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

May 9, 2011

EA-11-018

Mr. Preston D. Swafford
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3R-C
Chattanooga, TN 37402-2801

SUBJECT: FINAL SIGNIFICANCE DETERMINATION OF A RED FINDING, NOTICE OF VIOLATION, AND ASSESSMENT FOLLOW-UP LETTER (NRC INSPECTION REPORT NO. 05000259/2011008) BROWNS FERRY NUCLEAR PLANT

Dear Mr. Swafford:

This letter provides the final significance determination of one preliminary Greater than Green finding discussed in Nuclear Regulatory Commission (NRC) Inspection Report 05000259/2010005, 05000260/2010005 and 05000296/2010005, dated February 9, 2011, (ML110400431). The inspection finding was assessed using the NRC's Significance Determination Process and was preliminarily characterized as Greater than Green, which represents a finding with at least low to moderate safety significance that may require additional NRC inspection. The finding was characterized as the failure to establish adequate design control and perform adequate maintenance on the Unit 1 low pressure coolant injection (LPCI) outboard injection valve, 1-FCV-74-66, resulting in the valve being left in a significantly degraded condition that led to the residual heat removal (RHR) Loop II being unable to fulfill its safety function. The NRC's Inspection Report also identified one apparent violation corresponding to this finding.

A Regulatory Conference was held on April 4, 2011, to discuss your views on these issues. During the meeting, your staff described the Tennessee Valley Authority's (TVA) assessment of the root causes, functional capability of the valve, significance of the finding, and detailed corrective actions. TVA's root cause analysis concluded that the failure of 1-FCV-74-66 was caused by an original manufacturer defect (undersized threads). The TVA root cause analysis also concluded that because it was not reasonable for TVA to have identified the defect prior to the valve failure, a performance deficiency did not exist. TVA also presented the results of its analysis of 1-FCV-74-66 functional capability in its failed condition, concluding that the valve would not have prevented the low pressure coolant injection (LPCI) system from fulfilling its

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safety function during an accident scenario. TVA concluded that the valve disc would have lifted and provided full flow when the system was required to perform its intended safety function. Finally, TVA presented its assessment of the risk associated with this finding and determined it to be Green. TVA stated that Inspection Manual Chapter (IMC) 0609, Appendix M, Significance Determination Process Using Qualitative Criteria, procedure was the appropriate risk methodology for determining the risk of this issue, because the Appendix F process did not provide adequate consideration of all means available to mitigate the failure. TVA did not contest the NRC's characterization of the issue as a violation of Technical Specification (TS) Limiting Condition for Operations (LCO) 3.5.1, Emergency Core Cooling System (ECCS) – Operating.

TVA presented corrective action plans related to the valve failure and actions that are planned to address long-term fire strategies at the Browns Ferry station. The 1-FCV-74-66 valve was repaired promptly and inspections were performed on all similar valves for Units 1, 2, and 3 to verify their functional capability. TVA informed the NRC of plans to reduce operator manual actions, implement fire strategy related procedural changes, install modifications as a result of its review of National Fire Protection Association 805, "Performance-based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," and continue to reduce fire risk at the station. A summary of the Regulatory Conference (Accession no. ML111010106) is available electronically for public inspection from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

The NRC has thoroughly considered all available information provided by TVA during and after the regulatory conference and has concluded that this finding should be characterized as Red, a finding of high safety significance that will require additional NRC inspection. Additional NRC review included risk sensitivity evaluations, design issues (e.g., thread size and fillet welds), in-service testing, and potential use of IMC 0609, Appendix M, to assess significance of this issue.

The NRC performed risk sensitivity evaluations that took into account potential operator actions to use alternate core cooling injection sources following the 1-FCV-74-66 failure to pass system flow. These potential operator actions are not specified in TVA procedures. However, the NRC recognizes that alternate sources of core cooling flow paths may be available to support fire safe shutdown strategies. The results of these evaluations continue to confirm that the finding is appropriately characterized as Red. Because of TVA's fire mitigation strategy, the LPCI valve failure results in a significant increase in the core damage frequency to the facility due to the limited availability of alternative sources of reactor coolant inventory makeup. Details of the NRC's final determination are discussed in Enclosure 2.

