6B (AMS 5894) and **Stellite® 6K** should be preheated and maintained at 1000°F (35 8°C) to prevent cracking during welding and then still air cooled. Fixturing which would chill the weld rapidly should not be used. Standard weld joints are recommended. **Inconel®** 82, 92, or 625 filler metals are recommended for joining **Stellite® 6B (AMS 5894)** to softer materials such as carbon steel or stainless steel, while the harder cobalt- base filler metals such as **Stellite® 6** and **Stellite® 21** are recommended for joining **Stellite® 6B** (AMS 5894) to itself, especially if wear resistance is required in the weld areas. In the latter case, **Inconel®** 82, 92, or 625 may be used for root passes and then be overlayed with the harder
materials. Gas shielding of the root side of the gas tungsten-arc weldments is not mandatory but is recommended in order to improve weld penetration.

Adequate ventilation is required to control exposure to airborne dust, fumes, and particulate when machining, grinding or welding Stellite alloys. MSDS sheets are available.

Brazing

Stellite® 6B (AMS 5894) and **Stellite® 6K** are readily joined to other materials by brazing. All forms of surface dirt such as paint, ink, oil, chemical residues, etc., must be removed from the mating parts by etching, solvent scrubbing, degreasing, or other means. In addition, fluxing will be required during torch brazing operations when using silver brazing filler metal to help clean the joint and allow the filler metal to flow more freely over the mating surfaces. Brush joining areas generously with brazing flux prior to heating. When torch or induction brazing, as soon as the brazing filler metal melts, the source of heat should be removed and the parts positioned. The assembly should then be pressed together to squeeze out the excess flux and still air cooled. The parts should not be quenched.

Other brazing filler metals (i.e., gold, palladium, or nickel-based alloys) are satisfactory for joining **Stellite® 6B** (AMS 5894) and **Stellite® 6K**. Brazing filler metal selection depends on the service conditions expected.

A close fit of the mating surfaces is recommended. The finished joints will have greater strength if the filler metal is very thin, generally 0.001 - 0.005" (0.03 - 0.13 mm) thick.

Brazing with high-temperature filler materials is generally performed in a furnace. Induction and resistance heating with salt-bath and
metal-bath dip brazing have limited application. Vacuum furnaces held at less than one micron pressure or controlled atmosphere furnaces, having adequate moisture control at brazing temperatures (less than 60° F (15°C) dew point), produce the most satisfactory results. Controlled atmospheres such as hydrogen or cracked ammonia are suitable for brazing **Stellite® 6B (AMS 5894)** and **Stellite® 6K** base materials.

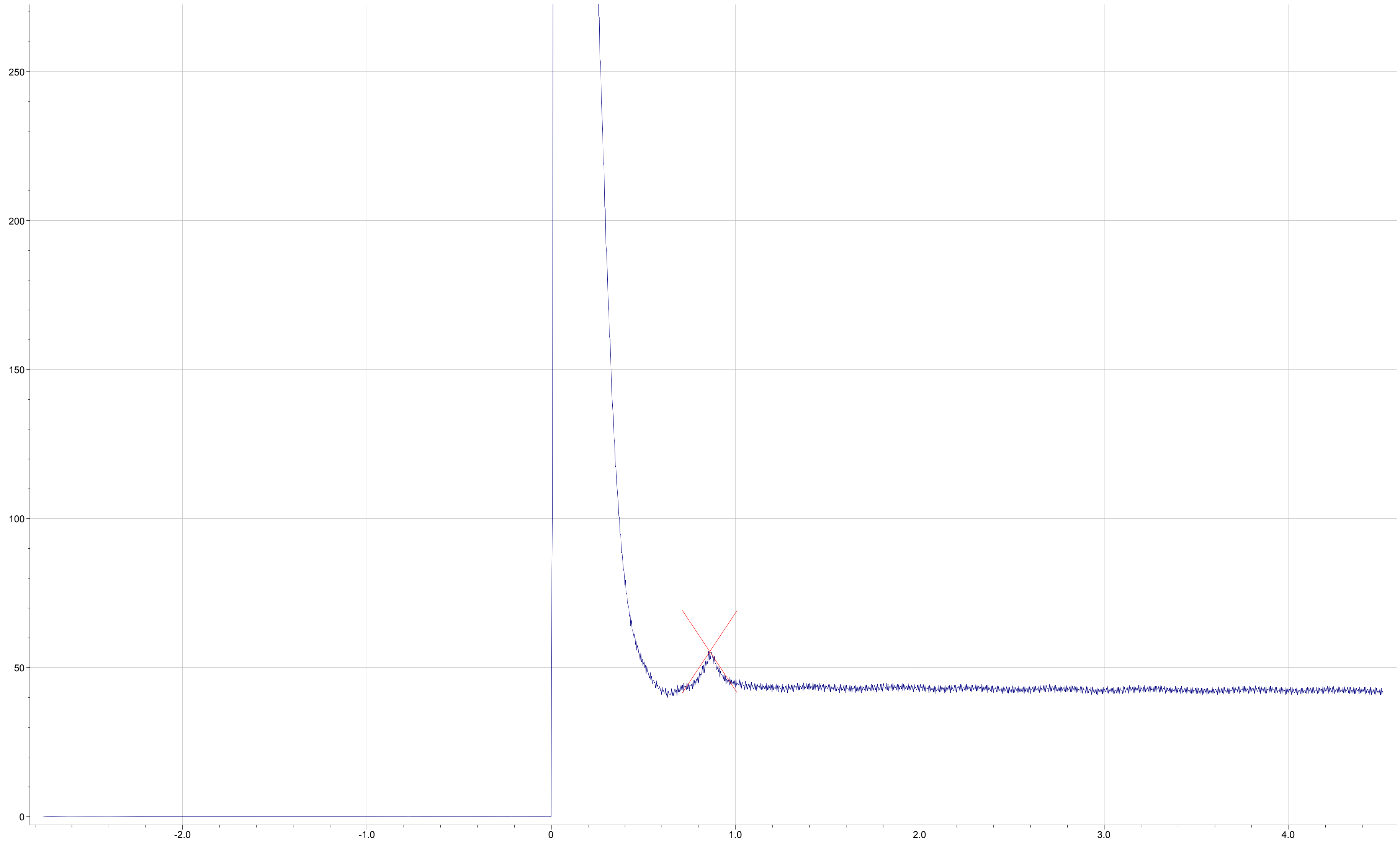
Enclosure 5

Attachment 3

MOVATS Traces (from 2006 until present)
for
1-FCV-074-0052, 1-FCV-074-0066,
2-FCV-074-0052, 2-FCV-074-0066,
3-FCV-074-0052, 3-FCV-074-0066

Analysis Print **04/11/2011 1:57:27 PM**

Valve ID	1FCV7452
Test Desc.	TSS 1.0 OCO
1-FCV-74-52 UNSEATING	



Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	55.31	A	0.8600	Sec	TSS 1.0 OCO	10/06/2006 6:49:23 AM	S:\...\1FCV7452\S2.NOR

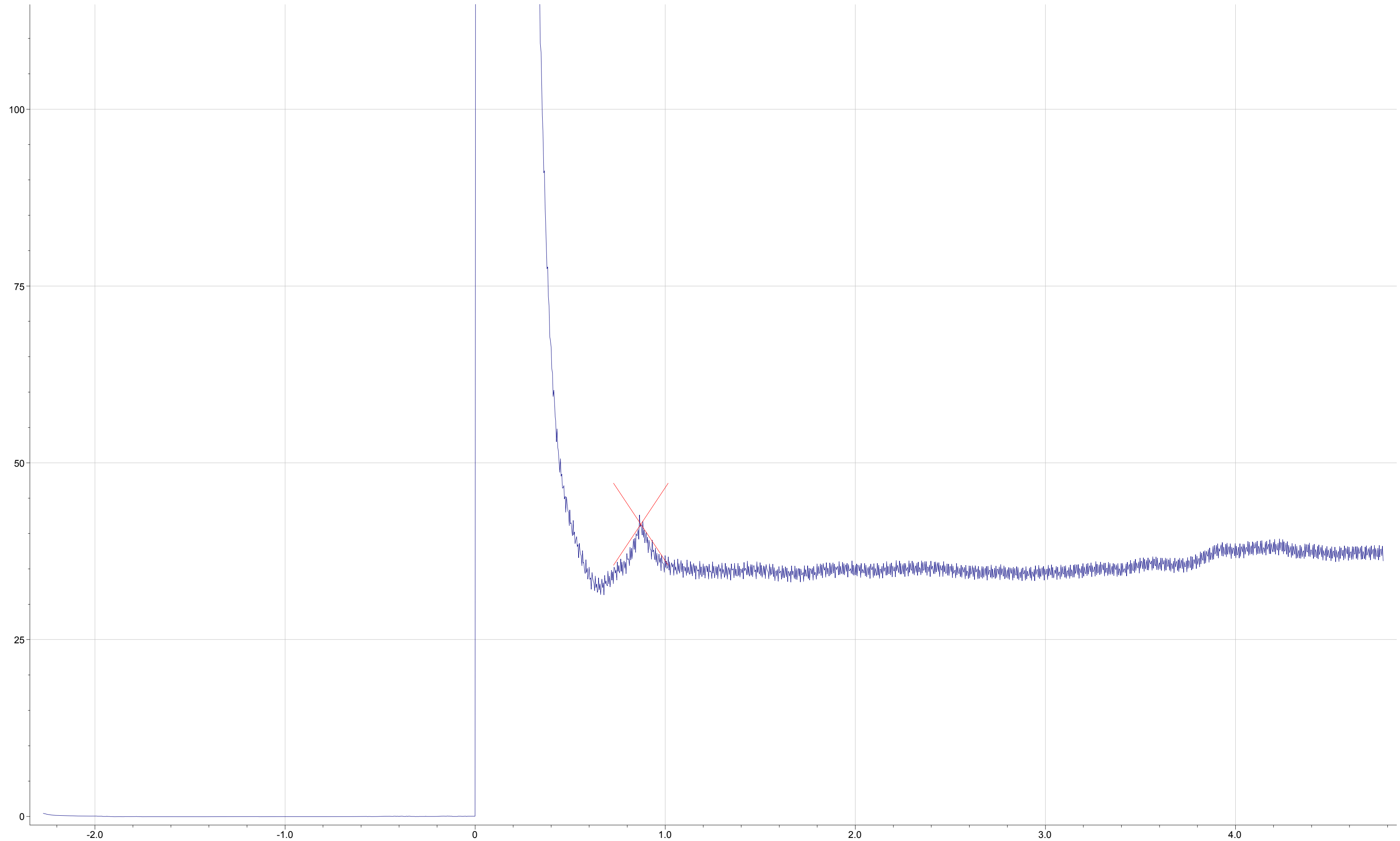
Enclosure 5

Analysis Print **04/11/2011 2:00:33 PM**

Valve ID 1FCV7452

Test Desc. AFFS/LS

1-FCV-74-52 UNSEATING s4



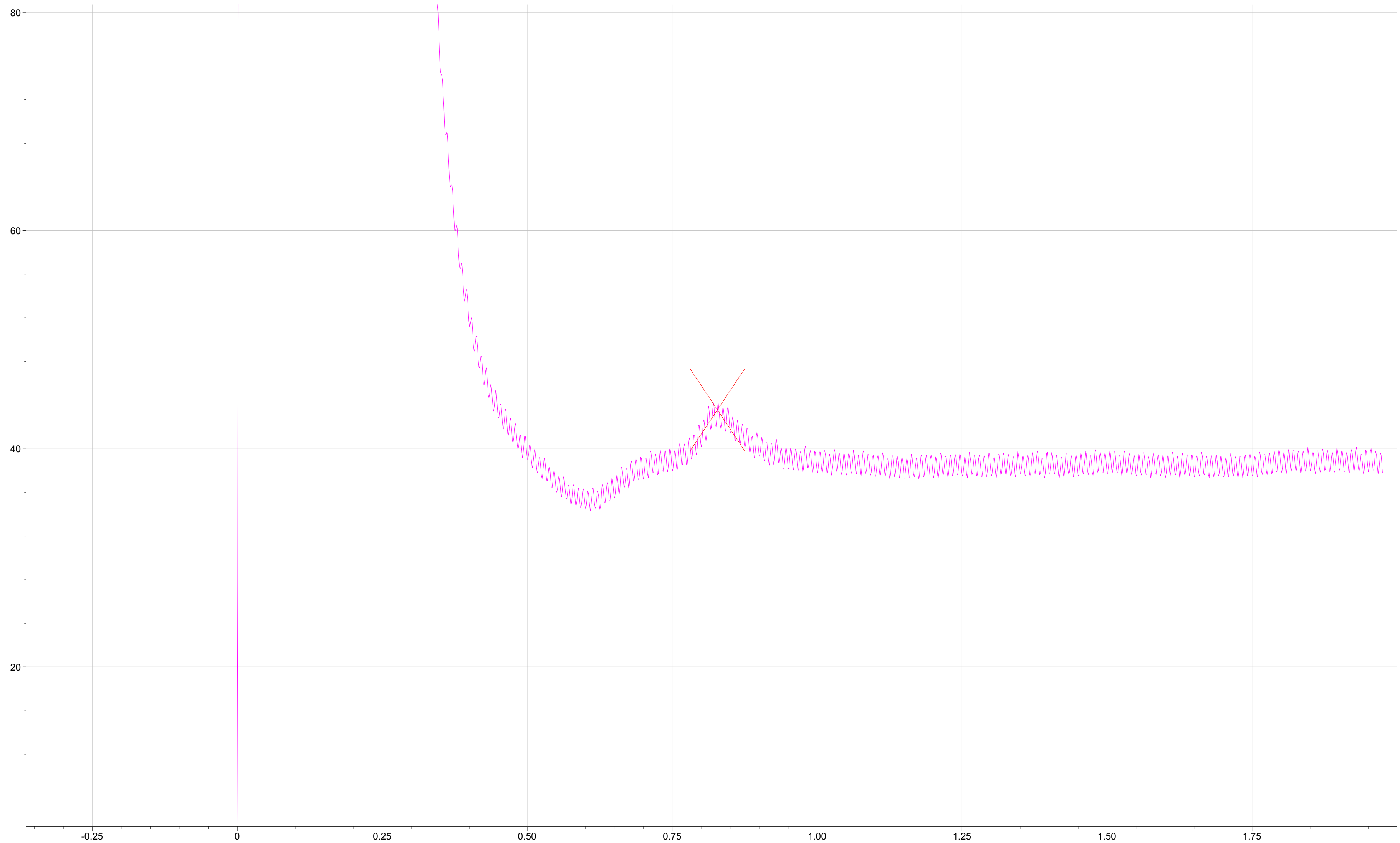
Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	41.29	A	0.8720	Sec	AFFS/LS	11/16/2008 10:21:31 AM	S:\...\1FCV7452\S4.NOR

Enclosure 5

Analysis Print **11/18/2010 1:34:56 PM**

Valve ID 1FCV7466

1-FCV-74-52 UNSEATING EVENT



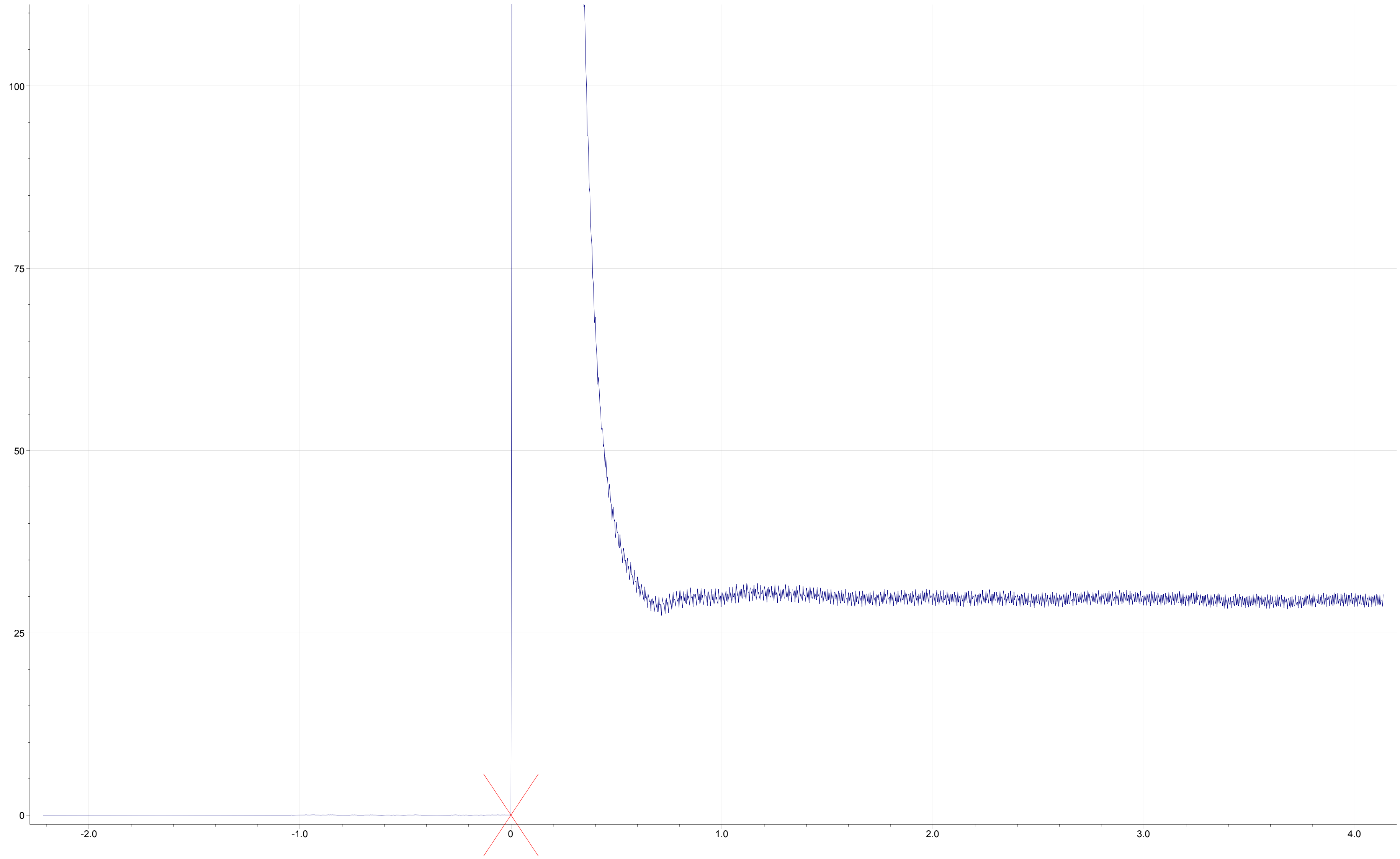
Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
4 --------	Ia RMS	43.56	A	0.8280	Sec	AL/FS/Part/@6024/TSS1	11/01/2010 1:35:59 AM	S:\...\1FCV7452\C5.NOR

Enclosure 5

Analysis Print **11/18/2010 11:41:26 AM**

Valve ID 1FCV7466

1-FCV-74-66 UNSEATING



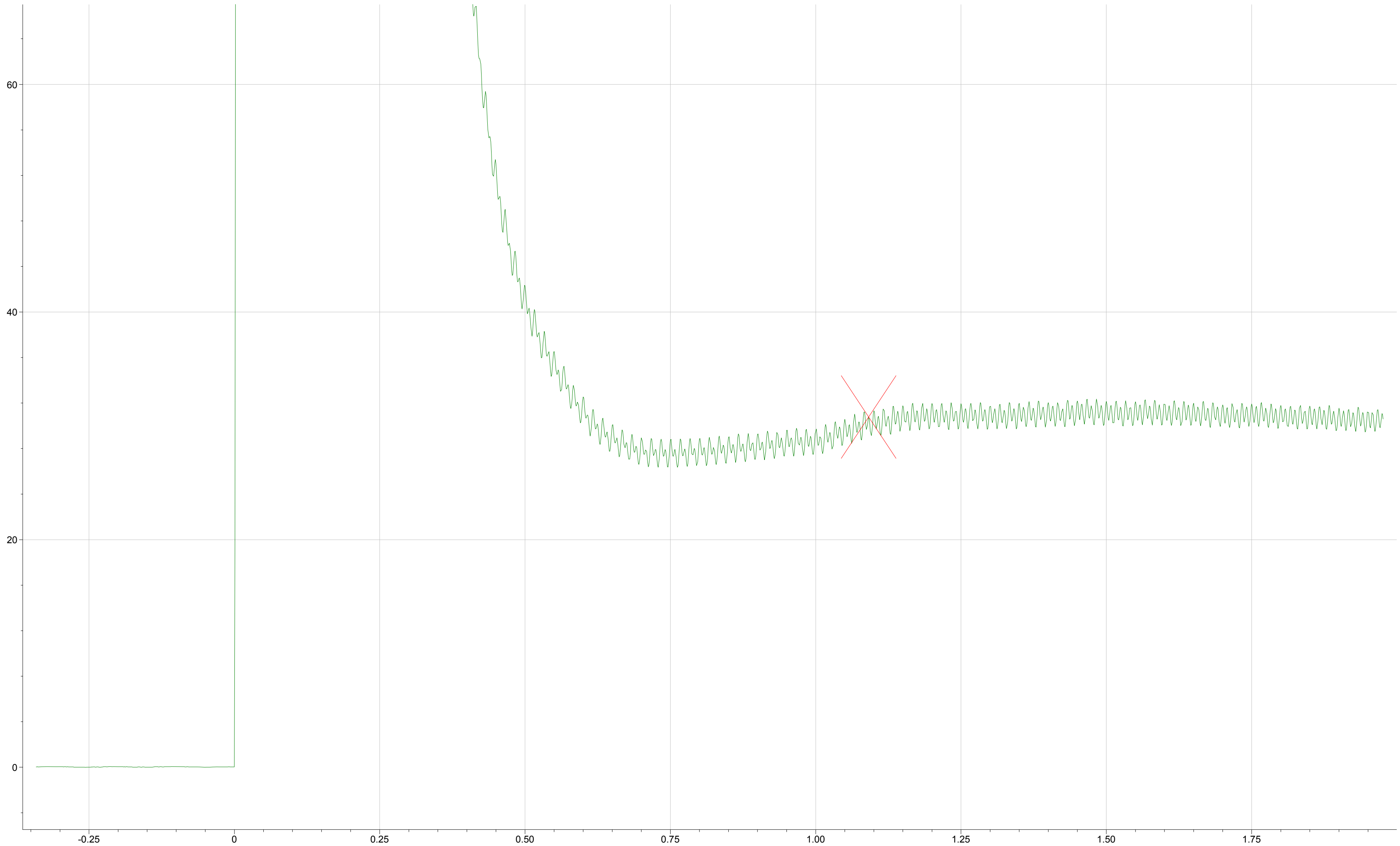
Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1 --------	Ia RMS	0.02	A	0.0000	Sec	AF TSS 2 OCO	10/09/2006 6:39:15 AM	S:\...\1FCV7466\C2.NOR

Enclosure 5

Analysis Print 11/18/2010 1:38:17 PM

Valve ID 1FCV7466

1-FCV-74-66 UNSEATING EVENT 2008



Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
2 --------	Ia RMS	30.76	A	1.0910	Sec	affs	10/31/2008 11:08:44 AM	S:\...\1FCV7466\C4.NOR

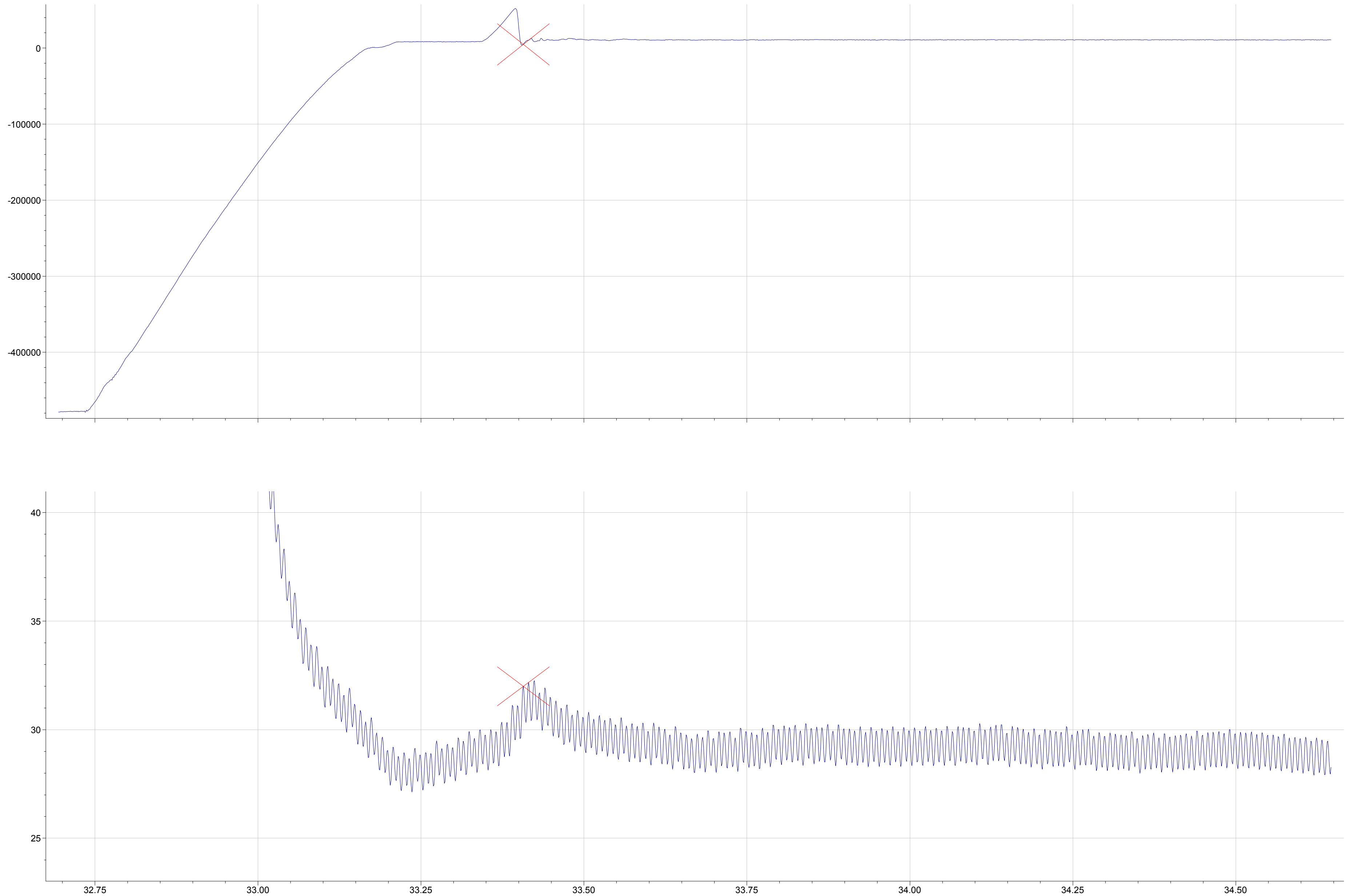
Enclosure 5

Analysis Print **11/18/2010 1:41:15 PM**

Valve ID 1FCV7466

Test Desc. ALFS/TSS1.0625

1-FCV-74-66 UNSEATING EVENT 2010

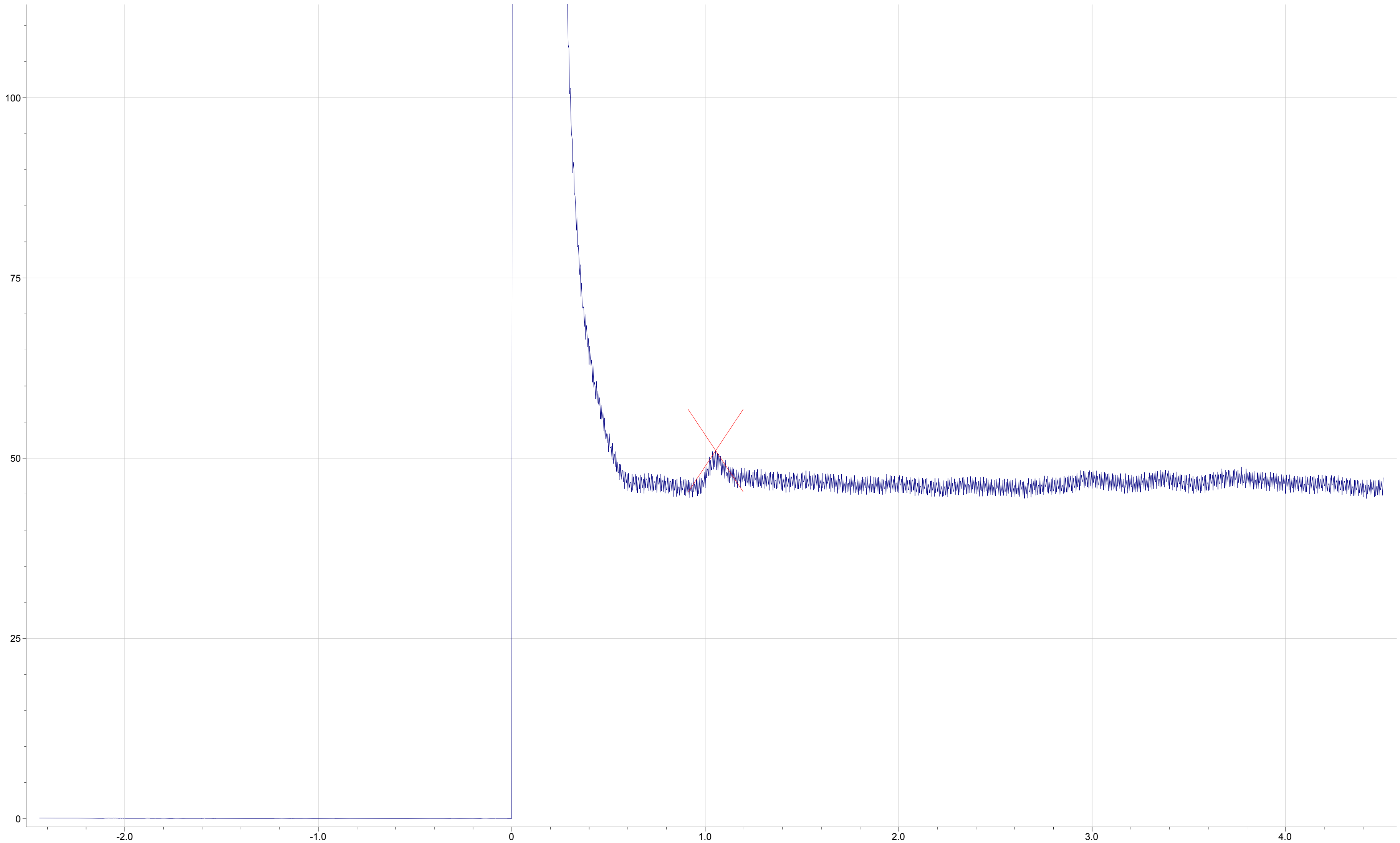


Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	ETT Thrust	4606	lbs	33.4070	Sec	ALFS/TSS1.0625	11/12/2010 11:08:31 PM	S:\...\1FCV7466\S6.NOR
2	Ia RMS	31.99	A	33.4070	Sec	ALFS/TSS1.0625	11/12/2010 11:08:31 PM	S:\...\1FCV7466\S6.NOR

