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

August 22, 2013

Mr. Preston D. Swafford
Executive Vice President and Chief Nuclear Officer
Tennessee Valley Authority
1101 Market Street, LP 3R
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC SUPPLEMENTAL 95003 INSPECTION REPORT 05000259/2013011, 05000260/2013011, AND 05000296/2013011

Dear Mr. Swafford:

On May 24, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed the onsite portion of an inspection at the Browns Ferry Nuclear Plant (BFN), Units 1, 2, and 3. The inspection was conducted in accordance with the guidance contained in NRC Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program" and Inspection Procedure (IP) 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input," and was performed in response to the facility's designation as having a Repetitive Degraded Cornerstone, as defined by the NRC's Reactor Oversight Process (ROP). The enclosed report documents the inspection Findings, which were discussed on July 11, 2013, with you and other members of your staff.

In our Annual Assessment Letter dated May 9, 2011, we informed you that BFN Unit 1 was placed in the Multiple/Repetitive Degraded Cornerstone Column (Column IV) of the NRC's Action Matrix. In accordance with IMC 0305, this decision was made on the basis of a RED Finding in the Mitigating Systems cornerstone. The Finding, open since the fourth quarter 2010, 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 valve degradation that precluded the residual heat removal (RHR) Loop II from being able to fulfill its safety function. The overall risk worth of this valve was significantly increased by the fire strategy in place at the time the valve failed.

To guide its performance improvement activities in response to the Red Finding, TVA developed an Integrated Improvement Plan (IIP), which it submitted to the NRC on August 23, 2012 (ML12240A106). The 95003 supplemental inspection procedure was conducted at Browns Ferry to gain insights into the breadth and depth of safety, organizational, and programmatic issues which Tennessee Valley Authority (TVA) addressed in its IIP. This inspection included a diagnostic review of programs and processes that are not typically inspected as part of the baseline inspection program. The inspection included an independent assessment of the safety culture at the Browns Ferry Nuclear Plant, including the results of TVA's third party safety culture assessment and root cause evaluation. Additionally, this inspection assessed the completed and planned actions related to the LPCI valve failure and the long-term fire strategies at the Browns Ferry station.

The results of our inspection indicate that Browns Ferry is being operated safely. The team found that Browns Ferry has made some gains toward improved performance as a result of implementation of the IIP. In addition, based on our review of the third party safety culture assessment and the NRC's independent graded safety culture evaluation, the team determined that Browns Ferry has an improved understanding of the importance of a strong safety culture. However, the team identified several performance deficiencies that were additional examples of the organizational and programmatic issues that Browns Ferry's IIP and the NRC had previously identified. In the past, BFN had been challenged with implementing changes that resulted in sustained improvement in safety system reliability, human performance, problem identification and resolution, the quality of engineering work products, and oversight of station activities. As TVA measures itself by industry standards, the station will need to continue implementation of the IIP to achieve substantial and sustained performance improvement. The team concluded that effective implementation of the IIP, supported by the allocation of adequate resources and continued enhanced oversight by TVA leadership, should lead to substantial and sustained performance improvement.

The team identified several issues that warranted revision to the IIP. The four issues that the team found were: 1) procedure quality issues were not effectively addressed; 2) the organization's ability to drive behaviors to get desired outcomes through an effective operationally focused organization lacked a clear strategy; 3) a significant lack of organizational focus to implement a human performance barrier control process involving continuous and independent verification to prevent human errors; and 4) station personnel did not consistently recognize and/or draw upon clear standards of excellence when performing common duties and responsibilities, indicating that the improving safety culture at the station may plateau without interim actions to achieve substantial and sustained performance improvement. Although the implementation of actions to address the four issues could not be verified during the inspection, the team reviewed the scope of TVA's action plans and determined that it was adequate to address the issues.

The team determined that reliability and performance of safety equipment has shown improvement. Corrective actions for equipment reliability included in the IIP enabled TVA to focus engineering resources on equipment reliability programs. The team found that the Long Term Asset Management (LTAM) program included a process to rank and prioritize equipment maintenance and modifications. The team concluded that effective implementation of the LTAM process should contribute to improvements in equipment reliability over time. The team also concluded that the work management processes for work scheduling, work planning, work execution, procedure use and adherence, and procedural quality areas still present challenges to improving overall station equipment performance. However, long-term implementation of the LTAM program, along with tactical engineering programs such as the Safe System Recovery

Plan and focused attention to improvement of the work management processes should achieve equipment performance improvement.

On August 9, 2013, TVA submitted a letter to the NRC, Commitments Related to the Browns Ferry IIP (ML 13224A263), committing to a specific set of actions to be completed in the near term. TVA stated that these actions, referred to as Tier 1 actions, would be completed by the dates specified in the Enclosure to the letter. The TVA commitment letter also stated that an additional set of actions, referred to as Tier 2 actions, would be completed to ensure sustained excellent performance and fulfill the long-term success criteria described in TVA's IIP. The NRC reviewed the TVA committed Tier 1 and Tier 2 plans and issued a Confirmatory Action Letter (ML13232A105) on August 22, 2013. This letter confirmed TVA's actions, which when effectively implemented and validated by the NRC, will support NRC's performance assessment of Browns Ferry Unit 1. This assessment will serve as the basis for the NRC to evaluate transition of Browns Ferry Unit 1 out of Column 4 of the Agency Action Matrix, in accordance with Reactor Oversight Process Inspection Manual Chapter 0305, Section 10.02.d.5.

The 95003 inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The team reviewed selected procedures and records, observed activities, and interviewed personnel. A listing of the documents requested by the team for review during the inspection is available electronically in the NRC's document system (ADAMS) as ML13052A371 and ML13088A221.

The 95003 inspection report documents numerous performance deficiencies that resulted in 16 NRC identified Findings. The Findings represent performance deficiencies in three Reactor Oversight Process cornerstones and involved six of the 13 NRC safety culture components. Each Finding was evaluated using the significance determination process and were determined to have very low safety significance (Green). One Finding, involving the failure to perform an evaluation using the 10 CFR 50.59 process, that could have impacted regulatory decisions, was assessed in accordance with the NRC Enforcement Policy.

The NRC is treating the violation as a non-cited violation (NCV) consistent with Section 2.3.2 of the Enforcement Policy. If you contest the NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to: 1) the Regional Administrator, Region II; 2) the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and 3) the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

Some of the Findings in this report include a cross-cutting aspect. If you disagree with a cross-cutting aspect assignment in the report, you should provide a response within 30 days of the date of this report, with the basis for your disagreement, to the Regional Administrator, Region II, and to the NRC Resident Inspector at the Browns Ferry Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any), will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Victor M. McCree
Regional Administrator

Docket Nos.: 50-259, 50-260, 50-296
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: Inspection Report 05000259/2013011,
05000260/2013011 and 05000296/2013011
Attachment 1: Supplemental Information
Attachment 2: Inspection Procedure 95003
Information Request, February 21, 2013
Attachment 3: Inspection Procedure 95003
Second Request for Information, March 29, 2013

cc: Distribution via Listserv

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

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NAME	CEven	JHeinly	CMoore	JEargle	DKern	AShaikh	DWright
DATE	08/13/2013	08/15/2013	08/15/2013	08/14/2013	08/13/2013	08/13/2013	
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
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DATE	08/15/2013	08/13/2013	08/12/2013	08/21/2013	08/15/2013	08/19/2013	08/15/2013
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Letter to Preston Swafford from Victor M. McCree dated August 22, 2013

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC SUPPLEMENTAL 95003 INSPECTION REPORT 05000259/2013011, 05000260/2013011, AND 05000296/2013011

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2013011, 05000260/2013011, 05000296/2013011
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	February 9, 2013, through June 18, 2013
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L. Harmon, Team Administrative Assistant, Region II

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D. Sieracki, Senior Safety Culture Program Manager, OE

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EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant Unit 1 entered the Multiple/Repetitive Degraded Cornerstone column of NRC's Action Matrix in the fourth quarter of 2010. The issue, which degraded the Mitigating Systems Cornerstone, was a finding of high safety significance (RED), for one of the Residual Heat Removal (RHR) Subsystems being inoperable for greater than the Technical Specification allowed outage time. Even though this was a failure of only one subsystem, the NRC recognized that because of the fire mitigation strategy implemented at BFN, there were certain fire scenarios that relied on the use of only one available train of RHR as the sole capable core cooling injection source.

The root cause analysis (RCA) for the RED finding identified the root causes to be:
1) mechanical failure due to undersized stem thread barrel; 2) deficient work instructions to verify stem thread dimensions during stem and disc reassembly in 1983; and 3) misapplication of active/passive function classification criteria which resulted in removing 1-FCV-74-66 from the NRC GL 89-10 valve test program. Six additional contributing causes were identified including:
1) inadequate knowledge and program bases for the In-service Testing (IST) program;
2) inadequate assessment and implementation of engineering programs for an extended period;
3) inadequate use of Corrective Action Program (CAP) including extent-of condition review, operating experience review, and untimely corrective actions; 4) inadequate TVA fleet governance and oversight of IST and MOV programs; 5) inadequate emphasis on regulatory compliance, and 6) non-conservative decision making by the Plant Operations Review Committee and senior station management. The team's independent assessment of the RCA and supporting documents determined that TVA had appropriately identified the apparent causes that led to the site challenges and the RCA was thorough and comprehensive.

Following the RED finding, fire strategies at the facility were modified, fire areas were redefined, and additional barriers were created to reduce fire risk. The team determined that interim measures implemented to address fire protection of safe shutdown equipment prior to their transition to National Fire Protection Association (NFPA) 805, "Performance – Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," that were reviewed by the team, were reasonable to assure safety.

The intent of this inspection was to allow the NRC to obtain a comprehensive understanding of the depth and breadth of safety, organizational, and performance issues at Browns Ferry Nuclear Station, and, where indicated, the potential for performance degradation. Furthermore, the NRC used this information to determine whether the continued operation of the facility was acceptable and whether additional regulatory actions were necessary.

This inspection was completed in accordance with NRC Inspection Procedure 95003, “Supplemental Inspection for Repetitive Degraded cornerstones, Multiple Degraded Cornerstones, Multiple YELLOW Inputs, or One RED Input.” This inspection was the third part of three inspections, implemented in a segmented approach for completion of the NRC 95003 inspection procedure.

The licensee performed a diagnostic review of the issues identified during the RCA of the RED Finding that BFN deemed needing additional review. As a result, BFN found a total of 21 fundamental problems areas (which include the actual finding and the related area of fire protection) warranting attention by TVA in the BFN recovery plan. The team reviewed the recovery plan, which was the performance improvement initiative titled the Integrated Improvement Plan (IIP), including a review of the causal analysis, action plans, effectiveness review plans, and associated performance metrics. In addition, the team completed an independent graded safety culture assessment. The team determined that the framework and controlling procedures for recovery, as well as, the process for monitoring ongoing conditions and events for potential revisions to the IIP were comprehensive and sound. The team concluded that TVA needed to reinforce the continued oversight and involvement in effectively implementing the IIP to ensure substantial and sustained performance improvement.

The overall result and conclusion of the inspection was that the plant was being operated safely and that Tennessee Valley Authority (TVA) had made some progress in improving Browns Ferry station performance. However, the inspection results show that TVA needs to aggressively continue the implementation IIP, to achieve substantial performance improvement. The team identified multiple areas that warranted revision to the IIP to ensure that performance improvement would be achieved. The areas were associated with Safety Culture, Procedure Quality, Human Performance Verification Program, and an Operations Led Organization.

The team performed a Safety Culture Assessment which included an evaluation of a third party safety culture report, an independent NRC graded safety culture evaluation, and areas of safety conscious work environment and the employee concerns program. Regarding safety culture, most of the departments demonstrated improvement in the 2013 safety culture survey results as compared to the results in the 2011 assessment. Based on the improvement in the results of the 2013 Independent Nuclear Safety Culture Assessment (INSCA) and verification by the Team’s independent graded safety culture assessment, many of the corrective actions taken to address the safety culture issues from the 2011 INSCA were generally effective. The team independently identified concerns that were consistent with the ongoing issues identified by the INSCA 2013 assessment; in particular, the following concerns were identified in the 2013 INSCA, staffing and resources, written quality of Problem Evaluation Reports in the corrective action program, deficiencies in procedures, and concerns about management getting staff input before making changes at the station.

The team's independent graded safety culture assessment confirmed that the results obtained from the 2011 and the 2013 INSCA were a reasonable characterization of the culture that existed at the site during that time period. The team found that employees perceived notable improvements in safety culture across the site. Employees had recognized a notable change in the overall focus of the site, from a production-focus and an emphasis on doing the minimum required to keep the plant running, to a safety-focus and emphasis on making conservative decisions. Employees also indicated that they had greater trust in upper management and perceived an increased level of support for raising safety concerns and increased emphasis on raising standards for safe performance. Despite the overall improved safety culture, translating the safety culture beliefs into repeatable, sustainable safety culture behaviors still remained a challenge at BFN. Some station personnel including operators, technicians, and their immediate supervisors were challenged to routinely exhibit site standards and expectations when performing normal duties and responsibilities involving work practices, decision making, and implementation of the problem identification and resolution programs. In addition, some procedures specifically used to operate the plant did not meet industry quality standards.

The team identified seven specific areas of concern that were not adequately covered by the licensee's IIP necessary to drive continued performance improvement progress. As a result the licensee developed a Safety Culture Improvement and Sustainability Plan. The following concerns warranted revisions to the IIP to ensure that performance improvement would be achieved:

1) Although employees exhibited attitudes that supported a positive safety culture, those behaviors were not consistently demonstrated, particularly by employees who were closest to the operation of the plant (individual contributors and supervisors).

2) The work management process was not effectively implemented to facilitate coordination between departments. The lack of coordination may have contributed to quality issues with work packages, and affected the timeliness of performing work.

3) Current resources may not be adequate to effectively manage the additional workload required to reduce backlogs and improve reliability at the station. In addition, the need for appropriate training and qualifications may create a gap between having enough staff and having enough qualified staff to meet work demands.

4) There was a recognized issue with the quality of procedures at the station; however, there lacked a systematic process for improving procedure quality in an efficient manner.

5) Management and supervisors were not consistently reinforcing desired behaviors and work practices through the use of direct observations and coaching. In addition, the station lacked a systematic process to improve behaviors and work practices through supervisor oversight.

6) Administration and oversight roles of the Nuclear Safety Culture Monitoring Panel required additional structure and involvement to monitor and drive continued and sustainable safety culture improvement across the station.

7) Administration and oversight of the BFN human performance (HU) plan were lacking strategic action plans and TVA Corporate oversight to monitor and manage the station's long-standing HU issues.

In the area of Safety Conscious Work Environment (SCWE) and the Employee Concerns Program, the team assessed that at the time of the inspection, there were no indications of a SCWE issue and improvements had been made to the Employee Concerns Program and BFN's actions to address these areas to be adequate.

The team performed an assessment of the Reactor Safety Strategic Performance area, which included engineering design, human performance, procedure quality, equipment performance, and configuration control. The team concluded that planned and implemented corrective actions were sufficient to prevent a decline in safety that could result in unsafe operations. The implemented and proposed actions in the IIP were appropriate to promote sustained improved performance.

Equipment associated with containment heat removal were, in general, adequately maintained in proper configuration and material condition to perform their designed safety functions. However, the team observed several examples in which the licensee accepted longstanding degraded conditions without pursuing timely resolution through the CAP (i.e., RHRSW and EECW pump differential thermal expansion, infrequent and incomplete GL 89-13 RHRSW pump pit inspections, cold weather protection for RHRSW and EECW pumps and piping, EECW check valve closure, macrofouling of RHR and EECW HXs, equipment labeling). These conditions historically challenged both equipment configuration and reliability. The team noted recent licensee progress to identify, fund, and schedule actions to correct several of the longstanding degraded equipment conditions.

Strategic Equipment Performance implemented by the Long Term Asset Management (LTAM) program created a process that ranks and prioritizes modifications and projects from a BFN site perspective. This program was implemented at the end of 2009. An essential enhancement to the LTAM program along with the recent establishment of a systematic and integrated work week schedule and the Functional Equipment Grouping (FEG) work week processes should help to provide sustainable improvement to overall equipment reliability. The LTAM program focused site resources on important equipment and projects that have the potential to improve equipment reliability over time. The implementation of the LTAM program along with the enhancement of other engineering programs such as the Safety System Recovery Program should help to improve the overall Strategic Management Program at BFN.

The team determined that the IIP corrective actions were comprehensive in nature and adequately addressed the identified root and contributing causes for Work Management. The team acknowledged that improvements have been made at the station with respect to the work management process; however, this is a new process for the station and additional implementation time is needed to show performance improvement is sustainable in this area. The team identified several examples where the work management process was not implemented in accordance with the program; specifically in the areas of work scheduling, work planning, work execution, procedure use and adherence, and procedural quality. In addition, the Work Management processes at BFN have not historically been robust. As a result, emergent/ tactical issues upset the schedule and then the long term Strategic Equipment Management plans have suffered because station priorities were directed away from the strategic priorities resulting in a focus on the emergent/tactical priority. Difficulties in implementing the work management process can also adversely affect the equipment performance monitoring and trending process. Even though the work management process corrective actions have been implemented to achieve full effectiveness there will be challenges to achieve overall improved equipment reliability at the station. Therefore, rigorous adherence to the process by the licensee's staff and rigorous oversight of the work management process by the licensee management will be necessary for sustained improvement.

BFN implemented reasonable actions to reduce and manage the design engineering backlog at levels appropriate to support safe plant operation. As of September 2012, BFN estimated the total volume of engineering design backlog items to be 5 years of work if performed by BFN staff. Actions identified in the IIP included hiring contactor resources to work down the engineering change package backlog and revision of fleet modification processes to ensure future engineering design change package closure documentation was included in work scope performed by contract labor rather than assigning this to onsite BFN engineering staff. The team verified these actions were implemented, and at the close of this inspection approximately 80 percent of the design backlog items had been completed. While progress was notable, the team determined that several related IIP actions were not fully implemented or had not had sufficient run-time to support NRC assessment of sustainability. Continued implementation was warranted in this area to ensure that substantial and sustainable performance improvement is achieved.

The team concluded that the licensee had showed some improvement in overall station performance as a result of actions taken in the areas of procedure use and adherence, human performance, technical rigor and ownership and accountability, procedure quality, and operational focus and decision making. This was evident by the improvement in performance metrics for these areas. The team also noted that BFN had extensive corrective actions in place, both completed and in-progress. In some areas, BFN's actions were too new to determine long-term performance improvement sustainability. The team identified several examples related to these areas where BFN staff failed to meet the standards established at the station.

The team identified multiple Findings and observations that demonstrated failures to meet BFN procedure use and adherence standards. This included Findings in the limited use of fundamental human performance tools by all organizations, lack of manager and supervisor oversight to enforce procedure use and adherence standards, inconsistent procedure use and adherence standards in corporate and site procedures, BFN acceptance of sub-standard procedures, and frequent examples of station personnel errors related to procedure use and adherence. The team concluded that station management did not methodically address and correct latent organizational human performance weaknesses, including procedure use and adherence and the limited use of human error prevention verification tools and practices.

A programmatic review of the human performance program concluded that there was not a systematic approach at BFN or TVA Corporate to address the human performance issues. Although a fleet Business Plan existed for Corporate and BFN's human performance improvement initiatives, these plans focused on high level strategic actions only and tactical implementation actions did not exist. In addition, the station did not methodically target and correct the latent organizational weaknesses with human performance, including procedure use and adherence and verification practices. Based upon a review of the IIP and associated actions, the team concluded that the station's focus warranted a systematic approach to improving work practices, decision making (rigor), and supervisory oversight to ensure long-term corrective actions were effective for performance improvement sustainability.