With respect to further review of design issues, the NRC acknowledges that the design aspects that were considered as part of the performance deficiency as discussed on April 4th, may not have been a primary contributor to the valve failure. Information was provided demonstrating that it was unlikely that the valve failure was caused by unthreading of the valve internals due to undersized welds. Additional information is provided in Enclosure 2.

The NRC also conducted additional reviews regarding the adequacy of the in-service testing (IST) program in order to determine the adequacy of the testing and to determine whether testing provided TVA with an opportunity to preclude and/or identity the LPCI valve failure sooner. In this regard, the post-conference supplemental information provided by TVA highlighted that certain aspects of its IST program were inadequate. Namely, the NRC determined that TVA's failure to implement an IST program in accordance with the American Society of Mechanical Engineers (ASME), Code for Operation and Maintenance of Nuclear Power Plants (OM Code), 1995 Edition, 1996 Addenda, Section ISTC 4.1, precluded the timely identification that the RHR loop II subsystem was unable to fulfill its safety function due to a failure of LPCI Outboard Injection Valve 1-FCV-74-66. The NRC has concluded that TVA's IST program inadequacy was well within its purview, and represents a performance deficiency. Details of the NRC's final determination regarding the performance deficiency are discussed in Enclosure 2.

On April 29, 2011, NRC staff discussed the IST program issue with TVA staff. The discussion included an exchange of information regarding the implementation of the OM Code requirements at Browns Ferry, and questions regarding the ability of TVA's IST program to verify operability and functionality of valves susceptible to stem and disc separations. TVA informed the NRC staff that it was in the process of disassembling the corresponding valves for the other RHR loops of all three units to conduct inspections and make necessary repairs or modifications. This action was considered appropriate while TVA determines what actions to take in response to the non-compliance of its IST program.

With respect to use of the IMC 0609, Appendix M, Significance Determination Process Using Qualitative Criteria (Accession No. ML111010166), the NRC has considered TVA's views and notes, however, that the guidance in IMC 0609, Appendix M, should only be applied when significant determination process methods and tools are not available or are not adequate to determine the significance of the finding. The NRC determined that the use of the existing significance determination process was the proper approach in determining the significance of this finding. Appendix M is utilized primarily when traditional probabilistic risk assessment (PRA) methods and tools are not adequate to provide reasonable estimates of the significance of the finding in a reasonable time frame. The PRA tools utilized to evaluate the significance of this finding provided reasonable estimates of the significance of the finding in a timely manner. Details of the NRC's final determination are discussed in Enclosure 2 and 3.

You have 30 calendar days from the date of this letter to appeal the staff's determination of significance for the identified Red finding. Such appeals will be considered to have merit only if they meet the criteria given in the IMC 0609, Attachment 2. An appeal must be sent in writing to the Regional Administrator, Region II, 245 Peachtree Center Avenue, NE, Suite 1200, Atlanta, GA 30303-1257.

The NRC also determined that a violation of Unit 1 Technical Specifications (TS) Limiting Condition for Operation (LCO) 3.5.1, Emergency Core Cooling System (ECCS) occurred, as cited in the enclosed Notice of Violation (Notice) (Enclosure 1). In accordance with the NRC's Enforcement Policy, the Notice is considered an escalated enforcement action because it is associated with a Red finding.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

For administrative purposes, this letter is issued as a separate NRC Inspection Report, No. 05000259/2011008. Apparent Violation 05000259/2010005-01 is now Violation 05000259/2011008-01, "RHR Subsystem Inoperable Beyond the TS Allowed Outage Time."

Because plant performance for this issue has been determined to be beyond the licensee response band, we have used the NRC's Action Matrix to determine the most appropriate NRC response for this event. As a result of our assessment review, we have assessed Browns Ferry Nuclear Station's performance for Unit 1 to be in the Multiple/Repetitive Degraded Cornerstone Column of the NRC's Action Matrix beginning in the fourth quarter of calendar year 2010.