Enclosure 5

Analysis Print **04/11/2011 2:50:42 PM**

Valve ID	2FCV7452
Test Desc.	ALLS/TSS3#2
2-FCV-74-52 UNSEATING	



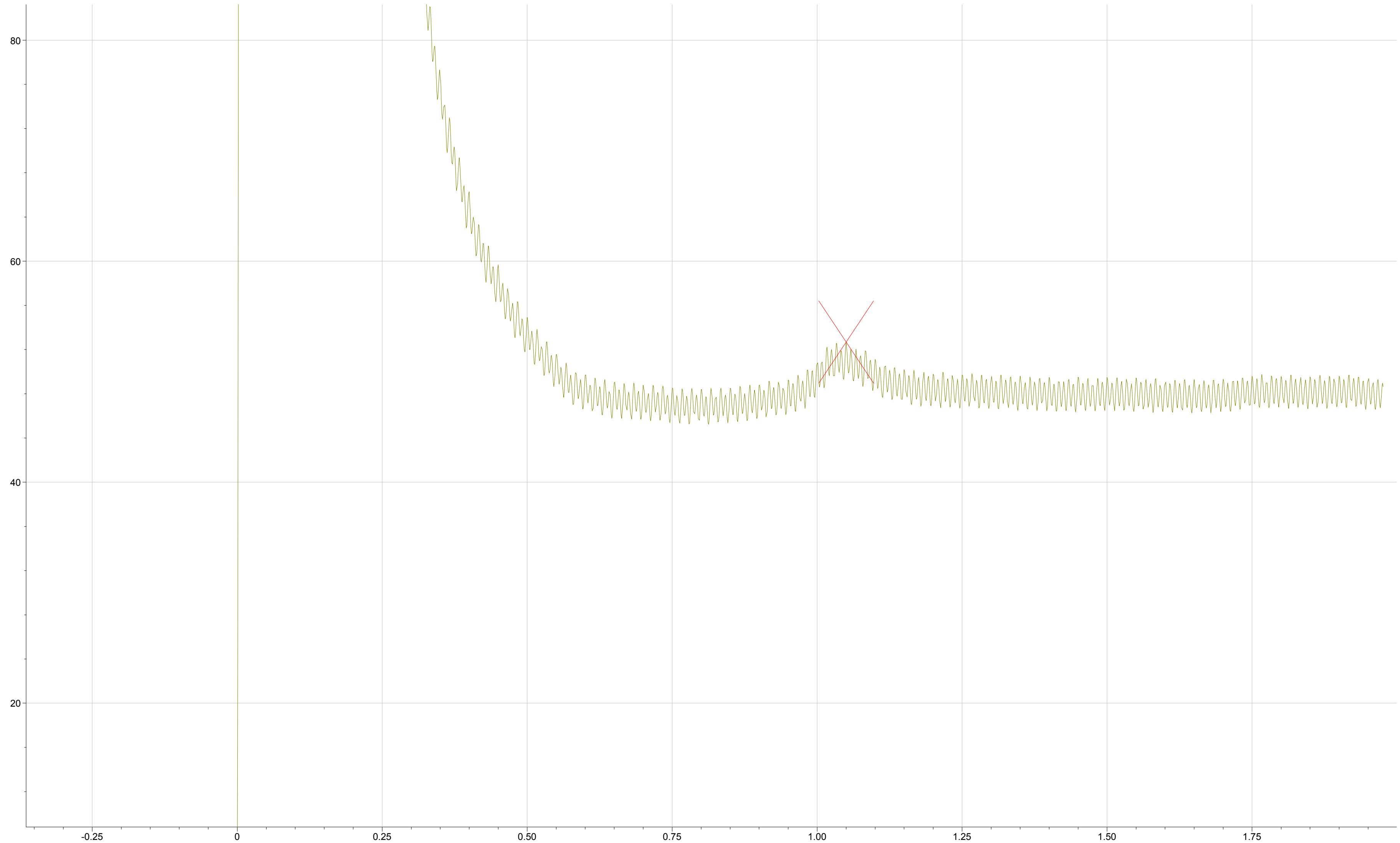
Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	51.01	A	1.0540	Sec	ALLS/TSS3#2	03/03/2007 11:33:46 AM	S:\...\2FCV7452\S21.NOR

Enclosure 5

Analysis Print **11/18/2010 1:35:33 PM**

Valve ID 1FCV7466

2-FCV-74-52 UNSEATING EVENT



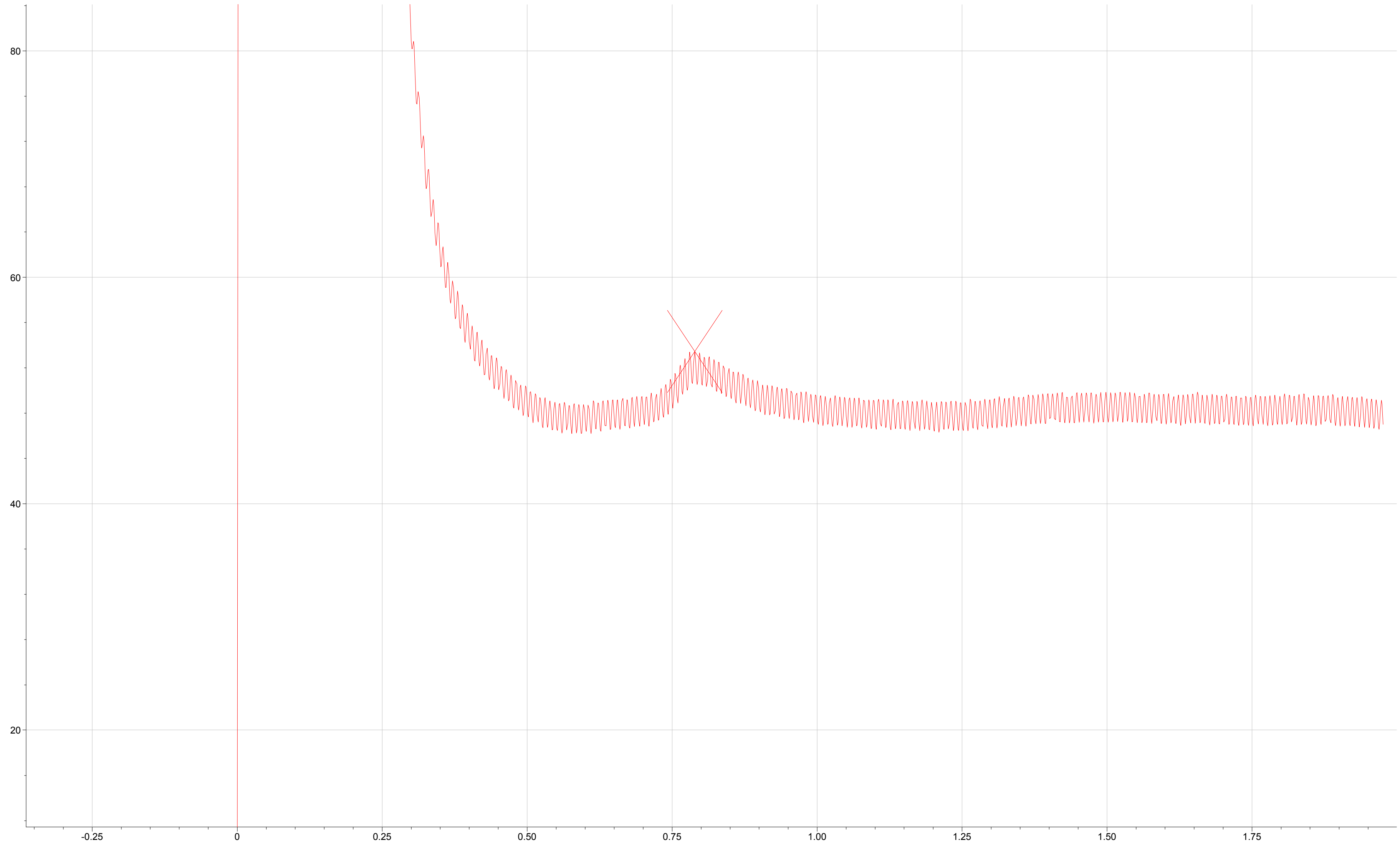
Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
5 --------	Ia RMS	52.67	A	1.0500	Sec	AF/ALFS LS	05/25/2009 3:13:54 PM	S:\...\2FCV7452\C25.NOR

Enclosure 5

Analysis Print **11/18/2010 1:36:07 PM**

Valve ID 1FCV7466

2-FCV-74-66 UNSEATING EVENT



Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
6 --------	Ia RMS	53.43	A	0.7890	Sec	AL SPRING PACK	03/30/2007 9:41:45 AM	S:\...\2FCV7466\C14.NOR

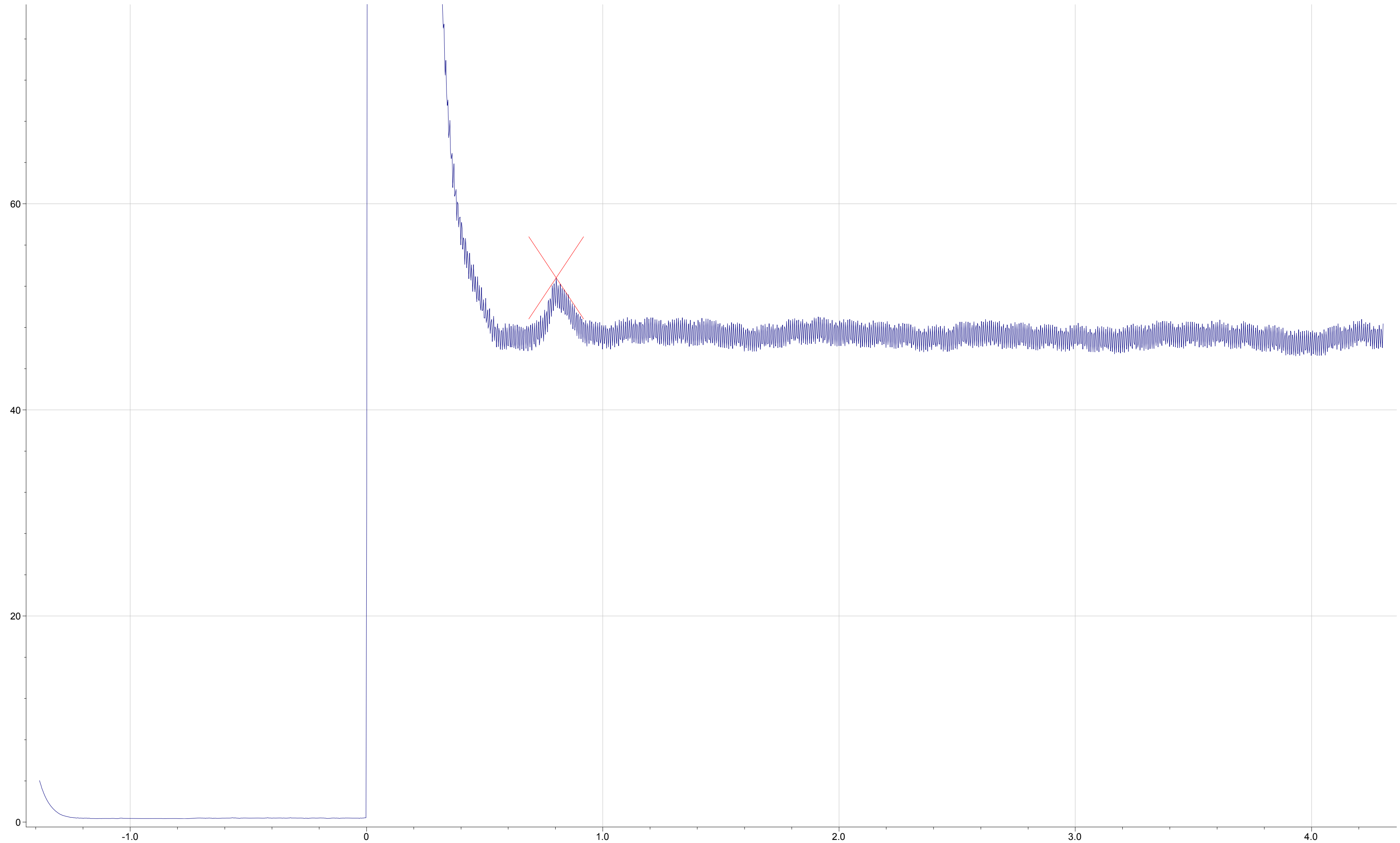
Enclosure 5

Analysis Print **04/11/2011 2:03:19 PM**

Valve ID 2FCV7466

Test Desc. ALFS/BS

2-FCV-74-66 UNSEATING



Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	52.80	A	0.8030	Sec	ALFS/BS	05/11/2009 2:36:33 PM	S:\...\2FCV7466\S15.NOR

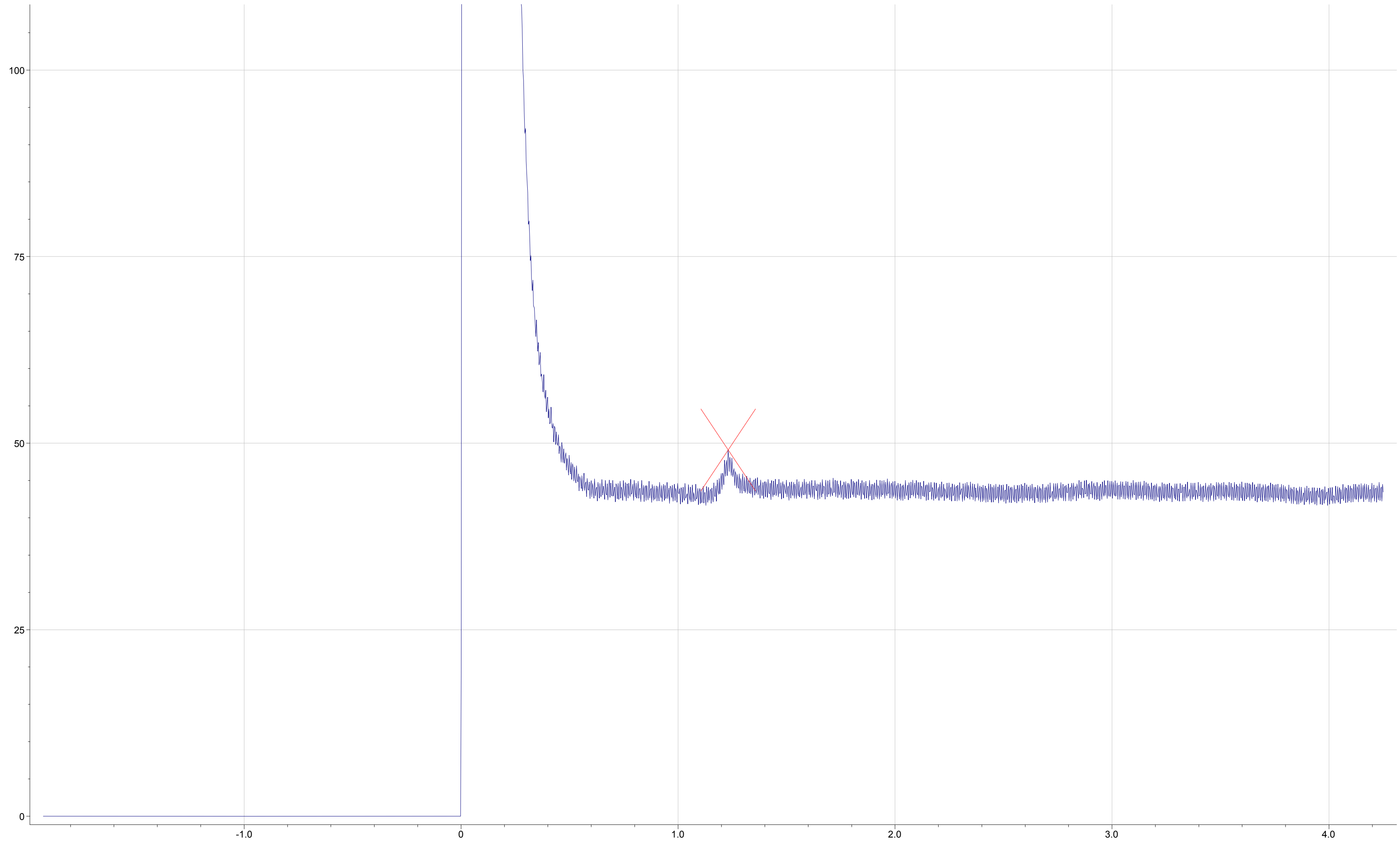
Enclosure 5

Analysis Print **04/11/2011 2:07:35 PM**

Valve ID 3FCV7452

Test Desc.

3-FCV-74-52 UNSEATING



Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	49.07	A	1.2310	Sec		03/06/2006 10:04:10 PM	S:\...\3FCV7452\S8.NOR

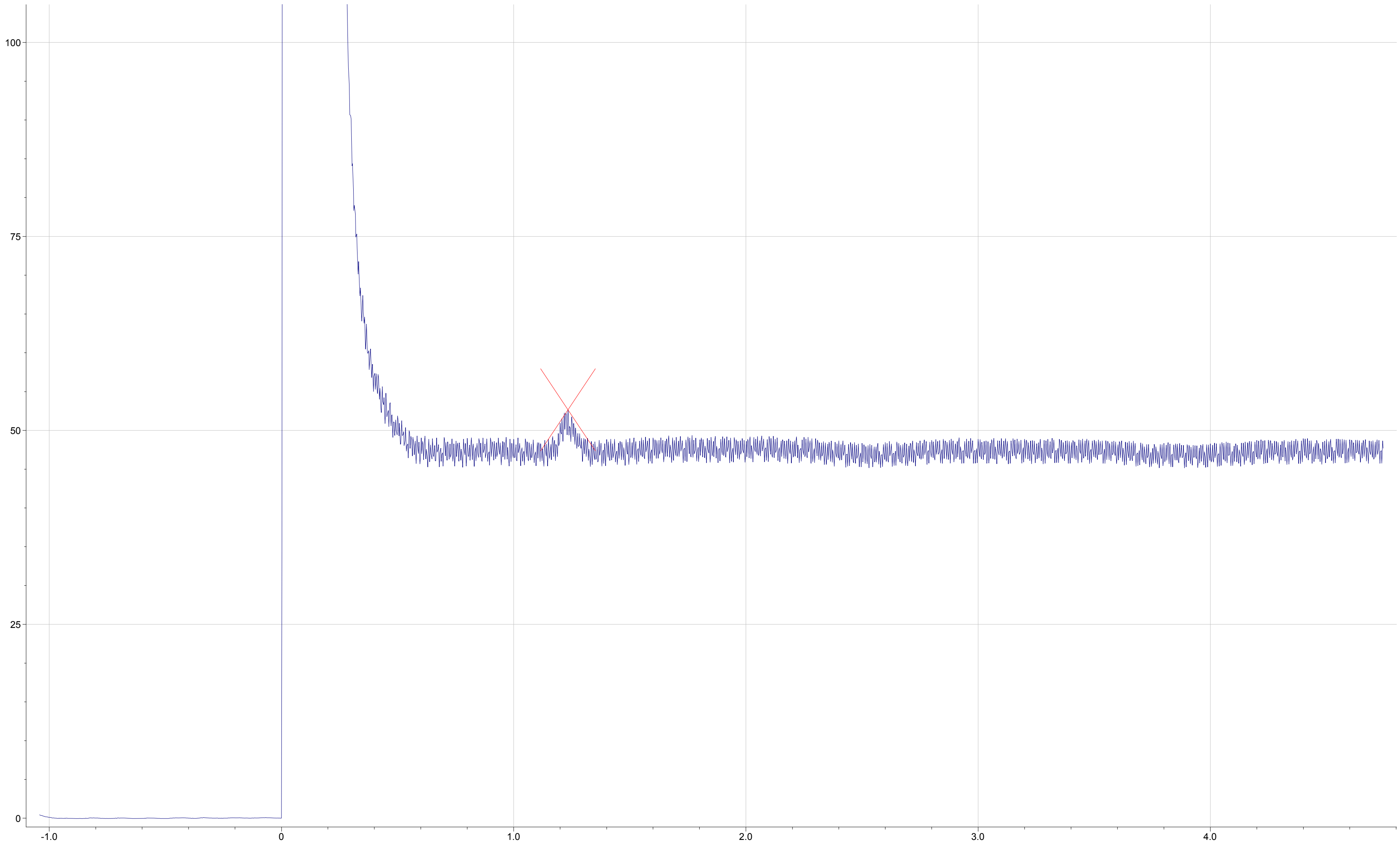
Enclosure 5

Analysis Print **04/11/2011 2:09:08 PM**

Valve ID 3FCV7452

Test Desc. affs ls

3-FCV-74-52 UNSEATING



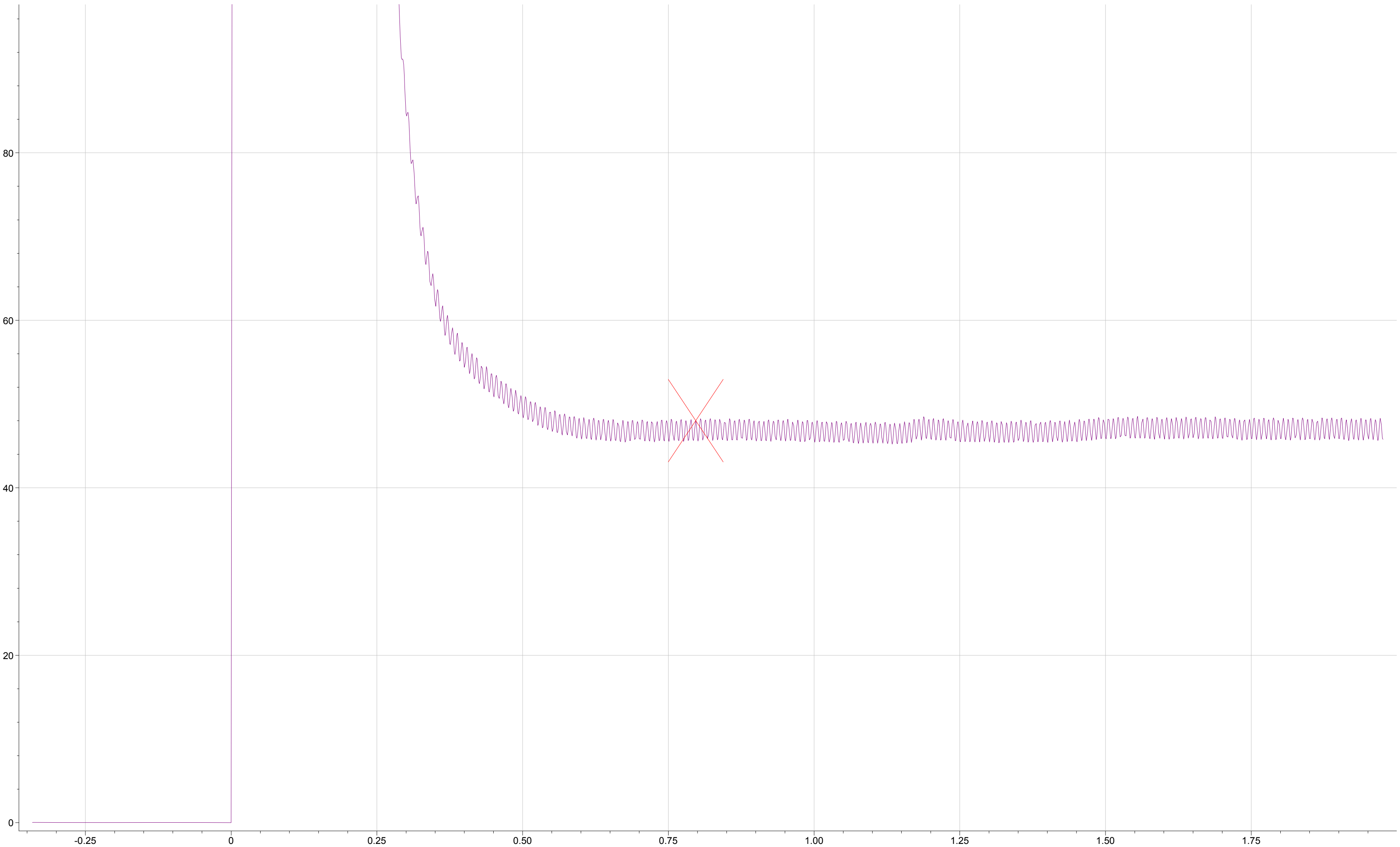
Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	52.64	A	1.2340	Sec	affs ls	04/16/2008 11:03:30 AM	S:\...\3FCV7452\S10.NOR

Enclosure 5

Analysis Print **11/18/2010 1:32:55 PM**

Valve ID 1FCV7466

3-FCV-74-52 UNSEATING EVENT

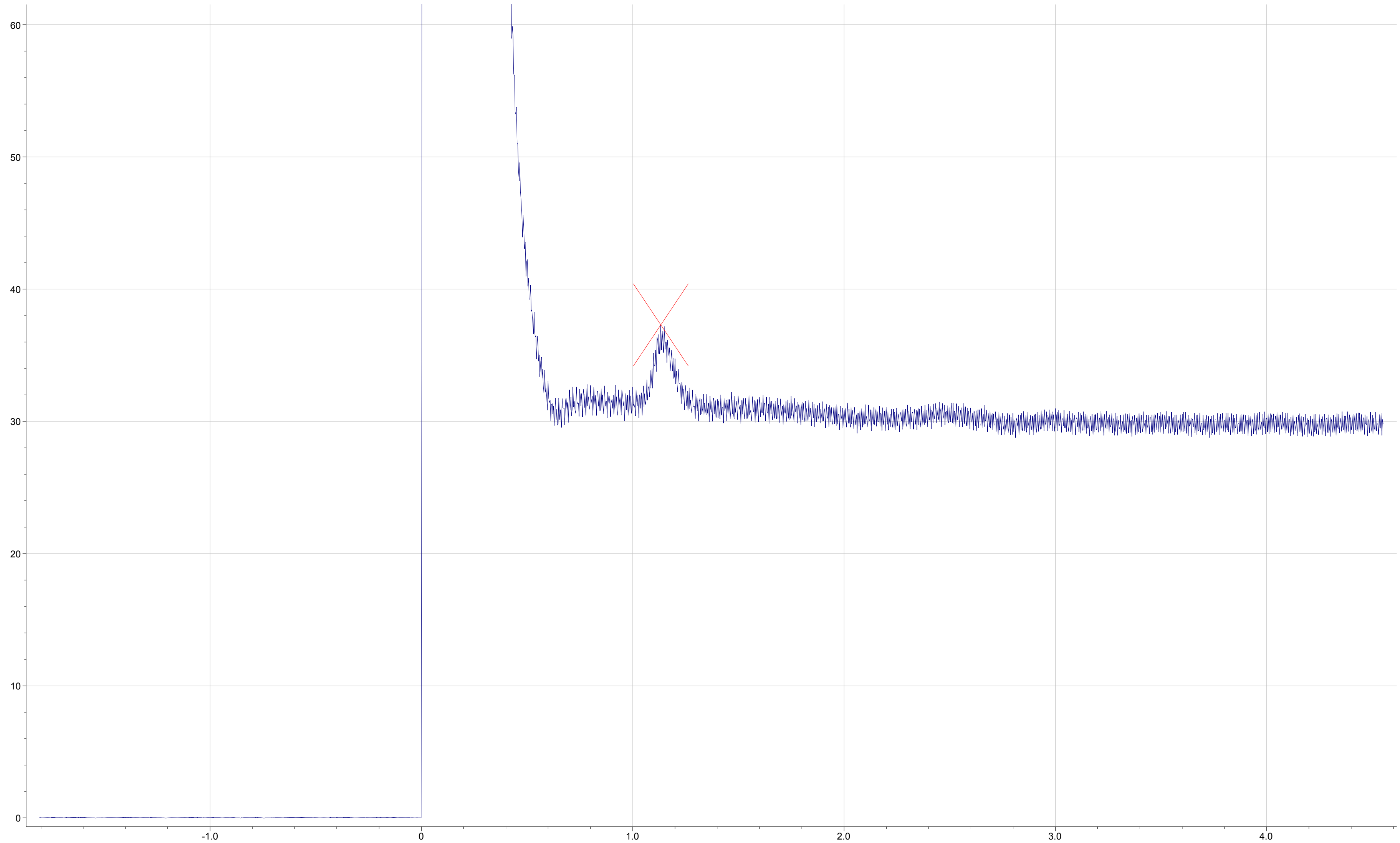


Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
7 --------	Ia RMS	48.00	A	0.7970	Sec	ALFS #3	03/10/2010 10:42:37 PM	S:\...\3FCV7452\C16.NOR