Regarding Technical Rigor and ownership and accountability, the team concluded that the licensee had adequately addressed the multitude of challenges at the site which formed the bases of the design related fundamental problem areas experienced at the site. The licensee's Safety Culture Continuous Improvement and Sustainability Plan included additional actions to address issues related to technical rigor and human performance.

Procedure quality issues at BFN have led to equipment degradation, equipment unavailability, plant transients and reactor scrams. The team concluded that when BFN made standard human performance tools an option rather than a requirement for critical evolutions, that action exacerbated human performance issues. Previous corrective actions have been ineffective in preventing recurrence of events in which procedure quality was either a contributing or a root cause. As a result of these conclusions, TVA developed a revision to the IIP to implement a site-wide procedure upgrade project to bring BFN procedure quality in line with established industry standards.

Following review of BFN's Operational Focus and Decision Making processes, the team determined by direct observation that the Operations Organization should take a leadership role to drive the station to improved performance that exemplifies an Operations led organization. As a result of these conclusions, the licensee developed an action plan entitled "Operations Centric Organization," to address the issues in the Operations Organization embracing the site-wide leadership role.

The team performed an assessment of licensee controls for identifying assessing and correcting performance deficiencies, this included performance identification and resolution, deficiency causal analysis, and governance and oversight. The CAP performance had improved overall; however, there were areas that were identified that indicated that BFN must remain cognizant of specific aspects of CAP that have not yielded the same level of performance improvement as the rest of the program. Specifically, support request (SR) quality, problem evaluation report (PER) trending, lower tier apparent cause evaluation (ACE) quality, and SR initiation threshold were aspects of CAP where the team identified issues that indicated continued attention to performance improvement progress was warranted. A limited number of corrective actions associated with these issues identified under the CAP problem area had not had sufficient implementation time or had not been completed such that the team could provide a full assessment of the effectiveness of correctives actions. However, the corrective actions taken to date have provided reasonable assurance that performance improvement would continue with implementation of planned and completed corrective actions in the IIP.

The team observed that the licensee had improved in the overall station organizational structure as a result of actions taken in the areas of governance and oversight and that the licensee's efforts to establish a governance framework as specified in the Nuclear Operating Model was sound. The team noted the licensee's efforts in establishing a fleet-wide management process had been overall effective in creating a mutually beneficial working relationship in the Fleet. The team recognized that the implementation of the Nuclear Operating Model and Governance, Oversight, Execution and Support framework at BFN warranted significant management oversight and involvement to result in long-term substantial and sustained performance improvement, specifically in the areas of oversight and human performance as addressed by the licensee's Safety Culture Continuous Improvement and Sustainability Plan.

The team also recognized that BFN performed extensive actions to align the organization around a common set of standards and goals (picture of excellence) and implement accountability. However, the IIP did not utilize this same approach with mid/lower level management and first line supervisors. The team observed multiple observations during the inspection where supervisors made inappropriate decisions, did not recognize or justified incorrect acts or behaviors from their workforce, or did not have the skill set to coach and correct poor work practices. BFN lacked a systematic approach to address this issue, such that the station would comprehensively target and correct the latent issues of workforce and supervisors' work practices and behaviors.

Lastly, the team reviewed other issues including the corrective actions identified in the IIP which addressed the causes of two substantive cross-cutting issues for thorough evaluation of identified problems and appropriate and timely corrective actions. The licensee completed the required third party safety culture assessment to address these two substantive cross-cutting issues. The team verified the actions identified in the IIP were appropriate to promote sustained improved performance.

SUMMARY OF FINDINGS

IR 05000259/2013011, 05000260/2013011, 05000296/2013011; Browns Ferry Nuclear Plant, Units 1, 2, and 3; NRC Supplemental 95003 Inspection Report

The report covered a supplemental inspection by the 95003 NRC team. Sixteen NRC identified Findings were identified. The significance of most Findings is identified by their color (Green, White, Yellow, and Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP); and, the cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

The NRC staff performed this supplemental inspection in accordance with NRC Inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded cornerstones, Multiple Degraded Cornerstones, Multiple YELLOW Inputs, or One RED Input," to assess the licensee's evaluation associated with a Browns Ferry Nuclear Plant Unit 1 Finding of high safety significance (RED), for one of the Residual Heat Removal Subsystems being inoperable for greater than the Technical Specification allowed outage time. Browns Ferry Nuclear Plant Unit 1 entered the Multiple/Repetitive Degraded column of NRC's Action Matrix in the fourth quarter of 2010. The NRC staff documented this Finding in NRC IR 05000259/2011008. During this supplemental inspection, the inspectors determined that the licensee performed a comprehensive diagnostic evaluation of the RED Finding. The supplemental inspection procedure was conducted to gain insights into the breadth and depth of safety, organizational, and programmatic issues which TVA addressed in their performance improvement initiative. This inspection was a diagnostic review and included reviews of programs and processes not inspected as part of the baseline inspection program. The results of this inspection have aided the NRC in deciding whether additional regulatory actions are necessary to assure public health and safety. The inspection reviewed and assessed the actions that have been taken and those that are planned related to the LPCI valve failure and the long-term fire strategies at the Browns Ferry station. The inspection included an independent assessment of the safety culture at the Browns Ferry Nuclear Plant. This aspect of the inspection validated TVA's third party safety culture assessment and root cause evaluation.

The overall result and conclusion of the inspection was that the plant is being operated safely and TVA had made some progress in improving Browns Ferry station performance. However TVA needs to aggressively continue the implementation of the Integrated Improvement Plan to achieve substantial and sustained performance improvement. The team identified four issues that warranted revision to the licensee's Integrated Improvement Plan to ensure that substantial and sustained performance improvement would be achieved. The areas warranting improvement were associated with Safety Culture, Procedure Quality, Human Performance Verification Program, and an Operational Focused Organization.

The RED Finding associated with this issue will remain open until completion and closure of items identified in the Confirmatory Action Letter as having a higher priority that will provide assurance that substantial and sustainable performance improvement will be achieved through implementation of the Integrated Improvement Plan. Upon satisfactory completion and inspection follow up of those items, the NRC will consider assessment of Browns Ferry Unit 1 for transition out of Column 4 in accordance with the guidance in IMC 0305, Operating Reactor Assessment Program.

A. NRC Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The team identified a Green non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion III, Design Control in that the licensee did not adequately evaluate a commercial grade dedication (CGD) of bearings prior to installing the bearings in a safety-related low pressure coolant injection (LPCI) motor generator (MG) set. Specifically, BFN did not perform an acceptance evaluation of non-conforming materials as required by Section 3.2.6 of NPG-SPP-04.2, Material Receipt and Inspection, Rev. 2. The licensee subsequently initiated prompt corrective actions that included an evaluation of acceptance of the installed bearings, a LPCI operability determination, an extent-of-condition review, and entered the issue in their corrective action program (PER 729646).

  The Finding was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Additionally the Finding was similar to Example 5.c in Appendix E of IMC 0612. The Finding was of very low significance because the finding was a design qualification deficiency and the affected structure system component (SSC) (3EN LPCI MG set) maintained its operability. This Finding had a cross-cutting aspect in the area of Human Performance, Decision Making because the licensee did not use conservative assumptions when making the decision to accept non-conforming commercial grade bearings for safety-related use, such that nuclear safety was supported. [H.1 (b)] (Section 5.1.3.2.1)

- Green. The team identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings for the licensee's failure to maintain effective configuration control as required by Procedure NPG-SPP-09.3, Rev. 13, "Plant Modifications and Engineering Change Control." Specifically, the licensee partially implemented permanent plant modifications to the Residual Heat Removal (RHR) and Core Spray (CS) systems under Design Change Notices (DCN) 69466 and 69467 and left these DCNs in partially implemented status beyond two refueling outages without approval of the Vice President of Engineering. This created the potential for a loss of configuration control of the CS and RHR systems. The licensee entered this issue of concern in their corrective action program as SR 739929 and PER 740729 that included actions to evaluate completion or cancellation of the remaining portions of the DCNs.

The team determined the Finding was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). The finding was of very low significance because it was not a design or qualification deficiency, and it did not result in an actual loss of one or more trains of the RHR or CS systems and/or their function. The finding had a cross-cutting aspect in the area of Human Performance, Work Control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of partially implemented DCNs on the plant. [H.3 (b)] (Section 5.1.3.2.2)

- Green. The team identified a Green, self-revealing non-cited violation (NCV) of Technical Specification (TS) 5.4.1, "Procedures." The team determined that BFN's clearance and tagging application related to the planned A2 residual heat removal service water (RHRSW) pump maintenance was not properly applied and verified as required by TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy," and NPG-SPP-10.3, Rev.1, "Verification Program." Two BFN assistant unit operators (AUOs) closed and danger tagged the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump discharge valve on May, 6, 2013. Upon starting the A1 RHRSW pump, control room alarms provided the operators indication of a system problem, and in the course of responding to the alarm, the operators noted the danger tag. The tags were removed and the pump was declared inoperable to fill and vent the system prior to returning it to an operable status. This issue was entered in to the corrective action program as PER 722859. The performance deficiencies were reasonably within BFNs ability to foresee and correct.

  This Finding was more than minor because it was associated with the human performance attribute which occurred when the AUOs closed and tagged the wrong RHRSW pump discharge valve. The AUOs errors adversely affected the Mitigating System cornerstone objective of ensuring the availability, reliability, and capability of the RHRSW and RHR systems that respond to initiating events to prevent undesirable consequences. The team determined that this Finding was of very low safety significance (Green) because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time. The team

determined that this Finding had a cross-cutting aspect in the area of Human Performance, Work Practices, because BFN AUOs did not use self-checking and peer checking human error prevention techniques to prevent the inadvertent closure and danger tagging of the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump valve during the application of a tagging clearance.
[H.4(a)] (Section 5.2.2.2.1)

- Green. The team identified a Green non-cited violation (NCV) of Technical Specification (TS) 5.4.1, "Procedures." The team determined that the maintenance Primary Authorized Employee (PAE) did not verify that all blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW pump planned maintenance. The PAE's decision to only verify two of nine clearance components was a violation of TVA Corporate Procedure NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy". The maintenance PAE did not ensure that the A2 RHRSW pump was isolated from an unexpected release of energy that could have resulted in personnel injury or pump damage. The PAE did not verify or recognize that the A2 RHRSW pump manual discharge valve was full open and not danger tagged closed on May, 6, 2013. This performance deficiency was reasonably within BFNs ability to foresee and correct.

  This Finding was more than minor because, if left uncorrected the BFN Maintenance Supervisor's failure to follow the clearance and tagging procedure requirement to verify all danger tag blocking points, he only verified two of nine danger tags, for the A 2 RHRSW planned pump the performance deficiency would have the potential to lead to a more significant safety concern, such as more severe plant transients, engineered safeguard system malfunctions, and a higher probability of personnel injury. The team determined that this Finding was of very low safety significance (Green) because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time. The team identified a cross-cutting aspect in the Work Practices component of the Human Performance area. Specifically, the licensee ensures supervisory and management oversight of work activities such that nuclear safety is supported. [H.2(c)]. (Section 5.2.2.2.2)

- Green. The team identified a Green, non-cited violation (NCV) of Technical Specification (TS) 5.4.1, "Procedures." The team determined that assistant unit operators' (AUOs) failure to comply with Procedure OPDP-1, Rev. 26, "Conduct of Operations," Sections 4.2 K. and M., related to the missing A1 RHRSW pump discharge valve label plate and the AUO's inadequate walkdown of the A1 RHRSW pump prior to the planned quarterly surveillance test pump start on May 6, 2013, were performance deficiencies that were reasonably within BFNs ability to foresee and correct. Immediate corrective actions by the licensee included revising the conduct of operations procedure, and enter the issue in the corrective action program as PERs 13161, 701486, and 722859.

This Finding was more than minor because, if TVA's failure to follow the Procedure OPDP-1 requirements was left uncorrected, the performance deficiencies would have the potential to lead to a more significant safety concern, such as more severe plant transients, or engineered safeguard system actuations or malfunctions. Additionally, this issue is similar to Example 4.e in IMC 0612, Appendix E, "Examples of Minor Issues," in that the A1 RHRSW pump discharge valve was missing the valve label plate and AUOs did not stop the A2 RHRSW pump clearance application to correct the valve label issue prior to proceeding with the danger tag application. This action was required by TVA Corporate Procedure OPDP-1, Rev. 26, "Conduct of Operations," and resulted in an improper valve manipulation due, in part, to the missing label plate. The team determined that this Finding was of very low safety significance (GREEN) because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time. The team determined that this Finding had a cross-cutting aspect in the area of Human Performance, Work Control. Specifically, the licensee plans and coordinates work activities, consistent with nuclear safety. In addition, the licensee appropriately coordinates work activities by incorporating actions to address: the impact of changes to the work scope or activity on the plant and human performance, the impact of the work on different job activities, and the need for work groups to maintain interfaces with offsite organizations, and communicate, coordinate, and cooperate with each other during activities in which interdepartmental coordination is necessary to assure plant and human performance, the need to keep personnel apprised of work status, the operational impact of work activities, and plant conditions that may affect work activities. [H.3(b)] (Section 5.2.2.2.3)

- Green. The team identified a non-cited violation of Technical Specification (TS) 5.4.1, which requires written procedures be established, implemented, and maintained covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, including surveillance tests. Specifically, a performance deficiency occurred, when the licensee failed to implement the procedure, which required that approved measuring and test equipment be used to measure the underfrequency relay settings during the performance of the Reactor Protection System circuit protector calibration surveillance procedure. Prompt corrective actions included determination that the equipment remained operable and entry of this issue into their corrective action program as problem evaluation report 731144.

The performance deficiency was determined to be more than minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern, because it could have affected the operability of the relays. The team used Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, for mitigating systems, and Inspection Manual Chapter 0609, Appendix. A, "The Significance Determination Process for Findings at Power," issued June 19, 2012, and determined the Finding to be of very low safety significance (Green) because the Finding did not result in the loss of functionality or operability of a structure, system, or component. The team identified a crosscutting aspect in the work practices component of the Human Performance area, because the licensee did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures [H.4(b)]. (Section 5.2.2.2.4)

- Green. The team identified a self-revealing, Green non-cited violation (NCV) of 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," due to BFN's failure to adequately manage the impact of an emergent risk condition related to the A1 residual heat removal service water (RHRSW) quarterly surveillance test. BFN recognized the online maintenance risk condition however, failed to implement appropriate risk management actions (RMAs) in accordance with Procedure BFN-ODM-4.18, "Protected Equipment." The 'A' and 'B' emergency diesel generators were required to be protected. BFN entered this issue into their corrective action program (CAP) as SR 730356. Specifically, on May 6, 2013, with the A2 RHRSW pump inoperable for planned maintenance, the A1 RHRSW pump was declared inoperable during the A1 RHRSW pump quarterly test due to a tagging error that resulted in Assistant Unit Operators closing and danger tagging the A1 pump manual discharge valve instead of the required A2 pump discharge valve. Upon starting the A1 RHRSW pump, control room alarms provided the operators indication of a system problem, and in the course of responding to the alarm, the operators noted the danger tag. The tags were removed and the pump was declared inoperable to fill and vent the system prior to returning it to an operable status. This issue was entered in to the corrective action program as PER 722859 and 731570.

The team determined that BFN's failure to adequately manage the impact of an emergent risk condition related to the A1 residual heat removal service water (RHRSW) quarterly surveillance test was a performance deficiency that was reasonably within BFNs ability to foresee and correct. The performance deficiency was determined to be more than minor and a Finding because, if the deficiency was left uncorrected, it had the potential to lead to a more significant safety concern. Specifically, the failure to take adequate RMAs could have led to unplanned inoperability of redundant TS or risk significant mitigating systems being relied upon to respond to initiating events to prevent undesirable consequences. The performance deficiency was also determined to be more than minor since it is similar to more than minor Example 7.e of Inspection Manual Chapter (IMC) 0612, Appendix E "Examples of Minor Issues." The Finding was evaluated in accordance with Appendix K, Maintenance Risk Assessment and Risk Management Significance Determination Process, of IMC 0609, "Significance Determination Process," and was determined to be of very low safety significance (Green). This Finding has a cross-cutting aspect in the area of Human Performance, Work Control, because BFN failed to implement immediate RMAs and communicate to the station personnel the change in plant risk condition and protected equipment requirements that may affect work activities. [H.3.(b)]. (Section 5.2.2.2.5)

- Green. The team identified a Green, non-cited violation (NCV) of Technical Specification (TS) 5.4.1, "Procedures." The team determined that BFN's Requirements for Concurrent Verification, Independent Verification, and Peer Checks were not consistently applied to plant procedures, instructions, and work documents as required by TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants." BFN documented the issue in SRs 722559, 726755, and PERs 707531, 722859, and 727405.

  This finding was more than minor because, if BFN site verification procedure requirement issues and adherence are left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern, such as more severe plant transients, or engineered safeguard system actuations or malfunctions. Additionally, this issue is similar to Example 4.b in IMC 0612, Appendix E, "Examples of Minor Issues," in that the recent inadequate use of human performance error prevention tools (self-checking, peer checking, and missing IVs and CVs in the Procedure NPG-SPP-10.3, Appendix "A," list of 35 BFN systems that are required to have verifications for procedures, instructions, and work documents) have resulted in a reactor scrams, unplanned safety and risk significant system inoperability and unavailability, or other transients. The Finding was determined to be of very low safety significance (Green) in accordance with Inspection Manual Chapter (IMC) 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, "The Significant Determination Process (SDP) for Findings At-Power," because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time. The team identified a cross-cutting aspect in the Resources component of the Human Performance area, because the licensee did not ensure that procedures were available and adequate to assure nuclear safety. Specifically, accurate and up-to-date procedures, work packages, and correct labeling of components. [H.2(c)]. (Section 5.3.2.2.1)

- Green. The team identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," due to BFNs failure to take corrective action to preclude repetition of a significant condition adverse to quality regarding procedure quality. Specifically, BFN self-identified corrective actions implemented to address inadequate procedures but did not identify and address a significant contributor to the inadequate procedures, resulting in several additional plant performance issues. The team identified multiple inadequate procedures across most BFN departments during the inspection document review and onsite inspection. BFN has conducted root causes, developed and implemented numerous corrective actions; however, procedural deficiencies continued to contribute to plant shutdowns, unplanned component unavailability, and rework activities. BFN documented the issue in PERs 680792 739429, and 740212.

  This Finding was determined to be more than minor because it associated with the human performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit this likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process for Findings At-Power," the team determined that the Finding was of very low safety significance because it did not cause a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition (e.g. loss of condenser, loss of feedwater). The team determined that the Finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because BFN did not thoroughly evaluate the extent of condition associated with inadequate procedures such that the corrective actions resolved the issue and prevented repetition. [P.1(c)] (Section 5.3.2.2.2)

- Green. The team identified a Green NCV of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, for the licensee's failure to incorporate appropriate quantitative acceptance criteria into a station battery inspection Procedure. Specifically, Procedure EPI-00248-BAT005, "Annual Inspection of 250V DC Main Battery Banks 1, 2, 3 and Associated Chargers," Revisions 18 and 19 did not provide the correct acceptance criteria for the battery bank connection resistance results. Prompt corrective actions included determination that main battery bank 1 remained operable and entry of the issue into the corrective action program (SR 731341 and PER 732511).