We will conduct a supplemental inspection (Inspection Procedure 95003) when you have notified us of your readiness for the NRC to review TVA's actions in response to the Red inspection finding. This inspection will provide the NRC with supplemental information regarding your performance, and insights into the breadth and depth of safety, organizational, and programmatic issues. This inspection is more diagnostic than indicative, and includes reviews of programs and processes not inspected as part of the baseline inspection program. Additional NRC assurance is required to ensure public health and safety beyond that provided by the baseline inspection program and the performance indicators at your facility. The results of this inspection will aid the NRC in deciding whether additional regulatory actions are necessary to assure public health and safety. The inspection will also include an assessment of the safety culture at the Browns Ferry Nuclear Plant. This aspect of the inspection will center on the validation of TVA's third party safety culture assessment and root cause evaluation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, Enclosure 1 and 2, and your response (if you choose to provide one), will be made available electronically for public inspection in the NRC Public Document Room or from ADAMS, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. However, because of the security-related information contained in Enclosure 3, and in accordance with 10 CFR 2.390, a copy of Enclosure 3 will not be available for public inspection. To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

Victor M. McCree
Regional Administrator

Docket No.: 50-259
License No.: DPR-33

Enclosures:
1. Notice of Violation
2. NRC Basis for Final Significance Determination
3. NRC Addendum to Phase 3 Risk Evaluation (**OFFICIAL USE ONLY – SECURITY-RELATED INFORMATION**)

cc w/encl: (See page 5)

cc w/Encls 1 & 2:
K. J. Polson
Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

C.J. Gannon
General Manager
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NOTICE OF VIOLATION

Tennessee Valley Authority	Docket No. 50-259
Browns Ferry Nuclear Plant	License No. DPR-33
Unit 1	EA-11-018

During an NRC inspection completed on December 31, 2010, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> Browns Ferry Nuclear Plant Unit 1 Technical Specification (TS) LCO 3.5.1, Emergency Core Cooling System (ECCS) - Operating, requires, in part, that each ECCS injection/spray subsystem shall be operable in Modes 1, 2 and 3. Action statement Condition A states that with one low pressure ECCS injection/spray subsystem inoperable, restore the low pressure ECCS injection/spray subsystem to operable status with seven days. Action statement Condition B states that with the required action and associated completion time of Condition A not met, be in Mode 3 within 12 hours and in Mode 4 within 36 hours.
>
> Contrary to the above, from March 13, 2009, to October 23, 2010, a Unit 1 low pressure ECCS injection/spray subsystem was inoperable while in Modes 1, 2 and 3, and the licensee failed to restore the subsystem to operable status within seven days, or complete Action statement Condition A and B within the required time. Specifically, the Unit 1 Residual Heat Removal Loop II subsystem was inoperable, because the licensee failed to maintain the Unit 1 outboard Low Pressure Coolant Injection (LPCI) valve 1-FCV-74-66 in an operable condition, which rendered a low pressure ECCS injection/spray subsystem (the RHR loop II subsystem) inoperable while Unit 1 was operating in Mode 1.

This violation is associated with a Red significance determination process finding for Unit 1 in the Mitigating Systems cornerstone.

Pursuant to the provisions of 10 CFR 2.201, Tennessee Valley Authority is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-11-018" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this 9th day of May 2011

NRC'S BASIS FOR FINAL SIGNIFICANCE DETERMINATION

The NRC's inspection report of February 9, 2011, documented the preliminary significance determination of a preliminary Greater than Green finding involving the Browns Ferry Nuclear Plant. The finding was also determined to be an apparent violation and was assessed under the applicable significance determination process (SDP).

A regulatory conference was held with the Tennessee Valley Authority (TVA) on April 4, 2011. During the conference, TVA acknowledged that a violation of NRC requirements occurred. Also, during the meeting, TVA management provided the results of their assessment regarding the significance of the finding, root cause, functional capability, and detailed corrective actions. More specifically, TVA presented the following positions: 1) No performance deficiency existed because their root cause analysis (RCA) determined the failure of 1-FCV-74-66 was caused by an original manufacturer defect which TVA could not have reasonably identified prior to the valve failure; 2) The degraded condition of 1-FCV-74-66 would not have prevented Residual Heat Removal (RHR) Loop II from fulfilling its safety function during an Appendix R fire scenario; and, 3) The significance of this finding was determined (by TVA) to be of very low safety significance (Green). Furthermore, TVA committed to submit additional technical information and answers to previously transmitted NRC questions for review. The results of NRC's review of the additional information and final significance determination are summarized below.