Enclosure 5

Analysis Print **04/11/2011 2:10:41 PM**

Valve ID	3FCV7466
Test Desc.	affs/ls
3-FCV-74-66 UNSEATING	



Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	37.28	A	1.1330	Sec	affs/ls	03/14/2006 12:45:47 PM	S:\...\3FCV7466\S7.NOR

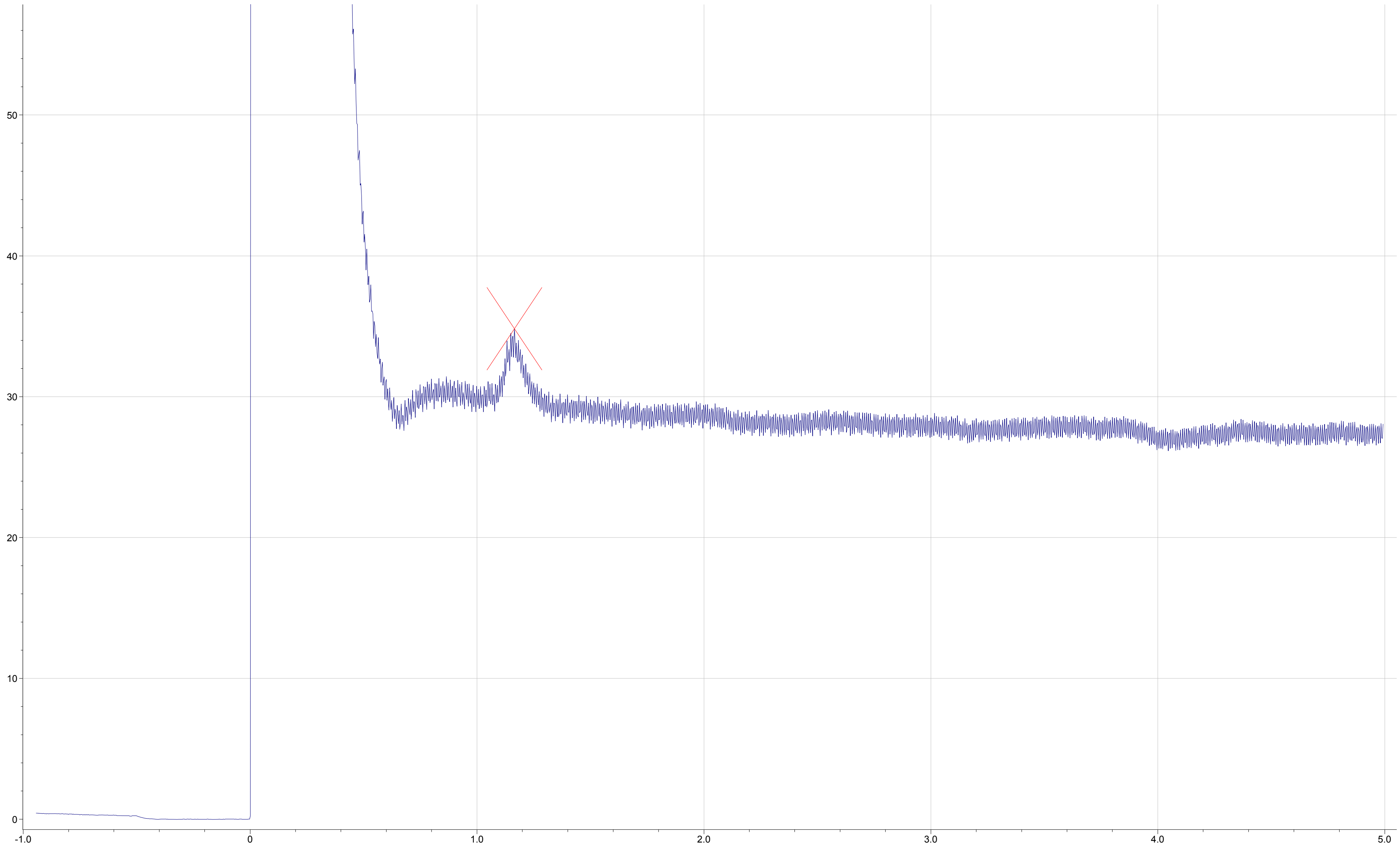
Enclosure 5

Analysis Print **04/11/2011 2:12:02 PM**

Valve ID 3FCV7466

Test Desc. AF @MCC

3-FCV-74-66 UNSEATING



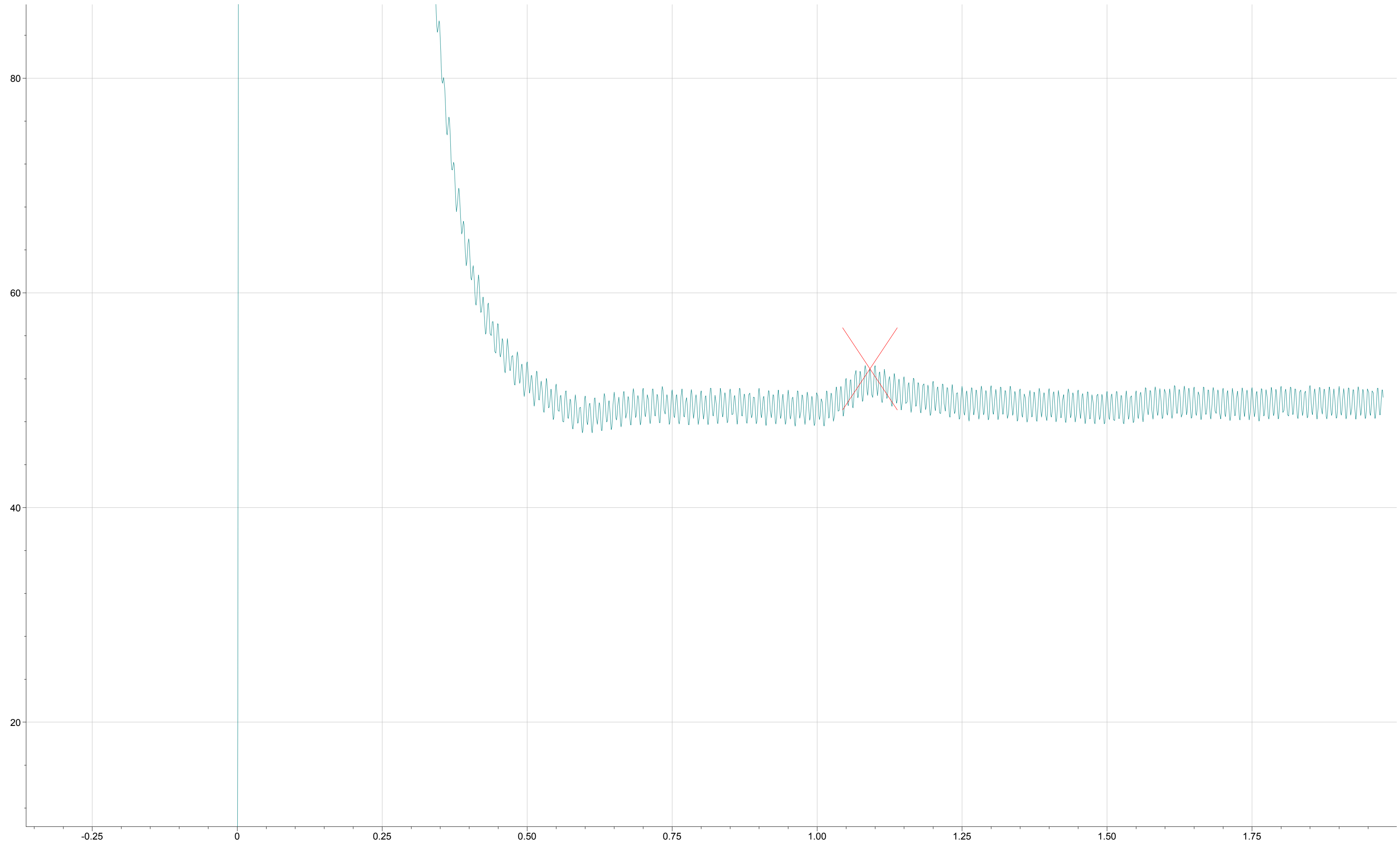
Graph	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
1	Ia RMS	34.81	A	1.1650	Sec	AF @MCC	03/24/2008 11:32:03 AM	S:\...\3FCV7466\S9.NOR

Enclosure 5

Analysis Print **11/18/2010 1:36:43 PM**

Valve ID 1FCV7466

3-FCV-74-66 UNSEATING EVENT

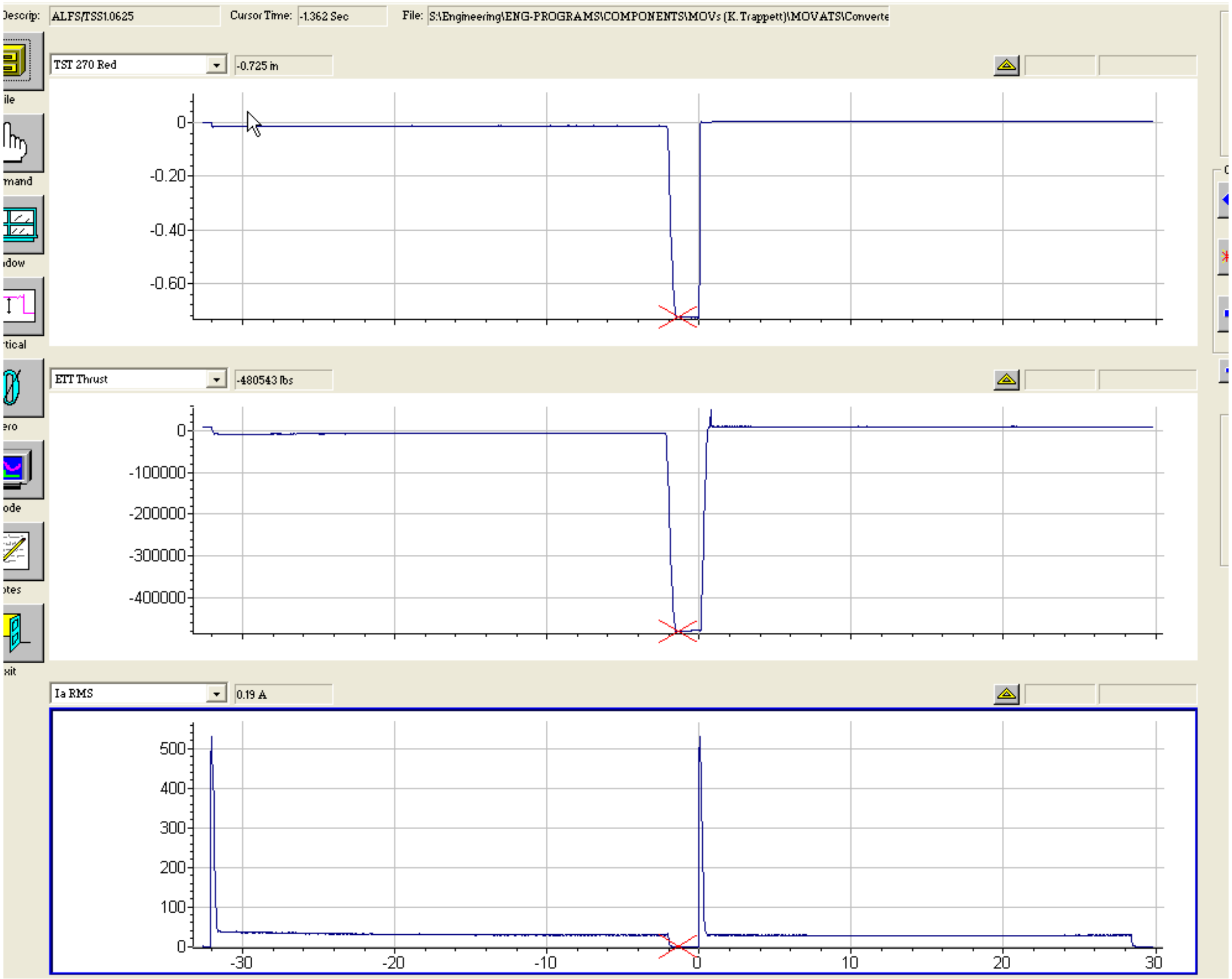


Trace	Signal Name	Value at Cursor				Test Title	Test Date	NOR File
8 --------	Ia RMS	52.91	A	1.0910	Sec	AL PARTIAL @ VLV	03/22/2010 4:59:33 AM	S:\...\3FCV7466\C14.NOR

Enclosure 5

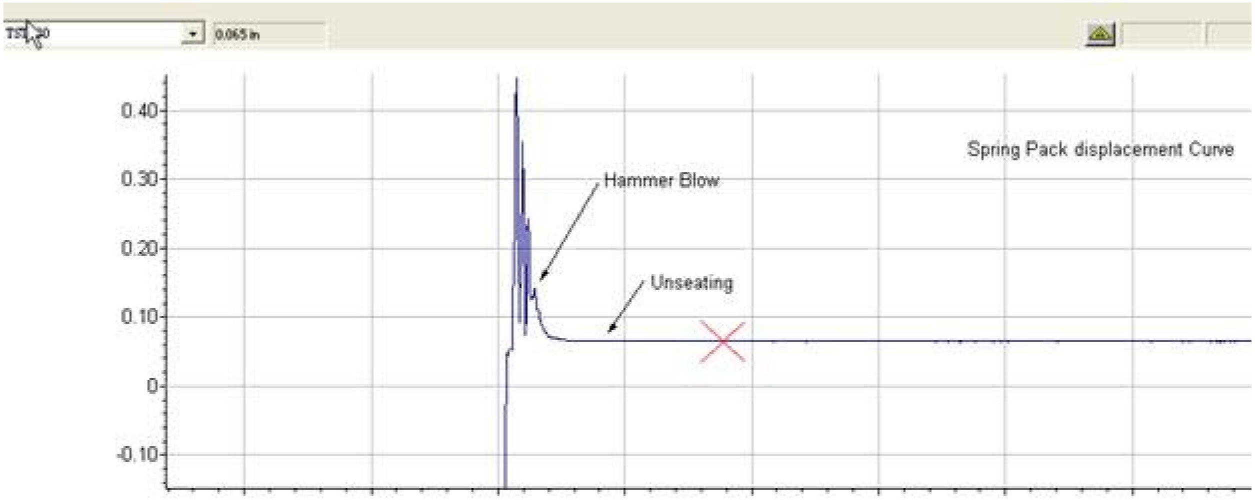
Attachment 4

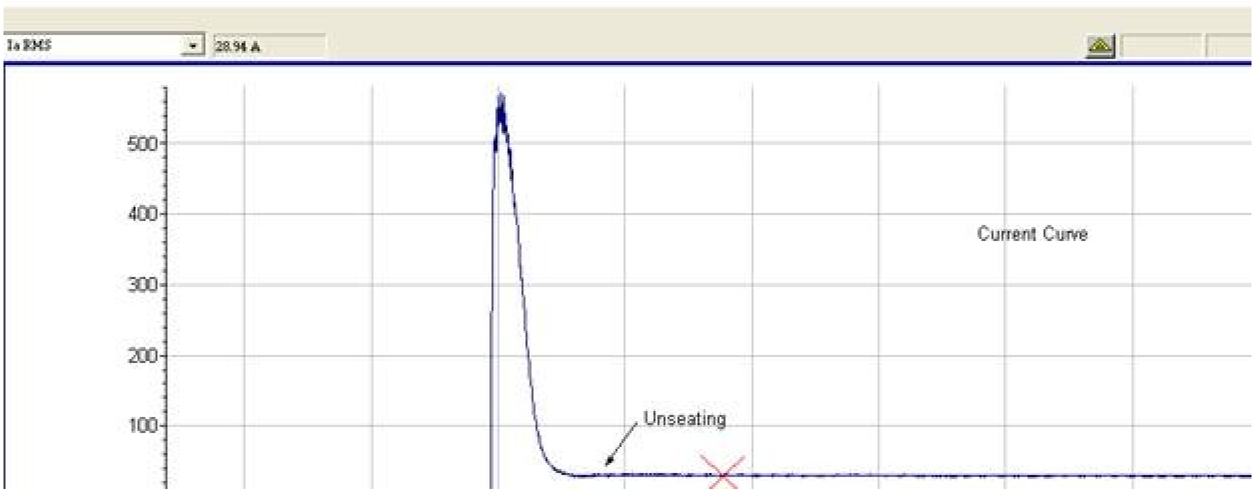
1-FCV-074-66 October 2006 MOV Partial MOVATS Parameters

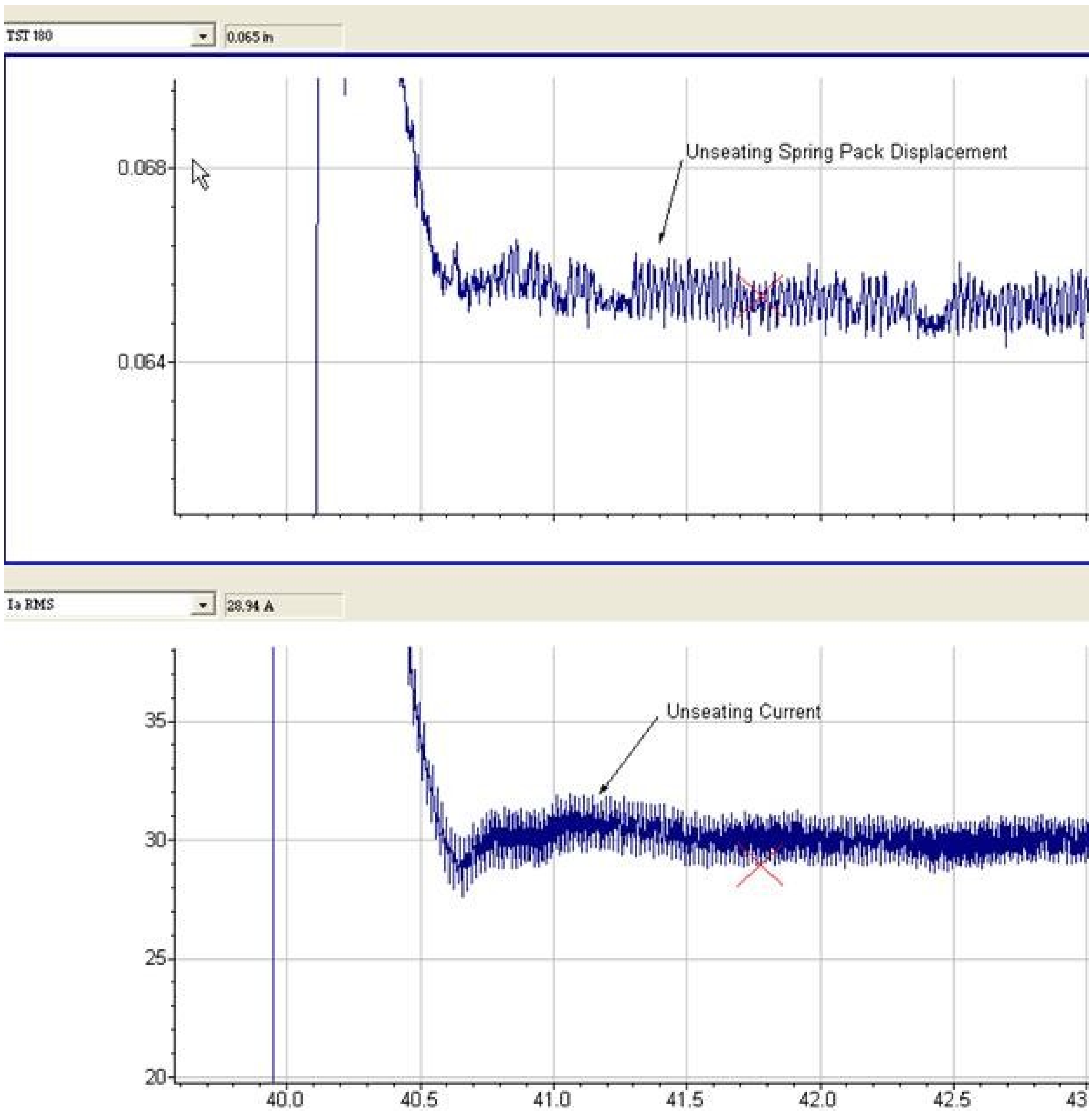


Descrip: ALFS/TSS1.0625
Cursor Time: -1.362 Sec
File: S:\Engineering\ENG-PROGRAMS\COMPONENTS\MOVs (K.Trappett)\MOVATS\Converte
TST 270 Red
-0.725 in
ETT Thrust
-480543 lbs
Ia RMS
0.19 A

Enclosure 5


0.065 in
0.40
0.30
0.20
0.10
0
-0.10
Spring Pack displacement Curve
Hammer Blow
Unseating


Ia RMS
28.94 A
500
400
300
200
100
Current Curve
Unseating


TST 180
0.065 in
Unseating Spring Pack Displacement
0.068
0.064
Ia RMS
28.94 A
Unseating Current
35
30
25
20
40.0
40.5
41.0
41.5
42.0
42.5
43

1. *The seat on Browns Ferry Nuclear Plant (BFN) valve 1-FCV-74-66 was refurbished during the BFN Unit 1 restart efforts. When were the seats of the other FCV-74-52/66 valves refurbished?*

TVA Response:

The information related to valve seat refurbishment is as follows:

Valve #	Seat refurbishment/clean date	Work order #
1-FCV-74-52	06/08/2006	Seat cleaned, polished and blue checked under WO 03-005591-010 (Page 118).
1-FCV-74-66	09/06/2006	Seat cleaned, polished and blue checked under WO 03004964-000 (Page 90)
2-FCV-74-52	No seat refurbishment after 1995	No record of refurbishment since 1995
2-FCV-74-66	No seat refurbishment after 1998	No record of refurbishment since 1998
3-FCV-74-52	No seat refurbishment after 1998	No record of refurbishment since 1998.
3-FCV-74-66	5/12/95	Seat cleaned, polished and blue checked under WO94002626-000 (page 26).

This table was developed based on the review of all maintenance records on these valves since 1995.

2. *The Structural Integrity report appears to indicate that the disc skirt may have become partially unscrewed and then the threads pulled out (fatigue and ductile overload were potential failure mechanisms). Explain why were the undersized welds on 1-FCV-74-66 not considered to be critical contributors to the failure.*

TVA Response:

For BFN valve 1-FCV-74-66, the stem was replaced by WO 03-004964-000 in 2006 and required the disassembly of the valve internals. The tack welds associated with the disc/disc skirt connection of 1-FCV-74-66 were replaced and QC verified the new welds during this process. An excerpt from WO 03-004964-000 is provided in Attachment 1.

The original vendor drawings for the FCV-74-52/66 valves do not specify tack weld size. During Unit 1 restart when the stem was replaced and the tack welds needed to be installed, guidance was absent on the weld size. The applicable TVA drawing 0-A-12337-M-1E was modified by DCN 51199 S2 for Unit 1 only. PIC #67379 (dated 6/10/06) was generated for a field change to add guidance for the tack weld for valve 1-FCV-74-66 on the design drawing A-12337-M-1E and approved on 6/12/06. The Unit 3 drawing (A-12337-M-3A) contained tack weld sizes which states “Field replacement of disc to be attached to disc skirt with four tack welds - 1/2” fillet weld, 1/2” long, 90 degrees apart, or two 7” long (MIN) 9” long (MAX) welds, 180 degrees apart.” The PIC requested that this Unit 3 guidance be added to the Unit 1 drawing.

The final drawing change which also added in a fillet size to the 7” to 9” weld wording (contrary to the PIC request) was completed 9/09/06. However, in recent discussion with Crane Nuclear, they stated that the tack welds are only for anti-rotation and that they are only concerned with ensuring weld fusion to prevent rotation since the tack welds are not considered to be load bearing.

The weld data sheet (performed 6/23/06) associated with WO 03-004964-000 indicated the length requirement (7 to 9 inches long) of each tack weld and that the two welds be 180 degrees apart, which is typical for tack welds. The QC inspector verified (dated 6/25/06) that the requirements on the weld data sheet were satisfied. QC appropriately sign-off on the welds because the 1/2” fillet guidance had not yet been added to the drawing.

Therefore, our review design requirements associated with the tack weld thickness has determined that the 1-FCV-074-66 valve tack welds did not have a thickness requirement when these welds were applied in 2006. The Root Cause Analysis report will be revised to reflect this additional information.

The Structural Integrity report (provided in Attachment 2) states with respect to these tack welds, “It is noteworthy that the design purpose of fillet welds such as these is generally not to provide additional axial load support, but rather as locking devices to keep the threaded joint from unscrewing.” Crane Nuclear indicated that the differential rotation forces between the skirt and the disc to be small (e.g., the unpinned skirt would tend to rotate with the disc) and as long as there is some weld fusion resisting high cycle rotational fatigue the size of the weld is not important. The metallurgical results (References 1 and 2) indicate that there was sufficient fusion to serve the function adequately as a tack weld to prevent rotation.

Crane Nuclear also noted that all loading is transmitted through the disc and disc skirt thread connection. Appropriately, the design did not consider axial stress because the weld cannot be stressed by axial loading with proper preloading of threads within manufacturer’s size tolerance and because of the large difference between the stiffness of the full sized threads and the weld. Undersized threads would significantly, if not altogether, reduce the preload and stiffness of the threads subjecting the weld to axial loading. Crane Nuclear further stated that the weld failure by axial forces would begin at the ends of the weld and propagate which is consistent with the results of the analysis performed by Southwest Research.

After the failure of valve 1-FCV-74-66, Southwest Research was retained to perform an on-site evaluation of the overall condition of the disc skirt paying particular attention to the broken tack welds and to make replicas of the fracture surface. Analysis of the replicas from the usable portions of the fracture surface indicated features consistent with fatigue (striations) and ductile tensile overload (dimpling). These features are fully consistent with initiation and initial propagation of the fracture along and across the weld cross-section due to fatigue with final failure occurring due to tensile overload (axial loading). Given the predominate crack propagation direction of the welds as discussed in the Southwest Research report (Reference 2), it is reasonable to conclude that the welds failed by axial overload or axial fatigue as discussed on page 10 of the report and evidenced in Figures 10, 29, 30 and 32.

Figure 10

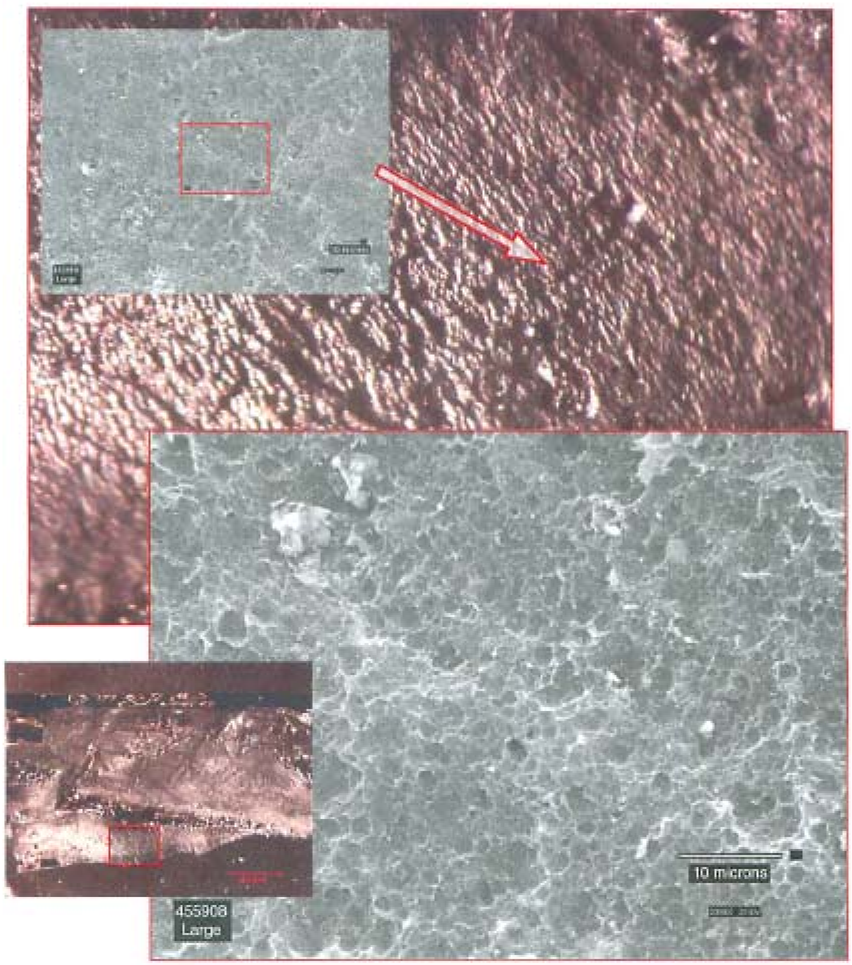


Figure 29. SEM replica image (2000X) showing dimples found on the fracture surface near the left side of the fractured weld.

Dimples shown in Figure 29 are a strong indication that the failure caused in this area was caused by overload.