  The team determined that BFN's failure to establish correct quantitative acceptance criteria after main bank battery replacement and after changing the battery inspection methodology in the annual battery test inspection procedure was a performance deficiency. The performance deficiency was determined to be more than minor and a Finding because it was associated with the procedure quality attribute of the Mitigating

Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The Finding was of very low safety significance (Green) because it was not a design or qualification deficiency and did not result in an actual loss of system and/or function. The Finding had a cross-cutting aspect in the area of Human Performance, Resources - Procedures, because BFN did not provide accurate and up-to-date procedures for the inspection of safety-related station batteries. [H.2(c)] (Section 5.3.2.2.3)

- Green. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to translate seismic uncertainties into acceptance criteria and measuring and test equipment accuracy requirements into the Reactor Protection System circuit protector calibration surveillance procedure. This was determined to be a performance deficiency. Prompt corrective actions included determination that the equipment remained operable and entry of this issue into their corrective action program as problem evaluation report 723605 and 730495.

  The performance deficiency was determined to be more than minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern because it could have affected the operability of the relays. The team used Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, for mitigating systems, and Inspection Manual Chapter 0609, Appendix. A, "The Significance Determination Process for Findings at Power," issued June 19, 2012, and determined the Finding to be of very low safety significance (Green) because the Finding did not result in the loss of functionality or operability of a structure, system, or component. The team did not identify a cross-cutting aspect because this performance deficiency has existed since 2006 and is not indicative of current licensee performance. (Section 5.3.2.2.4)

- Green. The team identified a non-cited violation of 10CFR50, Appendix B, Criterion XI, Test Control, because the licensee did not establish a test program for Residual Heat Removal Service Water (RHRSW) and Emergency Equipment Cooling Water (EECW) pumps such that the test adequately demonstrated the pumps would perform satisfactorily in service. Specifically, BFN did not perform RHRSW/EECW pump performance testing such that it adequately accounted for river water temperature impact on the pump lift, which affected pump flow and vibration performance. The test program did not account for changes to pump lift caused by river water temperature changes; as a result the test program did not adequately monitor pump and system performance and degradation. The licensee completed a prompt operability determination verifying that the pumps remained operable and documented the issue in PERs 730497 and 741036.

The Finding was more than minor because at affected the Mitigating System Cornerstone and if left uncorrected, could become a more significant safety concern. The team determined the Finding was of very low safety significance because it was not a design or qualification deficiency, and it did not result in an actual loss of one or more trains of the RHRSW or EECW systems and/or their function. The Finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Corrective Action Program, because the licensee did not to thoroughly evaluate the changes in RHRSW and EECW pump performance such that the resolution addressed the causes and extent-of-condition. [P.1(c)] (Section 5.4.3.2.1)

- Green. The team identified a green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, involving the failure to maintain adequate design control measures associated with the residual heat remove service water (RHRSW) system freeze protection. Specifically, the team identified that freeze protection was not installed on two RHRSW pump air relief valves (ARV) to maintain operability of the RHRSW system during extended periods of cold weather. BFN entered the issue into their corrective action program under SRs 731375, 727908, and 732519 and PER 732519 and concluded that an immediate operability concern was not present due to the current warm weather conditions and recent satisfactory pump testing. Additionally, BFN performed a detailed inspection of ARVs on all 12 RHRSW pumps, and identified deficiencies on ARVs for eight pumps and entered each item into the CAP.

  The team determined that failure to maintain adequate design control measures associated with the RHRSW system freeze protection was a performance deficiency. This Finding was more than minor because it adversely affected the design control attribute of the Mitigating Systems cornerstone and the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Inspection Manual Chapter 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” the team determined that the Finding was of very low safety significance (Green) because it was a deficiency affecting the design or qualification of a mitigating system, structure or component (SSC), where the SSC maintained its operability. The Finding had a cross-cutting aspect in the area of problem identification and resolution, corrective action program problem identification, because BFN did not maintain a low threshold for issue identification such that this issue was identified and resolved during numerous previous focused inspections of the RHRSW system configuration. [P.1(a)] (Section 6.1.4.2.1)

Cornerstone: Barrier Integrity

- Severity Level IV: The team identified a Severity Level IV non-cited violation of 10 CFR 50.59, Changes, Tests, and Experiments, for the licensee's failure to perform an evaluation of a change to the facility as described in the Updated Final Safety Analysis Report (UFSAR) and an associated Green Finding for the licensee's failure to perform an acceptable Ultrasonic (UT) examination in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI requirements. Specifically, this change resulted in a departure from the method of evaluation used to inspect for intragranular stress corrosion cracking (IGSCC) in reactor coolant pressure boundary components at BFN as described in the UFSAR and therefore, required a 10 CFR 50.59 evaluation to determine if the change would have required a license amendment request pursuant to 10 CFR 50.90. The licensee performed the required 10 CFR 50.59 evaluation and entered this issue of concern in their corrective action program (CAP) under SR 743380 and PER 744849.

  The team determined the underlying PD was more than minor and a Finding, because the PD affected the Barrier Integrity cornerstone and if left uncorrected, could become a more significant safety concern. Absent NRC identification of this PD, the licensee could have continued to perform UT examinations to detect IGSCC on safety-related components without obtaining the minimum required examination volume. This could result in IGSCC susceptible welds on ASME Code Class 1 piping being only partially examined for IGSCC flaws and could lead to safety-related components with potentially unacceptable service-induced flaws not detected during UT examinations being returned to service. The team evaluated the Finding's significance in accordance with IMC 0609, Appendix G, Shut-down Operations Significance Determination Process, because the PD occurred while Unit 2 was in cold shutdown. The team reviewed IMC 0609, Appendix G, Attachment 1, Checklists 5, 6, 7, and 8 and determined this Finding did not require a quantitative assessment. Therefore the Finding screened as having very low safety significance. The team determined the traditional violation was more than minor because of reasonable likelihood the departure from weld inspection methodology as described in the UFSAR would have required Commission review and approval prior to implementation. The team concluded that the violation of 10 CFR 50.59 was a Severity Level IV because the underlying PD screened Green under the SDP. The team also concluded that this Finding had a cross-cutting aspect in the area of Human Performance, Decision Making, because the licensee did not make safety significant or risk-significant decisions using a systematic process when faced with uncertain or unexpected plant conditions, to ensure safety was maintained. [H.1 (a)] (Section 5.1.4.2.1)

- Green. The team identified a Green, NRC identified non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to control deviations from the as built control room envelope design for seismically mounted ceiling light diffusers in accordance with instructions that assure quality standards are controlled. Specifically, contrary to the procedure the licensee unsecured three seismically mounted control room ceiling light diffusers and slid them over the top of other light diffusers creating a seismic missile hazard that could have impacted control room ventilation damper actuators. Once the licensee understood that unfastening the ceiling light diffusers and sliding them over top of other diffusers was creating unanalyzed modifications, the licensee removed the ceiling diffusers from the overhead and placed them in a seismically safe condition. In addition, the licensee clarified the procedure step to have the ceiling light diffusers removed completely. The licensee entered this issue into their CAP as PER 730443. The failure to control a planned modification of the seismically mounted control room ceiling light diffusers was a performance deficiency (PD).

  The PD was more than minor because it is associated with the design control attribute of the barrier integrity cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Using Inspection Manual Chapter 0609.04, "Phase 1-Initial Screening and Characterization of Findings," the team determined that the Finding had very low safety significance (Green) because the Finding only represents a degradation of the radiological barrier function for the control room. This Finding has a cross-cutting aspect in the area of human performance because the licensee did not define and effectively communicate expectations regarding procedural compliance and personnel follow procedures. (H.4.(b) (Section 5.2.4.2.1)

Cornerstone: Initiating Events

- Green: The team identified a NCV of 10 CFR 50, Appendix B, Criterion IX, Control of Special Processes for the licensee's failure to control non-destructive examination (NDE) activities by not having qualified NDE procedures required by applicable codes, standards, specifications, criteria, and other special requirements. Specifically, four Ultrasonic (UT) examination procedures did not contain any of the required American Society of Mechanical Engineers (ASME) Code Section XI, Appendix VIII essential variables or the explicit requirement to perform the UT examinations using applicable Performance Demonstrated Initiative (PDI) procedures. The licensee initiated prompt corrective actions to revise all UT implementing procedures to become qualified in accordance with ASME Code Section XI, Appendix VIII requirements and entered the issue into their corrective action program (PERs 730250 and 721446).

The Finding was more than minor, because it affected the Initiating Event cornerstone and if left uncorrected, could become a more significant safety concern. Absent NRC identification of this PD, the licensee could have continued performance of UT examinations on safety-related components using unqualified procedures. Performance of UT examination using unqualified procedures could lead to safety-related components with unacceptable service-induced flaws being returned to service without ASME code-specified evaluation or repair. The team determined the Finding was of very low significance because the Finding was not likely to result in exceeding the RCS leak rate for a small loss of coolant accident (LOCA) or cause total loss of function for a LOCA mitigating system. This Finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Operating Experience (OE) because the licensee did not implement and institutionalize OE pertaining to UT examination procedure issues through changes to station processes, procedures, and training programs to support plant safety. [P.2 (b)] (Section 6.1.6.2.1)

B. <u>Licensee Identified Violations</u>

None

REPORT DETAILS

1 Performance History

Browns Ferry Nuclear Plant Unit 1 entered the Multiple/Repetitive Degraded column of NRC's Action Matrix in the fourth quarter of 2010. The issue, which degraded the Mitigating Systems Cornerstone, was a Finding of high safety significance (RED), for the Residual Heat Removal Subsystem being inoperable for greater than the Technical Specification allowed outage time. This issue was documented in NRC Inspection Report 05000259/2011008, dated May 9, 2011 (ML 111290482).

On October 23, 2010, in support of the Browns Ferry Nuclear Plant (BFN) Unit 1 refueling outage U1R8, operators started the "B" residual heat removal (RHR) pump to provide shutdown cooling to the reactor. After 110 seconds of observing no flow to the reactor, the operators stopped the pump and promptly placed the redundant RHR pump in service located in a second redundant RHR subsystem to provide shutdown cooling to the reactor. The Tennessee Valley Authority (TVA), the licensee for BFN, subsequently found that the disc in the outboard low pressure coolant injection valve, 1-FCV-74-66, had separated from the stem/disc skirt assembly and lodged in the valve seat preventing flow to the reactor through one of the two redundant RHR subsystems.

On December 31, 2010, the NRC completed an inspection at BFN that identified a self-revealing, apparent violation of Unit 1 Technical Specifications Limiting Condition for Operations 3.5.1, Emergency Core Cooling System (ECCS) – Operating, for the failure to comply with the required actions for an inoperable residual heat removal and low pressure coolant injection subsystem due to the failure of 1-FCV-74-66. The issue was documented in NRC Inspection Report 50-259/2010-005, 50-260/2010-005, and 50-296/2010-005 dated February 9, 2011. In a letter dated March 2, 2011, the NRC characterized TVA's failure to establish adequate design control and perform adequate maintenance on 1-FCV-74-66 as a preliminary greater than GREEN inspection Finding. On May 9, 2011, the NRC issued the final significance determination of the preliminary greater than GREEN inspection Finding. The NRC concluded that the Finding was of high safety significance (RED) that required additional NRC inspection.

Specifically, the NRC concluded that the Finding was of high safety significance (RED) because the failure to maintain adequate design and perform adequate maintenance on the Unit 1 outboard low pressure coolant injection (LPCI) valve, 1-FCV-74-66, led to the RHR loop II being unable to fulfill its intended safety function. In addition to the detailed risk evaluation performed by the NRC, as prescribed in NRC Inspection Manual Chapter 0609, "Significance Determination Process," the NRC also 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. In particular, the NRC recognized that alternative sources of core cooling flow paths may be available even with the failure of 1-FCV-74-66. But because of the fire mitigation strategy implemented at BFN, there were certain fire scenarios that relied on the use of only one available train of RHR as the sole capable core cooling injection source. The results of these risk sensitivity evaluations supported that the Finding was appropriately characterized as RED. Moreover, based on the fire mitigation strategy utilized at BFN that relied on the use of one available train of RHR as the sole capable injection source during certain fires scenarios, deficiencies such as this valve failure will continue to have high risk impact. Following the issuance of the RED Finding, fire strategies were modified, fire areas were redefined, and additional fire barriers were installed to reduce fire risk.

Prior to the RED Finding associated with Unit 1, all three BFN units were in the Degraded cornerstone column (Column 3) of the NRC's Action Matrix for fire protection related issues. Specifically, a WHITE Finding related to failure to establish, implement and maintain an adequate procedure for combating a plant fire, and a YELLOW Finding associated with Appendix R for cables of redundant trains of systems that were not protected such that one train of systems necessary for achieving and maintaining hot shutdown conditions would remain free of fire damage (ML 101090503). These issues were inspected in accordance with the NRC's Reactor Oversight Process (ROP) and the inspection results were documented in NRC Inspection Report 50-259/2010-008, 50-260/2010-008, and 50-296/2010-008 (ML 103370638).

Subsequently in the fourth quarter of 2010, plant performance for Browns Ferry Units 2 and 3 returned to the Licensee Response Column (Column 1) of the Action Matrix. In the second quarter 2012, Units 2 and 3 moved to the Regulatory Response Column (Column 2) of the NRC's Reactor Oversight Process due to a WHITE Finding in the mitigating system cornerstone related to failure to complete training for revisions made to the Safe Shutdown Instructions (SSIs) (ML 12226A647), this Finding also applied to Unit 1, but since Unit 1 was already in Column 4 it remained in Column 4. These issues were inspected in accordance with the ROP and the inspection results were documented in NRC Inspection Report 50-259/2012-014, 50-260/2012-014, and 50-296/2012-014 (ML 12331A180).

In the first quarter of 2013, Performance Indicators (PI) for all three units exceeded the GREEN/WHITE threshold. Specifically:

- Unit 1: Mitigating Systems Performance Index, Emergency alternating current (AC) Power System (Mitigating System Cornerstone).
- Unit 1: Mitigating Systems Performance Index, High Pressure Injection System (Mitigating System Cornerstone).

- Unit 2: Mitigating Systems Performance Index, Emergency AC Power System, (Mitigating System Cornerstone).
- Unit 3: Unplanned Scrams per 7000 Critical Hours (Initiating Events Cornerstone).

As a result, since the WHITE PI for Unit 2 was in the same cornerstone as the existing WHITE Finding, in accordance with the ROP, it transitioned to the Degraded Cornerstone Column (Column 3) of the ROP action matrix. Unit 3 since the WHITE PI was in a different cornerstone as the existing WHITE Finding it remained in Regulatory Response Column (Column 2). Since Unit 1 was already in Column 4 it remained in Column 4. The change to the ROP action matrix for Unit 2 was described in the letter from the NRC to TVA, dated May 14, 2013 (ML13134A237). With the exception of the Unit 1, High Pressure Injection System WHITE PI, which is described in this report (Section 7.1), the remaining WHITE PIs will be inspected separately in accordance with the ROP inspection program.

2 Licensee Site Recovery and Integrated Improvement Plan

In response to this event, TVA has conducted an extensive diagnostic evaluation using insights and guidance from NRC Inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple YELLOW Inputs or One RED Input." This evaluation included reviews, assessments, and causal analyses that were performed to understand the underlying issues associated with performance at BFN and to guide efforts and development of actions to achieve sustained improved performance and reduce risk. In the August 23, 2012, letter from TVA to the NRC (ML 12240A106), the licensee provided the NRC the framework for recovery as described in their "Integrated Improvement Plan Summary."

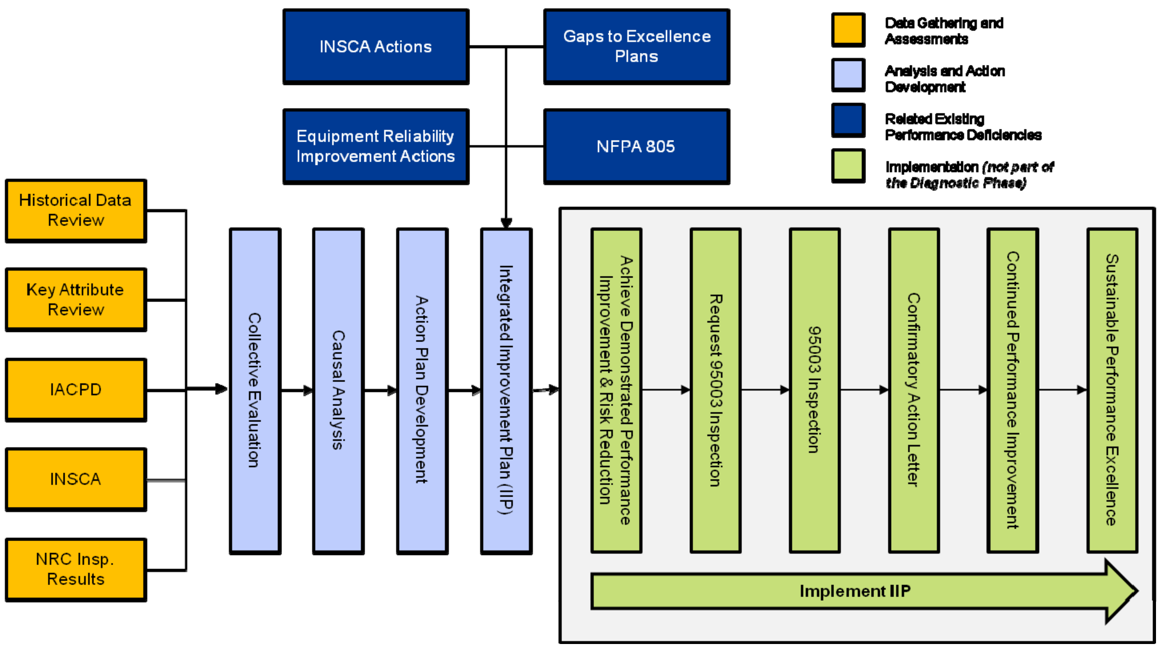
The licensee's effort was guided by a set of procedures that were developed using the detailed guidance in the 95003 Inspection Procedure as well as industry benchmarking data. The procedures used for this effort include the following documents:

- 95003-001 Historical Data Review,
- 95003-002 Collective Evaluation and Action Plan Development,
- 95003-003 Identification, Assessment and Correction of Performance Deficiencies,
- 95003-004 Assessment of Performance in the Reactor Safety Strategic Performance Area,
- 95003-005 BFN NRC Column 4 Inspection Readiness and Administrative Controls,
- 95003-006 Third Party Independent Nuclear Safety Culture Assessment,
- 95003-007 Project Review Boards, and
- 95003-008 Integrated Improvement Plan.

The licensee's recovery effort employed the following phased approach:

- Information Gathering and Collection,
- Collective Data Evaluation,
- Causal Analysis,
- Action Plan Development, and
- Integrated Improvement Plan (IIP) Implementation.

The licensee's approach is illustrated in the following figure.



The licensee's Information gathering and collection effort included:

- TVA Historical Data Review (HDR),
- Identification, Assessment and Correction of Performance Deficiencies (IACPD),
- Key Attributes Review (KAR),
- Independent Nuclear Safety Culture Assessment (INSCA),and
- NRC Inspection Results.

Information Gathering and Collection

Historical Data Review (HDR)

The purpose of the Historical Data Review was to collect and review historical plant records to identify previous failures and deficiencies.