1. Performance Deficiency

TVA Position

During the Regulatory Conference, TVA stated that their final root cause analysis (RCA) report had concluded there was only one root cause and no contributing causes to the 1-FCV-74-66 failure event. The root cause was determined to be undersized threads on the upper disc skirt. The other nonconforming conditions (e.g., undersized welds, missing disc-locking key) identified during the subsequent valve disassembly and inspections were not significant contributors to the ultimate failure of FCV-74-66. In addition to the undersized threads, TVA explained that the failure of the valve internals had to be brought about by an overload condition on the disc to skirt joint. TVA further described that this condition could have only been caused by periodic surveillance testing of the inboard RHR Loop II injection valve (1-FCV-74-67) which resulted in reactor coolant back pressure on top of the 1-FCV-74-66 disc. The combination of undersized threads and excessive reactor coolant backpressure directly caused the failure of FCV-74-66. Furthermore, TVA explained that the undersized threads were an original manufacturing defect in which no reasonable basis existed for TVA to have examined the threads and identify the undersized thread condition. Therefore, TVA concluded that there was no licensee performance deficiency associated with the FCV-74-66 failure event.

NRC Response

The NRC reviewed all available information provided by TVA regarding the failure of 1-FCV-74-66 which included the RCA report, test data, failure analysis reports and other failure evaluation reports. This included information presented during the regulatory conference of April 4, 2011, and all subsequent information submittals prior to issuance of this report. However, the evidence and analysis provided by TVA regarding the lack of a performance deficiency was not sufficient to substantiate their positions. Consequently, the NRC does not agree with TVA's conclusion that there was not a performance deficiency associated with the failure of FCV-74-66.

As described in inspection report (IR) 050-259/2010-005, a number of nonconforming conditions were identified by TVA once FCV-74-66 was disassembled and examined after its failure on October 23, 2010. These nonconforming conditions were as follows:

- The disc was found separated from the stem and upper disc skirt, which would normally be threaded onto the disc skirt and tack welded.

- The two 8 inch fillet welds between the disc skirt and the disc were fractured (welds completely broken apart). Also, the welds were undersized (i.e., a nominal 0.20 inch fillet weld versus the required 0.50 inch fillet) with general porosity, lack of fusion and cracking.

- No upper disc-skirt locking key was present.

- The threads on the upper disc skirt were found to be undersized, resulting in partial engagement of thread faces between the disc skirt and disc.

- The thrust washer between the stem and disc was missing.

Based on available evidence, TVA has concluded that the valve manufacturer provided a defective part (i.e., upper skirt with undersized threads) that was used in the original globe valve assembly for all Units 1, 2, and 3 RHR outboard injection valves. As such, TVA reported this defect in accordance with 10 CFR 21.2(c) as part of their Licensee Evaluation Report (LER) 50-259/2010-003-01 dated April 1, 2011.

TVA's root cause investigation determined that 1-FCV-74-66 failed prior to October 2008. The NRC has concluded that the time frame of the actual failure cannot be determined with any certainty, but the potential exists for the failure to have occurred as determined by TVA. The stem to disc separation could have occurred any time after the valve was reassembled and put in service going back to June 2006.

Based on review of the initial information provided by TVA, the failure of the disc to skirt tack welds pointed to unthreading of the disc from the skirt as a plausible contributor to the failure of the disc to skirt joint. But in response to the questions posed by inspectors, TVA provided additional information concerning the failure of the weld joints. Following additional review, the NRC has determined that the weld configuration on 1-FCV-74-66 reasonably achieved its design function to prevent unthreading of the disc to skirt joint. Therefore it is less likely that unthreading occurred and the design aspects that were considered as part of the performance deficiency as discussed on April 4th, may not have been a primary contributor to the valve failure.

The NRC reviewed TVA's information provided on 1-FCV-74-66 on valve performance and the in-service testing (IST) program. The NRC identified that the required in-service testing (IST) program provided TVA with an opportunity to preclude and/or identity the LPCI valve failure sooner. In this regard, the post-conference supplemental information provided by TVA highlighted that certain aspects of its IST program were deficient. Namely, TVA's failure to implement an IST program in accordance with the requirements of ASME 1995 Edition, 1996 Addenda, Section ISTC 4.1, precluded the timely identification that the RHR loop II subsystem was unable to fulfill its safety function due to a failure of LPCI Outboard Injection Valve 1-FCV-74-66.