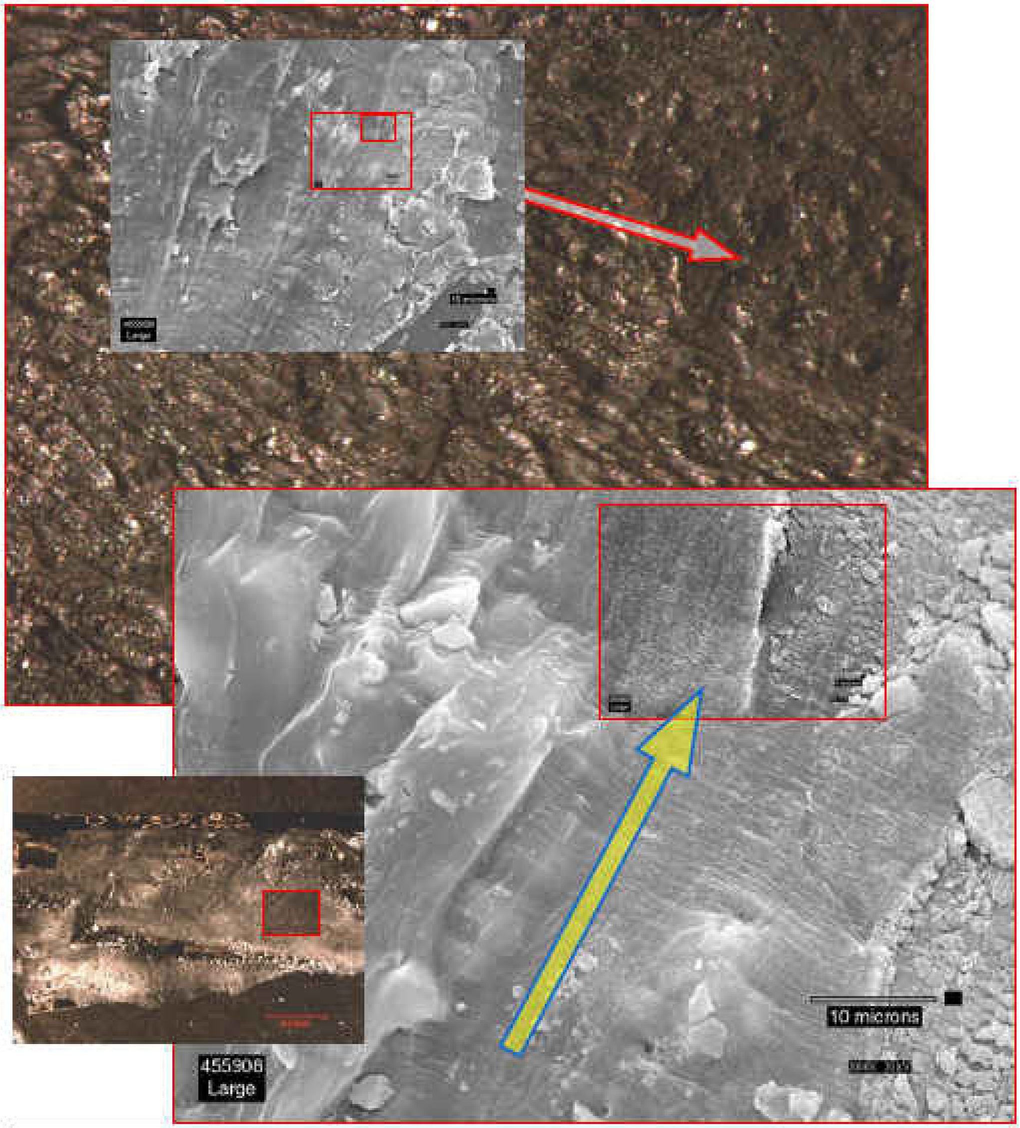


Figure 30. SEM replica image (2000X) showing possible fatigue striations found on the fracture surface near the left side of the fractured weld. (Spacing ~ 0.3 microns)

Figure 30 clearly indicates fatigue striation. The clearly establishes cyclic loading and fracture progression across the fracture surface consistent with loading in the axial direction.

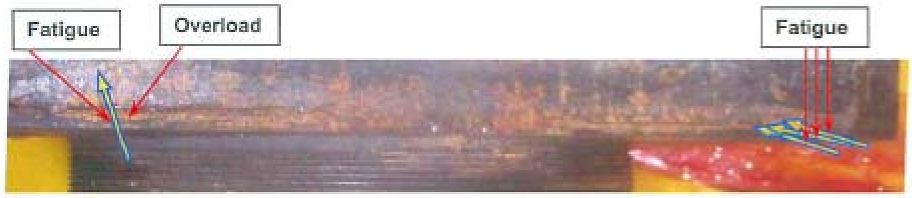


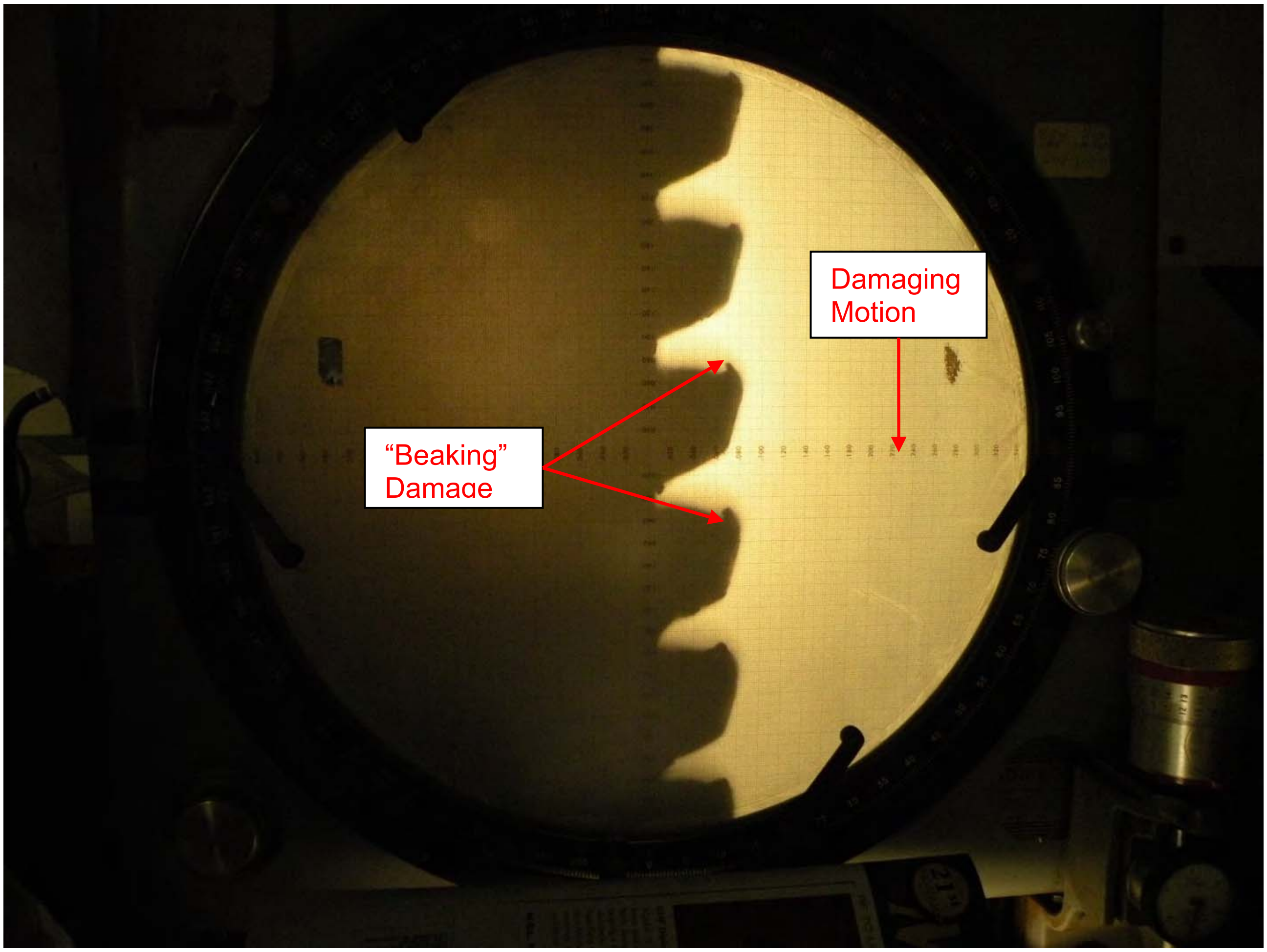
Figure 32. Near-actual-size view of the tack weld's fracture surface showing fracture mode and direction of propagation based on information from the replicas.

Figure 32 shows the locations where failure modes were identified in the replicas. In the areas where axial fatigue modes were identified as the failure mode, an arrow with a blue outline and a light-yellow fill is shown on the fracture surface. These arrows also show the propagation directions which are consistent with Crane Nuclear statement that the axial failure would start at the weld endpoint and propagate along the weld cross section. Where axial overload was the failure mode, a labeled arrow points to the location on the fracture surface.

Due to the difficulties of obtaining replicate samples, laboratory analysis of replicates, and uncertainties of the field analysis, it was decided that further metallurgical evaluations were necessary in order to provide more detailed analysis of the failure. Therefore, the assembly (upper portion of the angle valve including the stainless steel stem and cast steel skirt) was shipped to the Westinghouse Materials Center for destructive examination.

The resulting Westinghouse report (Reference 1) determined that the threads were undersized and showed mechanical damage starting with the first thread. Further detailed analysis indicated significant plastic deformation (beaking) of the threads beginning on the second thread (refer to Figure 3.10). With respect to question of the disc skirt becoming partially unscrewed, the formation of beaks is inconsistent with the threads unscrewing.

BOTTOM



TOP

Figure 3.10 Optical Comparator Image of Damaged Threads (Location Not Specified)

The beaking is more pronounced at 290 degrees and 20 degrees which agree with the asymmetrical loading model for the undersized threads. This is further corroborated by the evidence of flattened thread crests predominately at 110 degrees, where insufficient or limited contact does not allow for a sufficient force to be applied to create plastic deformation (beaking). Additionally, because of the asymmetric loading, no damage is visible at 200 degrees, indicating little to no contact with the threads in this location. The Structural Integrity analysis (Attachment 2) also showed that the threads are subject to significant axial forces under axial loads, consistent with the observations of severe damage (beaking) in some threads in the Westinghouse metallurgical report (Reference 1).

At the completion of the metallurgical examinations by both Southwest Research and Westinghouse, an independent metallurgical review (Reference 3) was conducted by a Burns and Roe metallurgist. This review concluded that the Westinghouse examination of the skirt threads showed primarily two types of damage. One form was a phenomenon which is referred to as "beaking" whereby deformation of the thread tips is aligned in the direction opposite of the applied load. This type damage was the predominant mechanism observed and is associated with pullout by an axial load rather than unscrewing. It was also noted that beaking was not observed around the entire circumference of the threads which indicates some type of asymmetrical loading. The second form of damage observed was flattened thread crests.

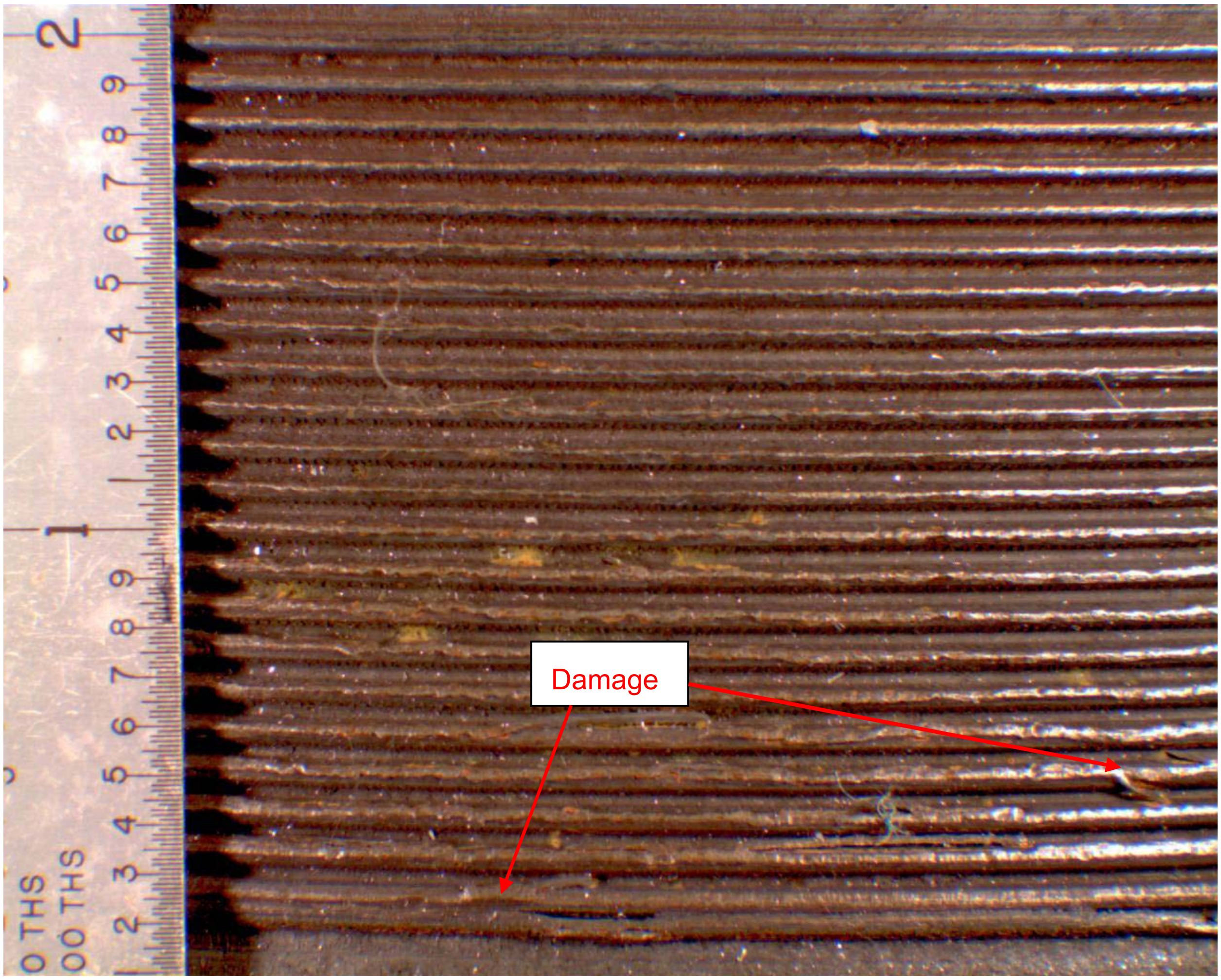
Finally, the Burns and Roe metallurgist concluded the combined metallurgical analyses provided evidence which suggest that the valve skirt to disc tack weld failed as a result of fatigue and tensile overload due to axial loading. The metallurgist also concluded that damage to the skirt threads resulting from undersizing shows that stem disengagement from the disc most likely occurred as a result of pullout after the weld failure rather than unscrewing. Although porosity and other anomalies were observed in the weld region, the metallurgist did not believe they were major contributors to the weld failure. The metallurgist also stated that a review of design documentation shows that proper procedures were employed for making the weld, and skill of the craft was the most likely cause for these anomalies.

Based on discussions with Crane Nuclear, the size of the tack weld whether 0.2“or 0.5“, makes no difference for axial loading as they are not intended to be load bearing. All loading is transmitted through the disc and disc skirt thread connection. The welds are strictly for anti-rotation and as long as there is fusion to some degree, combined with the v-notch trim, the anti-rotation design requirements are met. Crane Nuclear also stated that the 0.5” weld was significantly heavier than they would typically recommend and there had been no other design features associated with these valves, updated since the v-notch trim addition. The v-notch trim effectively eliminates the flow-induced vibration causing rotational loads.

With respect to non-axial fatigue failure of the welds, no evidence of high cycle fatigue, which would be indicative of flow induced vibration during operation (and the potential for the disc skirt to have become unscrewed), was found to be present in any of the metallurgical examinations (References 1, 2, and 3).

In addition, since the skirt is free to rotate on the stem (because no key is installed on the stem), there is no force that would cause relative rotation between the disc and skirt. Rotation of the disc is limited by the v-notch trim settling in the flow stream. This is further substantiated by damage on the first thread and the beginning of beaking on the second thread. Additionally, based on discussions with Crane Nuclear, pre-load on the thread is only hand tight, and with the undersized threads minimum contact and asymmetrical loading can be expected. The threads that are damaged, but not “beaked,” are indicative of minimum contact bending the tips, while not producing enough stress at the crest to cause beaking.

BOTTOM



TOP

Close-up Macrograph of Skirt Threads, Showing Thread Damage, 12 Threads per Inch Spacing (0 Degree View)

Although the tack welds are not designed as a load bearing feature, more weld metal would improve the axial load carrying capability of the disc skirt connection. The Structural Integrity report (Reference 4) did not reduce the capability of the 0.2” weld based on the porosity and de-lamination discussed in the Westinghouse report. The Structural Integrity report only considered the load that a 0.2” weld would be able to support in the event of the undersized threads. The threads are the axial load bearing component. As such, Structural Integrity did not consider the porosity and de-lamination of the welds. The Burns and Role independent metallurgist also evaluated the porosity and de-lamination of the welds and considered them to not be contributors to weld failure (Reference 3). The Structural Integrity report (Reference 4) stated that even a perfect 0.5” fillet weld would not be capable of withstanding the design backpressure when thread contact is reduced by undersized threads or plastically deformed threads (as it was in the case of the 1-FCV-74-66 failure). From a structural design standpoint, a fillet weld has an inherent flaw at the root of the weld which provides a stress riser for fatigue initiation when subjected to axial loading. This further supports why a tack weld is not considered for structural support.

Based on the variability in the load carrying capability of undersized threads and the variability associated with backpressure buildup, it is reasonably possible that the combination of 0.5" weld and undersized threads could resist higher axial loads than a 0.2" weld with undersized threads, although it is calculated to fail well below design backpressure. TVA reported that this additional work was in progress in a previous response. As a result of this possibility, Structural Integrity recently performed elastic-plastic analyses. These analyses and additional information are provided in Attachment 2. With respect to differences between valve 1-FCV-74-66 and the other FCV-74-52/66 valves, based on the review of Structural Integrity analyses and information, it is concluded that the difference is most likely due to some combination of the following variables.

- Differential pressure across the valve disc. The relative leak-tightness of the valves of the inboard (reactor pressure vessel) and outboard (residual heat removal system) side of FCV-74-52/66 valves during surveillance testing determines the magnitude of differential pressure the associated valve disc experiences. Since the leakage rate through large valves can vary, the actual pressure differential can also vary significantly from valve to valve.
- The condition of the disc threads. Variation in disc thread diameter due to manufacturing tolerances has a direct influence on the amount of thread engagement and the load required to cause failure.
- The extent of any asymmetries. As the asymmetry between mating threads increases, a lower force would be expected to thread damage and failure.

The results of these analyses further support the conclusions provided previously in response to this question.

Based on the above information, it is concluded that the tack welds of the disc/disc skirt connection of valve 1-FCV-74-66 failed due to axial loading causing fatigue or overload. Failure of the weld was directly related to the undersized threads. There was no thickness requirement for the tack welds installed in 2006, and the tack welds fully met their design function of preventing rotation. Therefore the tack welds were not a design or performance deficiency. If the condition of undersized threads on valve 1-FCV-74-66 had been eliminated prior to the valve failure, the anti-rotation tack welds would not have failed. Independent analysis by Structural Integrity clearly demonstrates that even a 0.5" fillet size would fail under axial loads resulting from design backpressure conditions (Reference 4). The tack welds on 1-FCV-74-66 are clearly not the cause of the failure and therefore are not considered to be critical contributors to the valve failure.

3. *For the refurbishment of 1-FCV-74-66 in 2006, were there any Quality Control (QC) hold points for the tack welds in the associated Work Order or the weld traveler?*

TVA Response:

For BFN valve 1-FCV-74-66, the stem was replaced by WO 03-004964-000 in 2006 and required the disassembly of the valve internals. The tack welds associated with the disc/disc skirt connection of 1-FCV-74-66 were replaced and QC verified the new welds during this process. An excerpt from WO 03-004964-000 is provided in Attachment 1.

The original vendor drawings for the FCV-74-52/66 valves do not specify tack weld size. During Unit 1 restart when the stem was replaced and the tack welds needed to be installed, guidance was absent on the weld size. The applicable TVA drawing 0-A-12337-M-1E was modified by DCN 51199 S2 for Unit 1 only. PIC #67379 (dated 6/10/06) was generated for a field change to add guidance for the tack weld for valve 1-FCV-74-66 on the design drawing A-12337-M-1E and approved on 6/12/06. The Unit 3 drawing (A-12337-M-3A) contained tack weld sizes which states "Field replacement of disc to be attached to disc skirt with four tack welds - 1/2" fillet weld, 1/2" long, 90 degrees apart, or two 7" long (MIN) 9" long (MAX) welds, 180 degrees apart." The PIC requested that this Unit 3 guidance be added to the Unit 1 drawing.

The final drawing change which also added in a fillet size to the 7" to 9" weld wording (contrary to the PIC request) was completed 9/09/06. However, in recent discussion with Crane Nuclear, they stated that the tack welds are only for anti-rotation and that they are only concerned with ensuring weld fusion to prevent rotation since the tack welds are not considered to be load bearing.

The weld data sheet (performed 6/23/06) associated with WO 03-004964-000 indicated the length requirement (7 to 9 inches long) of each tack weld and that the two welds be 180 degrees apart, which is typical for tack welds. The QC inspector verified (dated 6/25/06) that the requirements on the weld data sheet were satisfied. QC appropriately sign-off on the welds because the 1/2" fillet guidance had not yet been added to the drawing.

Therefore, our review design requirements associated with the tack weld thickness has determined that the 1-FCV-074-66 valve tack welds did not have a thickness requirement when these welds were applied in 2006. The Root Cause Analysis report will be revised to reflect this additional information.

4. *Discuss the effect of a negative dp, e.g., reactor pressure greater than the RHR shutoff head, across the valve disc and then increasing over time on the coefficient of friction (and the resulting impact on valve opening time) determined by the mock-up testing, since a positive dp across the valve disc (as existed during the mock-up testing) would not exist prior to the reactor pressure reaching the pressure associated with the RHR shutoff head.*

TVA Response:

Vibration reduces the coefficient of friction (COF) independent of pressure differential across the disc. The factors causing friction reduction by vibration are 1) superposition of the inertia force due to vibration acceleration on the friction force, 2) leveling or cancellation of alternate friction force due to the change in frictional directions, 3) increase of relative sliding velocity (kinematic affect), 4) surface flattening due to the progress of wear, and 5) material softening from the heat due to friction. Forces on the disc from differential pressure do not affect any of the above factors as long as the force does not cause the disc to move, in which case the disc would be liberated from the body. The assumed total closing thrust load from the motor actuator is greater than the load applied by the pressure differential associated with total normal operating reactor pressure (1030 psig). This thrust load approaches a limiting sudden load of twice the gradually applied load after approximately four strokes. Differential pressure with the high side being downstream (reactor side) is gradually applied as the inboard valve is opened. Since the pressure differential is gradually applied and less than the normal motor operator thrust it is not expected to further lodge the disc into the seat. Even if the differential pressure was assumed to be suddenly applied it would have a negligible effect on the deflection of the disc into the valve body since the deflection is approaching its limit after already being impacted by the actual maximum of 13 times (i.e., strokes) by a higher stem force. Therefore, the disc will release as soon as the differential pressure across the disc gets high enough to overcome the product of the body strain normal force caused by seating and the reduced COF. In other words the change in COF is independent of the differential pressure and the time to release the disc is when the differential pressure force exceeds the remaining frictional force. Applying a constant differential pressure for a period of time will have the same effect as applying a forcing function starting with a negative differential pressure and ending with a positive differential pressure of the same value for the same period of time. The reactor pressure is expected to be ~200 psia (see Attachment 3) with a containment pressure of 16.5 psia after the RHR pump is running for 7.5 minutes ($\Delta P = 372 + 16.5 - 200 = 188$ psi). The resulting differential pressure is well within the mock-up limiting differential pressure of 100 psi based on a reduction in the COF of 27.3% within 7 minutes.

5. *Provide any documentation for the root cause and corrective action taken in response to the 1974 event discussed in Abnormal Occurrence Report BFAO-50-260/7432W.*

TVA Response:

No additional information, from that provided in response to NRC Round 3 Question 8 dated 4/13/11, is available at this time. TVA is continuing to research this issue.

References

1. Westinghouse Report No. STD-MCE-10-198, “Browns Ferry 1 RHR Angle Valve Destructive Evaluation.”
2. Southwest Research Institute Project 18.18074.11.101, “On-Site Evaluation of Browns Ferry 1 FCV-74-066 RHR Disc Skirt.”
3. Burns and Roe Enterprises, Inc., “Metallurgical Failure Analysis of Browns Ferry Nuclear Plant - Unit 1 Residual Heat Removal Valve 1-FCV-74-066.”
4. SI Calculation No. 1001572.302, Revision 0, “Weld Fracture Mechanics and Stress Analysis of LPCI Injection Valve (1-FCV-74-66).”

Attachment 1

QC Report on 1-FCV-074-66 Weld Inspection

MMDP-10 CATEGORY I / II WELD DATA SHEET

Category I	x	II		WELD NO.: RHR-1-034-005-C0R0

SEC.XI YES[X] NO[ ]		MECHANICAL [X] STRUCTURAL [ ]		SR[X] QR [ ] NQR [ ]
WID: WO#03-004964-000	UNIT: 1	SYS NO: 074	COMPONENT: 1-FCV-074-0066	
WELD MAP: RHR-1-034	REV.00A	WMCR: A	TEMP:562°F	PRESSURE:1326 PSI / PWHT: N/A
JOINT TYPE: TACK WELD**	FILLET WELD SIZE: N/A		GOV. CODE: ASME SECT.XI	TVA CLASS: D

MATERIAL SOURCE DWG: WALWORTH CO. DWG#A-12337-M-IE, PIC#67379-AA01

DESIGN DRAWING:1-47W452-3, 1-47E811-1, WALWORTH CO. DWG#A-12337-M-IE, PIC#67379-AA01

DWP: ~~GT44-B-1-N~~ * ... 6-20-06	JOINT DESIGN:	TACK WELD**	PREHEAT: 350°F	PURGE: N/A

	MATERIAL TYPE & GRADE	DIA./SIZE	THICKNESS	PRODUCT FORM	HEAT CODE/SERIAL NO./EXISTING
1)	A217 GR WC6	N/A	N/A	DISC SKIRT	EXISTING
2)	A217 GR WC6	N/A	N/A	DISC	EXISTING

* * * WELDING VERIFICATION * * *

DWP REV: 4 PURGE DAMS INSTALLED-QI/QC SIGN/DATE: N/A

WELDER ID (SS#)	WELD FILLER TYPE/SIZE AND HEAT/LOT NO.	QI INT./CODE/DATE
417-23-4373	ER80S-B2 ~~E8018-B2~~ JL 6-20-06 0.125 F2791	JKK L2958 6/21/06
417-23-4373	ER80S-B2 0.125 F2791	JKK L2958 6/23/06

*** INSPECTION ACTIVITIES ***

PURGE DAM REMOVED-QC/QI SIGN/DATE: N/A

QI RECORD FIT-UP GAP(Struc Only): N/A RE/WE CHECK APPROPRIATE BOX: QI (QUALIFIED INDIVIDUAL) OR QC

1)PRE-WELD N-VT-3 REV. 24	ANI	QI: RELEASE CODE L2958 Steve K. Curdy 6/23/06	QI [ ] CODE ___ ACC[X]REJ[ ] QC [X] level II Douglas W. Hall 6-23-06
2)POST-WELD N-VT-3 REV. 24	ANI	CRAFT: RELEASE Jeff McElyea 6/24/06	QI [ ] CODE ___ ACC[✓]REJ[ ] QC [X] level II Robert Tomlinson 6-25-06
3)POST-WELD N-MT-6 REV. 27	ANI	CRAFT: RELEASE J McCarey 6/24/06	QC level II ACC[✓]REJ[ ] Robert Tomlinson 6-25-06
4)POST-WELD REV. ___	ANI	CRAFT: RELEASE	QC level ___ ACC[ ]REJ[ ] (*) QC NOTE VERIFY PREHEAT OF 350°F DWH 6-23-06
5)POST-WELD REV. ___	ANI	CRAFT: RELEASE	WE ACC[ ]REJ[ ] START 400°F SOAK AT 1055 DWH 6-26-06 STOP 400°F SOAK AT 1255 DWH 6-26-06

Release and QI/QC blocks require Sign./Date 400° @ 1055 1255 BAKE DONE

NOTES:**TACK WELDS TO BE 7" MIN.TO 9" MAX. IN LENGTH, AND 180° APART.

*ALT. DWPS CAN BE GT44-0-1-N WITH ER80S-B2 FILLER MATERIAL.

PREPARED BY	PREWELD REVIEW		FINAL REVIEW	
RE: JERRY LAWRENCE JL	WE: P.A. W...	DATE: 6-13-06	WE: Jon M. ...	DATE: 9/28/06
DATE:6/13/06	ANI: Curtis R Poole	DATE: 6/14/06	(*) ANI: ...	DATE: 06-14-07

Retention Period: LIFETIME Responsible Organization: RM

RHR-1-034-005-C0R0

(*) LATE ENTRY. WAS OVERLOOKED @ 10-02-06 CLOSURE.