For the scope of the HDR, BFN determined that data from a five year period (January 1, 2006, through June 30, 2011) was appropriate based on several factors, including the relevance of data to the performance deficiency, qualitative indications that BFN equipment and regulatory performance began to decline sometime after 2006, and recognition that starting the review before 2006 may introduce data that was not relevant to current performance issues. Plant records included NRC inspection reports, licensee event reports, the Institute for Nuclear Power Operations (INPO) plant events database, Nuclear Safety Review Board (NSRB) reports, quality assurance reports, Self-assessments, and corrective action documents. The HDR did not include Safety Culture Survey data and related assessments because the review of those documents was included as part of a third party Independent Safety Culture Assessment.

Identification, Assessment and Correction of Performance Deficiencies

The purpose of the IACPD review was to conduct a broad scope assessment of defined performance areas to determine whether current programs to identify, assess, and correct performance deficiencies are sufficient to prevent further performance degradations. Specifically, the scope of the IACPD evaluated the following seven performance areas: Significance Performance Deficiencies, Audit and Assessment, Allocating Resources, Performance Goals, Employee Concerns Program (ECP), Technical Resolution Dispositions, and Use of Industry information. In addition to the board scope assessments, under the IACPD, BFN conducted focused area assessments to follow up on specific items revealed during the initial broad scope assessments.

Key Attributes Review

The purpose of the KAR was to evaluate and verify the high safety and risk systems capability to fulfill their intended safety functions, to identify broad based safety, organization and performance issues and to evaluate emergency response organization readiness.

The scope of the Key Attribute Review was focused on evaluating the adequacy of programs and process in six key areas: Design, Human Performance, Procedure Quality, Equipment Performance, Configuration Control, and Emergency Response Organization Readiness. The following risk significant systems were selected to be evaluated: Residual Heat Removal and Emergency Diesel Generators (EDG).

Independent Nuclear Safety Culture Assessment

The purpose of the INSCA was to complete an assessment of BFN's Nuclear Safety Culture (NSC), which included Safety Conscious Work Environment (SCWE) and General Culture and Work Environment (GCWE) in alignment with NRC IP 95003. The scope focused on three key elements: Behaviors and Practices, SCWE and Effectiveness of BFN's ECP. The sources of input for this assessment included workforce survey results, workforce summary write-in comments, personnel interviews, behavioral observations, and documentation reviews. This assessment was in addition to safety culture reviews that BFN routinely implemented.

NRC Inspection Results

The licensee also included as part of its data collection the results of NRC inspections. This included the results of the IP 95003 Part 1 and 2 Inspections (ML113210602 and ML12059A314, respectively) and the associated Problem Identification and Resolution (PI&R) Inspection conducted in 2012. Further details regarding the three 95003 inspections are provided in Section 3.2 of this report.

Collective Data Evaluation

The results of the information gathering and collection effort were combined with the Findings and results from the failed Residual Heat Removal System Loop II outboard injection valve Root Cause Analysis (RCA). This information was integrated and collectively analyzed by the licensee for patterns, trends, or groupings.

After the information was assessed the licensee initially identified 15 Fundamental Problem Areas (FPA). Specifically:

FPA #	Title	Description
01	Management and Leadership Standards (MLS)	Leaders at all levels are not effectively modeling or reinforcing high standards to drive sustained positive performance changes and are tolerating less than acceptable standards of performance.

02	Operational Focus/Decision Making (OFDM)	Decision making at all levels of the station does not consistently demonstrate nuclear safety as the top priority and has contributed to significant events, unrecognized equipment inoperability, and deficient operability determinations.
03	Resource Management (RM)	Resource allocation decisions are inconsistent and have conflicting priority in managing core business and emergency work. This weakness manifests itself in reactive responses on equipment reliability and on the margin for managing nuclear safety.
04	Work Management (WM)	Work management failures contribute to maintenance backlogs and adversely affect equipment performance resulting in continued challenges to safe and reliable operation of the station. Previous actions to implement a robust work management process have been ineffective.
05	Corrective Action Program (CAP)	Execution of the corrective action program has been inconsistent and previous actions to improve performance have been ineffective.
06	Procedure Use and Adherence and Work Practices (PU&A)	Procedures and work instructions that support plant operations, maintenance and engineering are not followed and have contributed to plant operational events, maintenance errors, and industrial safety events.
07	Equipment Performance, Monitoring and Trending (EPMT)	Equipment Performance, Monitoring and Trending programs are not being implemented in a manner to prevent equipment failures. Performance metrics are not consistent or utilized to proactively to identify and resolve equipment reliability issues.
08	Strategic Equipment Management (SEM)	Equipment Reliability programs and processes needed to drive and sustain high levels of equipment reliability are not being implemented in a manner that results in the timely resolution of long standing equipment problems and the prevention of new problems.
09	Technical Rigor (TR)	Insufficient technical rigor results in rework, engineering design basis documentation flaws, and/or misconfigurations requiring additional work and resources.
10	Governance & Oversight (G&O)	The Nuclear Operating Model has not been effectively implemented. Governance, use of performance metrics, and corporate oversight have been less than effective at improving human and equipment performance, and regulatory margin.

11	Inappropriate Reliance on Processes (IRP)	Inadequate follow through and ownership through resolution, coincident with the belief that processes, not people, solve problems has hindered performance improvement.
12	Procedure/Instruction Quality (PIQ)	Procedures and work instructions do not fully support quality work, configuration control, human performance or record keeping and have contributed to plant events and performance deficiencies.
13	Equipment Programs and System Management (EPSM)	Engineering Programs designed to monitor and improve equipment performance are not effectively implemented and do not support long term equipment availability and reliability goals.
14	Design/Configuration Control (DCC)	Comprehensive understanding and management of design bases including key inputs, expected results, and outputs are not adequate. Configuration documentation and control (e.g., drawings, calculations, procedures, change backlog, modification packages, observations, and long standing clearances) challenges reliable plant operations.
15	Continuous Learning Environment (CLE)	Self-assessments, benchmarking, and the use and operating experience are not used effectively to improve station performance.

The licensee also included the issues that directly resulted in the RED Finding as FPAs specifically the LPCI valve failure and the impact of their fire protection mitigation strategy, which directly resulted in the higher risk significance of the valve failure.

FPA #	Title	Description
16	Performance Deficiency (RED Finding 74-66) (PD)	An undetected failure of 1-FCV-74-66, Residual Heat Removal (RHR) System Loop II Outboard Injection Valve, resulted in a loss of flow path for shutdown cooling, Low Pressure Coolant Injection (LPCI) function and Fire Strategy Response function for Loop II of RHR for a prolonged period of time. This resulted in an NRC Notice of Violation (NOV) and RED Finding in May 2011.
17	Fire Risk Reduction/NFPA 805 (FRR)	**Violation 1:** Failure to take timely corrective action to achieve compliance with NRC requirements. **Violation 2:** A revision to the BFN post-fire safe shutdown instruction entry conditions that could have delayed operator response to a major disabling fire event was not adequately evaluated prior to implementation.

Based on the licensee's assessment of the independent nuclear safety culture assessment report, BFN concluded that the following two additional FPAs were warranted.

FPA #	Title	Description
18	Safety Conscious Work Environment (SCWE)	BFN SCWE weaknesses include examples of unwillingness to report or inform supervisors of nuclear safety issues, and management's failures to effectively use indicators and precursors of a chilled environment to correct performance.
19	Employee Concerns Program (ECP)	Weakness in the execution of and confidence in the Employee Concerns Program (ECP). These weaknesses have contributed to BFN being ineffective at evaluating and resolving potential nuclear safety issues.

As part of the licensee's information gathering and collective evaluation efforts, they periodically assessed the site's performance for risk significant events or conditions to determine if the related causes from these events or conditions were either missed during their development of their improvement plan or if the related causes would warrant altering the basis of the established improvement plan, or if completed actions associated improvement plan were determined to be ineffective. Based on these assessments the licensee identified two more FPAs. Specifically:

FPA #	Title	Description
20	Training (TRN)	Knowledge and skill weaknesses related to plant transients and events are not being thoroughly identified and evaluated. This has led to missed opportunities to make adjustments to both initial and continuing training programs.
21	Independent Oversight (IO)	Independent oversight activities at BFN have not been fully effective in arresting the performance decline at BFN.

Subsequently the licensee divided the FPAs in to five focus areas to enable better communication to station personnel, specifically: 1) Corrective Action Program, 2) Operational Decision Making, 3) Accountability, 4) Equipment Reliability and 5) Fire Risk Reduction. Furthermore, the licensee concluded that all five of the focus areas were affected by the station safety culture. The breakdown of the FPAs into the focus areas was illustrated by the following:

	BFN Focus Area	Action Plans
SAFETY CULTURE	**Corrective Action Program**	• Continuous Improvement Environment (CLE) • Corrective Action Program (CAP) • Employee Concerns Program (ECP)
	Operational Decision Making	• Operations Focus / Decision Making (OF/DM) • Resource Management (RM) • Governance & Oversight (G&O) • Independent Oversight (IO)
	Accountability	• Management & Leadership Standards (MLS) • Procedure Use & Adherence / Work Practices (PU&A) • Procedure / Instruction Quality (PIQ) • Inappropriate Reliance on Processes / Silo'd Performance (IRP) • Training (TRN) • Safety Conscious Work Environment (SCWE)
	Equipment Reliability	• Work Management (WM) • Engineering Programs and System Management (EPSM) • Technical Rigor (TR) • Strategic Equipment Management (SEM) • Equipment Performance Monitoring & Trending (EPMT) • Design / Configuration Control (DCC) • 1-FCV-74-66 RED Finding
	Fire Risk Reduction	• Fire Risk Reduction

Causal Analysis and Action Plan Development

Each of the FPAs was entered into the licensee's Corrective Action Program. BFN performed a causal analysis for each FPA, to determine the underlying causes, extent of condition, developed corrective actions and means to measure the effectiveness of the corrective actions. This resulted in action plans developed by the licensee to address each identified fundamental problem area.

Integrated Improvement Plan

In the development of the integrated improvement plan, the licensee combined the FPA actions plans along with four other related existing major performance deficiencies. These existing deficiencies were: 1) INSCA actions, 2) Gaps to Excellence Plans, 3) Equipment Reliability Improvement Plan, and 4) effort to transition to National Fire Protection Association (NFPA) 805, “Performance – Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants,” as part of their effort to improve their fire mitigation strategy and reduce their fire risk. According to the licensee, the Integrated Improvement plan represents a summary of Findings, and analysis, resulting actions, and performance metrics associated with their efforts for improving performance to sustainable levels of excellence and to reduce station risk.

To assess their progress and improvement, BFN established a set of performance metrics that were identified to track how the station was specifically adhering to the IIP and to trend performance. These metrics included some fleet-wide indicators as well as some specific to activities at Browns Ferry. In addition, BFN utilized the information from the metrics to allow the BFN management team to “check and adjust” as needed. In addition to the metrics, BFN also used some previously established and newly established challenge and review boards/processes to assess their progress. These boards were established to ensure progress by verifying the quality and efficacy of corrective actions, monitoring action completion and proper closure through CAP, and certify that intended improvements were being achieved and would be sustained. These boards included:

- Corrective Action Review Board (CARB); An independent oversight designed to challenge the causal analysis teams for depth and breadth of analysis and to challenge the ability to implement the proposed action(s).
- Action Closure Review Board (ACRB); Part of the process that provided a graded approach to rigorous closure and documentation of actions contained in the Integrated Improvement Plan (IIP).
- Effectiveness Review Challenge Board (ERCB); A challenge process that evaluated the macroscopic implementation progress and effectiveness made in IIP Action Plan focus areas on a periodic basis. This process focused on performance in areas of strategic significance in improving station overall performance.
- Executive Oversight Board; An oversight board that assisted the BFN recovery team in carrying out its mission by providing independent assessment by Senior NPG management, aided by Industry Subject Matter Experts.

3 NRC Inspection Methodology and Diagnostic Assessment

3.1 Background

The intent of this inspection was to allow the NRC to obtain a comprehensive understanding of the depth and breadth of safety, organizational, and performance issues at Browns Ferry Nuclear Station, and, where data indicated, the potential for serious performance degradation. Furthermore, the NRC used this information to determine whether the continued operation of the facility was acceptable and whether additional regulatory actions may be necessary to arrest declining plant performance.

This inspection was the third part of three inspections being implemented in a segmented approach for completing the NRC 95003 inspection procedure. The reason for completing the 95003 inspection in parts was to allow the Agency to identify whether the licensee was improving and whether the improvements were being sustained.

The first inspection, Part 1, was conducted to provide an evaluation of any immediate as-found safety issues related to the licensee's valve engineering and maintenance programs and to identify any immediate safety issues involving selected safety-related systems. The results of this inspection were documented in NRC Inspection Report 50-259/2011011 (ML 113210602). The second inspection, Part 2, was performed to evaluate maintenance programs at the station. Maintenance was a focus because of the poor equipment reliability performance at the station. The results of this inspection were documented in NRC Inspection Report 259/2011012 (ML12059A314). In addition, a Problem Identification and Resolution (PI&R) Inspection was completed following the Part 2 inspections, although this inspection was not explicitly part of the 95003 Inspection it provided insights regarding the licensee's corrective action program and the station's safety culture, which were vital to the Agency's assessment of Browns Ferry. The results of the PI&R Inspection were documented in NRC Inspection Report 50-259/2012-007, 50-260/2012-007, and 50-296/2012-007 (ML12150A219). The insights gained from these inspections were used to focus the effort of the 95003 Part 3 Inspection.

In accordance with the NRC process, following the completion of this inspection, the NRC will assess BFN's performance by comparing the results of the Part 1, 2 and associated PI&R inspections to the results of this inspection. Additionally, the NRC will evaluate the entire inspection effort to assess the licensee performance improvement and the likelihood of sustained improvement in station performance based on the planned actions as described in the licensee's IIP. Significant items identified by the NRC that warrant additional BFN attention to achieve substantial and sustainable improved performance will be selected for inspection follow up. Those items determined to be necessary to address the findings from this inspection were provided in a commitment letter from TVA on August 9, 2013 (ML13224A263). Acknowledgement of these commitments will be provided in a Confirmative Action Letter (CAL). Once the NRC is satisfied that the necessary CAL action items are complete, and the NRC ROP inspection requirements have been satisfied, the NRC will conduct an assessment that will determine whether BFN unit 1 should be removed from the multiple, repetitive degraded cornerstone column of the Agency action matrix.

3.2 NRC 95003 Inspection Part 3 Overview

This inspection was intended to provide a current "snap shot' of the licensee's performance that would be compared to the performance determined during the 95003 inspection, Parts 1 and 2, and the PI&R inspection. The Part 3 inspection was completed in accordance with NRC inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded cornerstones, Multiple Degraded Cornerstones, Multiple YELLOW Inputs, or One RED Input" (ML102020551). The inspection plan focused on the ROP strategic areas of concern. The team completed reviews of the Reactor Safety Strategic Performance Arena, the Licensee Controls for Identifying, Assessing, and Correcting Performance Deficiencies, the Assessment of Safety Culture, and Evaluation of the LPCI Valve Deficiencies that Resulted in the RED Finding. Since the strategic areas of Radiation Protection, Security, and Emergency Preparedness did not reach the threshold for inspection, these areas were not explicitly addressed during this Inspection.

The team reviewed the licensee's recovery plan, and the actions to address each FPA, including a review of the causal analysis, action plans, effectiveness review plans, and associated metrics. The team verified that the licensee used tangible performance measurements (metrics) consistent with recognized industry standards of measured performance. Prior to implementing this inspection, the NRC used the data from the performance metrics to determine whether the licensee's implementation of the IIP had achieved improved performance specifically to have confidence that measured performance improvement had been observed prior to the Agency accepting that the licensee was ready for the inspection to proceed. During the inspection, the team performed an independent verification of selected data used in the licensee's performance metrics. Also, the team verified the validity of the licensee's performance as indicated by their performance metrics through direct inspection and observation of the licensee's performance when conducting routine duties and responsibilities. Finally, the inspection team used these performance metrics to determine whether a positive, measurable change in performance had occurred in each fundamental programmatic area. This approach allowed the team to focus on the differences between the licensee's performance and the Integrated Improvement Plan (IIP), to assess whether the IIP would lead to an adequate and reasonable margin above minimum industry standards of performance, and whether the licensee would be able to sustain higher standards of industry performance.

3.3 Inspection Objectives

The objectives of this inspection were:

1. To provide the NRC additional information to be used in deciding whether the continued operation of the facility was acceptable and whether additional regulatory actions were necessary to arrest declining plant performance.

2. To provide an independent assessment of the extent of risk significant issues to aid in the determination of whether an unacceptable margin of safety existed.

3. To independently assess the adequacy of the programs and processes used by the licensee to identify, evaluate, and correct performance issues.

4. To independently evaluate the adequacy of programs and processes in the affected strategic performance areas.

5. To provide insight into the overall root and contributing causes of identified performance deficiencies.

6. To evaluate the licensee's third-party safety culture assessment and conduct a graded assessment of the licensee's safety culture based on the results of the evaluation.

3.4 Integrated Improvement Plan Review

3.4.1 Inspection Scope: The team assessed the licensee's recovery process to determine whether it was sufficient to prevent a decline in performance that could result in unsafe operations and that actions in place or planned would achieve substantial and sustained performance improvement.

Specifically the team assessed the following:

- The licensee's recovery framework and controlling procedures,
- The IIP,
- The licensee's reviews of issues and events occurring after the establishment of the IIP,
- The metrics and associated basis,
- The recovery plans for the metrics that were less than green,

- The licensee's internally performed 95003 inspection, and
- The corrective actions for Findings from the NRC 95003 Part 1 and 2 Inspections.

A review of each FPA is contained in specific Sections of this report.
Specific documents reviewed are listed in the Attachment.

3.4.2 Observations: No Findings of significance were identified.

Licensee's Recovery Framework and Controlling Procedures

The framework established by the applicable procedures was systematic and provided adequate guidance to identify and address problems across the station with sufficient depth and breathe. In addition, the process established by the licensee to assess the completion of the specified actions, and to complete effectiveness reviews prior to closing each of the identified fundamental problem areas was rigorous and provided structure to drive sustained improvement.

Integrated Improvement Plan

The IIP was developed with sufficient rigor, and was an overall effective tool for the licensee to assess, improve and measure stations performance. It provided a comprehensive assessment across the station and was inclusive of the all the identified FPAs. Notwithstanding, the team identified areas where the licensee's IIP warranted revision to ensure that substantial and sustainable performance improvement will be achieved on a programmatic or station-wide level. Specifically in the areas of:

- Safety Culture (Section 4),
- Procedure Quality (Section 5.3.2),
- Human Performance Verification Programs (Section 5.3.2.2.1), and
- Operational Focused Organization (Section 5.4.2.2).

In response to these identified issues in the IIP, the licensee initiated corrective action plans to address them. Specific details regarding these areas were provided in the applicable Sections of the inspection report.

Licensee's Reviews of Issues and Events Occurring after the Establishment of the IIP

As part of the recovery process the licensee completed periodic reviews of events or conditions to determine whether revisions should be made to their Collective Evaluation Report and established action plans. Specifically, the licensee reviewed significant events and conditions that occurred following the completion of the Collective Evaluation Report in July 2011, to determine whether the event and or condition was enveloped by the identified FPA, and if the corrective actions established by the FPA, if fully implemented, would have been effective in preventing the event or condition. The licensee's reviews were documented in Significant Event and Issue Review Reports.