The in-service testing (IST) program implemented by TVA at Browns Ferry to meet the requirements of 10 CFR 50.55a, [incorporates by reference, with conditions, the American Society of Mechanical Engineers (ASME), Code for Operation and Maintenance of Nuclear Power Plants (OM Code), 1995 Edition, 1996 Addenda], was inadequate to identify the inability of LPCI Valve 1- FCV-74-66 to perform its intended safety function. 10 CFR 50.55a(b)(3)(ii) requires licensees to comply with the provisions for testing motor-operated valves in OM Code In-service Test Section C (ISTC) 4.2, 1995 Edition with the 1996 and 1997 Addenda and establish a program to ensure that motor-operated valves continue to be capable of performing their design basis safety functions. Despite the operating experience with LPCI Valve 1-FCV-74-66 and other similar valves at Browns Ferry Units 1, 2, and 3, the TVA program at Browns Ferry implemented in response to 10 CFR 50.55a(b)(3)(ii) did not ensure that LPCI Valve 1-FCV-74-66 continued to be capable of performing its design-basis safety function.

Section 4.1 of the OM Code, 1995 Edition with the 1996 and 1997 Addenda requires verification that valve operation is accurately indicated. 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."*

In NUREG 1482 (April 1995), Guidelines for Inservice Testing at Nuclear Power Plants, the NRC staff discussed its interpretation of the ASME OM Code requirement for verification of remote position indication. In Section 4.2.7, "Verification of Remote Position Indication for Valves by Methods Other Than Direct Observation," the staff noted that the Code requires that valves with remote position indicators be observed at least once every 2 years to verify that valve position is accurately indicated. The staff stated that if remote valve position cannot be verified by local observation at the valve, an acceptable approach is for the licensee to observe operational parameters such as leakage, pressure, and flow that give positive indication of the valve's actual position(s). The staff indicated its interpretation of the Code requirement by stating that for certain types of valves that can be observed locally, but for which valve stem travel does not assure the stem is attached to the disk, the local observation must be supplemented by observing an operating parameter as required in the Code. In the basis discussion, the staff stated that accurate position indication for safety-related valves is important for reactor operation during all plant conditions. Therefore, the staff noted that the Code requires verification of the accuracy of the remote position indication for all valves in the IST program with remote position indication. The staff indicated that several options are available to verify the indication that a valve obturator is attached and moving. For example, the staff referenced leak-rate testing, in-line flow rate instrumentation, and system and differential pressures for position indication of valve position.

In Revision 1 to NUREG-1482, the NRC staff in Section 4.2.7 discussed its interpretation of the ASME OM Code for position indication verification. The staff continued to specify that the first sentence in ISTC 4.1 provides the requirement for verification of the accuracy of the remote position indication for all valves in the IST program with remote position indication. The staff noted that when a licensee cannot verify remote valve position by local observation, an acceptable approach is to observe operational parameters (such as leakage, pressure, and flow) that give a positive indication of the valve's actual position(s). The staff modified the discussion regarding supplementing local observations (i.e., "must" to "should") to reflect that the NUREG provided guidance for licensee IST programs.

The requirement of ISTC 4.1 is implemented by TVA testing surveillance procedure, 1-SR-3.3.3.1.4(H II). The acceptance criteria requires that valve position be "visually checked" in the correct position. This method of verification does not ensure that the disc is attached to the disc and therefore is unable to adequately verify valve internal operations, as described in the ASME code as obturator position. In addition, TVA had knowledge that this valve design is susceptible to stem and disc separation based on its design configuration.

Additionally, 1-SR 3.6.1.3.5, TVA's procedure to comply with ASME ISTC 4.2.3, was performed quarterly during the window of possible valve failure. This procedure did not identify the separated stem and disc assembly. ISTC 4.2.3 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. "*

TVA testing acceptance criteria for implementing procedure, 1-SR 3.6.1.3.5, intended to meet the ASME code requirements via verification of the open/shut indicating lights during valve stroke and time testing. This surveillance was also unable to adequately verify obturator movement, and did not identify the stem and disc separation.