ASME SECTION XI

76

Enclosure 6 replaced

TENNESSEE VALLEY AUTHORITY	RECORD OF MAGNETIC PARTICLE EXAM	REPORT NO. R- N/A

PROJECT: BFN UNIT: 1 CYCLE: 6R
SYSTEM 074 RESIDUAL HEAT REMOVAL
WELD / COMPONENT I.D.: RHR-1-034-005 CORO
CONFIG.: DISC - SKIRT TO DISC
PROC.: N-MT- 6 REV 27 TC N/A
EXAMINATION CODE: ASME SECTION III
CODE CLASS: 2 CATEGORY: N/A
CODE ITEM No N/A

EXAMINATION DATE: 06-25-06
EXAM SURFACE: ☐ ID ☒ OD
ORIGINAL ☒ RE-EXAM ☐
VISUAL CARD S/N: 518
REF. DRAWING NO.: Weld Map

ACCEPTANCE CRITERIA
APPDX A ☒ APPDX B ☐
OTHER: N/A

METHOD OF MAGNETIZATION

EXAMINATION MEDIUM: DRY POWDER COLOR: RED 8A BATCH NO.: N/A

YOKE Y5☐ Y6 ☐	PRODS: AC☐ DC☐	COILS: AC☐ DC☐
OTHER: PARKER / B100	EQUIP TYPE: N/A	EQUIP. TYPE: N/A
EQUIP S/N: 2593	EQUIP S/N: N/A	EQUIP S/N: N/A
POLE SPACING: 3-6 INCHES	PROD SPACING: N/A inches	COIL TURNS: N/A
TEST WEIGHT SN E17322 CAL DUE: 11-03-2006	MAG. CURRENT: N/A amps	MAG. CURRENT: N/A amps

BLACK LIGHT OR LIGHT METER S/N: N/A CALIBRATION DUE DATE: N/A

INTENSITY VERIFICATION TIMES: INIT.: N/A 1) N/A 2) N/A 3) N/A

EXAMINATION RESULTS: SATISFACTORY ☒ UNSATISFACTORY ☐ NOI NO. N/A

EXPLANATION OF EXAM RESULTS: NO RECORDABLE INDICATIONS NOTED
PERFORMED IAW ASME SECTION III CL. 1
BFR-1-FCV-074-0066

COMMENTS / LIMITATIONS: WO# 03-004964-000 7-9" TACKWELD FINAL
DCN/ECN - NONE

ORIGINAL

ILLUMINATION CHECK ADEQUATE ☒ MT POWDER CHECK ADEQUATE ☒

EXAMINER: Robert TOMLINSON [signature] LEVEL II 06-25-06
EXAMINER: N/A LEVEL N/A
REVIEWER: CRBOYD - [signature] LEVEL II DATE: 6-27-06

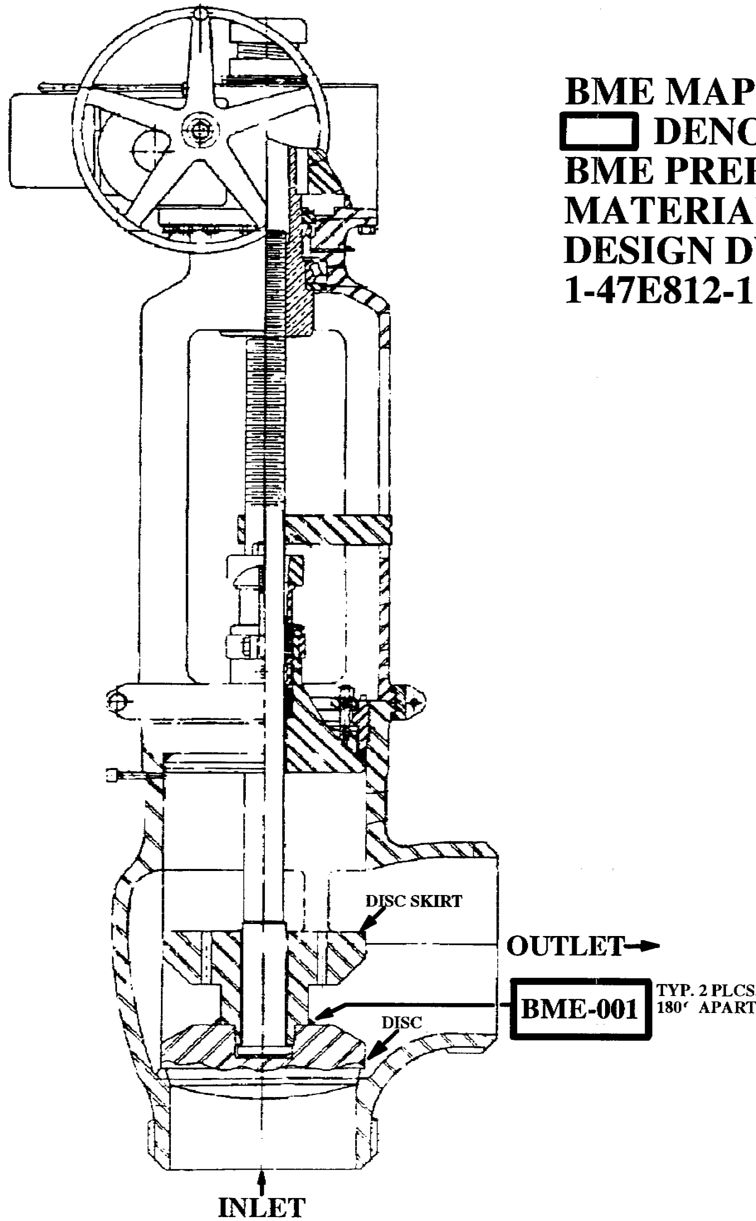
ANII: [signature]
DATE: 06-14-07
PAGE: 1 OF 1

M&TE 202575
TN-000221

[signature] 6-26-06

replaced Enclosure 6 7 6

BME MAP
☐ DENOTES BME NO.
BME PREFIX: 03-004964-000-
MATERIAL SOURCE:A-12337-M-I-E
DESIGN DWG:A-12337-M-I-E
1-47E812-1, 1-47W452-3



Enclosure 6

MMDP-10
BASE METAL/SURFACE EVALUATION SHEET

BME Number: 03-004964-000-BME-001

- - - - - - - - CONDITION IDENTIFIED - - - - - - - -

WID: W.O.03-004964-000 UNIT: 1 SYS: 074 LOCATION: U-1 565 DRYWELL CLEAN ROOM.
COMPONENT: BFR-1-FCV-074-0066 ID NO. N/A HT/SER# N/A

☐ FAB DAMAGE ☐ MAT'L DEFECT ☐ ARC STRIKE(s) ☒ OTHER: REMOVE WELDS FROM VLV SKIRT TO DISC.

DISCONTINUITY SKETCH: LENGTH, WIDTH, and DEPTH (include reference points)

VALVE DISC TO SKIRT WELD.
2 EA WELDS 7 TO 9" LG.
180 DEG APART.

Identified By: L THURSTON DATE: 30-MAY-06 PAGER: 95-156 PHONE: 6254

- - - - - - - - WE/RE DISPOSITION - - - - - - -

SR[X] QR[ ] NSR[ ] SEC XI: YES[X] NO[ ] CODE: 2 TVA CLASS: D TEMP: 562 PRESS: 1326
MAT'L TY/GR: A217 WC6 NOM THICKNESS: ***" MIN NOMINAL THICKNESS:**
DRAWINGS: A-12337-M-1E, 1-47W452-3

INSTRUCTION: ☐ LIGHT FILING/BUFFING ☐ WELD REPAIR ☐ REPLACE ☒ OTHER: **CRAFT TO ONLY REMOVE THE WELDS THAT ATTACHES THE DISC SKIRT TO THE DISC BY MECHANICAL MEANS, ENSURING THAT EXTREME CAUTION IS USED TO ENSURE NO ENCROACHMENT INTO THE SURROUNDING BASE METAL. BUFF/BLEND THE AREAS TO RESTORE THE DISC AND DISC SKIRT TO THEIR ORIGINAL CONFIGURATION. CRAFT TO CIRCLE THE WELD REMOVAL AREAS WITH AN APPROVED MARKER. QC TO PERFORM A N-VT-3, N-MT-6 OR A N-PT-9, AND A MECH. ON THE WELD REMOVAL AREAS TO ENSURE NO INDICATIONS EXISTS, ENSURE THE ORIGINAL CONTOUR HAS BEEN RESTORED, AND NO ENCROACHMENT INTO THE BASE METAL EXISTS.

ACC ☐ REJ ☐

☒ N-VT-3 ☒ N-MT-6 or ☒ N-PT-9 QC ☒ SIGN/DATE: ________________ LEV/CODE___ ___

QC: ☒ Mech. ☐ N-GP-17 ☐ N-UT-24 DEPTH OF DEPRESSION: __________ Attach Insp. record

PREPARED BY: TOMMY PARRISH 30-MAY-06 RE/WE SIGN/DATE:	PREWORK REVIEW: SWE SIGN/DATE: Larry Laurence 6-1-06

(Add weld data sheet/weld map for required welding)

- - - - - - - - ENGINEERING DISPOSITION - - - - - - - -

DESIGN MINIMUM WALL/THICKNESS: ACTUAL WALL THICKNESS:

MINIMUM DESIGN WALL THICKNESS SATISFIED ☐ UNSATISFIED ☐

COMMENTS:

NO BME REQ'D. WELD #005 REINSTALLED WELD IN SAME FOOTPRINT. [signature] 9-16-06

SITE ENGINEERING SIGN/DATE:

WE/SE FINAL REVIEW:	ANI/ANII FINAL REVIEW:
SIGN/DATE: N/A [signature] 9-16-06	SIGN/DATE: N/A [signature] 9-16-06

Retention Period: Lifetime Responsible Organization: RM

Attachment 2

Structural Integrity Associates
Elastic-Plastic Stress Analysis of LPCI Injection Valve (1-FCV-74-66)

Additional Considerations Regarding Browns Ferry LPCI Injection Valve Failure

April 19, 2011

This document summarizes additional analyses and discussion regarding the failure of LPCI injection valve 1-FCV-74-66 at Brown's Ferry Nuclear Unit 1 (BFN-1). It attempts to address a number of questions regarding our earlier analyses and report [1, 2, 3] and poses additional theories regarding the cause of the failure. Overall conclusions of the study are:

1. The predicted pullout load of the threaded joint was significantly smaller than that of the as-designed joint due to undersized thread conditions.
2. Pullout of the threaded joint was clearly possible at the opening thrust load predicted to occur in a test condition in which the valve is opened against essentially reactor pressure on the back side of the disc (429 kips).
3. The tack welds were installed to prevent unscrewing of the threaded joint, and offered little additional resistance to pullout of the threaded joint.
4. The metallurgical failure analysis of the skirt threads showed evidence of asymmetric loading of the threaded joint, which is consistent with the excess clearance created by the undersized thread conditions. Such asymmetry would further reduce the pullout loads relative to those predicted by the axisymmetric analyses discussed herein.

Thread Pullout Calculation

Our earlier calculation [1] utilized the minimum measured major skirt diameter of 6.311" in order to derive a conservative, lower bound pullout load, and thus the maximum possible effect of the undersized thread condition. (See Figure 1) The actual skirt diameter measurements, as reported in [4] were:

Table 3.1 Thread Diameter Measurements			
Distance from Bottom End (in)	OD 0 / 180 Deg (in)	OD 90 / 270 Deg (in)	Average
0.25	6.311	6.326	6.319
0.5	6.32	6.331	6.326
0.75	6.332	6.334	6.333
1	6.333	6.334	6.334
1.25	6.332	6.335	6.334
1.5	6.332	6.337	6.335
1.75	6.334	6.337	6.336

The thread pullout calculations of [1] were thus repeated under a number of assumptions regarding thread diameters and engagement length [6], the results of which are summarized in Table 1 below.

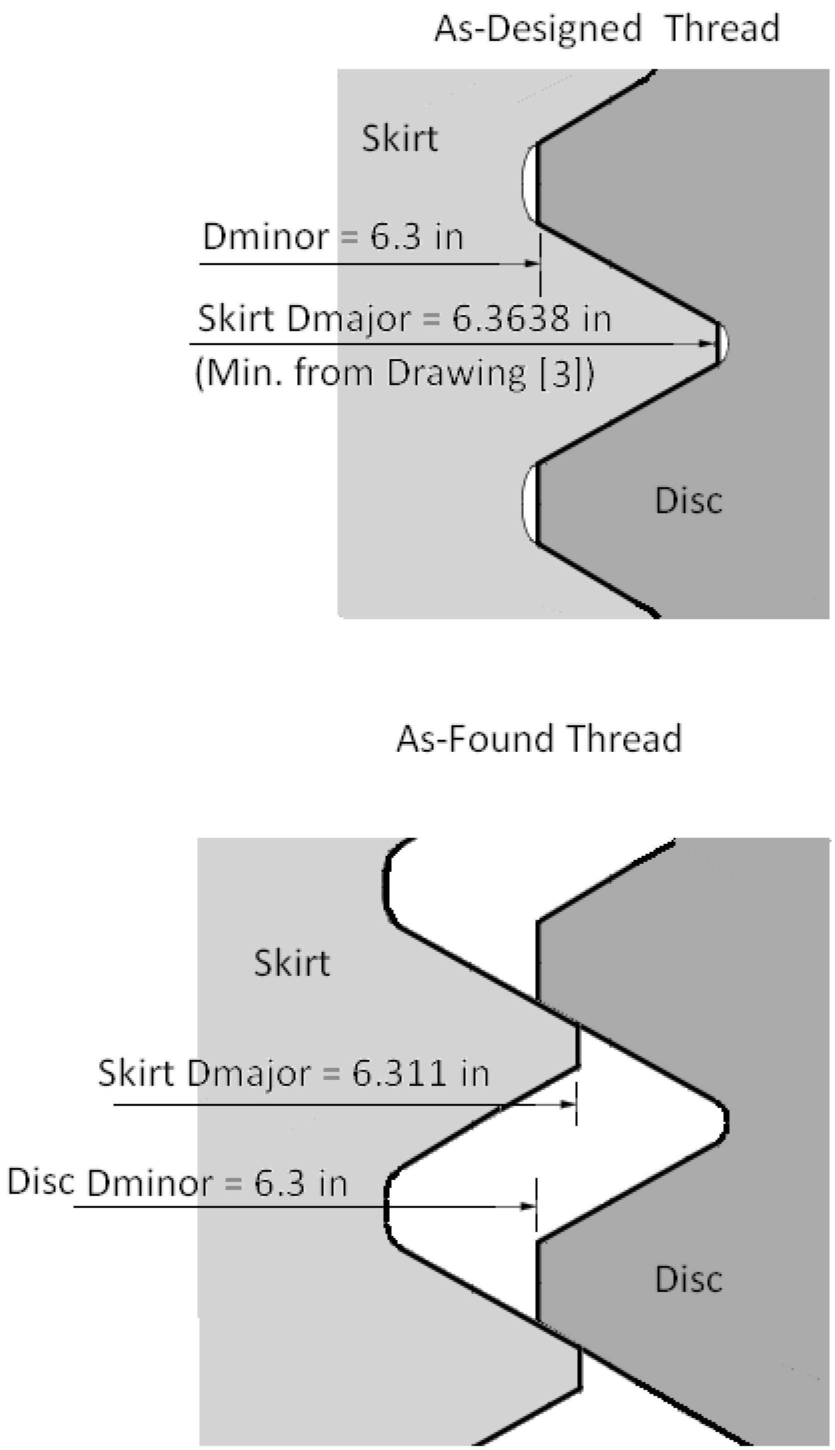


Figure 1 – Illustration of Thread Undersize Condition with Minimum Measured Skirt Diameter

Table 1 – Summary of Revised Thread Pullout Calculations from [6]

	n	Le (in)	K_{nmax} (in)	E_{smin} (in)	D_{smin} (in)	D_{save} (in)	A_{TS} (in^2)	Shear Strength (ksi)	F (kips)
As-Designed Thread				6.3097	-	-	16.839		884.056
As-Found Thread with Min Major Dia. of Skirt (using Eq. 2)				6.2630	-	-	7.168		376.313
As-Found Thread with Min Major Dia. of Skirt (using Eq. 3)		1.500		-	6.311	-	5.974		313.611
As-Found Thread with Ave Major Dia. of Skirt (using Eq. 3)	12		6.300	-	-	6.331	9.999	52.50	524.952
As-Found Thread with Ave Major Dia. of Skirt and Designed Thread Engagement Length (using Eq. 3)		1.922		-	-	6.331	12.812		672.638
As-Found Thread with Ave Major Dia. of Skirt and Estimated Thread Engagement Length (using Eq. 3)		1.172		-	-	6.334(1)	8.364		439.090

It is seen from this table that a range of pullout loads is predicted, ranging from the predicted load for the as-designed thread (884 kips) down to the conservatively low value of 314 kips predicted previously [1]. If the average measured skirt major diameter is used over the entire thread engagement length, the pullout load is 525 kips. If a reduced engagement length is assumed, the predicted pullout load is 439 kips.

A noteworthy uncertainty in the above calculations is the minor diameter assumed for the disc threads. A value of 6.3" was provided by TVA, but there were no as-built measurements taken, and a design drawing was not available indicating what the tolerances were on this dimension. Bickford's book on "Design and Behavior of Bolted Joints" [5] states: "If the bolt is undersized or the nut oversized, thread contact areas will be less than those planned by the designer, and substantial deformation may occur." The metallurgical failure analysis report [4] identified substantial deformation in many of the skirt threads from the failed valve, consistent with an undersized skirt thread (bolt) and/or oversized disc thread (nut). Two types of deformation were observed as summarized in Figure 2 and Table 2 below.

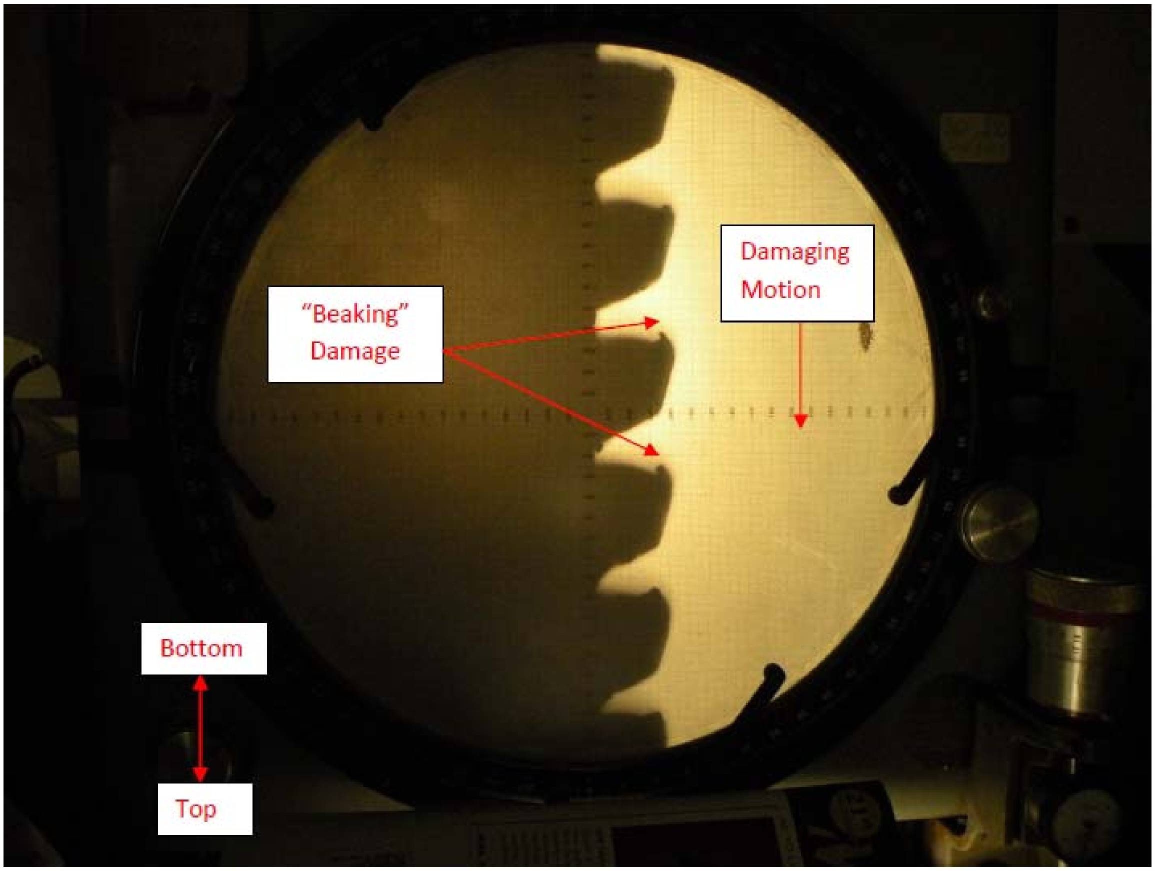


Figure 2 - Optical Comparator Image of Damaged Threads (Fig. 3-10 from [4])

"Beaking" damage consisted of deformation in which part of the threads were extruded towards the bottom of the skirt, which is consistent with the skirt being pulled out of the disc by an overload in the upward direction. A second form of damage was manifested as flat thread peaks, which is consistent with very small thread contact such that the skirt could pull through the disc threads without major (beaking) deformation. Also observed in [4]: "Some threads had no apparent damage. The mixed damage forms suggest that the threads were probably not unscrewed but rather were removed by an asymmetrical force or were the result of an inconsistent mating surface in the base."

Given the observed thread damage, and the fact that the skirt was evidently separated from the disc with little or no damage to some threads, it is considered highly likely that there was minimal thread engagement and that the pullout loads were on the lower end of the range presented in Table 1 above.

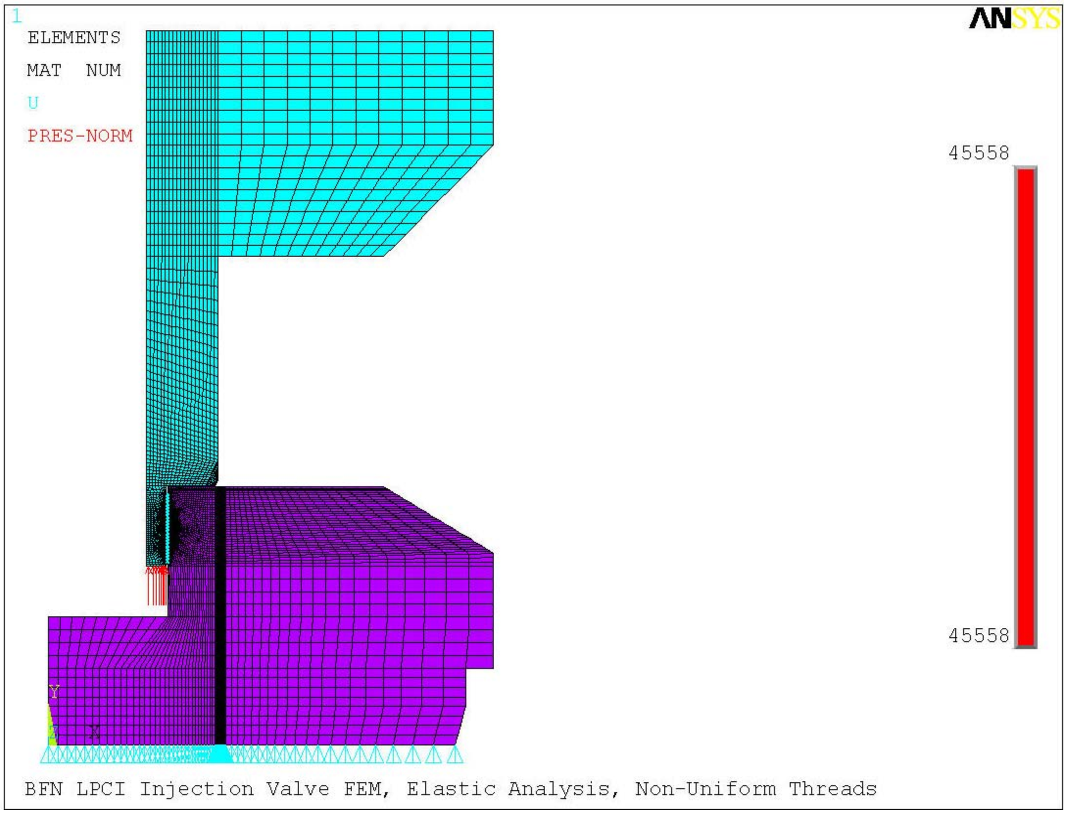
Table 2 – Reported Extent of Thread Damage from [4]

Table 3.3 Summary of Thread Damage (See Figures 3.11 through 3.34)								
Thread Number	20 Degrees		110 Degrees		200 Degrees		290 Degrees	
(Top)	Damage*	Beaking	Damage*	Beaking	Damage*	Beaking	Damage*	Beaking
1	Yes	No	Yes	No	No	No	-	-
2	Yes	Yes	Yes	No	No	No	-	-
3	Yes	No	Yes	No	No	No	Yes	Yes
4	Yes	No	Yes	No	No	No	Yes	Yes
5	Yes	No	Yes	Yes	No	No	Yes	Yes
6	Yes	No	Yes	No	No	No	Yes	Yes
7	Yes	Yes	Yes	No	No	No	Yes	Yes
8	Yes	Yes	Yes	No	No	No	Yes	Yes
9	Yes	No	Yes	No	No	No	Yes	Yes
10	Yes	No	Yes	Yes	No	No	Yes	Yes
11	Yes	Yes	Yes	No	No	No	Yes	Yes
12	Yes	Yes	Yes	No	No	No	Yes	Yes
13	Yes	Yes	Yes	No	No	No	Yes	No
14	No	No	Yes	No	No	No	Yes	No
15	No	No	Yes	No	No	No	Yes	No
16	Yes	No	Yes	No	No	No	Yes	No
17	Yes	No	Yes	No	No	No	Yes	No
18	Yes	No	Yes	No	No	No	Yes	No
19	Yes	Yes	Yes	No	No	No	Yes	No
20	Yes	No	Yes	No	No	-	-	-
Bottom								
Percentage	90.0%	35.0%	100.0%	10.0%	0.0%	0.0%	100.0%	58.8%

* Apparent damage. The original condition of the threads is unknown. Thus, the extent of damage is uncertain.

Elastic-Plastic Analysis

To shed further light on the above study, elastic-plastic calculations were performed [7] using the axisymmetric model developed in [2], but modifying the thread sizes to the averages of the measured thread diameters rather than the minimum. The model and thread diameters used are summarized in Figure 3. Two elastic-plastic cases were run. In Case 1, the larger diameter 6.334” (top 14) threads engaged first, followed by engagement of the 6.322” (bottom 8) threads once sufficient deformation occurred. In Case 2, the bottom eight threads were assumed to not engage, which would be consistent with slightly oversized disc threads and little or no damage to those threads during pullout. This was judged to be a reasonably conservative approximation in the axisymmetric model, based on the relative damage reported in Table 2. The results of the two analyses are presented in Figure 4, in the form of load versus displacement curves of the skirt relative to the disc.