The team reviewed each of the Significant Event and Issue Review Reports and compared the events and conditions contained in the reports to the significant events and conditions captured in the licensee's corrective action program for the same time frame to verify the completeness of the licensee's effort. Additionally, the team verified that the licensee's reviews were done thoroughly and in accordance with the procedural guidance. The team found the licensee's effort to be comprehensive and thorough.

Performance Metrics and Associated Performance Metrics Basis

The team assessed the licensee's performance metrics and the associated basis for each. The licensee established a suite of performance metrics to provide a picture of station performance in the FPAs and other high priority improvement initiatives at Browns Ferry. These metrics were governed by licensee Procedure 95003-008, "Integrated Improvement Plan." Forty-five metrics were established in total and were a combination of existing fleet and station metrics and newly developed metrics to monitor and trend station performance. Due to station performance below industry standards during the time of the transition to Column 4 of the NRC Action Matrix, the performance thresholds for these metrics were established at levels lower than industry standards. The licensee basis for these thresholds was so the licensee could more effectively monitor plant performance and determine whether adequate improvement and sustainability was demonstrated. Once sustained improvement was obtained, the licensee intended to re-establish the metric goals to be in alignment with the industry standards as described in the licensee's Safety Culture Continuous Improvement and Sustainability Plan (PER 757451 and 743724).

In general, the team found that the metrics established by the licensee were appropriate to monitor station performance in the FPAs. The team recognized the value in initially using less challenging goals to promote as well as monitor station improvement; however, the team also recognized the need to re-establish the metric goals to be aligned with the industry standards to establish and maintain substantial and sustainable improved performance. During the inspection, the team identified issues related to the performance metrics used by the licensee. Specifically:

- Governance, Oversight, Execution and Support (GOES): This metric monitored the site performance in executing the attributes of several fleet standards based on the Corporate Functional Area Managers (CFAMs) monthly assessments. The team's assessment of the attributes used by the licensee to monitor GOES determined that the most significant attribute monitored by this metric was the use of the escalation process. The use of the escalation process as an attribute to measure performance measured the site's failure to implement TVA Corporate standards. However, the team found that this performance metric weighted the site's failures to implement corporate standards the same as several purely administrative elements, such as meeting attendance. The licensee addressed this issue in their corrective action program.

- Site Human Performance Error Rate: This metric monitored the number of site clock resets per 10,000 person-hours worked (including supplemental workers). The licensee performance as monitored by this metric has been GREEN for the last year. Based on the team's observations and a review of the licensee's corrective action program, the larger number of low level human performance errors occurring at the Browns Ferry Station were not being identified by this very high level metric. The licensee's indicated in their Safety Culture Continuous Improvement and Sustainability Plan that actions will be taken to develop a more effective metric as described in PERs 757451 and 743724.

- Critical Preventative Maintenance (PMs) Deferred: This metric monitored the number of Critical PMs deferred per unit per month, and indicated the organization's ability to complete the most important preventative maintenance activities. The team determined that this indicator, along with a separate fleet performance indicator associated with Total PMs Deferred-Per Unit, was not being reported correctly. This occurred because the licensee's report query methodology was not sufficient to identify all of the PM Deferrals performed within a current month. The result of this incorrect methodology was non-conservative fleet performance indicators for Critical PMs Deferred-Per Unit and Total PMs Deferred-Per Unit. The licensee addressed this issue in their corrective action program as SRs 723976, and 724755.

- Scope Stability: This metric monitored the effectiveness of the work week schedules to include all the necessary and related activities for each work week. The team determined that the process for monitoring this metric did not accurately reflect Work Management performance. Specifically, the team observed that BFN work planning was using multiple schedule lists to account for Work Orders (WOs) on the T-Week schedule that needed to be planned. (The T-Week schedule is a formalized process conducted on a weekly basis starting at 26 weeks prior to a significant maintenance work activity and is used for preparation and planning work activities.) The computer program used to track WOs that needed to be planned did not contain the correct filters, and therefore was not correctly tracking all of the

WOs that needed to be planned. As a result, the Daily Work Management Milestone Matrix – Planning Hit List Report, which tracks the performance of the work planning department in developing work packages for the WOs specified on the T-Week Schedule, was not accurate and therefore, the associated metric was also inaccurate. The licensee documented this issue in their corrective action program by initiating SR 728688.

<u>Licensee's Recovery Plans for the Metrics that were Less than Green</u>
With respect to the licensee's performance in the areas monitored by these metrics, BFN used a color code to grade their performance associated with each metric. Green represented good performance, followed by yellow and then red. Of the forty-five performance metrics, five were below the established green performance threshold. Specifically:

- Collective Radiation Exposure (red),
- Operational Focus Aggregate Impact (yellow),
- Total Preventive Maintenance in Second Half of Grace Period (red),
- Limiting Conditions of Operations (LCO) Management (red),
- Critical PMs Deferred (red).

Of these five indicators, the trends for the three metrics were trending in the negative direction:

- Collective Radiation Exposure ,
- Total Preventive Maintenance in Second Half of Grace Period, and
- Limiting Conditions of Operations Management.

The team assessed the licensee's recovery plans for the five metrics that were below the licensee's established green goals:

- <u>Collective Radiation Exposure (red)</u>: This indicator measured the total external whole body exposure and internal exposure for station personnel, contractors and visitors. Although BFN had made steady improvement in this area since October 2010, the outage performance in the fall of 2012 and spring of 2013 were challenged by high source term and increase refueling outage scope and duration. Furthermore, emergent issues related to radiation waste resulted in additional exposure. The licensee's plans in place to reduce the plant source terms should be effective. In addition, reduction in radiation exposure improvements in the work management process have been recognized as needing improvement as described in Section 5.5.2 of this report.

- Operational Focus Aggregate Impact (yellow): This indicator measures the overall impact to the Operating staff from such things as Operator Workarounds, Operator Burdens and Control Room Deficiencies as defined by the licensee's programs. This indicator has been slowly and steadily improving over the last year. The prioritizing and scheduling of the activities was being completed in accordance with the licensee's process. Based on the schedule the indicator should achieve green status in the very near future.

- Total Preventive Maintenance in Second Half of Grace Period (red): This metric was a leading indicator for deferred or late PMs, and has been red since November 2012. The reason for the red performance was threefold: maintenance effort being focused on the safety system recover plan, emergent plant work and overall work week performance. The licensee's actions to address these issues were contained in SR 727035. Additional discussion regarding the work management process was provided in Section 5.5.2 of this report.

- Limiting Conditions of Operations Management (red): This monthly metric measured the ability of the station to execute planned equipment outages and out of service time for Technical Specification (TS) equipment in accordance with the planned work schedule duration. In April 2013, the indicator was Red, associated with a mismatch between out of service duration and scheduled duration of greater than 25 percent. In this case, the actual out of service time was less than the scheduled time, which was positive from a safety perspective; however, from the licensee's work management perspective it indicated an issue with the estimated time to perform the work. The reason for the over estimation of time to perform the specific work was that the work activity was a first time evolution. The licensee's actions were to ensure realistic and accurate time estimation was directed by SR 727045, and was considered appropriate for continued improvement.

- Critical PMs Deferred (red): This metric measured the number of critical PM activities deferred per unit per month. This metric was red due to a station-wide re-alignment of PM maintenance activities. The purpose of the licensee's re-alignment effort was to ensure all critical PMs were scheduled with the planned equipment outage windows and to allow for more consistent maintenance strategies. Although the metric had been red since January 2013, the re-alignment effort had been effective and the trend was heading toward green. The licensee's actions to address the less than green performance was initiated in SR 727048, and was considered appropriate for continued improvement. Additional discussion regarding the work management process was provided in Section 5.5.2 of this report.

Licensee Internally-Performed 95003 Inspection

Regarding the licensee's internally-performed 95003 Inspection; the team reviewed the following assessment reports, and, in general, found the approach and methodology to be sound. However, it was noted that theses assessments were focused on document reviews as compared to observations of actual work activities. Moreover, the team noted that several of the issues identified as a result of these assessments were the same as the issues identified during this inspection. A few of the examples include:

- In maintenance, managers and supervisors are not meeting (licensee's) expectations for reinforcing standards as they conducted field observations of their personnel. (95003 Readiness Assessment Performance Report – Maintenance Combined Report) (Sections 4.5, 5.2.4, 6.1.2 and 6.1.5)

- Leaders were not sustaining efforts to continuously enforce standards and expectations for human performance behavior. Furthermore, the degree of improvement varied from department to department. (95003 Readiness Assessment Performance Report – Governance & Oversight Combined Report) (Sections 4.5, 5.2.4, 6.1.2 and 6.1.5)

- The licensee's staff still sees the weaknesses/concerns in resources, work control, self and independent assessments, continuous learning, and organizational change management as areas needing additional attention. (95003 Readiness Assessment Performance Report – Safety Culture/Safety Conscious Work Environment Combined Report) (Sections 5.5.2, 6.1.3, 6.1.6, 6.1.7)

- Operating shifts have become tolerant toward this condition and are not driving the site toward excellence in this area. (95003 Readiness Assessment Performance Report – Operations/Decision Making) (Section 5.4.2.2)

- Steps in procedures and work orders are lacking sufficient detail to prevent errors. Work orders and procedures do not consistently contain required information (i.e. torque values); steps do not contain sufficient detail and leave critical decisions to the technician, which has resulted in damaged equipment. (95003 Readiness Assessment Performance Report – Maintenance Combined Report) (Section 5.3.2)

- Use of human performance tools, place keeping, when performing work has been used inconsistently. When craftsmen implement the tool incorrectly and management is not providing feedback to correct this deficiency. (95003 Readiness Assessment Performance Report – Maintenance Combined Report) (Sections 4.5, 5.2.2, 5.2.4, 5,4,2, 6.1.2 and 6.1.5)

- Feedback process is in place, it is not being used effectively by maintenance or work management. A comprehensive plan to improve the use of feedback needs to be developed to prevent delays in work activities or potential rework. (95003 Readiness Assessment Performance Report – Maintenance Combined Report) (Section 5.5.2)

- Adequacy and effectiveness of corrective actions for Human Performance may pose a challenge to effectiveness and/or sustainability. (95003 Readiness Assessment Performance Report – Operations/Decision Making) (Section 5.2.4)

- Managers and supervisors are not meeting expectations for reinforcing standards as they conduct field observations of their personnel. (95003 Readiness Assessment Performance Report – Governance & Oversight Combined Report) (Sections 4.5, 5.2.4, 6.1.2 and 6.1.5)

- The station continues to be challenged in adequately assessing on-line risk. (95003 Readiness Assessment Performance Report – Engineering Combined Report) (Section 5.2.2.2.5)

Specific details of the team's related observations of the issues above have been discussed in the applicable sections of the inspection report. Moreover, the team recognized that continued TVA oversight and involvement in these areas would be necessary to achieve substantial and sustainable performance improvement.

<u>Corrective Actions for Findings from the NRC 95003 Part 1 and 2 Inspections</u>

The team assessed the licensee's actions to address the NRC Findings and associated Non-Cited Violations (NCVs) from the 95003 Part 1 and 2 Inspections. In general, the team found the licensee's evaluation, corrective actions, (completed and planned), and extent of condition reviews to be adequate. In particular the team assessed the following Findings:

- NCV 05000259, 260, 296/2011011-01, “Failure to Implement Requirements of the Inservice Testing Program.”
- NCV 05000259, 260, 296/2011011-02, “Failure to Reestablish Motor Operated Valve Design Basis Capability after Performing Modifications to the Valves.”
- NCV 05000259/2011011-03, “Inadequate Functional Evaluations Performed to Support Operability of Overthrust Motor Operated Valves.”
- NCV 05000259, 260, 296/2011012-01, “Degraded Electrolytic Capacitor Test Results Not Entered into the Corrective Action Program.”

In addition, the team reviewed and closed Unresolved Item (URI) 05000259, 260, 296/2011011-05, regarding ASME (American Society of Mechanical Engineers) Code Compliance in Section 7.2 of this report.

3.4.3 Assessment Results: The team determined that the licensee’s framework and controlling procedures for recovery, as well as, the licensee’s process for monitoring ongoing conditions and events for potential revisions to the IIP were comprehensive and sound. During the inspection, the team identified four areas where the licensee’s approach was not completely effective to create the needed improvement on a programmatic or station-wide level, specifically in the areas of Safety Culture, Procedure Quality, Verification Programs and Operational Focused Organization. In response to these identified issues in the IIP, the licensee initiated corrective actions to revise the IIP.

In general, the team found the performance metrics developed to monitor plant performance and trend improvement to be sound, with some exceptions identified in the metrics associated with: Governance, Oversight, Execution and Support (GOES), Site Human Performance Error Rate, Critical PMs Deferred and Scope Stability. The team considered the licensee’s plans to re-establish the metric goals to be in alignment with industry standards to be vital for achieving substantial and sustainable performance improvement.

The performance metrics, monitored by the licensee, indicated improvements in most individual areas and for the plant overall. The specific areas with performance below the licensee’s established goals had reasonable recovery plans in place to drive improvement.

Regarding the licensee’s internally-performed 95003 inspection, the team found the process to be generally sound. Moreover the team found that many of the issues identified by the licensee during their internally-performed 95003 inspection matched those identified by the team. The team found that this reinforced the conclusion that

TVA needs continued oversight and involvement to effectively implementing the IIP and ensure substantial and sustained performance improvement

4. Safety Culture Assessment

4.1 Inspection Overview

The NRC defines safety culture as “the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment.” Using Inspection Procedure (IP) 95003, the team: 1) evaluated the independent third-party nuclear safety culture assessments conducted at Browns Ferry Nuclear Station in 2011 and 2013; and 2) performed a graded assessment of BFN’s safety culture by conducting focus groups, interviews, behavioral observations, and document reviews. The team used Inspection Manual Chapter 0310, “Components within the Cross-Cutting Areas,” as a framework for assessing safety culture, and developed questions for the focus group interviews, based on the 13 cross-cutting components described within IMC 0310.

The team completed 39 focus group interviews with BFN staff, first line supervisors, and long-term contractors, and 16 interviews with BFN management. Each focus group consisted of six to eight employees. A total of 253 employees participated in the focus group interviews, or approximately 15 percent of the BFN workforce. The team also conducted behavioral observations to gain insights on how work was being performed in the field. The information from the focus group interviews, individual interviews, document reviews, and behavioral observations were organized and discussed in this report. In addition, the team reviewed two apparent cause evaluations for the Fundamental Problem Areas of Employee Concerns Program (ECP), and Safety Conscious Work Environment. The team completed a comprehensive review of BFN’s ECP as well as the process for screening disciplinary actions. The team also evaluated the Nuclear Safety Culture Monitoring Panel (NSCMP) and Site Leadership Team (SLT) meetings to verify whether they were effective methods for monitoring and sustaining a positive safety culture at BFN.

During the inspection, the team identified five issues of concern which the licensee entered into their Integrated Improvement Plan. The first issue was that although employees exhibited attitudes that supported a positive safety culture, those behaviors were not consistently demonstrated, particularly by employees who were closest to the operation of the plant (individual contributors and supervisors). The second issue identified was that the work management process was not effectively implemented to facilitate coordination between departments. The lack of coordination may have contributed to quality issues with work packages, and affected the timeliness of performing work. The third issue identified was that current resources may not be adequate to effectively manage the additional workload required to reduce backlogs and improve reliability at the station. In addition, the need for appropriate training and qualifications may create a gap between having enough staff and having enough qualified staff to meet work demands. The fourth issue identified was that there was a recognized issue with the quality of procedures at the station, but they lacked a systematic process for improving procedure quality in an efficient manner. And finally, the team identified that management and supervisory oversight did not consistently reinforce desired behaviors and work practices through the use of direct observations and coaching.

4.2 Safety Conscious Work Environment (FPA 18 – SCA)

4.2.1 Inspection Scope: The team assessed BFN's safety conscious work environment to determine whether it was sufficient to encourage and support employees to raise nuclear safety concerns and prevent, detect, and mitigate perceptions of retaliation for raising concerns. The team reviewed various site documentation and focus group responses to determine whether there has been improvement since SCWE was identified as an "area in need of attention" in the 2011 Independent Nuclear Safety Culture Assessment Report. The team focused on several areas to obtain an understanding of the activities on site to establish and maintain a SCWE, including SCWE policy, procedures, and training materials, Problem Evaluation Reports (PERS), and the associated Apparent Cause Evaluation (ACE) 571348 for BFN's FPA associated with SCWE. The team also performed focus group discussions and interviewed key management.

4.2.2 Observations: No Findings of significance were identified.

Environment for Raising Concerns

The team determined that station personnel generally felt comfortable raising concerns and did not feel intimidated raising concerns verbally or through the corrective action process. They did not have fear of repercussions for raising safety concerns, and the staff generally felt that their management would support them and detect or prevent retaliation for raising safety concerns. The team reviewed the site SCWE Policy Statement, which stated that it was everyone's responsibility to promptly raise safety concerns and established that nuclear safety was the overriding priority. The policy provided guidance for station personnel to express concerns and differing views. This was validated by the focus group participants. BFN personnel were all familiar with the SCWE policy and were aware of the different avenues for raising nuclear safety concerns.

The team noted that it was site policy to provide initial SCWE training to all new employees, and that the Tennessee Valley Authority Nuclear Power Group (NPG) "Commitment to Nuclear Safety" training was required for all employees annually. The team reviewed SCWE training materials including attendance records and noted that the SCWE policies were reflected in the training given to staff. The team also noted that there was rigor in tracking the training attendance. During interviews and focus group discussions, station personnel reinforced this by stating that SCWE training was required and that training reinforced the principles in the SCWE policy. The team noted that management received additional training on SCWE, including the TVA Safety Supervisor Academy and "Safely Speaking" training sessions that were held in 2012. Station personnel felt that the SCWE and safety culture policies were generally reflected in management behaviors.

Across the board, employees demonstrated knowledge regarding "Good Catch" awards associated with raising safety concerns; however, some groups were more aware of the process being used than other groups. During observations of PER screening committee meetings, the team noted that the threshold for determining a "Good Catch" demarcation on a SR or PER were inconsistent among the various groups. However, the team did not identify any examples where inconsistently assigned "Good Catch" awards affected the staff's willingness to write PERs.

<u>Preventing, Detecting, and Mitigating Perceptions of Retaliation</u>

The team determined that, based on information obtained from the focus group interviews and individual interviews, personnel felt free to raise nuclear safety concerns and personnel did not believe that they would be retaliated against for raising nuclear safety concerns.

The team also reviewed documentation regarding recent PERs that had been submitted anonymously by site personnel, as this could be an indication that personnel fear retaliation if they attached their name to a concern submitted to the corrective action program. The issues of concern that were submitted as anonymous PERs included:

- Unwillingness by maintenance management to accept differing opinions,
- Maintenance management put a PER box inside the labor shop and required personnel to vet all PERs through the manager. Some believed this circumvented the PER process and discouraged them from writing anonymous PERs in fear of retaliation,
- Radiation Protection (RP) personnel continued to be understaffed and felt that this had not been acknowledged or addressed by management.

- Modification's (MODs) management not resetting the site clock for human performance errors, and
- Some personnel expressed concern with the Quality Assurance (QA) group's increased (or more intensive) oversight of craft work, and some felt it hindered their work.

The team acknowledged there was a steady trend in the number of anonymous PERs. However, the first quarter of 2013 indicated a decline in the overall number of anonymous PERs. Specifically, in the first quarter 2013, there were 16 anonymous PERs, which was a reduction from 31 in the fourth quarter 2012. The previous quarters reported 23 in the third quarter and 45 in the second quarter of 2012. Even with the slight decline in the first quarter 2013, the licensee self-identified the continuing trend during the first quarter NSCMP meeting in May 2013 and subsequently generated PER 721085. As part of the PER, the licensee documented that the rise in anonymous PERs were to coincide with outage periods, and as a result, created a corrective action to compare the number of anonymous PERs initiated in the first quarter of 2013 to the anonymous PERs initiated in the previous three quarters to determine the significance in the increase of anonymous PERs initiated.