Subsequent to the refurbishment and reassembly of 1-FCV-74-66 in 2006, two surveillance tests were performed, 1-SR-3.3.3.1.4(HII) and 1-SR-3.6.1.3.5. The staff concluded that the opportunity existed for the testing program to discover the failure had the testing program met the code requirements to verify that valve operation is accurately indicated.

The staff also considered other actions that the licensee may have taken to verify parameters for ASME code requirements:

- The staff questioned the licensee specifically on other actions beyond using the indication lights to verify obturator movement. The licensee responded that they use lights and local position indication (stem movement), because that meets the code requirements and is consistent with industry practices. The staff has concluded that this was an improper interpretation and implementation of the code requirements.

- The staff additionally verified, with the licensee, that flow testing or flow parameter verification is not used to verify stem to disc separation. The staff did not find that the other licensee's procedures and actions provided a means to identify stem to disc separation. Specifically the staff considered flow testing on the 1-FCV-74-68 in the RHR loop II system. This procedure was not designed in any way for verification of 1-FCV-74-66 proper obturator movement and therefore was not able to meet ASME code requirements and continued ability of 1-FCV-74-66 to fulfill its safety function.

Furthermore, TVA had operating experience that indicated this valve design is susceptible to separation failures. Previous issues experienced on multiple valves (including 1-FCV-74-66) at Browns Ferry established that this valve was susceptible to stem and disc separation. One similar instance resulted in a valve disc separating from the stem and becoming stuck in its seat. The previous failure was identified following a failure of the system to operate when being placed in service. Other valves at the Browns Ferry site also have experienced stem and disc separation issues (see NRC Special Inspection Report 05000259, 260, and 296/2008007, Section 4OA2.f).

Based on our review, the NRC has determined that certain aspects of TVA's IST program were inadequate. Namely, the NRC determined that TVA's failure to implement an IST program in accordance with the American Society of Mechanical Engineers (ASME), Code for Operation and Maintenance of Nuclear Power Plants (OM Code), 1995 Edition, 1996 Addenda, Section ISTC 4.1, precluded the timely identification that the RHR loop II subsystem was unable to fulfill its safety function due to a failure of LPCI Outboard Injection Valve 1-FCV-74-66. The NRC has concluded that TVA's IST program inadequacy was well within its purview, and represents a performance deficiency

2. **Valve Functionality**

TVA Position

During the Regulatory Conference, TVA presented the results of a functionality assessment of 1-FCV-74-66. TVA hypothesized that pressure pulsations during operation of the 1B RHR pump while 1-FCV-74-66 was in its failed condition would induce vibration of the valve of a sufficient magnitude to cause the coefficient of friction (COF) between the valve disc and seat surfaces to decrease and allow the valve disc to free itself from its stuck condition. TVA concluded that, notwithstanding the degraded condition of the valve, that they had high confidence the valve disc would release from its stuck condition in time to mitigate the consequences of a postulated accident scenario. TVA further supported their position with the reasoning that the valve had previously acted as a lift check valve when the system was placed in service in 2009. This was based on TVA's conclusion that the valve was previously separated from the stem in 2008 as indicated by valve test data that went unrecognized during testing.

NRC Response

The NRC has reviewed the information provided by TVA, and disagrees with TVA's conclusion that the LPCI valve would have functioned with a high degree of confidence. The NRC has determined that TVA's conclusion was based on the following: 1) a limited amount of empirical evidence supporting the hypothesis of the time required to free the stuck valve disc; 2) test results with a high number of uncertainties in the testing methodology; and 3) certain unvalidated assumptions and calculations.

The NRC identified there was a very limited amount of empirical evidence presented in the testing to support their hypothesis of the time required to free the stuck valve disc. TVA's determination of the maximum time required for the valve to become dislodged was based on the results of a single test having test parameters significantly different than the test's calculated system conditions. Additionally, TVA's determination of the minimum time required for the valve to become dislodged, which was used to validate that the testing conditions were representative of the actual conditions that existed in the plant at the time of the discovery, was also based on the results of a single test having test parameters significantly different than the calculated system conditions.