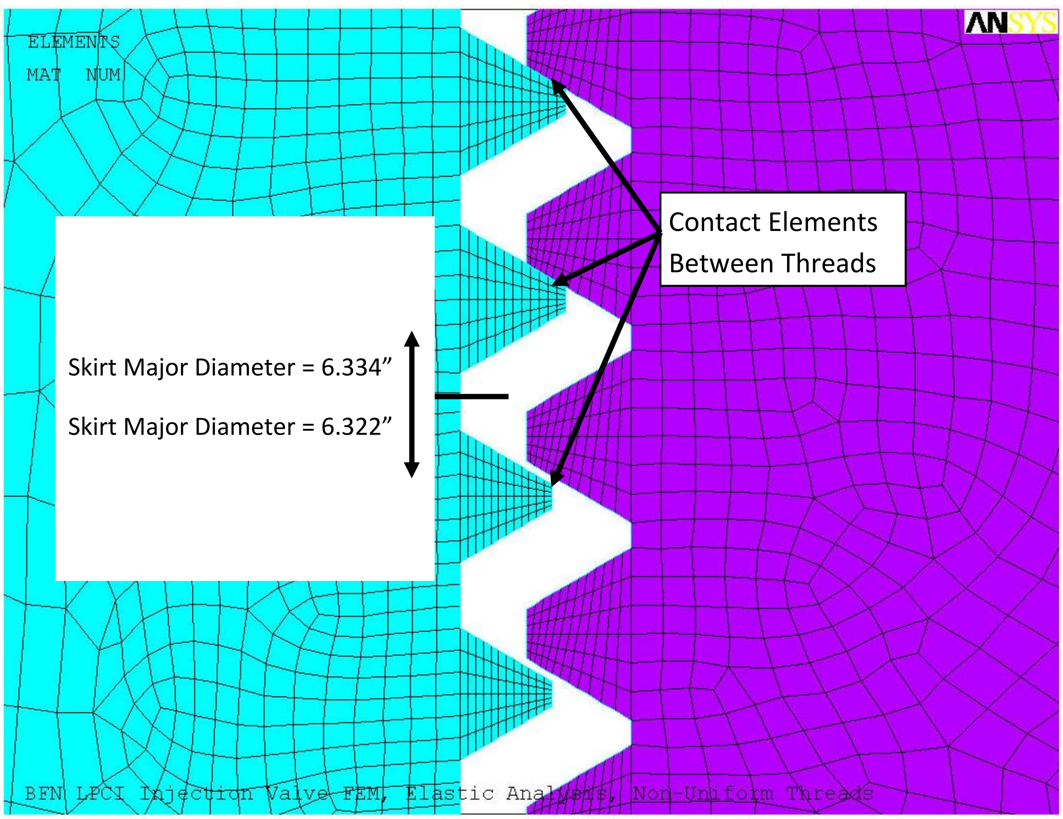


Figure 1: Elastic-Plastic FEM Details

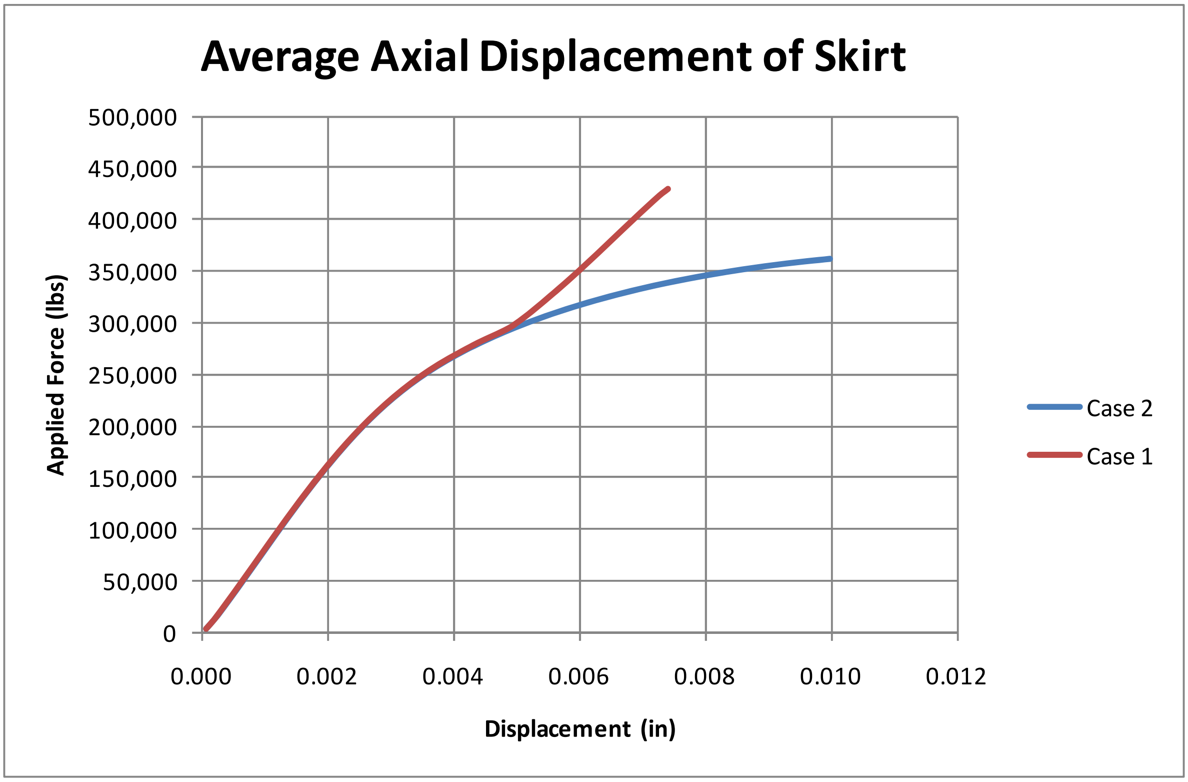


Figure 4 – Results of Elastic-Plastic Analysis

It is seen from this figure that the two cases track identically up to a load of ~300 kips, at which point, the threads have undergone ~0.005 inches displacement. At that point, in Case 1, the remaining bottom threads engage, and the joint is able to sustain additional load up to the max load applied to the model, 430 kips. In Case 2, on the other hand, the bottom threads don't engage, and the curve flattens out at a maximum load of ~360 kips (the analyses failed to converge beyond that point, indicative of a limit load failure or pullout). In summary, the elastic-plastic analysis [7] yielded similar results to the previously discussed thread pullout calculation. Depending on the thread diameters and engagement length assumed, pullout failure of the joint is predicted at loads on the order of 350 to 500 kips, well short of the load capacity of the as-designed joint (884 kips). The analysis also showed that the threads are subject to significant plastic deformation under these loads, consistent with the observations of severe damage (beaking) in some threads in the metallurgical report [4]. Also note, from Table 2, that the beaking is more prevalent in the top threads, and at certain azimuths (especially 290 degrees). This is consistent with the above assumption of upper thread only engagement in Case 2, and also indicative that the thread engagement was not perfectly concentric.

Effect of Fillet Welds

The above elastic-plastic analyses [7] do not include the effect of the fillet welds on the pullout load. It is noteworthy that the design purpose of fillet welds such as these is generally not to provide additional axial load support, but rather as locking devices to keep the threaded joint from unscrewing.

Prior elastic analyses [2] considered the effect of the welds, and predicted that the weld would share a small portion of the loading in the elastic regime (25% weld versus 75% threads). Elastic stresses in the welds were as listed in Table 3 below, depending on the weld size and whether the threads are assumed to be engaged or not. It was also noted that the weld picked up maximum load at a thread displacement of 0.005 inches. Given the amount of plastic displacement of the threads predicted in Figure 4, the threads would be expected to pick up maximum stress under either Case 1 or Case 2, and that either weld size would likely fail under the opening thrust load with full reactor back pressure (429 kips).

Table 3 – Calculated Weld Stresses at 314 kips [4]

	Thread Engagement	Membrane Stress (ksi)
0.5 inch weld	No	53.88
	Yes	13.36
0.2 inch weld	No	122.55
	Yes	29.92

Asymmetric Loading Effects

It appears likely from the nature of the thread damage in Table 2 that the loads were not applied in a concentric fashion around the threaded joint. One axis (200°) showed no thread damage over the entire length of the threads, while another (290°) exhibited severe damage (beaking) in the top ten or so threads, plus minor damage to all threads. Bickford [5] comments that "If the threads on either (bolt or nut) are slightly out of round, they will not be fully engaged during a portion of each turn. . . . These problems may cause significant loss of strength in the threads." The undersized skirt threads (and possible oversized disc threads) create significant clearance (slop) in the threaded joint. If, for example, the joint was assembled and preloaded in a horizontal position, then the disc threads would be offset due to gravity towards the side that was down during assembly, which would result in asymmetric thread engagement. The likely consequence of such asymmetry would be further reduction in pullout loads relative to the predictions of our axisymmetric analyses. Such a condition would be consistent with the observations, in Table 2 above, of significantly different thread damage in different azimuths.

Variables that contribute to the likelihood of failure

The following variables are sources of uncertainty in the estimated force required to result in a separation of the valve skirt and disc. The actual value of these variables is unknown, which makes it difficult to predict their exact contribution to the failure of 1-FCV-74-66.

- Differential pressure across the valve disc. The relative leak-tightness of the LPCI valves on the inboard (RPV) and outboard (RHR) sides of valve 1-FCV-74-66 during surveillance testing will determine the magnitude of the differential pressure the valve disc experiences. Since the leakage rate through large valves lacks a high degree of repeatability, the actual pressure differential can also vary significantly from valve to valve.
- The condition of the disc threads. Variation in the disc thread diameter due to manufacturing tolerances will have a direct influence on the amount of thread engagement and the load required to cause failure.
- The extent of any asymmetries. As the asymmetry between mating threads increases, a lower force would be expected to cause thread damage and failure.

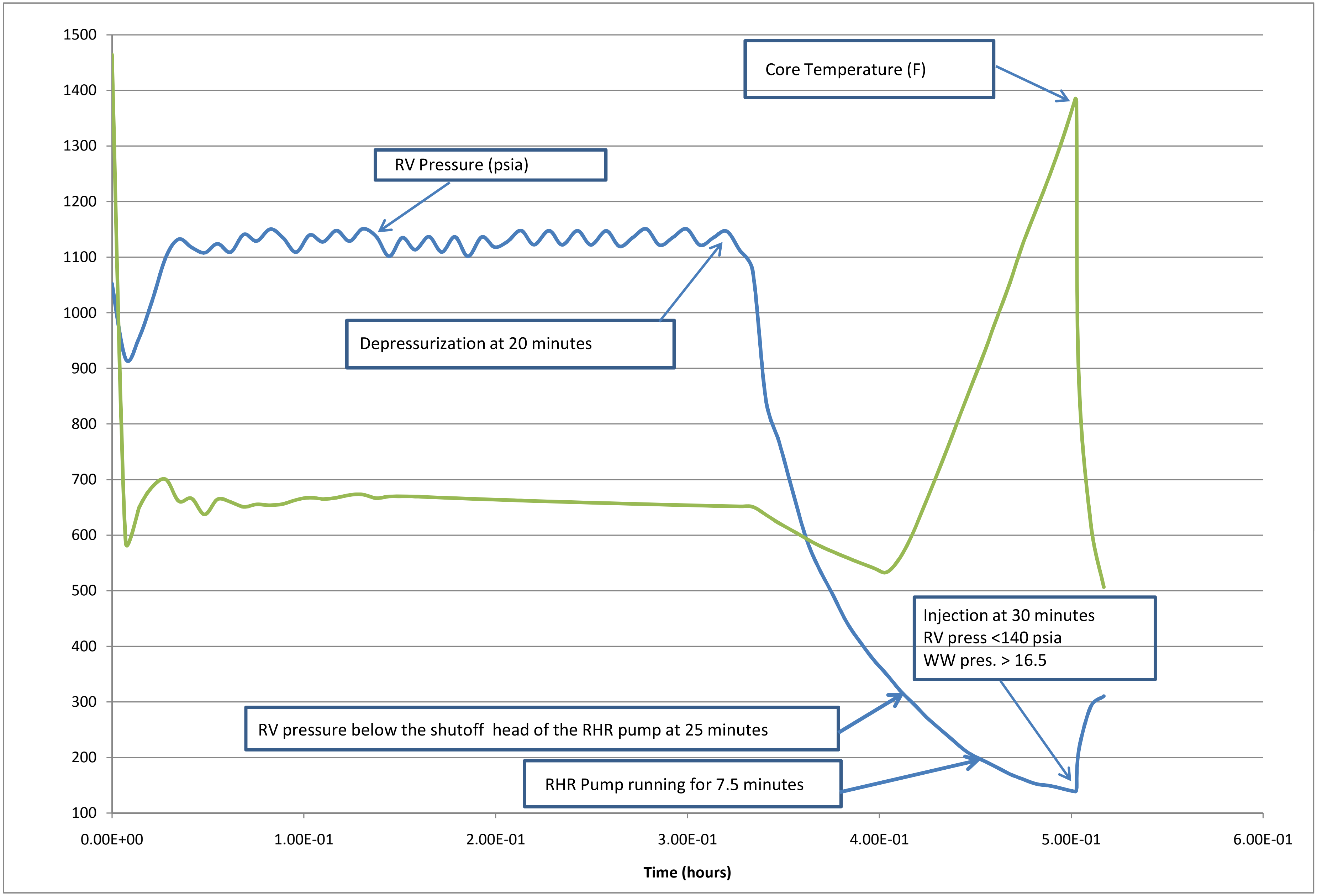
Since only 1-FCV-74-66 failed and skirt threads from a spare component compared closely to the failed skirt, a reasonable conclusion is that the difference is most likely due to some combination of the variables listed above.

References

1. SI Calculation No. 1001572.301, Revision 0, "LPCI Injection Valve (1-FCV-74-66) Thread Static Shear Strength Calculation."
2. SI Calculation No. 1001572.302, Revision 0, "Weld Fracture Mechanics and Stress Analysis of LPCI Injection Valve (1-FCV-74-66)"
3. SI Letter Report 1001572.401, Revision 0, "BFN Valve Failure Evaluation"
4. Westinghouse Report No. STD-MCE-10-198, "Browns Ferry 1 RHR Angle Valve Destructive Evaluation," Westinghouse Proprietary Information, SI File No. 1001572.206P
5. J. H. Bickford, "An Introduction to the Design and Behavior of Bolted Joints," 3rd Edition, Taylor & Francis Group, 1995.
6. SI Calculation No. 1001572.301, Revision 1A, "LPCI Injection Valve (1-FCV-74-66) Thread Static Shear Strength Calculation."
7. SI Calculation No. 1001572.304, Revision A, "Elastic-Plastic Stress Analysis of LPCI Injection Valve (1-FCV-74-66)."

Attachment 3

Browns Ferry Nuclear Plant Appendix R Depressurization Curve



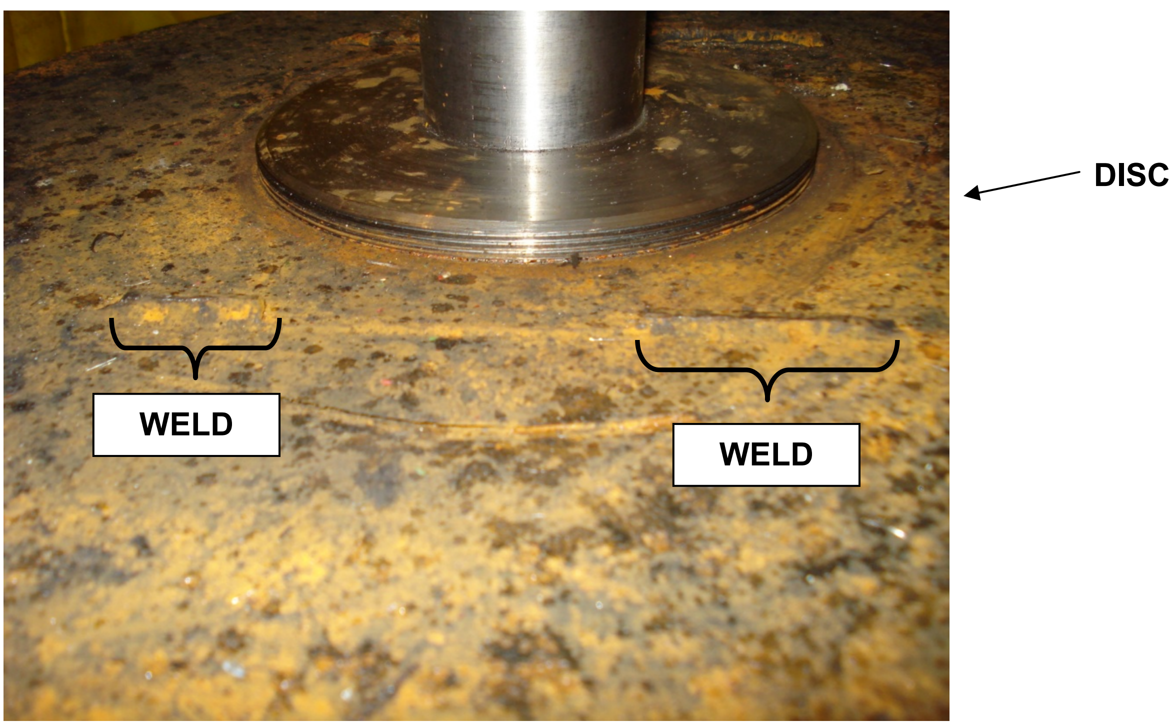
1500
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0.00E+00
1.00E-01
2.00E-01
3.00E-01
4.00E-01
5.00E-01
6.00E-01
Time (hours)
Core Temperature (F)
RV Pressure (psia)
Depressurization at 20 minutes
Injection at 30 minutes
RV press <140 psia
WW pres. > 16.5
RV pressure below the shutoff head of the RHR pump at 25 minutes
RHR Pump running for 7.5 minutes

Enclosure 6

1. *Could the 1-FCV-74-66 valve disc rotate relative to the skirt based on the tack weld condition at the time of discovery?*

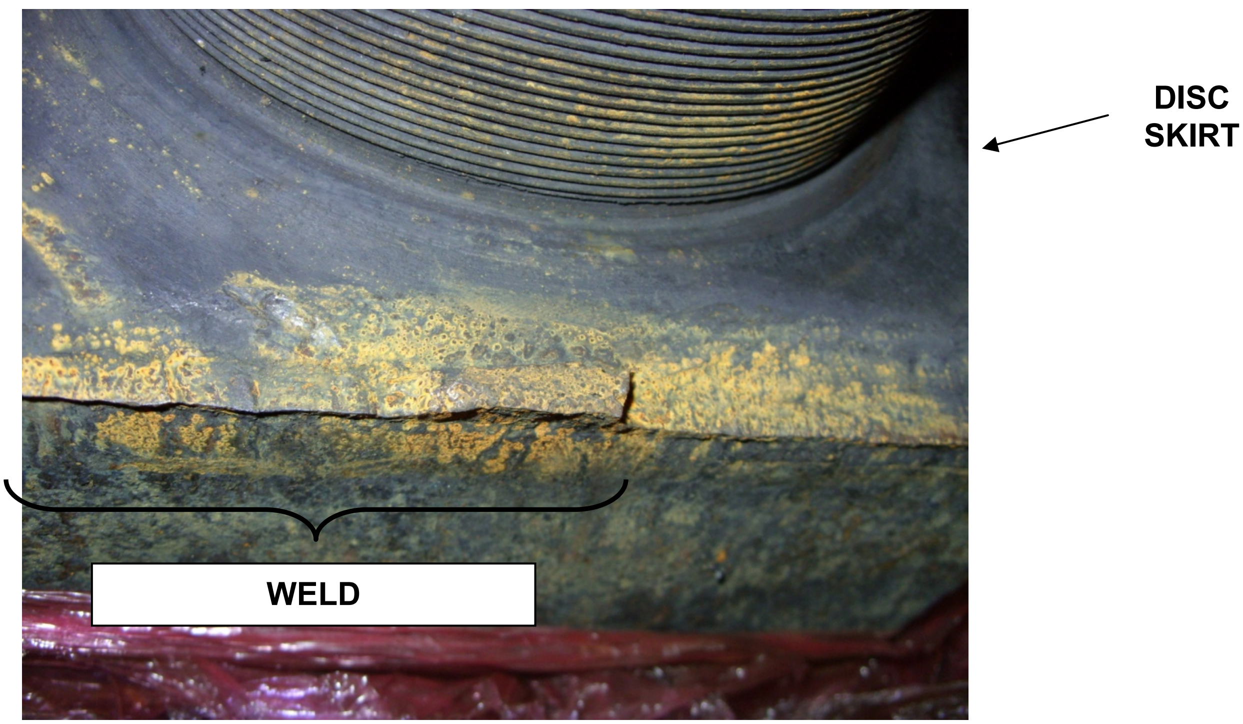
TVA Response:

1-FCV-74-66 failure occurred due to an axial "pull out" instead of a torsional failure. This is identified by the weld segments left on the disc and disc skirt. The remaining weld segments condition at the time of discovery are not consistent with a rotational event, because any significant rotation would have knocked them off. Typically the valve disk and disc skirt are snug tight prior to welding as discussed in the General Electric Field Deviation Instruction (see the attachment). The thread dimensions according to drawing C-12337-7-3A are 6 3/8 -12 NS-3, which is a pitch of 12 threads per inch which is what was observed, which means in one rotation the linear movement of the skirt away from the disc is 1/12 inch, or 0.08333. Based on the height and orientation of the protruding portions of weld left on the skirt and disc (greater than 1/12"), the protruding weld segments would act as a stop to the rotational motion of the skirt versus the disc. The locations of these protruding weld segments would prevent even one full rotation of the skirt away from the disc. See the pictures below. Therefore, the valve disc could not have rotated relative to the skirt based on the condition of the tack weld at the time of discovery.

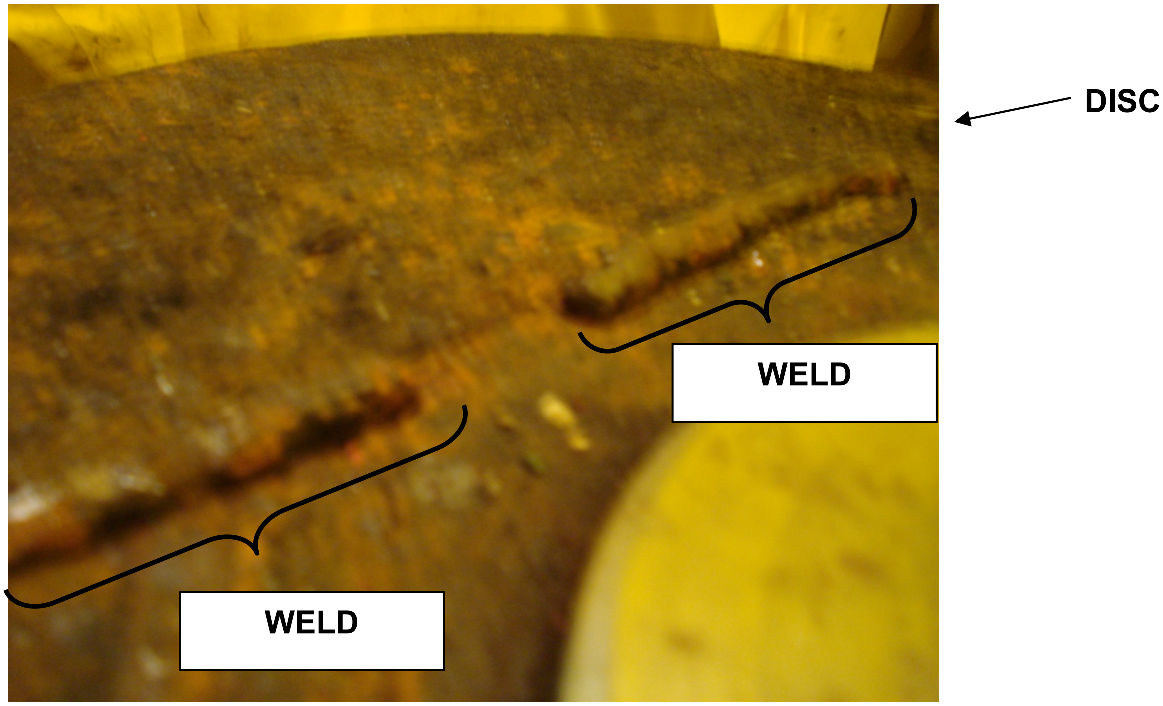


View from top of 1-FCV-74-66 with extraction device installed

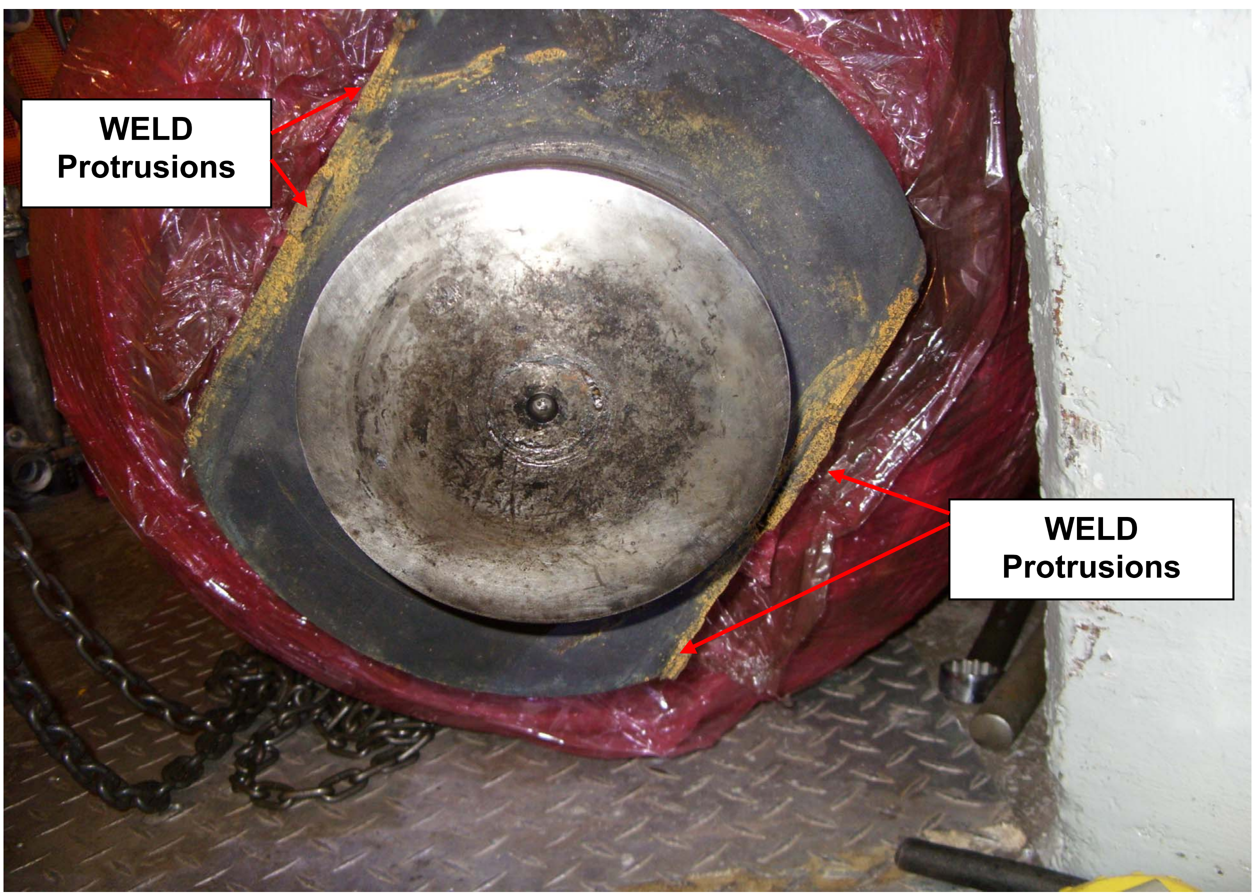
Figure 10 from Southwest Research Report



Thread side of skirt with protruding weld



Top of disc



Bottom of skirt with stem installed

2. *Why did the station not recognize the disc to stem separation during venting in November 2008?*

TVA Response:

(Note: TVA recognizes that the response to Question #23 (dated April 5, 2011) in the Round 1 questions and responses did not include sufficient detail. A similar request (Question #1) was included in the Round 3 set of questions from the NRC dated April 7, 2011. TVA provided a response dated April 14, 2011. The original version of the response below was provided to and discussed with the NRC on April 25, 2011. As a result of that discussion and in order to provide completeness and historical clarity, TVA has revised the April 25th response to include elements of the April 14th response and address the deficiencies in the April 5th response.)

It was not reasonable for plant personnel to recognize disc to stem separation on the 1-FCV-74-66 valve during venting in November 2008. This conclusion is supported by the following discussion.

Technical Specification (TS) surveillance requirement SR 3.5.1.1 states, "*Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.*" Because there were no high point vents on the RHR Loops, the procedural guidance in place in 2008 called for venting from the 1-FCV-74-52 body vent for Loop I and 1-FCV-74-66 body vent for Loop II. Venting was performed monthly per procedure 1/2/3-SR-3.5.1.1 (RHR I and RHR II) to ensure that the lines were full of water in accordance with the requirements specified in SR 3.5.1.1 and SR 3.5.2.2 (water hammer prevention). The TS requirement and its implementing procedure were not intended to detect a separated disc. Each valve body vent consists of a horizontal ½" diameter line directly off the top of the valve body (~4" down from the pressure seal), an elbow down, and two vertically oriented globe vent valves configured lower than the vent line off the valve body. The vent valves have internal seat orifices ~¼" wide when the valves are fully open. Unit 1 at BFN was in "lay-up" condition for several years prior to restart, and the vent lines were not refurbished or tested as a part of restart. Therefore, each line was susceptible to clogging by debris both before and during flow through the line.

Venting of Loop I was attempted on October 3, 2008 and Loop II on November 11, 2008. Successful venting would entail a large quantity of water with a relatively steady flow rate. This venting was unsuccessful on both Loop I and Loop II. For example, during the venting of Loop II, a small amount (approximately two cups) of water was collected with a gradually diminishing flow rate, both of which were symptoms of line blockage; therefore, the vent line was assumed to be plugged. Depending on the amount, size, and type of restriction the observed flow of liquid from blockage can appear similar to depressurizing an enclosed volume (e.g., volume between the inboard and outboard valves). The restricted flow of liquid through the vent pipe as a result of blockage can be so small that the pipe does not fill completely, and the gradually fills until liquid flows out of the end of the pipe similar to depressurizing an enclosed volume. Additional debris can then dislodge and build up in the pipe, causing complete blockage, also similar to depressurizing an enclosed volume.

Work Order (WO) 08-723810-000 was initiated to perform the necessary maintenance to clear the Loop II vent line. WO 08-723810-000 throttled 1-FCV-74-66 to a mid-travel position and attempted to vent to verify there was no flow blockage in the bonnet (caused by change in position of the disc skirt) with the valve in the full open position. This attempt to vent was unsuccessful, so it was assumed the blockage was in the vent line/vent valves. Since WO 08-723810-000 had no further instructions that could be conducted, Problem Evaluation Report (PER) 156971 was written to specifically create actions necessary address the insufficient venting of the bonnet vent lines. The PER response created WO 08-723813-000 which was written to perform troubleshooting and venting of the line, or to replace the valve and line to re-establish the vent path if troubleshooting was unsuccessful.

In the interim, an alternate methodology (ultrasonic testing) was used to meet the TS requirements. Functional Evaluation (FE) 42924 and FE 43012 provided the technical justification for the non-conforming condition associated with venting and required a revision to 1-SR-3.5.1.1 (RHR I and RHR II) to perform ultrasonic testing monthly until such a time as these obstructions were cleared via WO 08-723813-000. The revised procedure was successfully performed.

At that time there was no reason to assume that the disc for valve 1-FCV-72-66 had separated from the skirt/stem because flow was established through the valve three days later. In addition, the disc was later found to be not separated from the disc skirt on valve 1-FCV-74-52, even though it exhibited the same unsuccessful venting symptoms as valve 1-FCV-72-66.