The amount of anonymous PERS concerned the team with respect to why individuals would not attach their names to issues they identified. As part of the focus group interview questioning, the team attempted to gain an understanding of the use of anonymous PERs as an avenue for reporting. However, based upon results of the focus group discussions, the team identified no current negative examples of a safety conscious work environment. Focus group participants generally stated that they felt free to raise concerns and had, and would, use multiple avenues to raise safety concerns. The team concluded that although there continued to be anonymous PERs written, these PERs represented a small percentage of the total PERs written, that the aggregate impact of the anonymous PERs did not represent a negative station environment and that BFN personnel felt free to raise safety issues.

<u>Resolution of Concerns</u>

The team concluded that employees at the site generally demonstrated a questioning attitude. In addition, recent improvements in the Correction Action Program have increased confidence that issues would be addressed. The corrective action and task tracking software, while still a bit cumbersome to some groups, had made it easier for employees to log and track SRs and PERs. Some employees commented that they previously were hesitant to raise issues in the CAP because they felt that there would be a “boomerang” effect, such that the employee would be called upon to provide the solution by initiating the SR, thus creating work for the SR initiator. Station personnel expressed that this was no longer the case for safety concerns raised at the site that were put into the CAP. For concerns raised that were related to harassment, intimidation, retaliation, or discrimination (HIRD), the team did not identify any examples of HIRD issues that were not being addressed by the licensee. Focus group participants could not readily identify examples where there were repercussions for HIRD-related concerns, and few were aware of any HIRD-related concerns at all.

BFN organized a SCWE High Impact Team (HIT team), as part of the IIP, to review PERs that were potentially relevant to nuclear safety culture and SCWE. The HIT team met periodically to review and provided additional information regarding SCWE coded PERs and anonymous PERs, as well as to determine what actions should be undertaken to resolve the issues and to communicate feedback to station personnel. The team reviewed a sampling of SCWE HIT meeting minutes and noted that there was generally a feedback mechanism associated with each PER reviewed. However, during the Focus Groups discussions, there were no known recent examples of SCWE issues handled by the licensee and likewise, the focus group members’ perception of how the licensee handled SCWE-related issues was indeterminate. The team recognized that the implementation of actions to establish a healthy SCWE at BFN warranted continued management oversight and involvement to result in substantial and sustainable improvement.

Apparent Cause Evaluation

The team evaluated the licensee’s ACE for FPA 18, “Safety Conscious Work Environment.” Specifically, the NRC evaluated: 1) that completion of the analysis was in accordance with the licensee’s process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee’s FPA adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee’s Integrated Improvement Plan (IIP) and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

The team determined that the evaluation appropriately identified the apparent and contributing causes related to SCWE issues at BFN. The evaluation appropriately considered the extent of condition and extent of cause, and incorporated both internal and external operating experience.

The two apparent causes identified in the evaluation were:

- Management had not effectively established a trusting relationship with employees in order to strengthen the SCWE, and
- Management did not effectively use CAP to bring issues to resolution when indicators and precursors of a chilled environment were identified.

The two contributing causes identified in the evaluation were:

- ECP staff personnel were not viewed as competent and trustworthy, and
- Management did not consistently hold personnel accountable for inappropriate SCWE behaviors.

The ACE performed by the licensee included a review of previously identified Findings and documented observations from the NRC, the Institute for Nuclear Power Operations, the Nuclear Safety Review Board (NSRB), and the 2011 Independent Nuclear Safety Culture Assessment as well as a historical document review. The analysis presented the relationships from the cause to the primary issues of concern. The primary gaps identified in the INSCA report were that individuals were unwilling to report or inform site management of nuclear safety issues and that management failed to hold personnel accountable for behaviors that were not supportive of SCWE. The ACE determined that the concerns with SCWE affected BFN employees as well as individuals contracted onsite.
Corrective actions implemented to address the SCWE issues included:

- Providing coaching to leaders via intrusive focus on the strategic plan with external contracted individuals,
- Performing periodic assessments of progress and documented results,
- Providing "Safely Speaking" training to First Line Supervisors and higher level management,
- Providing safety culture briefings across site organizations,
- Issuing weekly communications specifically focused on SCWE,
- Conducting interim effectiveness reviews to determine effectiveness of actions within site organizations to gauge improvements,
- Having the members of BFN's Safety Culture Team continue to conduct pulse interviews of priority organization personnel,

- Creating and implementing a governance and oversight model in a procedure for the primary contracting organization on site,
- Revising CAP procedures to provide additional guidance on anonymous PER and SCWE issues, and
- Revising the routine communication strategy pertaining to chilled work environment. In accordance with "Communications Plan," ECP-2, Rev. 1, the licensee included requirements to conduct ongoing employee pulsing to monitor the SCWE within the site workforce.

This evaluation referenced the root cause analysis (RCA) performed for FPA 1, Management and Leadership Standards (MLS), as the correction actions implemented overlap between these two fundamental problem areas (i.e. MLS and SCWE). It was also determined that the root causes of the insufficiencies in the management and leadership area directly affected the SCWE at BFN. The root cause evaluation for FPA 1 is discussed in further detail in Section 6.1.2 of this inspection report.

The NRC concluded that these corrective actions addressed the deficiencies identified in the cause evaluation. Additionally, input from focus group interviews conducted by the team confirmed that these actions have been effective in improving the safety conscious work environment at the station.

4.2.3 Assessment Results: For the FPA 18, Safety Conscious Work Environment, the team assessed site documentation, site policy statement, training materials, and the apparent cause evaluation, and determined that at the time of the inspection, there was no indication of a SCWE issue, and the licensee's actions to address this FPA were adequate. The team concluded that in order to achieve continued sustainability and substantial improvement of this FPA, implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential.

4.3 Employee Concerns Program (FPA 19 – SCA)

4.3.1 Inspection Scope: The team assessed the licensee's Employee Concerns Program to determine whether it was sufficient to prevent further decline in the safety conscious work environment and the safety culture at BFN that could result in unsafe operations. The team also assessed actions in place or planned to determine if they would promote sustained improved performance. The team reviewed the ECP procedure, ECP files, PERS, and associated ACE related to PER 571345. The team also performed focus groups meetings and interviewed the ECP managers.

4.3.2 Observations: No Findings of significance were identified.

The team determined that BFN was making significant progress towards establishing an effective ECP. However, because revised procedures and changes had been in place for a short period of time, it was too soon for the team to be able to assess their effectiveness. As a result of issues identified in PER 571345, Revision (Rev.) 0002, “Employee Concerns Program Apparent Cause Evaluation PER Report”, issued in December 2012, all procedures associated with TVA ECP at BFN were revised in early 2013. Upon further TVA management review, procedures were again revised on May 10, 2013. The revised procedures included changes to incorporate corrective actions to address issues and gaps identified by the ACE. As part of the effort to revise the ECP policies and procedures, industry experts were consulted by the licensee to benchmark the TVA ECP against high performing nuclear organizations and to leverage ECP best practices. As a result, the team determined that the revised procedures were realigned consistent with many top industry ECP programs. The changes effectively addressed previously identified issues in policies and procedures. However, it was too soon for the team to determine whether or not the changes that had been implemented were effective at addressing identified programmatic gaps and issues.

In addition to procedural changes, TVA initiated a number of organizational changes in the BFN ECP reporting chain and organizational structure. Some of the proposed staffing changes were not scheduled to take place until the end of fiscal year (FY) 2013. The planned staffing changes included filling two permanent ECP specialist positions on site, in addition to the position of ECP Senior Program Manager (TVA Corporate).

During this inspection period the full time BFN ECP specialist was actively working to increase the awareness of ECP by making the program more visible and accessible at the site, thereby addressing any potential issue with trust in the program or the ECP Specialist specifically. Efforts to increase visibility included the ECP specialist increasing the frequency of his attendance at specific work group meetings to provide ECP outreach and education as well as time in the plant. An interview with the ECP Specialist indicated that these activities were performed to positively affect trust and credibility perceptions of the ECP and specifically the ECP Specialist. Additional corrective actions included the construction of a second expanded ECP office located within the plant and wider distribution of ECP posters and advertising materials throughout the site. Although the FY 2013 ECP hiring plan had not yet been implemented, the BFN ECP specialist’s investigative workload was being supported temporarily through the rehiring of two former TVA employees with previous ECP experience, which adequately addressed the current ECP workload. Focus group interviews indicated that, although the BFN ECP specialist may not have been known by name, individuals stated that they were familiar with the ECP function and indicated a willingness to use its services if needed. There were a few remaining pockets of personnel in specific departments who indicated a lack of confidence in the ECP, based on negative experiences when using the program several years ago. However, overall most focus group participants indicated trust in the ECP and did not have any concerns with the ECP's ability to maintain confidentiality.

A review of ECP-3, Rev. 0, "Training and Qualification, Appendix A, ECP Staff Training Checklist" for the ECP Specialist, indicated the ECP Specialist had received all the required training. ECP-3 was completed by all ECP staff. In a comparison of training requirements for BFN ECP staff to other industry ECP staff, the team noted that BFN training on the ECP-3 was specific to BFN attributes and did not include information from outside sources such as NRC, INPO, or Nuclear Energy Institute (NEI) documents that contain pertinent information for new ECP staff to become familiar with. The ECP Specialist indicated that ECP-3 had not been recently revised. The interview with the ECP Specialist resulted in all questions posed by the team being responded to appropriately, indicating competence in the ability to manage the ECP for BFN.

In addition to the BFN ECP specialist, the primary site contractor had an ECP representative assigned to BFN. The contractor ECP representative demonstrated ECP support by attending daily contractor morning meetings and by spending significant amounts of time in the plant among various work groups. Furthermore, the contractor ECP procedures had recently been revised to align more with BFN ECP procedures. BFN ECP staff conducted an audit of the contractor ECP on a biennial basis to ensure that their program was meeting BFN ECP expectations and requirements.

The team reviewed a random sampling of BFN ECP documents. BFN ECP quarterly reports for the first quarter of 2011 and the first quarter of 2013 were reviewed, as well as exit interview forms for the period of January through June, 2012. In addition, 12 individual BFN ECP case files from 2012 and 2013 were reviewed. The review included files that were closed through the rapid resolution process, as well as those closed through the standard ECP investigation file closure process. Files were complete and were organized in a manner consistent with the most recent TVA BFN ECP guidance and were dispositioned appropriately. The team also performed a limited review of contractor ECP files. Contractor ECP files were complete, consistent with contractor policies and procedures, and were dispositioned in accordance with contractor ECP procedures.

BFN was addressing ECP issues that existed prior to the implementation of the corrective actions associated with PER 571345, Rev. 2. Based upon documentation reviews, interviews with individuals and focus group interviews, observations of ECP-related meetings, as well as visible ECP postings throughout the plant, the team determined that the BFN ECP was making significant progress towards establishing an effective ECP that was comparable to successful programs within the industry. Notwithstanding the significant progress made at the time of the inspection, the team noted the importance of implementing the planned staffing changes that included the availability of two TVA ECP specialists at BFN, along with the support of an ECP Senior Program Manager. These actions were important to a successful ECP at BFN. As noted previously, because of the short amount of implementation time under the revised ECP program, policies, and procedures, the team was unable to determine whether or not the changes were effective at addressing ECP gaps and issues as well as a basis of assessing the longer term sustainability of the program changes. The team found that a self-assessment of the BFN ECP was scheduled for August 2013 to assess the effectiveness of these changes.

Apparent Cause Evaluation

The team reviewed the ACE associated with FPA 19, Employees Concern Program, issued in December, 2012. Specifically, the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's FPA adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's IIP and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

The team compared the results of the completed corrective actions with the BFN ECP program review and the focus group interviews to determine whether the corrective actions were effective in addressing the ECP programmatic and procedural issues at the station.

The team determined that the ACE appropriately identified the apparent and contributing causes related to the ECP at the station. The evaluation appropriately considered the extent of condition and extent of cause, and incorporated both internal and external operating experience. Corrective actions implemented as a result of this ACE adequately addressed the identified causes and included:

- Benchmarking the industry to identify best practices and implementing ECP procedures revisions to address gaps in the BFN ECP program,
- Developing and implementing standards and guidance for the TVA fleet ECP program,
- Engaging an experienced ECP specialist consultant to provide recommendations to identify gaps in excellence and expectations, and
- Developing a ‘Gap to Excellence’ plan which appropriately addressed the issues.

4.3.3 Assessment Results: For FPA 19, Employee Concerns Program, the team assessed site procedures, ECP files, the ACE, and determined that at the time of the inspection, the corrective actions were adequate to address the deficiencies identified in the ACE. Additionally, input from focus group interviews conducted by the team indicated that ECP improvements had been made; however, there had not been enough implementation time to adequately assess the sustainability of the corrective actions taken in the ECP at BFN. Nonetheless, for continued sustainability and substantial improvement of the FPA, implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential.

4.4 Evaluation of Third-Party Safety Culture Assessment

4.4.1 Inspection Scope: Consistent with inspection requirements in Section 02.07 of IP 95003, the NRC evaluated the licensee’s third-party safety culture assessment to determine whether: 1) the assessment was comprehensive; 2) the assessment was methodologically sound; 3) the assessment team members were independent and qualified; 4) the data collected supported the conclusions derived from the assessment; and 5) the licensee’s corrective actions in response to the assessment Findings were effective.

The team focused the review on the safety culture assessment conducted by a third party vendor, in 2011 and the associated corrective actions implemented based on the results of the 2011 assessment. The team then reviewed the results of a follow-up assessment conducted by the same third party vendor in 2013 to evaluate whether the more recent results indicated improving trends. In 2011 and 2012 the team reviewed the vendor’s proposed methodology and overall plan for conducting the assessment and considered it to be sound.

4.4.2 Observations: No Findings of significance were identified.

Comprehensiveness

The team concluded that BFN's independent nuclear safety culture assessment, conducted by a third party vendor, was both comprehensive and provided appropriate indications of the safety culture that existed at BFN at the time of the assessments in early 2011 and early 2013. All functional organizations, including BFN management, TVA Corporate management, and long-term contractors (greater than 6 months), were included in the assessment. The content of the survey was of sufficient breadth to capture information related to all of the safety culture components included in IMC 0310. In addition, the interviews and behavioral observations completed in conjunction with the survey provided information on the safety culture components using a different methodology to confirm and provide context to the survey results.

All employees on site, including long-term contractors, were invited to participate in the survey portion of the assessment, thus a population-based strategy was used as opposed to a sampling strategy. The employee response rate for the 2011 survey was 59 percent, which was much lower than the target rate of 70 percent. The low response rate raised concerns about whether the survey results were representative of the entire site. The third party vendor responded to this concern by conducting interviews with personnel who did not participate in the survey to determine whether there were systematic differences between survey responders and non-responders. The confidential interviews provided information to validate that, although the response rate was low for the 2011 survey, the non-responders that were interviewed did not provide significantly different ratings as compared to the responders. The team found that the overall response rate for the 2013 assessment survey was 86 percent, 1716 respondents. This was a substantial increase from the employee response rate obtained in 2011, and was sufficient to provide confidence that the responses received were an appropriate characterization of the entire site.

Assessment Methods

The team concluded that the methods used to perform the INSCA were appropriate, although some issues were identified, particularly in the safety culture survey. Multiple methodologies were used to gather data, including a survey, interviews with individual contributors, management, and subject matter experts, and behavioral observations of meetings and field work. The third party assessment team was able to self-identify the survey issues and responded to those issues by enhancing the use of other methodologies; for example, by conducting additional targeted interviews and increasing the number of behavioral observations. The multi-method approach was an appropriate strategy to conduct a complete assessment of safety culture at the station.

The survey tool used during the assessment had been used at various nuclear power plants in the United States, including two previous administrations at BFN in 2006 and 2009. Analyses performed by an independent statistical analysis firm indicated that the survey met accepted standards for internal consistency and construct validity. However, based on the confidential interviews with personnel, the third party assessment team determined that there was a positive bias to the survey results. The survey contractor determined that a positive bias was evident because the majority of interviewees provided quantitative ratings higher than could be justified by the rationale given for ratings. The higher-than-justified ratings were noted to occur most often from interviewees who only had nuclear industry experience within TVA. The largest contribution to the high results came from a survey input for treating nuclear safety as the top priority and for maintaining standards and expectations during the last refueling outage. This positive bias was noted in both the 2011 and 2013 assessments. As a result, the survey, by itself, was not considered as a completely accurate indicator of safety culture at BFN. Instead, the differences observed between the survey results and information obtained through interviews and observations suggested a gap between safety culture-related attitudes and actual behaviors. This gap was also observed during the NRC's graded safety culture assessment, as discussed in Section 4.5.

Independence and Qualifications

The team verified that the third party assessment team was independent from BFN and had appropriate qualifications to conduct the assessments. The biographies of the assessment team members indicated that the team was composed of individuals with extensive experience in nuclear power plant operations and applicable knowledge of nuclear safety culture.

Support for Assessment Conclusions

The overall summary conclusions of the 2011 and 2013 assessment results presented an appropriately critical assessment of the safety culture at BFN. The 2011 assessment identified over 70 issues in nuclear safety culture at BFN, and over 20 organizations that had specific safety culture issues. The recommendations provided in the report considered the positive bias of the survey results and suggested that even nominal issues received immediate attention. Overall, there were notable improvements in the survey results in 2013 over the 2011 survey results, but the 2013 assessment highlighted areas that continue to be issues. The inclusion of personnel interviews and behavioral observations were critical to the comprehensiveness of the assessment and provided unique information about ongoing issues that would not necessarily have been noted based solely on the survey results.

Effectiveness of Corrective Actions

The licensee chartered an internal safety culture team to review the results of the 2011 third party assessment to develop and monitor corrective actions associated with the assessment. The issues identified in the 2011 assessment were grouped into specific areas of focus, which then became the basis for the first nine fundamental problem areas that BFN developed for their IIP. All of the issues from the 2011 assessment were incorporated into BFN's fundamental problem areas, including the addition of SCWE and the ECP. PER Action 514964-074 provided a crosswalk of the issues from the 2011 independent assessment mapped to FPA and corrective actions. Department-specific corrective actions were developed to address issues in the 2011 assessment identified within specific department. Cases existed where a specific department scored lower on the safety culture survey than the rest of BFN. These department-specific corrective actions were all tracked under PER 514964 and were independent of the fundamental problem areas in the IIP because they were related to the department-specific issues rather than issues that affected all of BFN.

4.4.3 Assessment Results: Most of the departments within BFN demonstrated improvement in the licensee's 2013 third party safety culture assessment as compared to the results in the licensee's 2011 third party safety culture assessment. However, there remained three departments that had lower safety culture survey scores in 2013 as compared to 2011 or had notably lower scores than the rest of BFN. In the 2011 assessment security, online work control, and rapid response engineering were departments that had low scores, but showed marginal improvement in the 2013 assessment. The team determined that corrective actions taken within these respective departments had not been effective in that the actions taken did not result in improvements in safety culture perceptions. The NRC also identified specific safety culture concerns within these departments during focus group interviews. The interviews resulted in an independent confirmation of the results of the 2013 assessment.