During review of the testing results presented by TVA, the NRC identified a high number of uncertainties in the testing methodology which challenged the level of confidence that the testing was representative of actual system conditions. The NRC identified that several actual plant conditions that could affect test results were not factored into the testing model. Examples of these issues included, but were not limited to: 1) the test assembly components were not all constructed to the same scale; 2) the testing applied vibrations to the test disc by direct metal to metal contact while the system transmits pressure through water; and 3) lack of accounting for system construction, mounting, and mass in the test set-up. Additionally, the level of confidence in the validity of the test vibrations intended to simulate system operating pressure pulsations was questionable due to an unvalidated method of translation of the recorded system pressure data into simulated effects on the model valve disc. Further uncertainty was added due to the method in which the simulated pressure pulsations were applied to the test model, because the testing used air hammers to apply direct mechanical agitation to the test model without validation that the effects were comparable to the pressure pulsations actually caused in a fluid system from pump impeller displacement.

The NRC also identified the use of unaccounted for variables, and unvalidated assumptions and calculations, in the testing process. These added additional uncertainty to the validity of the test results and the conclusions made from those results. Examples and/or associated issues included, but were not limited to: 1) timing results from the scaled test model were considered to directly represent the expected times for the actual valve; 2) the calculated maximum force achieved from multiple applications of a consistent force was not verified consistent with the theorized application; 3) other effects such as thermal binding of the valve disc were not considered; and, 4) the behavior differences between the mechanical surface defects used to replicate corrosion effects on surface COF and actual surface corrosion were unaddressed.

Based on the evidence provided, the NRC determined that there is insufficient evidence to determine whether or not the valve previously functioned as a check valve with reasonable certainty. The theory that the valve disc was separated from the stem prior to system operations in March 2009 was not found to be supported by any conclusive evidence. The information obtained from valve testing data in 2008, referenced as verification of the valve disc separation was found to be ambiguous based on the fact that another system valve, that is known to not be separated, showed similar test results. Additionally, there have been two instances (1974 and 2010 events) that a valve disc has separated from the stem and stuck in its seat and for both occurrences the disc was found to not have dislodged from a stuck condition during system operation.

Based on the preponderance of the evidence, the NRC was not able to substantiate that the valve disc would release from its stuck condition in time to mitigate the consequences of a postulated accident scenario.

3. Significance of Finding

TVA Position

During the Regulatory Conference TVA stated that IMC 0609 Appendix M, Significance Determination Process Using Qualitative Criteria, was appropriate for determining the risk associated with this finding. TVA concluded the risk associated with this finding as very low safety significance (GREEN). TVA stated that the Probabilitistic Risk Assessment (PRA) results did not account for alternate means of injection cooling.

NRC Response

The IMC 0609, Appendix M procedure specifies that it should be used when SDP methods and tools are not available or are not adequate to determine the significance of the finding within the established SDP timeliness goal of 90 days. The NRC concluded that the use of Appendix M in this case was not appropriate, since reasonable SDP results were attained within a timely manner.

The NRC recognized throughout the risk assessment evaluation process that operators would likely take additional actions to provide a core cooling source after the failure of 1-FCV-74-66 that was not evaluated in the NRC phase III risk analysis. These actions were not initially considered because in accordance with SDP guidance, risk credit is only granted if certain criteria are met (e.g., actions are proceduralized, trained on, necessary equipment is available) which these actions did not meet. To achieve a broader, more informed insight to the risk significance of this finding, the NRC conducted risk sensitivity evaluations on the actions operators may take to use alternate means of core cooling using alternative safety-related equipment during the pertinent accident scenarios. The sensitivity evaluations gave credit for operator actions with RHR loop II injection unavailable to cool the core using other emergency core cooling systems, without any available procedures, to accomplish these actions. The results of the sensitivity studies found that the overall risk was reduced by a factor of approximately 8 times, however this reduction did not cause the significance of the issue to change the risk characterization.

Additionally, control building fire scenario risk had not been evaluated in the phase III risk analysis. Control building fire scenarios that employed the use of the RHR Loop II system in the Safe Shutdown Instruction procedure were evaluated as part of this sensitivity evaluation. The NRC determined that the risk of these fire scenarios contributed an additional 5E-5 to the overall risk impact of the valve failure.

Based on our review, when the aforementioned factors are considered (either collectively or individually) the lower bound of risk for the LPCI Valve 74-66 performance deficiency remained > 1E-4.