In order to reduce dose to workers as low as reasonably achievable, the vent lines including vent valves were replaced with new prefabricated assemblies in 2010 under WO 08-723813-000. Further examination was not considered necessary at the time since the obstructed vent lines were replaced. This WO was tied to PER 156971. With the completion of the activities of the WO, all corrective actions have been completed and are either “closed” or in “waiting for approval” status. PER corrective action 156971-002 states “This condition was corrected by the completion of WO 08-723813-000 during the U1R8 RFO.”

In summary, it was not reasonable to expect station personnel to make a correlation between the lack of vent capability and the separation of the disc and skirt on valve 1-FCV-74-66 because:

- The venting configuration was highly susceptible to blockage;
- Attempted venting on Loop I failed one month prior;
- Vented water quantity and flow rate were characteristic of blockage;
- 1-FCV-74-66 passed flow three days later when loop II was successfully placed in shutdown cooling; and
- The disc was not later found to be separated from the skirt/stem on valve 1-FCV-74-52, even though it exhibited the same unsuccessful venting symptoms as valve 1-FCV-74-66.

3. *Why were the threads not recognized as contributing to the disc to stem separation that occurred in 1974?*

TVA Response:

The 1974 event involving Browns Ferry Nuclear Plant (BFN) Unit 2 valve 2-FCV-74-66 was determined to be a rotational event with separation of the disc and skirt clearly caused by unscrewing from the skirt threads due to broken tack welds (note that the V-Notch Disc Trim had not yet been installed on any of the FCV -74-52/66 valves), and not a pull-out event (i.e., caused by undersized threads) that was discovered in October 2010. It was also noted that partial unscrewing existed on two other valves (i.e., BFN Unit 1 valves 1-FCV-74-66 and 1-FCV-74-52). In none of the cases was there any notation of visible damage to the threads. The Tennessee Valley Authority Abnormal Occurrence Report (AOR BFA0-50-260/7432W), which reported this event to the NRC stated the following.

> "The valve was disassembled and the disc found separated from the stem. The disc was removed from the valve body and seating surfaces were visually inspected; <u>the mating threads on the disc and disc guide were cleaned, inspected, and found satisfactory</u>. The tack welds preventing rotation of the disc on the disk guide were found broken, and all parts were cleaned and inspected. Repair was made by cutting a weld bevel on the disc guide, reassembling the disc and guide, and applying a larger, stronger retaining weld to prevent separation of the parts.
>
> The valve was reassembled and functionally tested satisfactorily.
>
> Valves in similar positions on both units 1 and 2 will be disassembled and inspected, and an additional weld will be added to the disc and guide during unit outages when conditions permit."

During cleaning and inspection of the 2-FCV-74-66 mating threads of the disc and disc guide (i.e., disc skirt) in 1974, if vertical damage (axial pullout) of the threads had existed, it would have been observed. During the visual inspections of the 1-FCV-74-66 mating threads of the disc and disc skirt in October 2010, thread damage was easily observed , which was subsequently confirmed by the metallurgical examination conducted at Westinghouse.

In 1974, it would have been normal for investigations of this nature to be performed by the Supplier (GE) as an FDDR (Field Deviation Disposition Report) and thus TVA has requested GE to investigate their Design Record Files (DRF). Subsequent to this event Engineering Change Notice (ECN) L1473 (1975) was initiated for the incorporation of the V-Notch Disc Trim modifications to the FCV-74-52/66 valves correcting rotational issues due to flow induced vibration.

Recent investigations found General Electric (GE) Field Deviation Instruction (FDI) 190 dated December 26, 1977 (see the attachment), which in response to the AOR, established additional requirements for the tack weld. The GE FDI stated "Entire length of both flatted areas should be welded with a generous weld." Note that no weld thickness specification was provided. TVA fully complied with this vendor recommendation by completion of a 7" to

9" weld along the flatted surface. The GE FDI 190 requirement was later implemented through TVA Mechanical Maintenance Instruction 15.3.5.1.N, "RHR Angle Valve FCV-74-52 FCV-74-66 Disassembly, Repair, Reassembly, and Testing Unit 1, 2, and 3."

Attachment

GE FDI 190

GENERAL ELECTRIC
NUCLEAR ENERGY DIVISION

R11 911023 017

CAREFORD

INITIATING DATE 12/26/74
FDI NO. 190/87100-1
SHEET 1 OF 1
PROJECT Brown's Ferry 2

FDI DIRECTED TO
(GE FIELD REPRESENTATIVE AND LOCATION)

EQUIPMENT Angle Globe Valve

MPL NO. 2-10-154 A

920413T0122

2

DESCRIPTION OF TASK:

The purpose of this FDI is to strengthen the connection between the valve disc and skirt.

1. Rack out the power to valve motor operator and disconnect wiring.
2. Follow valve disassembly instructions in the valve manual.
3. Remove disc, skirt, and stem from valve.
4. Grind off our otherwise remove old tack weld deposits from both disc and skirt.
5. delete Bevel the flatted edges of the disc skirt with approzimately 3/8 inch leg on each edge.
6. Assemble disc, stem, and skirt making sure skirt is seated on disc.
7. Fillet (less than ½" throat dim) Weld with 1/8 inch electrode of ASME SA-298 A7-F5 309-15 of 309-16. per SM 44-E-2 and temperature bead technique Acceptable alternate electrodes are MIL-E-22200/2, Type MIL-309-15 or MIL-309-16.
8. delete Electrical characteristics for welding are 23 to 25 volts, 65 to 100 amps.
9. MSMA welding should be used.
10. Clean and PT root pass. No linear indications allowed.
11. Entire length of both flatted edges should be welded with a generous weld.
12. delete Preheat 60F minimum. No PWHT required.
13. Visual inspect the welds.
14. Reassemble valve.
15. While the valve is disassembled, dismount the operating drive and verify tightness of upper roller bearing locknut and set screws.

FOR INFORMATION ONLY IO

DATE JAN 31 1975

(MECH ENGG BR)

M1M -1.3.5.-B

TVA JAN 10 1975
PROJECT: BROWNS FERRY 1-2-3
CONTRACT NOS.: 86000 98744 ~~87000 41750~~
TITLE:

SIGNATURES	DATE
1. ORIGINATOR R.T. Reich	12/31/74
2. PROJECT MANAGER [illegible]	1/3/75
3. ENGINEERING R.T. Reich	12/31/74
4.	

ANSWERED BY LETTER NO. 12765

DATE COMPLETED

BY:
(SIGNATURE)

NED-663 (REV 11/70)

BEST AVAILABLE COPY

Enclosure 7

(NOT TO BE DISTRIBUTED EXTERNALLY)

FIELD DISPOSITION INSTRUCTION
ACTION AND APPROVAL

GENERAL ELECTRIC
NUCLEAR ENERGY DIVISION

FDI NO. 190/87000 -1
PROJECT Brown's Ferry 2
DESIGN ENGINEER R.T. Reich
COMPONENT NO. 151
ESTIMATED COST $ 2100/each
COST APPROVED ON ECN NO. N/A

INITIAL EACH ITEM IN APPROPRIATE COLUMN

YES	NO	
RTR		BUY ITEM MPL NO. 10-154
		VENDOR Walworth
		P.O. NO. 205H0998
		BUYER CONTACTED D. Firestone (NAME)
		MAKE ITEM
		ECN NO. ______ APPLIES
		MATERIAL PURCHASE REQUIRED
		RELEASE ENGINEER N/A
		OTHER PLANTS SIMILARLY AFFECTED (LIST WITH FDI NUMBERS)

PLANT	FDI NO.	ESTIMATED COST
Brown's Ferry 1	280/87000	$2100/each valve
" 1	281/87000	"

COST RESPONSIBILITY INFORMATION:

G.E. MUST BEAR THE COSTS OF THE REPAIR & ATTEMPT TO RECOVER FROM THE VENDOR RTR

SUPPLEMENTAL COST APPROVAL:

$10,000 TO $25,000 ______

OVER $25,000 ______

COST CODE: ______

BY: ______ (FINANCE)

ED-668A (10-70)

Enclosure 7

Question 1. - Provide the basis for why 1-FCV-74-66 is not part of the GL 89-10 program.

TVA Response:

Regulatory Requirements

All MOVs in safety-related piping systems were considered to be within the scope of Generic Letter (GL) 89-10. However, MOVs that were not required to change positions during design basis events or in plant emergency procedures could be eliminated from the GL 89-10 program per Supplement 1 to GL 89-10. In addition, GL 89-10 originally required the inclusion of passive-position changeable valves where the MOV was not blocked to prevent inadvertent operation; however, Supplement 4 to GL 89-10 eliminated this requirement for BWRs. Therefore, it is permissible to exclude from the GL 89-10 program an MOV that is not required to change positions during design basis events or in plant emergency procedures. This position was accepted by the NRC in its letter dated March 18, 1997 as described below.

Discussion

In a letter from T. E. Abney to the NRC dated January 6, 1997 (Attachment 1), TVA provided a response to the NRC letter dated October 7, 1996 (Attachment 2) for re-evaluation of the safety functions of certain MOVs removed from, or not included in, the BFN GL 89-10 program. In Enclosure 1 of the January 6, 1997 letter, Page E1-10 of the submitted letter, both FCV-74-52 and FCV-74-66 were identified as "not required by plant procedures to operate the RHR system in the suppression pool cooling mode. Therefore, these valves have no redundant safety function and will not be included in the GL 89-10 program." Both the 1-FCV- 74-52 and 1-FCV-74-66 valves have a safety function to remain in the open position to support LPCI injection. They are required to be open and remain open during normal plant operation. Therefore, they are classified as Passive MOVs by the MOV Program and are not included in the BFN GL 89-10 MOV Program.

In a letter from NRC to TVA dated March 18, 1997 (Attachment 3), NRC stated that "the changes committed to in Mr. Abney's January 6, 1997 letter (Attachment 1) are considered adequate to address our (NRC's) concerns on this subject (reduced scope of valves in GL 89-10 Program)." Accordingly, the NRC accepted TVA's justification for excluding the FCV-74-52 and FCV-74-66 valves for the BFN GL 89-10 program.

In addition, TVA has previously stated that the disc to stem separation occurred in 2008 and the valve passed flow in March 2009. Further independent testing was conducted by Performance Improvement International and concluded that the valve was capable of passing flow with the stem to disc separation.

Question 2. - Provide WO package and all supporting information that documents the partial MOVATs performed in 2006 and 2008 for 1-FCV-74-66.

TVA Response:

The following WO packages are applicable and were provided by BFN Licensing to the NRC.

WO #04-716746 was performed in 2006 (Attachment 4)
WO 2008-714852-000 was performed in 2008 (Attachment 5)

Question 3. - Explain why the 3-FCV-74-52 and the 1-FCV-74-52 valve unseating forces are not consistent from test to test.

TVA Response:

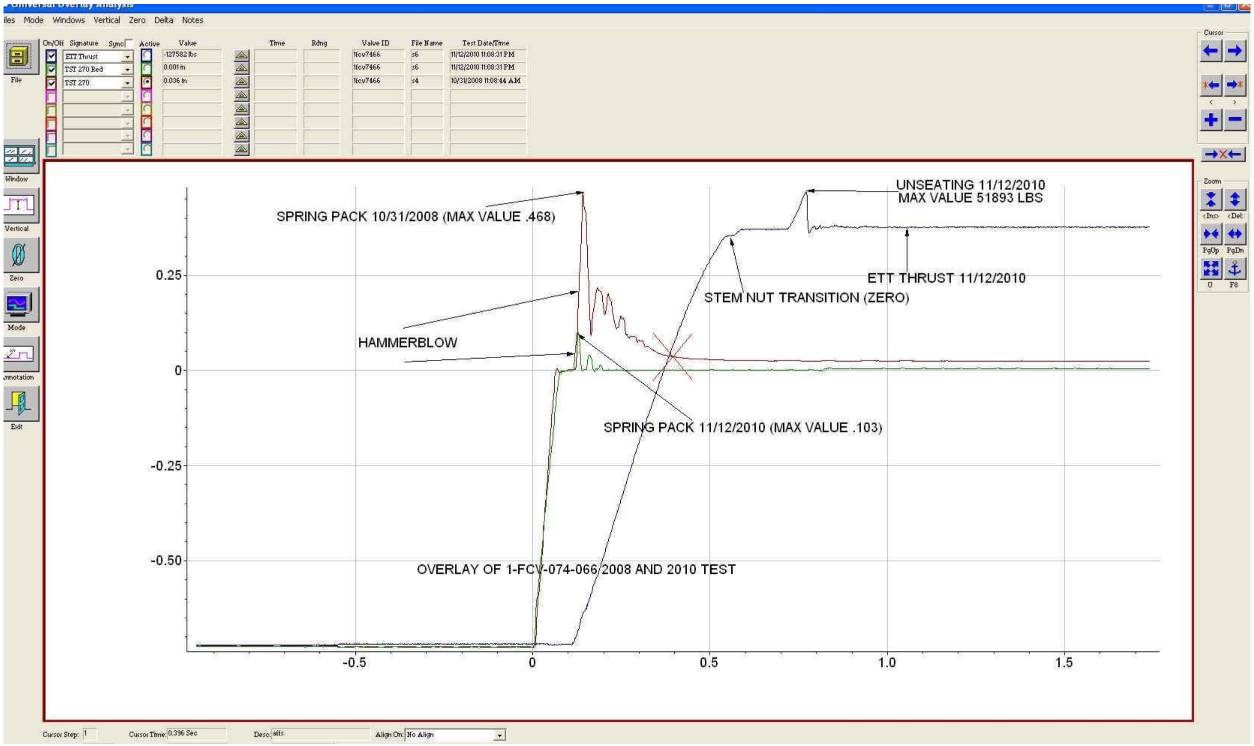
Table A5.1 (Attachment 6) of the Root Cause Analysis (RCA) report provides a qualitative assessment of whether unseating is visible from the partial MOVATs data. Tabular results for 3-FCV-74-52 show that unseating was visible for some tests and not visible for other tests. The inconsistency in qualitative unseating results for 3-FCV-74-52 was explained in the TVA response to question 6 in our March 31, 2011 submittal as variation in disc-to-seat COF. Table A5.1, however, does not show inconsistent unseating results for 1-FCV-74-52.

Question 4. - Provide the actual unseating forces for 1-FCV-74-52 in 2008 and 2010. Provide the actual unseating forces for the other valves as well.

TVA Response:

Prior to the discovery of the 1-FCV-74-66 stem-disc separation event in October, 2010, direct stem thrust measurements were not taken for the six RHR outboard LPCI angle globe valves (FCV-74-52, FCV-74-66) since they were not in the BFN GL 89-10 program as discussed in response to Question 1 above. However, the partial MOVATS data that we did take does not allow for the determination of actual unseating forces. Data acquired consisted of motor current, and, more recently, spring pack displacement. Although spring pack displacement is proportional to drive sleeve torque, the spring pack displacement was not calibrated and only approximate torque values can be obtained using Limitorque generic spring pack curves. In addition, only loading events that exceed the spring pack preload can be seen. As was shown in the figure (shown below) for Question 7 in our response dated March 31, 2011, the first open valve stroke loading event seen in the spring pack displacement represents the actuator hammerblow. A second loading event approximately 0.75 seconds later would be an indication of unseating, but only if unseating exceeds the spring pack preload.

Therefore, based on the information provided above, we are unable to provide the actual unseating forces. Quantification of unseating forces will not be possible until direct stem thrust measurements are obtained beginning at the next RFO on each unit.



Question 5. - Provide the date when the WO was initiated and date when the WO was worked to address the plugged bonnet vents for 1-FCV-74-52 and -66 (Thierry provided WO 08-723813-000 as a reference).

TVA Response:

The plugged bonnet vents were described in PER 156971 dated 11/11/2008 and Work Order (WO) 08-723813-000 was initiated as the PER response to address the condition by replacing the vent valves. TVA concluded that these bonnet vents were in fact plugged based on recurrent and recent experience with similar vents that were confirmed to be plugged with foreign material. WO 08-723813-000 was signed off completed and accepted by Operations on 11/19/2010.

As discussed in response to question 2 of the NRC questions dated 4/22/11 an alternate methodology (ultrasonic testing) was used to meet the Technical Specification (TS) surveillance requirement SR 3.5.1.1 which states, "*Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.*" Functional Evaluation (FE) 42924 and FE 43012 provided the technical justification for the non-conforming condition associated with the apparently plugged vent and required a revision to procedure 1-SR-3.5.1.1 (RHR I and RHR II) to perform ultrasonic testing monthly until such a time as these vent obstructions were cleared via WO 08-723813-000. The revised procedure was successfully performed.

Question 6 - MOVATs data traces provided depicts a date of October 31, 2008 while the RCA states the MOVATs data was obtained in November 2008. Was data taken both in Oct and Nov or should the RCA state Oct?

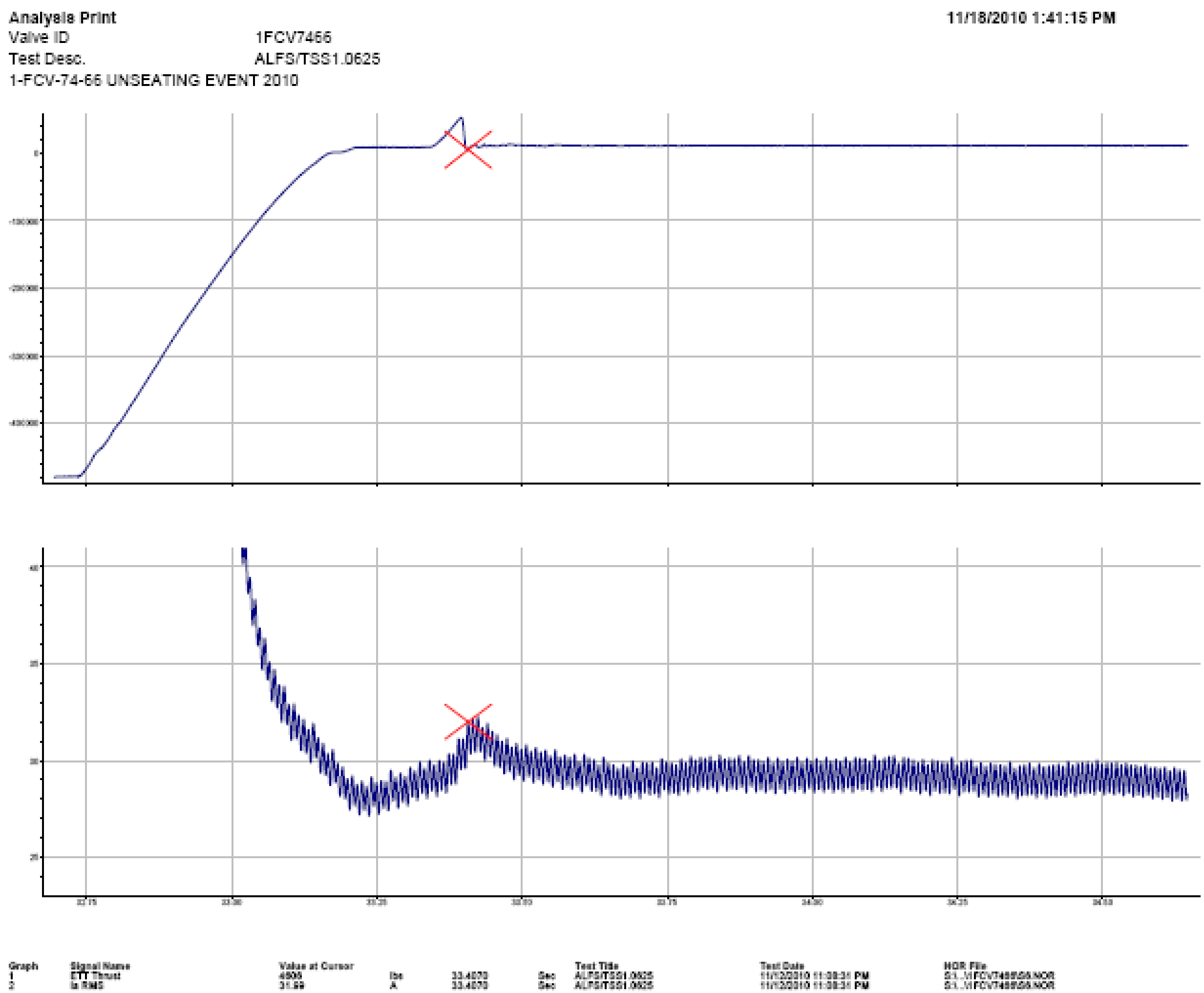
TVA Response:

The data was taken only once on October 31, 2008. Table A5.1 of the Root Cause Analysis will be updated to indicate that the correct date is October 31, 2008.

Question 7. - Provide the 2010 MOVATs data taken for 1-FCV-74-66 after the valve was repaired.

TVA Response:

The 2010 MOVATS data taken for 1-FCV-74-66 after the repair are provided below and are also attached in the Root Cause Analysis.



NOTE: The X denotes the unseating of the valve disc.

Question 8. - Provide the program document for the GL 89-10 program.

TVA's Response:

The program document (NETP-115) was provided by BFN Licensing to the NRC on 07/01/2011. It is also attached to this response (Attachment 7).

Question 9. - PER 271338 RCA rev 1 Attachment 7 specifies that 1-SR-3.5.1.6 and 1-SR-3.3.5.1.6 document instances when the 1-FCV-74-66 was known to have been stroked by date performed. These SRs perform flow test and logic functional test. 1-SR-3.6.1.3.5 and 1-SR-3.3.3.1.4 would be the correct SRs that would have required stroking the valve. Is the data in the table for valve stroke history incorrect or are the wrong SRs referenced?

TVA Response:

Valve 1-FCV-74-66 is stroked during execution of the following surveillance procedures:

Procedure	**Steps where 1-FCV-74-66 is stroked**
1-SR-3.5.1.6 (RHR II) Quarterly Frequency	Not stroked.
1-SR-3.3.5.1.6 (C II) 2-year Frequency	7.2 [20]: Close 7.2 [28]: Open 7.2 [35]: Close 7.2 [38]: Open 7.2 [40]: Close 7.2 [43]: Open 7.2 [46]: Close 7.2 [61]: Open 7.6 [1]: Close 7.6 [20]: Open
1-SR-3.6.1.3.5 (RHR II) Quarterly Frequency	7.2 [1]: Close 7.2 [2]: Open 7.2 [4.1]: Close 7.2 [4.2]: Open 7.2 [5]: Possible stroke if not in original position
1-SR-3.3.3.1.4 (H II) 2 year frequency	7.2 [4]: Close 7.2 [8]: Open 7.2 [10]: Close 7.2 [14]: Possible stroke if not in original position

Therefore, the reference in Attachment 7 of the RCA to 1-SR-3.5.1.6 (RHR II) is incorrect since it does not have procedure steps that specify the stroking of 1-FCV-74-66. The reference to procedure 1-SR-3.3.5.1.6 (C II) is correct. In addition, procedures 1-SR-3.6.1.3.5 (RHR II), and 1-SR-3.3.3.1.4 (H II) also have procedure steps that specify the stroking of 1-FCV-74-66. Therefore, the wrong SR procedures are referenced in the RCA and the data in the RCA table for the valve stroke history is incorrect. However, we estimate that the total number of valve strokes will close to that given in table A5.1 of Attachment 7 of the RCA. Therefore, the conclusions in the RCA should remain valid. This attachment will be revised to include the correct surveillance procedure references and the revised stroke count.

Question 10. - Provide a copy of the entire procedure of ECI-0-000-MOV09 r20 and EPI-0-000-MOV001 r48. (Parts of these procedures were in the WOs and they want to see the whole procedure.)

TVA Response:

Procedures ECI-0-000-MOV09 r20 (Attachment 8) and EPI-0-000-MOV001 r48 (Attachment 9) are attached and were previously provided by BFN Licensing.

Question 11. - What is requiring the 2 year frequency for the partial MOVATs? Are they scheduled PMs?

TVA Response:

1-FCV-74-66 was maintained by the Preventive Maintenance (PM) Program. The PM program called for a partial MOVATS every 2-years for this valve, which was scheduled to be consistent with a refueling outage cycle basis for equipment reliability reasons.

Question 12. - If this valve were in the GL 89-10 program would the frequency change; would you be doing more work on the same frequency?

TVA Response:

If the 1-FCV-74-66 valve was in the BFN GL 89-10 program, a baseline for performance would be established on a once per refueling outage basis until a performance trend was established. Once the baseline was established then the frequency would be set in accordance with the MOV program (NETP 115, Attachment 7). If this valve was incorporated into the MOV program, a full MOVATS test instead of the partial MOVATS test would be performed on the frequency set in accordance with the MOV program.

ATTACHMENT 1

ATTACHMENT 2

ATTACHMENT 3

ATTACHMENT 4

ATTACHMENT 5

ATTACHMENT 6

Table – A5.1 - MOVATs Data

1-FCV-074-0052		1-FCV-074-0066		2-FCV-074-0052		2-FCV-074-0066		3-FCV-074-0052		3-FCV-074-0066	
Date	Unseated	Date	Unseated	Date	Unseated	Date	Unseated	Date	Unseated	Date	Unseated
Nov-10	Yes	Nov-10	Yes *	May-09	Yes	May-09	Yes	Mar-10	**No**	Mar-10	Yes
Nov-08	Yes	Nov-08	**No**	Mar-07	Yes	Mar-07	Yes	Apr-08	Yes	Mar-08	Yes
Oct-06	Yes	Oct-06	**No**	Apr-05	Yes	Mar-05	Yes	Mar-06	Yes	Mar-06	Yes
				Feb-03	Yes	Mar-03	Yes	Mar-04	**No**	Mar-04	Yes
				Mar-01	Yes	Apr-01	Yes	Mar-02	**No**	Apr-02	Yes
				Apr-99	Yes	Apr-99	Yes	Apr-00	Yes	Apr-00	Yes
				Sep-97	Yes	Oct-97	Yes	Oct-98	Yes	Sep-98	Yes
* Test performed post rebuild.				Mar-96	Yes	Apr-96	Yes				

ATTACHMENT 7

ATTACHMENT 8

ATTACHMENT 9

Question 1 - Provide a copy of the PER from a few years ago on EOIs (i.e., related to using the 74-66 valve in the EOIs).

TVA Response:

TVA has been unable to locate any PERs associated with using the 74-66 valve in the EOIs. However, the following information is provided regarding the identification of motor-operated valves (MOVs) in the Emergency Operating Instructions (EOIs).

The Updated Final Safety Analysis Report, TVA Design Criteria and EOIs have been reviewed to determine the safety-related function/position of FCV-74-52 and FCV-74-66. This review concluded that FCV-74-52 and FCV-74-66 are normally open and must remain open to perform their safety-related function of allowing injection water to enter the reactor vessel. This conclusion is consistent with the scoping review performed for the NRC Generic Letter 89-10 Program (see 6Jan1997 Letter to NRC and 18Mar1997 Letter from the NRC) that also determined FCV-74-52 and FCV-74-66 are not required to close or throttle injection flow during a Design Basis Accident (DBA). Further, some other utilities have removed valves equivalent to FCV-74-52 and FCV-74-66 from the GL 89-10 program at similarly designed plants.

The process used to identify valves that are required to be in the GL 89-10 program included a review of the EOIs; however, consistent with the rest of the industry, not all MOVs included in the EOIs are in the GL 89-10 program. This is because the EOIs consider additional equipment failures and accident scenarios that could require an MOV to have a function beyond those credited in the safety analysis. FCV-74-52 and FCV-74-66 have throttling and closure capability and the EOIs rely on this capability for controlling injection flow or other functions, but these capabilities are not required or credited in the safety analysis for mitigating DBAs, and; therefore, this supports TVA's conclusion that they are not required to be in the GL 89-10 Program.

Question 2 - Clarify/change 2009 to 2008 on answer to Question 1 dated 6/29/11.

TVA Response:

Corrected in revision 1 and sent to Browns Ferry Nuclear Plant (BFN) Licensing 7/7/2011. Also corrected the steps in Question 9 of 1-SR-3.3.5.1.6 (C II) 2-year Frequency to additional stroke performance in step 7.2[10] and 7.2[14] in revision 2. (Attachment 1)

Question 3 - When was full MOVATS done on valves during the restart of Unit 1, e.g., 74-67 and 74-53.

TVA Response:

The full MOVATS test was performed on valve 74-67 during the restart of Unit 1 on 9/16/2006. The full MOVATS test was performed on valve74-53 during the restart of Unit 1 on 10/2/2006. Full MOVATS testing was not performed on the 74-52 or 74-66 valves as part of the Unit 1 restart.

Question 4 - Do we perform procedures ECI-0-000-MOV09 and EPI-0-000-MOV001 for valves in the Generic Letter 89-10 program on a 2 year frequency.

TVA Response:

No, the Preventive Maintenance (PM) work order for the specific MOV will specify the frequency and what specific instruction/procedures are to be performed in accordance with the GL 89-10 program requirements.

Procedure EPI-0-000-MOV001 is an electrical inspection procedure that is performed at difference frequencies for different MOVs based on the program requirements. Procedure ECI-0-000-MOV009 is a MOVATS testing procedure that is performed at different frequencies for different MOVs as well as in accordance with program requirements. Furthermore, in EPI-0-000-MOV001; Section 8.2, Post Maintenance Testing, Step [5.1] identifies the partial MOVATS PM requirement as specified in ECI -000-MOV009. Note that this is not GL 89-10 required testing. The partial MOVATS testing instruction is in Attachment 5 of ECI-0-000-MOV09.

Question 5 - Are there acceptance criteria for partial MOVAT testing or is partial MOVAT testing performed as a good practice and for trending purposes only.

TVA Response:

The partial MOVATS testing is performed primarily as a good practice and for trending purposes. Attachment 5 of BFN procedure ECI-0-000-MOV009 provides instructions for the partial MOVATS testing. Step 1.3[4] of this procedure calls for a verification that the acquired test data is acceptable. However, this is not referring to meeting acceptance criteria, but whether the data was successfully acquired or not.