Based on the improvement in the results of the 2013 Independent Nuclear Safety Culture Assessment (INSCA), many of the corrective actions taken to address the safety culture issues from the 2011 INSCA were effective overall. However, the team concluded that there were some significant issues that were not adequately addressed by the corrective actions taken and related to those issues they did not show evidence of significant improvement in the 2013 assessment. The NRC also identified concerns that were consistent with the ongoing issues identified by the 2013 assessment. In particular, the following concerns identified in the 2013 INSCA were also identified by the team as concerns, which included staffing and resources, writing quality PERs in the corrective action program, deficiencies in procedures, and concerns about management getting staff input before making changes at the station.

Following discussion with the licensee, an action plan was generated to address the team's concerns, PERs 742931 and 757451, Safety Culture Improvement and Sustainability Plan, which included actions to address staffing and resources, writing quality PERs in the corrective action program, deficiencies in procedures, and concerns about management getting staff input before making changes at the station.

4.5 NRC Independent Safety Culture Observations

4.5.1 Inspection Scope: The team's assessment of BFN's safety culture included conducting 39 focus group interviews and 16 individual interviews. The team asked questions related to the 13 cross-cutting components in IMC 0310 and included additional questions specific to BFN's focus area on procedure adherence and quality issues. Each focus group interview consisted of six to eight employees from across the site. A total of 253 employees participated in the focus group interviews and individual interviews, resulting in approximately 15 percent of BFN's workforce. The focus group interviews consisted of craft personnel and supervisors from Operations, Maintenance, Chemistry, Radiation Protection, Security, Work Control, Engineering, Quality Assurance (QA), Training, Safety and Licensing, and long-term contractors.

4.5.2 Observations: No Findings of significance were identified.

The following observations were divided into the 13 Cross-Cutting Components described in IMC 0310 with an additional Section on procedure adherence and quality.

4.5.2.1 **Decision Making (Rigor) Assessment Results**

Focus Group Interview Summary

Results of focus group discussions indicated a perception that conservative decision making during on-line and outage work had improved at BFN. Focus group participants provided several examples of management decisions to remove equipment from service for repair before reaching the threshold of inoperability. Station personnel indicated that the management team was supportive of the additional time added to the last outage, due to emergent work being included in the scope. Focus group participants also indicated that the most recent outage was longer than planned because management was being conservative, and took the time to do the 'right' things. The staff believed that the decision to start the outage early to fix a Reactor Core Isolation Cooling (RCIC) valve was a safety-focused decision, and the employees indicated that the basis for that decision was communicated throughout the site. The participants further indicated that the "quick-fix" mentality, though previously pervasive, did not exist anymore, but instead equipment was being fixed correctly and in a timely manner.

Station personnel stated during the focus group discussions that they had the authority to stop work and that they would be supported by their management if they exercised their stop work authority. The security department did not necessarily share that perception. Instead security personnel were concerned that their first line supervisors were hesitant to make decisions. Security participants believed that their supervisors may not have had the perception that they had the authority to make decisions.

The team found that some QA staff were less optimistic than the rest of the organization regarding the site's emphasis on production versus safety. There was a view in the QA department that the rest of the personnel on site had an overly positive view of the improvements in safety culture at BFN. Some QA personnel were concerned that, although BFN staff perceived that management's emphasis had shifted from a production focus to being safety focused when making organization-level decisions, they did not believe that the site's overall culture, in terms of day-to-day decision making had changed as much. During the focus group interviews and individual interviews, QA personnel provided examples to support their perception, such as observing non-conservation decision making during their assessments and field observations. QA staff also noted a discrepancy between the human performance observations that they were documenting and the observations documented by supervisors during field observations of activities. Overall, QA personnel were documenting many more human performance issues than supervisors during behavioral observations. Supervisors were not as conservative as QA personnel in recognizing and correcting human performance issues during field observations.

Team Observations

The team acknowledged improvements had been made by the station in the area of decision making and rigor. There were examples during the 2013 refueling outage, where station management utilized safety focused decision making and technical rigor as outage challenges were occurring. For example, there was additional work added to the outage scope to address long-term equipment deficiencies and outage schedules were extended to address newly discovered equipment deficiencies identified during the outage. However, the team identified multiple key observations and Findings of very low safety significance associated with the behaviors in this area.

The team reviewed an engineering evaluation for PER 730443 in which control room operators slid three light diffusers over the top of the other light diffusers for surveillance test, 0-SR-3.3.7.1.4, “Control Room Ventilation Logic System Functional Test – Radiation Monitors.” The engineering analysis failed to consider impacts of the light diffusers becoming seismic missile hazards or the overhang limit of the diffuser to become a fall hazard. This issue was documented as a Finding and associated NCV in Section 5.2.4.2.1. The team also identified a Finding involving an inappropriate commercial grade dedication of safety-related bearings by the licensee. In January 2013, the independent laboratory test results indicated three bearings failed to meet specific acceptance criteria; however, the licensee’s engineer performing the commercial grade dedication review made an "engineering judgment" and accepted the remaining six bearings. Two of the six bearings accepted by TVA had been installed in safety-related equipment. This issue was documented as a Finding and associated NCV in Section 5.1.3.2.1.

The team identified another Finding that was considered as an example of poor engineering decision making and rigor involving the licensee’s failure to implement an adequate test program for residual heat removal service water (RHRSW) and essential equipment cooling water (EECW). The team identified the test did not adequately account for the river water temperature impact on the pump lift and a resultant change in pump flow and vibration performance. This demonstrated a lack of engineering technical rigor with respect to fully understanding the effect of all the parameters that can influence equipment performance. Refer to Finding and associated NCV in Section 5.4.3.2.1 for additional details.

In the Operations Department, the team identified a Finding associated with the verification practice exemptions documented in Attachment 8, "Peer Check Exemption List," of TVA Corporate Procedure "Conduct of Operations," OPDP-1, Rev. 27. The attachment contained a list of activities and procedures that TVA operations determined were exempt from requiring the performance of peer checks, which included actions in the Abnormal Operating Instructions (AOIs) and Emergency Operating Instructions (EOIs). The team considered this aspect of the Finding to be an example of poor decision making and rigor, because verification practices are a key barrier control to prevent human error when manipulating plant equipment and prevent safety events. The AOI peer check exemptions were not consistent with the TVA Corporate Procedure NPG-SPP-10.3, "Verification Program," Rev. 1, and NRC regulatory requirements. Refer to the Finding and associated NCV in Section 5.3.2.2.1 for additional details.

Although none of the following observations were considered to be more than minor examples of violations of NRC requirements, the team identified multiple examples of less than adequate rigor and decision making with respect to the performance of immediate determinations of operability (IDO). Examples included on April 27, 2013, a high pressure coolant injection (HPCI) tubing leak was identified with an estimated leakage of five drops per minute. The associated IDO in SR 718260 was performed by the Senior Reactor Operator (SRO) without verifying the function of the instrument tube, source of water or oil, water leak impact on the HPCI main pump, or determination of whether the water was contaminated or clean. In addition, the SRO could not immediately answer questions concerning details that were used to determine whether the HPCI system was operable. The SRO later followed up with the team and provided additional facts to support the IDO. Second, the IDO for PER 731144 contained factual inaccuracies. The IDO stated that the Unit 3 Reactor Protection System (RPS) relays had been replaced when they had not. The IDO for PER 718260 was copied and pasted into SR 718259; including the reference to an unrelated service water SR and a description of the tubing leak identified in SR 718260. These examples of poor rigor and decision making are discussed in more detail in FPA 2, Operational Focus and Decision Making, Section 5.4.2 in this report.

In the Maintenance Department, the team observed the work activity for RHRSW pump impeller adjustment, in which the work task was completed without using the lubrication as listed as "Required Equipment." In addition, the torque values used in the work package were different than the vendor manual recommendations. When questioned by the inspector, the technician initiated SR 726149 regarding vendor manual torque values and lubrication requirements. In addition, when questioned by the NRC, the mechanical supervisor also failed to recognize nuclear safety importance and potential impacts on the RHRSW pump operations due to the lubrication and torque value discrepancies. Both the technician and the supervisor did not apply the adequate level of rigor towards the importance of vendor recommended lubrication and torque values as it affected pump performance.

The team identified an example of less than adequate rigor and decision making that involved multiple station organizations. The team identified a Finding for the failure to install insulation on two RHRSW pump discharge vacuum breaker valves. Operators toured this area twice per day and system engineers walked down the system regularly and did not identify this issue that could impact operability. The lack of safety focused decision making and rigor was exhibited by plant personnel who have a responsibility to directly observe system parameters and performance, but failed to recognize the significance and existing deficiencies. This Finding and associated NCV was documented in Section 6.1.4.2.1.

The team identified a Severity Level IV Violation when the licensee failed to perform a 10 CFR 50.59 evaluation for inter granular stress corrosion crack (IGSCC) examination on a Class 1 piping weld. Specifically, in March 2013, BFN made changes to the facility without obtaining a license amendment. As a result of the less than adequate rigor and decision making applied, BFN did not perform the evaluation method consistent with the Updated Final Safety Analysis Report (UFSAR) and Generic Letter (GL) 88-01 examination requirements. This violation was documented in Section 5.1.4.2.1.

Comparison Summary

Comparing the focus group interview discussions with the inspection observations, the team identified a discrepancy between the licensee's staff perceived improvements in decision making and overall rigor and the team's inspection observations and events that were occurring at the time of the inspection. Although the team acknowledged improvements had been made by the station in the area of decision making and rigor, the team observed examples of issues involving decision making and rigor, which indicated that this continued to affect performance across multiple departments at BFN.

Licensee Actions Identified to Revise IIP

The area of decision making was identified as a fundamental problem area. Corrective actions to address decision making specific to the Operations Department are found in FPA 2, Operational Focus/Decision Making, (Section

5.4.2). In addition, correctives to address technical rigor deficiencies are documented in FPA 9, Technical Rigor, (Section 5.1.4).

The team reviewed BFN's existing corrective actions in the area of rigor and decision making, both of which are attributes of technical human performance. The team identified that, although corrective actions existed, and improvements had been observed by the licensee and the NRC, the BFN corrective actions were not systematically approached at BFN or TVA Corporate to address this issue. The station did not methodically target and correct the latent organizational weaknesses with respect to the use of rigor and decision making in the workforce and supervisors' work practices and behaviors. Issues with rigor and decision making continued to result in human performance errors and events at BFN. The team was concerned that the lack of a systematic approach to address these issues would plateau the licensee's performance improvement initiatives with respect to safety culture and workforce behaviors. The team's concern was discussed with the licensee and the licensee subsequently generated PER 742931, which is discussed in more detail in Section 4.8, Summary and Conclusions. The team reviewed the corrective actions and determined that they were appropriate to address the issues in the areas of decision making and rigor.

4.5.2.2 **Resources**

Focus Group Interview Summary

BFN identified Resources as a FPA. Focus group discussions indicated, with the exception of the security and maintenance departments, that there were significant issues with staffing across the site. BFN staff expressed a concern that current staffing levels were not appropriate for a three unit boiling water reactor (BWR) site. Focus group participants indicated that benchmarking three unit BWR staffing levels was difficult because there are only a few three unit sites in the industry; however, they also indicated that management was aware of the staffing concerns and was actively trying to understand the appropriate staffing level at BFN.

Personnel from multiple departments within BFN also indicated a concern about the engineering backlog when engineering contractors were no longer on site due to the 95003 project effort working towards completion. Also, there were specific concerns from the licensee's staff in the Engineering Department that there were not enough qualified senior level engineers available to mentor newly hired engineers. BFN hired a number of engineers in the last year, but many of those were entry level engineers with no nuclear experience. The team interviewed the Engineering Manager, who indicated that he recognized this gap, and was currently in the process of recruiting mid-level career engineers who could be easily qualified. With respect to the Operations Department, there was a concern that the operations trainers were not sufficiently qualified to teach the specifics of BFN technology and therefore operators were failing initial licensing exams. This situation had led to a lack of qualified operators. Adding to the concern about the number of qualified operators, management had instituted a practice of taking operators and placing them in other positions at BFN in order to provide operations' knowledge to other departments. While the departments receiving the operators and the operations staff saw this as a benefit for disseminating operations knowledge across the site, the operations staff reported that this practice also left the Operations Department deficient of qualified staff. The team heard through the focus group interviews that there were also many SROs reaching retirement age, and operations' staff expressed a concern that although there were currently multiple classes of SROs in training, the number of retiring SROs may exceed the number of newly licensed SROs at BFN.

In terms of equipment and monetary resources, the focus group discussions indicated that although BFN has had a history of equipment reliability issues, station personnel currently perceive Corporate TVA's funding for equipment replacements as a positive improvement.

Team Observations

In the area of resources, the team observed a few key observations. The perception of the staff during the focus group interviews was, overall, optimistic and they felt that management was taking actions related to resources. The team did note that overall, station performance indicators, related specifically to or impacted by resources, reflected improvement in the areas of critical work order backlog, vendor manual and drawing backlogs, and Design Change Notice (DCNs) backlogs. However, the team observed relatively high backlogs in some areas of CAP corrective actions. The licensee had previously identified this as part of the new CAP emphasis at the station and the new CAP organizational structure. BFN was working to address this issue. In addition, the team observed resource strains due to new programs or improvement plans, like the SRO focus on improved operability determinations and work week schedule preparation.

Comparison Summary

The team concluded that the focus group discussions were consistent with the team's inspection observations. Although corrective actions were in progress, it was not clear to the team, from a change management perspective, how the licensee had considered the new administrative obligations and their effects on the plant staff for long term sustainability. The team considered resources to be an issue warranting revision to the IIP.

Licensee Actions Identified to Revise IIP

The area of resources was identified as a FPA in the IIP. The team found that there were staffing plans in place in most departments and BFN was making progress in this area. The corrective actions are addressed under FPA 3, Resource Management in Section 6.1.3. in this report.

Regarding sustainability of the licensee's IIP actions in the area of Resources, the team identified Resources as an issue warranting revision to the IIP. Specifically, the current resources may not be adequate to effectively manage the workload related to performance improvement. In addition, the need for appropriate training and qualifications may create a gap between having enough staff and having enough qualified staff to meet work demands. The team discussed this issue with the licensee and the licensee subsequently generated PER 742931. The team reviewed the licensee's action plan to address this issue and found that the actions were appropriate to address the concern related to the area of Resources.

4.5.2.3 **Work Control**

Focus Group Interview Summary

Results of the focus group discussions indicated that the work control process and work package quality were both improving. However, there was still a significant amount of progress that was needed. During the focus group discussions, the staff also provided some examples of positive changes. For example, during outages, the planners and schedulers physically worked together, and this was believed by staff to be more effective. The staff indicated that the correct work tasks were incorporated into outage planning. For example, in RP, the team was told that certain valves, which were not previously in the valve testing program, had recently been added into the program resulting in a perception that the station was testing all the valves. The staff acknowledged that work being scheduled during the outage was actually being performed during the outage. For example, 90 percent of the scheduled work during the most recent outage was completed, and the staff viewed this as a positive action.

Although station personnel discussed examples of improvements in the work control process and work package quality, the staff had multiple examples where improvements were still needed. From the focus group interviews, the team specifically identified three areas of concern in work control: scheduling, interdepartmental coordination, and planning. The three areas of concern are discussed below:

1) Scheduling: The staff indicated that the station was still having issues with the work management T-week process in that several examples were discussed indicating that the T-week schedule was not maintained. The T-week process was defined as a formalized process conducted on a weekly basis starting at 26 weeks prior to a significant maintenance work activity and is used for preparation and planning work activities. The staff saw some improvement, however, higher priority issues continued to interrupt and alter the T-week schedule. In the work management group, staff indicated that T-week schedules were not easy to use; however, the staff believed this was being addressed by management. The staff also indicated that there had been an increase in the use of work management software program, which had positively affected scheduling work.

2) Interdepartmental Coordination: The staff indicated that there were significant issues with coordinating work between departments, for example, operations and maintenance. Staff indicated that coordination between schedulers and planners for online work still needed improvement. This issue was causing perturbations in the work schedule. There were work packages that had quality or completeness issues when they were needed to implement the work, which caused work to be delayed.

3) Planning: The staff believed that during the last refueling outage, scheduling and prioritizing had improved from previous outages. The team was told by the licensee staff that there had been an improvement in the balance of refueling outage planned work and online planned work. The focus group staff expressed that a ‘Ready-Ready’ work control team, which is a final readiness review, was viewed as a positive addition to the on-line work control process. Staff further indicated that the outage work planning process was better implemented than the on-line work planning process because outage work planning’s ‘Ready-Ready’ Team had existed for a longer period of time.

<u>Team Observations</u>

In the area of work control, the team's observations were consistent with the results of the focus groups. The majority of the team's key observations were important in the areas of scheduling, interdepartmental coordination, and planning. Specifically the team observed that the Outage and Scheduling Performance Indicator (OSPI) program, used for scheduling, did not identify all the work orders needed for planning or for tracking performance indicators. The team also observed that an In-Service Testing (IST) for Unit 2 Stand-by Liquid Control (SLC) pumps was performed in March 2013 with vibration test equipment that was not calibrated over the code required range. The licensee had identified the same calibration issue in 2012, and they had generated PER 680798 to have the instrument calibrated over the correct range. However, the calibration was not performed prior to the test, nor was the IST performance placed on hold pending the need to perform the calibration. The licensee generated SR 729845 to evaluate the validity of the test and impact on Unit 2 SLC operability. This issue was determined to be a minor violation of regulatory requirements in accordance with Inspection Manual Chapter 0612.

The team also observed the following examples; during a 3A Unit Service Transformer replacement, DCN 61731. The work guidance failed to include a post modification testing of the differential protection 387SA that would simulate actual operating conditions; and during diesel D6 overhaul work, a wire did not get re-landed following the removal of a switch for maintenance, which resulted in additional LCO time to subsequently connect the wire. The work package did not contain a step to lift or re-land this wire. Regulatory action was determined not to be required for this event because it was licensee identified during post maintenance testing while the EDG was still out of service. Therefore, even though the work instructions may have been deficient, since this was found during post maintenance testing, and was corrected prior to the EDG being returned to service, the Finding was not more than minor.

The team observed work week schedule and interdepartmental coordination. The team identified the licensee's failure to manage emergent risk conditions during RHRSW A1 and A2 inoperability. Specifically, on May 6, 2013, during the A1 RHRSW quarterly pump test, BFN did not adequately manage the impact of the increase in emergent risk condition during the self-revealing inoperability of both A1 and A2 RHRSW pumps. The licensee had originally recognized the online maintenance risk associated with the A1 RHRSW test but failed to initiate protected equipment barriers per Procedure BFN-ODM-4.18, "Protected Equipment." Reference the Finding and associated NCV in Section 5.2.2.2.5 for additional details.

Comparison Summary

The team determined that the information received from the focus group discussions was consistent with the inspection observations in the area of work control. The licensee was implementing corrective actions; however, it was a new process and the sustainability of these actions would require continued monitoring.

Licensee Actions Identified to Revise IIP

The corrective actions in work management and work control were developed to address licensee identified issues under FPA 4, Work Management. The team found that many of the actions were still in progress. NRC inspection results in the area of work management were documented under FPA 4, Work Management in Section 5.5.2 of this report.