Per the Root Cause Analysis (RCA), the GL 89-10 Program (NETP-115) will monitor (test and trend) the FCV-74-52 and FCV-74-66 periodically as a Category 2 MOV (i.e., not in the GL 89-10 commitment population) effective in January 2011. Performance data will be collected for trending purpose and acceptance criteria will be established for all six (3 units and 2 loops/unit) of the Outboard LPCI Injection MOVs as part of the MOV Program requirement. Corrective actions taken as part of PER 147628 will address these items.

ATTACHMENT 1

Question 1. - Provide the basis for why 1-FCV-74-66 is not part of the GL 89-10 program.

TVA Response:

Regulatory Requirements

All MOVs in safety-related piping systems were considered to be within the scope of Generic Letter (GL) 89-10. However, MOVs that were not required to change positions during design basis events or in plant emergency procedures could be eliminated from the GL 89-10 program per Supplement 1 to GL 89-10. In addition, GL 89-10 originally required the inclusion of passive-position changeable valves where the MOV was not blocked to prevent inadvertent operation; however, Supplement 4 to GL 89-10 eliminated this requirement for BWRs. Therefore, it is permissible to exclude from the GL 89-10 program an MOV that is not required to change positions during design basis events or in plant emergency procedures. This position was accepted by the NRC in its letter dated March 18, 1997 as described below.

Discussion

In a letter from T. E. Abney to the NRC dated January 6, 1997 (Attachment 1), TVA provided a response to the NRC letter dated October 7, 1996 (Attachment 2) for re-evaluation of the safety functions of certain MOVs removed from, or not included in, the BFN GL 89-10 program. In Enclosure 1 of the January 6, 1997 letter, Page E1-10 of the submitted letter, both FCV-74-52 and FCV-74-66 were identified as “not required by plant procedures to operate the RHR system in the suppression pool cooling mode. Therefore, these valves have no redundant safety function and will not be included in the GL 89-10 program.” Both the 1-FCV- 74-52 and 1-FCV-74-66 valves have a safety function to remain in the open position to support LPCI injection. They are required to be open and remain open during normal plant operation. Therefore, they are classified as Passive MOVs by the MOV Program and are not included in the BFN GL 89-10 MOV Program.

In a letter from NRC to TVA dated March 18, 1997 (Attachment 3), NRC stated that “the changes committed to in Mr. Abney’s January 6, 1997 letter (Attachment 1) are considered adequate to address our (NRC’s) concerns on this subject (reduced scope of valves in GL 89-10 Program).” Accordingly, the NRC accepted TVA’s justification for excluding the FCV-74-52 and FCV-74-66 valves for the BFN GL 89-10 program.

In addition, TVA has previously stated that the disc to stem separation occurred in 2008 and the valve passed flow in March 2009. Further independent testing was conducted by Performance Improvement International and concluded that the valve was capable of passing flow with the stem to disc separation.

Question 2. - Provide WO package and all supporting information that documents the partial MOVATs performed in 2006 and 2008 for 1-FCV-74-66.

TVA Response:

The following WO packages are applicable and were provided by BFN Licensing to the NRC.

WO #04-716746 was performed in 2006 (Attachment 4)
WO 2008-714852-000 was performed in 2008 (Attachment 5)

Question 3. - Explain why the 3-FCV-74-52 and the 1-FCV-74-52 valve unseating forces are not consistent from test to test.

TVA Response:

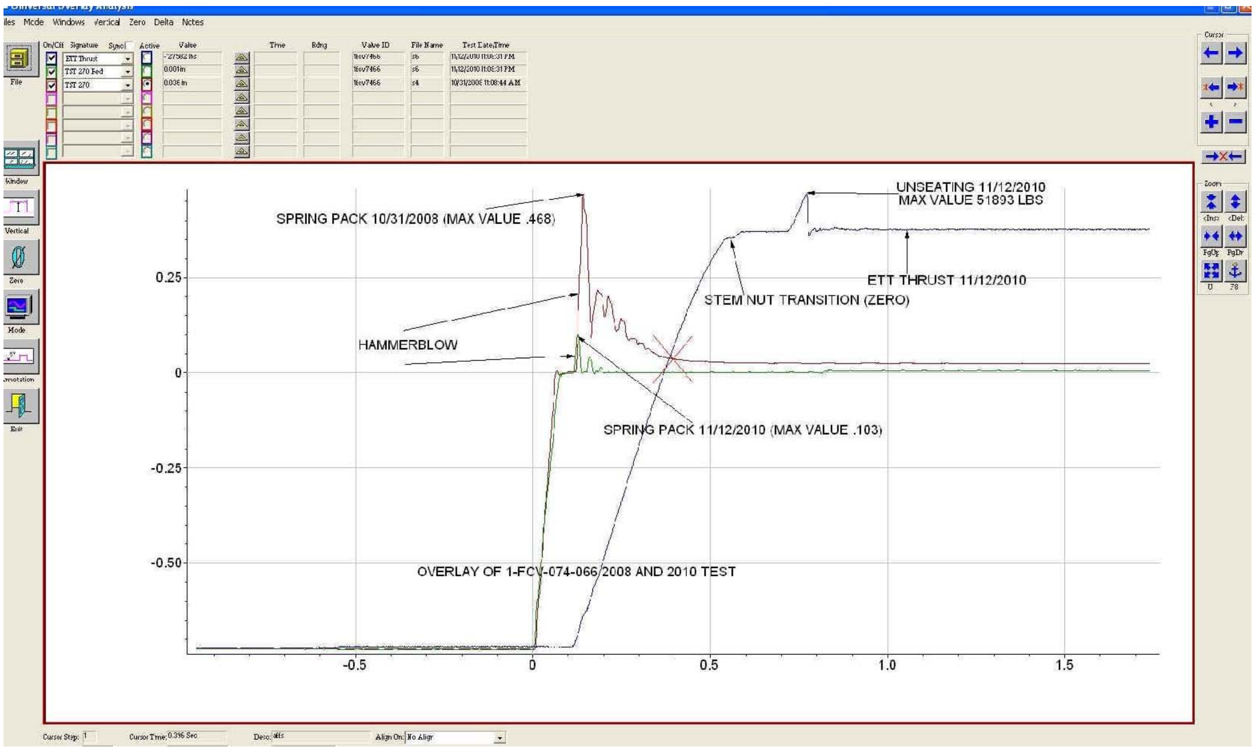
Table A5.1 (Attachment 6) of the Root Cause Analysis (RCA) report provides a qualitative assessment of whether unseating is visible from the partial MOVATs data. Tabular results for 3-FCV-74-52 show that unseating was visible for some tests and not visible for other tests. The inconsistency in qualitative unseating results for 3-FCV-74-52 was explained in the TVA response to question 6 in our March 31, 2011 submittal as variation in disc-to-seat COF. Table A5.1, however, does not show inconsistent unseating results for 1-FCV-74-52.

Question 4. - Provide the actual unseating forces for 1-FCV-74-52 in 2008 and 2010. Provide the actual unseating forces for the other valves as well.

TVA Response:

Prior to the discovery of the 1-FCV-74-66 stem-disc separation event in October, 2010, direct stem thrust measurements were not taken for the six RHR outboard LPCI angle globe valves (FCV-74-52, FCV-74-66) since they were not in the BFN GL 89-10 program as discussed in response to Question 1 above. However, the partial MOVATS data that we did take does not allow for the determination of actual unseating forces. Data acquired consisted of motor current, and, more recently, spring pack displacement. Although spring pack displacement is proportional to drive sleeve torque, the spring pack displacement was not calibrated and only approximate torque values can be obtained using Limitorque generic spring pack curves. In addition, only loading events that exceed the spring pack preload can be seen. As was shown in the figure (shown below) for Question 7 in our response dated March 31, 2011, the first open valve stroke loading event seen in the spring pack displacement represents the actuator hammerblow. A second loading event approximately 0.75 seconds later would be an indication of unseating, but only if unseating exceeds the spring pack preload.

Therefore, based on the information provided above, we are unable to provide the actual unseating forces. Quantification of unseating forces will not be possible until direct stem thrust measurements are obtained beginning at the next RFO on each unit.



Question 5. - Provide the date when the WO was initiated and date when the WO was worked to address the plugged bonnet vents for 1-FCV-74-52 and -66 (Thierry provided WO 08-723813-000 as a reference).

TVA Response:

The plugged bonnet vents were described in PER 156971 dated 11/11/2008 and Work Order (WO) 08-723813-000 was initiated as the PER response to address the condition by replacing the vent valves. TVA concluded that these bonnet vents were in fact plugged based on recurrent and recent experience with similar vents that were confirmed to be plugged with foreign material. WO 08-723813-000 was signed off completed and accepted by Operations on 11/19/2010.

As discussed in response to question 2 of the NRC questions dated 4/22/11 an alternate methodology (ultrasonic testing) was used to meet the Technical Specification (TS) surveillance requirement SR 3.5.1.1 which states, "*Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.*" Functional Evaluation (FE) 42924 and FE 43012 provided the technical justification for the non-conforming condition associated with the apparently plugged vent and required a revision to procedure 1-SR-3.5.1.1 (RHR I and RHR II) to perform ultrasonic testing monthly until such a time as these vent obstructions were cleared via WO 08-723813-000. The revised procedure was successfully performed.

Question 6 - MOVATs data traces provided depicts a date of October 31, 2008 while the RCA states the MOVATs data was obtained in November 2008. Was data taken both in Oct and Nov or should the RCA state Oct?

TVA Response:

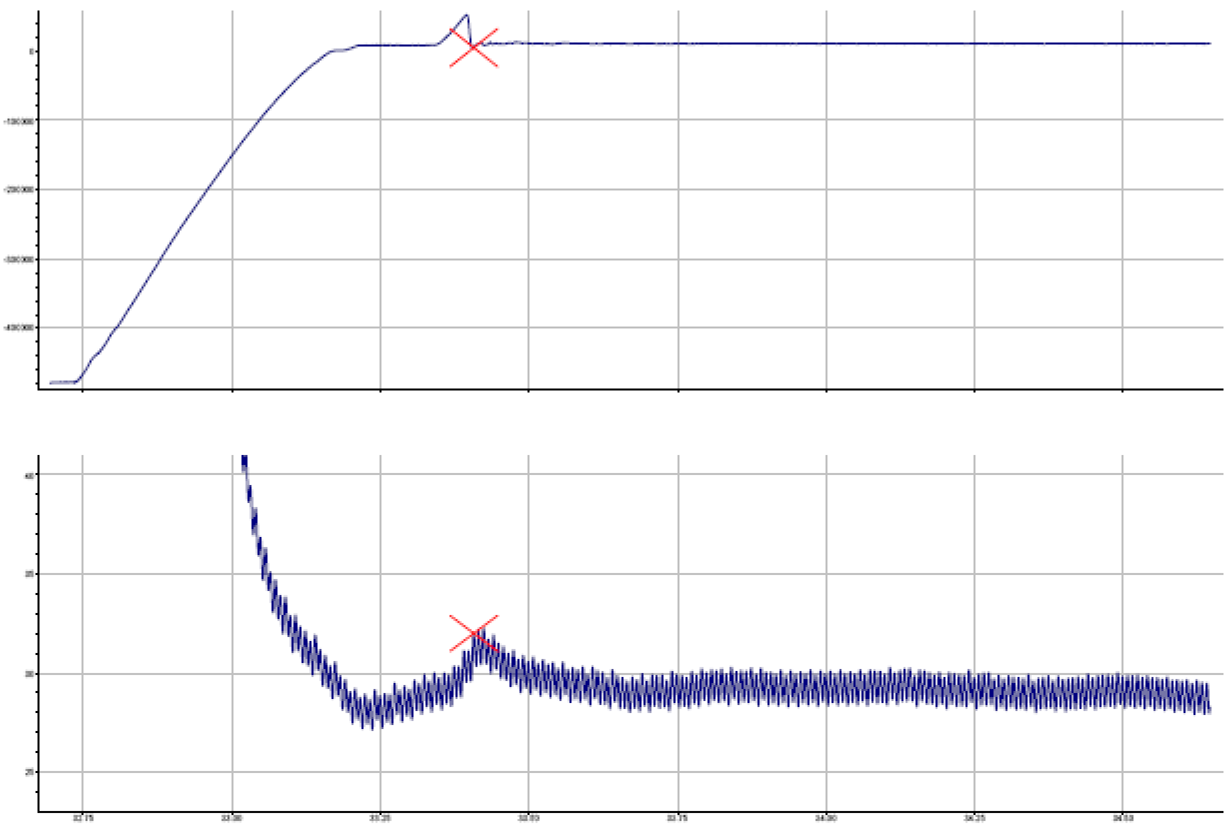
The data was taken only once on October 31, 2008. Table A5.1 of the Root Cause Analysis will be updated to indicate that the correct date is October 31, 2008.

Question 7. - Provide the 2010 MOVATs data taken for 1-FCV-74-66 after the valve was repaired.

TVA Response:

The 2010 MOVATS data taken for 1-FCV-74-66 after the repair are provided below and are also attached in the Root Cause Analysis.

Analysis Print **11/18/2010 1:41:15 PM**
Valve ID 1FCV7466
Test Desc. ALFS/TSS1.0625
1-FCV-74-66 UNSEATING EVENT 2010



Graph	Signal Name	Value at Cursor				Test Title	Test Date	HOR File
1	ETT Thrust	4906	lbs	33.4070	Sec	ALFS/TSS1.0625	11/12/2010 11:38:31 PM	S:\...\1FCV7466\56.NOR
2	Ia RMS	31.69	A	33.4070	Sec	ALFS/TSS1.0625	11/12/2010 11:38:31 PM	S:\...\1FCV7466\56.NOR

NOTE: The X denotes the unseating of the valve disc.

Question 8. - Provide the program document for the GL 89-10 program.

TVA's Response:

The program document (NETP-115) was provided by BFN Licensing to the NRC on 07/01/2011. It is also attached to this response (Attachment 7).

Question 9. - PER 271338 RCA rev 1 Attachment 7 specifies that 1-SR-3.5.1.6 and 1-SR-3.3.5.1.6 document instances when the 1-FCV-74-66 was known to have been stroked by date performed. These SRs perform flow test and logic functional test. 1-SR-3.6.1.3.5 and 1-SR-3.3.3.1.4 would be the correct SRs that would have required stroking the valve. Is the data in the table for valve stroke history incorrect or are the wrong SRs referenced?

TVA Response:

Valve 1-FCV-74-66 is stroked during execution of the following surveillance procedures:

Procedure	**Steps where 1-FCV-74-66 is stroked**
1-SR-3.5.1.6 (RHR II) Quarterly Frequency	Not stroked.
1-SR-3.3.5.1.6 (C II) 2-year Frequency	7.2[10]: Close 7.2[14]: Open 7.2 [20]: Close 7.2 [28]: Open 7.2 [35]: Close 7.2 [38]: Open 7.2 [40]: Close 7.2 [43]: Open 7.2 [46]: Close 7.2 [61]: Open 7.6 [1]: Close 7.6 [20]: Open
1-SR-3.6.1.3.5 (RHR II) Quarterly Frequency	7.2 [1]: Close 7.2 [2]: Open 7.2 [4.1]: Close 7.2 [4.2]: Open 7.2 [5]: Possible stroke if not in original position
1-SR-3.3.3.1.4 (H II) 2 year frequency	7.2 [4]: Close 7.2 [8]: Open 7.2 [10]: Close 7.2 [14]: Possible stroke if not in original position

Therefore, the reference in Attachment 7 of the RCA to 1-SR-3.5.1.6 (RHR II) is incorrect since it does not have procedure steps that specify the stroking of 1-FCV-74-66. The reference to procedure 1-SR-3.3.5.1.6 (C II) is correct. In addition, procedures 1-SR-3.6.1.3.5 (RHR II), and 1-SR-3.3.3.1.4 (H II) also have procedure steps that specify the stroking of 1-FCV-74-66. Therefore, the wrong SR procedures are referenced in the RCA and the data in the RCA table for the valve stroke history is incorrect. However, we estimate that the total number of valve strokes will close to that given in table A5.1 of Attachment 7 of the RCA. Therefore, the conclusions in the RCA should remain valid. This attachment will be revised to include the correct surveillance procedure references and the revised stroke count.

Question 10. - Provide a copy of the entire procedure of ECI-0-000-MOV09 r20 and EPI-0-000-MOV001 r48. (Parts of these procedures were in the WOs and they want to see the whole procedure.)

TVA Response:

Procedures ECI-0-000-MOV09 r20 (Attachment 8) and EPI-0-000-MOV001 r48 (Attachment 9) are attached and were previously provided by BFN Licensing.

Question 11. - What is requiring the 2 year frequency for the partial MOVATs? Are they scheduled PMs?

TVA Response:

1-FCV-74-66 was maintained by the Preventive Maintenance (PM) Program. The PM program called for a partial MOVATS every 2-years for this valve, which was scheduled to be consistent with a refueling outage cycle basis for equipment reliability reasons.

Question 12. - If this valve were in the GL 89-10 program would the frequency change; would you be doing more work on the same frequency?

TVA Response:

If the 1-FCV-74-66 valve was in the BFN GL 89-10 program, a baseline for performance would be established on a once per refueling outage basis until a performance trend was established. Once the baseline was established then the frequency would be set in accordance with the MOV program (NETP 115, Attachment 7). If this valve was incorporated into the MOV program, a full MOVATS test instead of the partial MOVATS test would be performed on the frequency set in accordance with the MOV program.

Question 1 - Were full MOVATS performed on valves 74-67, and 74-53 during the restart of Unit 1 in 2006, and were full MOVATS performed in 2008? If not, how was the frequency established?

TVA Response:

The full MOVATS test was performed on valve 74-67 during the restart of Unit 1 on 9/16/2006. Full MOVATS was performed again in 2008 for valve 74-67 as part of the TVA program periodic verification test in accordance with the 120 month GL 89-10 program schedule. Full MOVATS was again performed as a post maintenance test (PMT) in 2010 because it was modified as part of the Joint Owners Group (JOG) upgrade. The GL 89-10 program testing frequency for this valve is 120 months.

The full MOVATS test was performed on valve 74-53 during the restart of Unit 1 on 10/2/2006. Full MOVATS were performed again in 2007 as PMT for valve repair and not as part of the GL 89-10 program, and it was performed again in 2010 because of JOG upgrade maintenance. The GL 89-10 program testing frequency for this valve is 120 months.

Normally, the periodic GL 89-10 program testing frequency is established for the GL 89-10 program valves based on risk (PRA risk ranking) and margin of the MOV. As an example; a high risk and low margin MOV would be tested every 2-years while a low risk and high margin MOV would be tested every 10 years. This process is described in the TVA GL 89-10 program document NETP-115.

In 2006, valve 1-FCV- 74-66 had a stem replacement. Since this valve was not in the GL 89-10 program, a full MOVATS test was not performed at that time (during the restart of Unit 1). If this valve had been in the GL 89-10 program our requirements (NETP 115) would have required a full MOVATS as part of the PMT. After successful PMT, the requirements for full MOVATS would be in accordance with the TVA program (NETP 115) based on risk and margin as previously discussed. Refer also to Question 12 of the 6/29/11 responses.

Question 1 - Were full MOVATS performed on valves 74-67, and 74-53 during the restart of Unit 1 in 2006, and were full MOVATS performed in 2008? If not, how was the frequency established?

TVA Response:

The full MOVATS test was performed on valve 74-67 during the restart of Unit 1 on 9/16/2006. Full MOVATS was performed again in 2008 for valve 74-67 as part of the TVA program periodic verification test in accordance with the 120 month GL 89-10 program schedule. Note that the scheduling of this test was based on the 120 month program schedule and was not required for any other reason. Full MOVATS was again performed as a post maintenance test (PMT) in 2010 because it was modified as part of the Joint Owners Group (JOG) upgrade. The GL 89-10 program testing frequency for this valve is 120 months.

The full MOVATS test was performed on valve 74-53 during the restart of Unit 1 on 10/2/2006. Full MOVATS were performed again in 2007 as PMT for valve repair and not as part of the GL 89-10 program, and it was performed again in 2010 because of JOG upgrade maintenance. The GL 89-10 program testing frequency for this valve is 120 months.

Normally, the periodic GL 89-10 program testing frequency is established for the GL 89-10 program valves based on risk (PRA risk ranking) and margin of the MOV. As an example; a high risk and low margin MOV would be tested every 2-years while a low risk and high margin MOV would be tested every 10 years. This process is described in the TVA GL 89-10 program document NETP-115.

In 2006, valve 1-FCV- 74-66 had a stem replacement. Since this valve was not in the GL 89-10 program, a full MOVATS test was not performed at that time (during the restart of Unit 1). If this valve had been in the GL 89-10 program our requirements (NETP 115) would have required a full MOVATS as part of the PMT. After successful PMT, the requirements for full MOVATS would be in accordance with the TVA program (NETP 115) based on risk and margin as previously discussed. Review of the 1-FCV-74-66 valve indicates that upon adding the Unit 1 74-66/52 valves to the program in 2006 it would have received a follow-up confirmatory full MOVATS test at the subsequent refuel outage and then would likely have received a full MOVATS test on a 120 month frequency based on the assumption that these valves would have similar low risk and high margin as the 74-53/67 valves unless the confirmatory full MOVATS test showed results that were of concern. However, if the 74-66/52 valves were included in the GL 89-10 program in 1997 then full MOVATS testing of these valves would have been performed in 2006 during U1 restart. If these test results were comparable to those for the same valve on Units 2 and 3 then no testing other than that required by the program frequency, most likely 120 months, would have been performed. Refer also to Question 12 of the 6/29/11 responses.

As discussed in the response to Question 1 dated July 7, 2011, the EOIs consider additional equipment failures and accident scenarios that could require a MOV to have a function beyond those credited in the safety analysis.

Valve FCV-74-52 and valve FCV-74-66 are required to be closed should valves FCV-74-53 and FCV-74-67, respectively be open when initiating suppression pool cooling, drywell sprays or suppression chamber sprays (see Step 2 of EOI Appendix 17A, Step 6 of EOI Appendix 17B and Step 6 of EOI Appendix 17C, respectively). The initiation of suppression pool cooling and suppression chamber sprays is not discussed in Section 14.6.3 of the SAR as a manual action following a LOCA-DBA. The initiation of drywell sprays is explicitly described in the Section 14.6.3 as a manually initiated action, which can be taken following a LOCA-DBA. The exact words in Section 14.6.3 are: "*...The containment spray would normally not be activated at all...*" The basis for this statement is also in Section 14.6.3 of the SAR, which reads: "*...After the reactor vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow offers considerable cooling to the drywell and causes a depressurization of the containment as the steam in the drywell is condensed...*"

In Supplement 1 to GL 89-10 states (as described on page 3 of the enclosure to NRC letter to TVA, dated 7Oct1997): *...safety-related MOVs that are always in their safety position, or would have no affect on the operation of the safety train if placed in the nonsafety position, could be removed from the GL 89-10 program...* When initiating suppression pool cooling, drywell sprays or suppression chamber sprays, clearly if FCV-74-53 and FCV-74-67 is closed, the position of FCV-74-52 and FCV-74-66, respectively, does not matter. If FCV-74-53 and FCV-74-67 is open and FCV-74-52 and FCV-74-66, respectively, is open then depending on the pressure in the reactor vessel, all RHR pump(s) flow or some portion of this flow will be directed through the desired flow path to the suppression pool, drywell sprays or suppression chamber sprays.

As discussed above, only the use of drywell sprays is discussed in Section 14.6.3 of the SAR. And as discussed above, water that is discharged from the recirculation break has a similar effect in containment cooling as water that is discharged from the drywell sprays. Based on these SAR statements, it is reasonable to conclude that the position of FCV-74-52 and FCV-74-66 has *no affect on the operation of the safety train.* Therefore, based on the guidance in Supplement 1 of GL 89-10, FCV-74-52 and FCV-74-66 are not required to be included in the GL 89-10 Program.

As discussed in the response to Question 1 dated July 7, 2011, the EOIs consider additional equipment failures and accident scenarios that could require a MOV to have a function beyond those credited in the safety analysis.

Valve FCV-74-52 and valve FCV-74-66 are required to be closed should valves FCV-74-53 and FCV-74-67, respectively be open when initiating suppression pool cooling, drywell sprays or suppression chamber sprays (see Step 2 of EOI Appendix 17A, Step 6 of EOI Appendix 17B and Step 6 of EOI Appendix 17C, respectively). The initiation of suppression pool cooling and suppression chamber sprays is not discussed in Section 14.6.3 of the UFSAR as a manual action following a LOCA-DBA. The initiation of drywell sprays is described in Section 14.6.3 as a manually initiated action. However, Section 14.6.3 also states that initiation of drywell sprays would normally not be taken following a LOCA-DBA. In addition, there is discussion in Section 4.8.6.2 of the UFSAR that also indicates the initiation of suppression pool cooling, drywell sprays or suppression chamber sprays is dependent on adequate core cooling following a LOCA-DBA. That is, these alignments may not be used depending on the break size, location and equipment failures assumed.

The above described UFSAR statements indicate that not initiating drywell sprays will not significantly change the results of the containment analysis in Section 14.6.3 of the UFSAR. However, the case of no drywell spray is not explicitly evaluated in the UFSAR. General Electric Hitachi (GEH) performed the LOCA-DBA containment analysis for BFN. The need for drywell sprays to maintain containment pressure below its design limit was discussed with GEH on 11Jul2011. GEH stated that the peak containment pressure occurs early following a LOCA-DBA (<10 minutes), and concurred that the drywell spray function is not needed for a DBA-LOCA. GEH stated that the long-term containment analysis is performed assuming drywell sprays are in operation simply because that is most limiting regarding NPSH available for the ECCS pumps. This minimizes containment pressure and is conservative when determining the NPSH available to the ECCS pumps.

In Supplement 1 to GL 89-10 states (as described on page 3 of the enclosure to NRC letter to TVA, dated 7Oct1997): *...safety-related MOVs that are always in their safety position, or would have no affect on the operation of the safety train if placed in the nonsafety position, could be removed from the GL 89-10 program...*

When initiating suppression pool cooling, drywell sprays or suppression chamber sprays, clearly if FCV-74-53 and FCV-74-67 is closed, the position of FCV-74-52 and FCV-74-66, respectively, does not matter. If FCV-74-53 and FCV-74-67 is open and FCV-74-52 and FCV-74-66, respectively, is open then depending on the pressure in the reactor vessel, all RHR pump(s) flow or some portion of this flow will be directed through the desired flow path to the suppression pool, drywell sprays or suppression chamber sprays with the balance of the flow being discharged to the reactor vessel.

As discussed in Section 14.6.3 of the UFSAR, water that is discharged from the recirculation break has a similar effect on containment cooling as water that is discharged from the drywell sprays so the flow split between these two paths does not significantly change the results of the containment analysis. The exact statement in Section 14.6.3 of the UFSAR reads: "*...After the reactor vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow offers considerable cooling to the drywell and causes a depressurization of the containment as the steam in the drywell is condensed...*"

For suppression pool cooling, the relevant parameter is the total flow through the RHR Heat Exchangers and this water may return to the suppression pool via any path (e.g., a break in a pipe connected to the reactor vessel, the drywell sprays, the suppression chamber sprays) so the flow split(s) does not significantly change the results of the containment analysis.

Based on these evaluations, it is reasonable to conclude that the position of FCV-74-52 and FCV-74-66 has *no affect on the operation of the safety train.* Therefore, using the guidance in Supplement 1 of GL 89-10, FCV-74-52 and FCV-74-66 are not required to be included in the GL 89-10 Program.

1. Are the RHRSW outlet valves in the 89-10 program?

TVA Response:

Assuming these are the RHRSW Heat Exchanger Outlet Valves (1,2,3-FCV-23-34,40,46,52), they are in the MOV Program. These valves were put in to the GL 89-10 program because they meet the criteria of supplement 1 to GL 89-10. The failure of these valves was detected in 2008 when the valves were disassembled and not because of MOV testing in accordance with the GL 89-10 program.

2. The 2008 W.O. for the 1-FCV-74-66 valve specifies performance of a partial MOVATS in accordance with MOV 009. Section 2.3 of MOV 009 states if a partial MOVATS is required per a W.O. then use only Att. 5. Att. 5 is not in the W.O. and it appears the W.O. used selected parts of section 7.

TVA response:

The following responses are based on Work Oder 08-714852-000 (attached).

a. Was Att. 5 used per step 2.3?

No, Page 13 of the work order file (or page 9 of MOV009), indicated that the Step 2.3 was "N/A". The test performer used step 1.2 on the same page to meet his testing requirement.

b. If not why not?

Att. 5 was not used to perform the test because the testing instructions (Page 7 step 1.2 of the work order file) required the test data to include spring pack displacement which can only be obtained at the valve, as well as electrical data (normally from Partial MOVATS at the MCC; motor control center). The testing personnel used Attachment 7 (at the valve test) and collected all the needed data at one place rather than going to two places (at the valve and at the MCC).

c. What was basis for only performing parts of section 7?

The basis for only performing parts of Section 7 of MOV009 was mainly to meet the test instruction requirement as discussed in the response to "b" above.

3. Have the EOI Appendices been revised regarding utilization of valves 74-52 (66) since the scope of the GL 89-10 program was developed?

TVA Response:

The EOI Appendices have not changed with respect to utilization of valves 74-52 (66). The current revision of 2-EOI APPENDIX-17A directs the operator to verify closed 2-FCV-74-52(66) in step 2.f. and Revision 5 of 2-EOI-APPENDIX-17A which was issued 9/8/95 has the same action in the same step.