Regarding sustainability, the team identified Work Control as an area that warranted continued implementation of the IIP. Specifically, the work management process had not effectively implemented change regarding the issues and observations that the team or the licensee had identified such as facilitation and coordination between departments and that the lack of coordination may contribute to quality issues with work packages, and affect the timeliness of performing work. The team determined that the IIP warranted revision related to the safety culture aspect in that without a systematic strategy to ensure effective results the IIP performance improvement may not be sustained. The team discussed this with the licensee and the licensee subsequently generated PER 742931, which identified that work management was not effectively implemented and was affecting plant equipment and resulted in quality issues. The PER was generated to address safety culture continuous improvement and sustainability. The team reviewed the action plan that the licensee generated to address this issue and determined that it was appropriate to address the issues in the area of work management and work control.

4.5.2.4 **Work Practices**

Focus Group Interview Summary

Results from the focus group discussions indicated that communication regarding plant and safety issues had increased. The site used stand downs, the plan of the day, emails, and other site-wide communications to specifically emphasis the use of human performance tools. There were mixed views about the approach to supervisory oversight; some perceived they had too much supervisory oversight while others perceived they had less oversight due to an increase in management meetings. In general, the staff perceived the Electronic Performance Observation Program (ePOP) as positive. The focus group discussions indicated that all people believed they had stop work authority.

Team Observations

The team acknowledged improvements had been made by the station in the area of work practices. However, the team identified multiple observations and Findings associated with the behaviors in this area. The team observed multiple examples across the station where workers and supervisors failed to meet TVA procedure requirements and management expectations, which continued to result in human performance errors and events. The team determined that work practices was a continuing challenge for the licensee's IIP effectiveness, primarily evidenced by inconsistent human performance technique application and usage, including procedure adherence and verification practices.

The team identified an example of the Operations Department failing to follow site procedures. This Finding involved a failure to control a modification to the seismically mounted control room ceiling light diffusers. Specifically, surveillance Procedure 0-SR-3.3.7.1.4, directed the operators to remove three ceiling light diffusers. However, the team found that the operators slid three light diffusers over the top of the other light diffusers and were left in this condition for 6 days while the surveillance was temporarily suspended for other non-related conditions. The control room operators, including the supervisors, failed to follow procedures to remove the diffusers. This issue was documented in Section 5.2.4.2.1.

The team identified an example of poor work practices involving the Engineering Department, as part of a Finding for the failure to follow DCN procedures. Specifically, the team identified two modifications, DCNs 69466 and 69467 that had remained in a partially implemented status for greater than two refueling outages without the required approval. The team noted this example of poor work practices, specifically related to human error prevention techniques and procedure adherence. Refer to Section 5.1.3.2.2 for additional details.

The team identified an example of poor work practices involving the Maintenance Department with respect to the failure to adequately implement a surveillance procedure. During the review of the surveillance procedure the team identified a step that required an independent verification be completed, but only observed one set of initials were entered in a step when two were required. In addition, the team observed that the technicians performing the task had marked Not

Applicable for Measuring and Test Equipment (M&TE) required for the instrument and instead used non-approved M&TE to complete the procedure. The team noted this example of poor work practices, specifically related to verification practices and procedure adherence. Refer Section 5.2.2.2.4 for additional details.

The team observed additional examples of poor work practices in the Maintenance Department, specifically inadequate procedure use and adherence. While observing work order (WO) 11468440, the team identified Procedure MPI-0-000-BLT001, "Belt Drive Maintenance," Section 3.0 step E required that steps marked Not Applicable required prior concurrence from the work supervisor, which was not obtained. The team identified that the technicians used Not Applicable throughout the procedure without prior approval from their supervisor. The work was stopped and SR 729689 was generated. The work being performed was not on a safety-related component and as a result, no regulatory action was required.

The team identified an example of not meeting work practice expectations that involved multiple station organizations. In the Operations Department, the team identified a Finding associated with two assistant unit operators (AUOs) who incorrectly applied a clearance tag on the wrong train of RHRSW. Specifically, the AUOs were assigned to apply a clearance on an RHRSW pump for maintenance work. However, the operators failed to apply the tags properly, which resulted in a safety-related RHRSW pump becoming inoperable in excess of the Technical Specification requirements. The team determined that the operators did not utilize proper verification practices, including self-check and peer check human error prevention techniques and a failure to follow procedure. Refer to Section 5.2.2.2.1 for additional details.

The team also identified an example of not meeting work practice expectations involving the Maintenance Department related to the work authorization process. The maintenance supervisor was required to verify all danger tag blocking points, per Procedure "Clearance Procedure to Safely Control Energy," NPG-SPP-10.2, Rev. 5; however, only two of nine danger tags were verified at the start of a maintenance activity. As a result, the supervisor did not recognize the danger tag for an RHRSW pump manual discharge valve had been incorrectly applied to another RHRSW pump. Maintenance work subsequently started on the RHRSW pump with the discharge valve not danger tagged and in the open position as required by the work activity. The team noted this as an example of poor work practices at the supervisor and the workforce level. Specifically, the supervisor failed to follow procedures, management expectations, and did not ensure an adequate zone of protection to the workers doing maintenance work. In addition, the team considered this poor work practices at the worker level for less than adequate usage of human error prevention techniques. Refer to Section 5.2.2.2.2 for additional details.

The team identified multiple examples of poor housekeeping and material condition while performing field observations and plant walk-downs. The team observed housekeeping issues in the emergency diesel generator rooms, reactor building (RB), safety-related battery room, refuel floor, and intake structure. Although these issues were discussed with the licensee staff, in some cases, SRs were generated after NRC prompting. Although none of the issues were identified as more than minor, the aggregate review of the observations indicated that the workers may not value the importance of housekeeping. During an outside operator walk-down, the team observed a 25 to 30 foot extension cord strung over junction boxes and supports to power the radiological survey frisker at the entrance to the stand-by gas treatment (SBGT) rooms. At the time of discovery, the team discussed this issue with the operator; however, a SR was not written until after the NRC questioned whether this issue had been documented. The licensee generated SR 740564.

Comparison Summary

Comparing the focus group discussions with the inspection observations, the team identified a discrepancy between what the licensee's staff perceived as increased communications and oversight in the area of work practices, and the workforce and supervisors' behaviors observed by the team during the inspection. The team acknowledged improvements had been made by the station in the area of work practices, most notably in the alignment of communications with a focused message. However, the team did not consistently observe that the message communicated was aligned with the observed behaviors exhibited by the workforce and supervisors. The team noted that the area of Work Practices as it specifically relates to safety culture warranted additional actions in the IIP, based on the number and significance of the issues observed by the team involving poor human performance behaviors, specifically in procedure adherence and verification practices, and that these examples continued to affect performance across multiple departments at BFN.

Licensee Actions Identified to Revise IIP

The area of procedure use and adherence was specifically identified as a fundamental problem area with corrective actions that are discussed in more detail in FPA 6, Procedure Use and Adherence, in Section 5.2.2. of this report.

However, the licensee had not precisely identified work practices and human performance at the workforce and supervisor level as a FPA or had developed a systematic approach to address work practice behaviors.

During the focus groups, the team acknowledged employees exhibited attitudes that supported a positive safety culture and that they had demonstrated a higher regard for the importance of a strong safety culture at the Browns Ferry Nuclear Plant; however, based on direct observation of staff performing their duties and responsibilities the team concluded that those behaviors were not consistently demonstrated, particularly by employees who were closest to the operation of the plant (individual contributors and supervisors). As a result, the team determined that the IIP warranted revision to address this issue.

The team's concern regarding the lack of a systematic approach to address station work practices and human performance was discussed with the licensee and the licensee subsequently generated PER 742931 to address safety culture continuous improvement and sustainability. The team reviewed the action plan that the licensee generated to address this issue and determined that it was appropriate to address the issues in the area of work practices.

4.5.2.5. **Corrective Action Program**

Focus Group Interview Summary

Results from the focus group discussions indicated that the CAP had greatly improved. Focus group discussions indicated that station personnel were using the CAP more than in the past, and that they were strongly encouraged by the management team to use the CAP for all issues. Even though the CAP had improved, the staff observed some challenges with using the corrective action and work tracking computer software. The software was cumbersome and some employees had difficulty in writing and searching for PERs. However, the continued challenges with the corrective action and work tracking had not prevented any employee from using CAP. Personnel believed that the training provided for the corrective action and work tracking software had not been effective at teaching people how to use the software. Focus group discussions also indicated that new updates and changes to the software were not being communicated to the staff.

Once an issue was entered into CAP and because of the way issues were prioritized, some departments believed that anything regarded as a low priority issue would never get addressed. Some staff stated that the CAP was ineffective because they did not readily see issues being addressed if they were of low safety significance. This lack of resolution led to diminished confidence in the program. However, this did not preclude anyone from using the CAP process. Focus group participants stated that the threshold for writing PERs was lower than it was in previous years, and this was viewed as a positive.

Through the focus group discussions, the team discovered that in several organizations PERs could not be written against TVA Corporate organizations, specifically, Human Resources (HR) or Industrial Safety. While gathering more information on this issue, the team learned that this perception was an actual reality. The team discussed this concern with the licensee who subsequently generated procedure revision for Procedure NPG-SPP-03.1.4, “Corrective Action Program Screening and Oversight,” Rev. 0014 to address the issue. Although correcting this issue was valuable to the licensee’s process, there was no regulatory aspect associated with how the licensee correct human resources and industrial safety issues, therefore no violations of regulatory requirements occurred.

Team Observations

The team observed improved performance in the organizational structure and usage of CAP at BFN. The team reviewed PERs and SRs, analysis products including root cause and apparent cause evaluations, and performance metrics associated with trending of the program health at the station. The team also attended station CAP meetings and performed interviews with members of the CAP organization.

The team did observe several examples of conditions that warranted the generation of SRs, but the SRs were not generated in a timely manner. None of the SRs were related to high safety significant issues. In each case, once questioned by the NRC, the licensee initiated a SR to address the issue.

The team also noted several examples of poor SR quality during the initial generation process. Although the station was making improvements in this area, the team noted that at the time of the inspection, BFN did not have a formal process, similar to the ePOP process, to ensure personal accountability for CAP expectations.

The team identified quality issues with low-tier apparent cause evaluations. Specifically during the review of PERs 704964, 695320, and 638433, it was noted that the problem statement and apparent cause were the same. In addition, the ACE for PER 672780 identified a programmatic deficiency as the apparent cause, but the corrective actions in place did not address a program problem. The licensee generated SR 729324 to address these issues identified that were related to lower-tier ACE quality. See Section 6.1.4.2.2 for the details and regulatory aspects of this issue.

Although the team did note that the station's use of CAP had improved, the team also acknowledged that the IIP actions needed additional implementation time to ensure the program changes would be effective.

Comparison Summary

The team determined that the information received from the focus group discussions was consistent with the inspection observations in the area of CAP. The team concluded that the station's use of CAP had improved and that the IIP actions were adequate, but more time was needed to implement the actions to achieve substantial and sustainable performance improvement.

Licensee Actions Identified to Revise IIP

CAP had been identified as a FPA and the licensee developed corrective actions to address issues identified in their root cause analyses. These corrective actions were reviewed and assessed under FPA 5, Corrective Action Program, in Section 6.1.4 of this report.

4.5.2.6 Environment for Raising Concerns

Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture component of Environment for Raising Concerns. The team's assessment of the environment for raising concerns is described above in FPA 19, Employee Concerns Program, Section 4.3.

4.5.2.7 Preventing, Detecting and Mitigating Perceptions of Retaliation

Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture component of Preventing, Detecting, and Mitigating Perceptions of Retaliation. The team's assessment of safety conscious work environment is described above the FPA 18, Safety Conscious Work Environment, Section 4.2.

4.5.2.8 **Operating Experience**

Focus Group Interview Summary

The team reviewed the Operating Experience (OE) program as part of the safety culture assessment. The program was robust and comprehensive. The OE manager position was no longer a part time position at BFN. The manager reported to corporate management and had counterparts at each of the other TVA stations. The manager taught thirty training courses a year on use of OE and how to search industry databanks. The staff spoke positively of the OE training. There was also OE specific training given in each RCA and ACE qualification course. Each station department had an OE department manager who helped to collect data relevant to the activities in that department.

When asked about OE, employees gave multiple examples of receiving information daily including in the plan of the day, OE emails, during pre-job briefs, in work packages, during morning meetings, in newsletters, etc. Staff believed this was a positive change in the overall implementation of OE; specifically the OE received during pre-job briefs seemed to be more relevant to the job.

Team Observations

The team observed improved performance in the organizational structure and usage of OE at BFN. The team did not identify any examples of the licensee not using or applying OE that resulted in regulatory impact.

Comparison Summary

The team determined that the information received from the focus group discussions was overall consistent with the inspection observations in the area of operating experience. Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture component of Operating Experience.

Licensee Actions Identified to Revise IIP

Continuous learning environment, which included OE, was identified as a FPA. The licensee developed corrective actions related to operating experience. These corrective actions were reviewed and assessed under FPA 15, Continuous Learning Environment in Section 6.1.6 of this report.

4.5.2.9 **Self and Independent Assessments**

Focus Group Interviews Summary

Generally, the staff believed internal assessments were more effective than the external independent assessments. However, the focus group discussions indicated that there were too many assessments done each year. At the time of the inspection there was a belief at the station that because BFN is a three unit BWR station, it was uniquely different from other nuclear power stations. The focus group discussions indicated that, in the past, external organizations would conduct benchmarking trips at BFN and make suggestions for improvements. There were concerns noted that management was quick to make the recommended changes, but the changes were not necessarily good for BFN. In addition, focus group discussions indicated that other external stakeholders often made recommendations for changes without considering the unique nature of BFN.

BFN staff indicated that there was a lot of communication about the 2011 INSCA survey results. However, the staff did not have a good understanding of the actions that were taken as a result of other specific assessments. When asked about the discrepancy in participation rates between the 2011 and 2013 surveys, the team was told that employees were strongly encouraged to take the survey in 2013. In some groups, the staff noted that because the actions taken after the 2011 survey were deemed effective, they felt confident that management was listening to them, and therefore they were more willing to participate in the 2013 assessment.

Team Observations

In the area of self and independent assessments, the team observed approximately an equal number of positive and negative observations with respect to the licensee performing assessments. Of the key observations, examples were identified in the area of CAP trending with respect to equipment parameters and repetitive equipment degradation or failures. The team identified that when multiple Essential Equipment Cooling Water header leaks occurred or when service water system check valves had multiple failures; individual PERS were written; however, a trend PER had not been written to investigate and understand the aggregate impact. In both cases, the licensee subsequently generated a trend PER for each issue, SR 721104 and SR 723619. In addition, the team identified that the engineering program assessment for buried cable did not document as found conditions such as water level, cable conditions, etc. which resulted in the licensee not being able to perform a trending assessment for moisture monitoring. The team also identified that when oil was added to an RHRSW pump on two separate occasions, the PERs that were written had different trend codes assigned, which could impact the licensee's trending capability.

The team identified examples during infield observations and documents reviewed from the last year and a half when the criticality of the QA audit findings and observations were in some cases more critical than the individual departments' self-assessments. An example of a field observation was during a work evaluation where Instrumentation and Control (I&C) technicians removed a speed sensor pick-up unit from reactor feedwater pump (RFP) turbine front standard. Based upon the step order in which the technicians were performing the work, QA questioned both the technicians' actions and the supervisor that the work package did not specifically state that steps could be performed in any order. Upon further review, it was discovered that the work package had this step in the document; however, the step was not in the revision that the technicians were using in the field. The regulatory aspect of this issue was minor in accordance with IMC 0612.

Comparison Summary

The team determined that the information received from the focus group discussions was overall consistent with the inspection observations in the area of self and independent assessments. The team did note there was a delta between the quality of some of the self-assessment tools and how they compare with external assessments. Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture component of Self and Independent Assessments.

Licensee Actions Identified to Revise IIP

Continuous learning environment, which included self and independent assessments, was identified as an FPA. The licensee developed corrective actions related to self and independent assessments. These corrective actions were reviewed and assessed under FPA 15, Continuous Learning Environment, in Section 6.1.6 of this report.

4.5.2.10 **Accountability**

Focus Group Interview Summary

The team observed that a positive consequence of the site's performance improvement effort was to create a strong sense of empowerment, individual responsibility for site performance, and pride in the site within the workforce. This sense of responsibility was evidenced by participants expressing a strong willingness to be held accountable for individual and site performance. For example, staff believed that poor performance or inappropriate conduct might have resulted in termination. However, "honest mistakes" were considered learning opportunities thereby dispelling the belief that accountability was punitive. Use of positive reinforcement, and the "Good Catch" reward was mentioned by staff as being a positive tool for accountability. Additionally, focus group discussions indicated that the station personnel accepted management coaching and peer-coaching as tools to help drive accountability.

Interviews with personnel in the engineering organization indicated that there were significant improvements in this area for their group. The Engineering Review Team, specifically, was identified as a strong change agent for improvement. Given that the primary objective of this team was to review submittals generated by their department and to provide necessary feedback, the outcome of adding technical rigor to their packages resulted in a vast improvement in the overall quality of work.

Team Observations

The team observed a large number of observations in the area of accountability, specifically in individual, supervisory, and programmatic accountability.

In the area of individual and supervisory accountability, the team observed several examples, one of which included a maintenance technician that found the diameter of an adjustable pulley on the turbine room supply fan 2B motor had changed since they adjusted it the previous day. After being questioned by the NRC inspector regarding the validity of the as-found reading and why the as-left diameter didn't match the as-found from the day before, the technician stopped work and notified his supervisor. Related to the same activity, the supervisor did not exhibit a questioning attitude regarding the change in sheave diameter and did not enforce stop work expectations with the technician when unexpected conditions were found. There were no violations of regulatory requirements associated with this issue.

The team observed another example of poor accountability when a maintenance supervisor did not perform a complete verification of danger tags prior to authorizing the start of maintenance work for an A2 RHRSW pump impeller adjustment. The team determined that the station was not enforcing consistent standards across the departments, and the Maintenance Department was not holding themselves accountable for the supervisor's inappropriate work practices. At the time of discovery, the Maintenance Department had not performed a thorough investigation of the event and did not classify this event as a Department Clock Reset, although the team noted that the Operations Department had reset their Department Clock for hanging a tag on the wrong component during the same activity. After being questioned by team, the licensee performed a subsequent review and determined that a Maintenance Department Clock Reset should have occurred and generated SR 722559 to address this issue. There is a Finding associated with this activity and is discussed in Sections 4.5.2.4 and 5.2.2.2.2.

The team identified examples of programmatic accountability issues in the area of the corrective action program. The team identified that the licensee was not using a formal method, similar to the observation program, to document poor quality CAP products, including the generation of SRs. The team found that accountability and feedback mechanisms were being verbally performed by the supervisor. As a result, there was no tracking and feedback mechanism for performance improvement. This observation was discussed with the licensee who subsequently generated PER 726064 to evaluate this issue. There were no violations of regulatory requirements associated with this issue.

The team recognized that management was missing opportunities related to accountability when it was determined that since June 2012 up to May 2013 that, on average, Corrective Action Review Board (CARB) was observed two times a month by a representative from Corporate or Site Vice Presidents (SVP). The team noted during a review of CAP program Procedure NPG-SPP-03.1 that this procedure expected that the Corporate and SVP were to actively participate in CARB as needed. The team noted that based upon the frequency that the observations were being performed; this observation may be a missed opportunity to ensure CARB members were being held accountable. There were no violations of regulatory requirements associated with this issue.

During the inspection, the team reviewed the licensee's observation program, ePOP, which was a mechanism to improve workforce performance through coaching and accountability. The observation program had been in place for several years but starting in 2012, the licensee had taken multiple initiatives to improve the program. At the time of the inspection, the corrective actions were on-going and many had not had enough implementation time to indicate sustained improved performance. However, the team observed inconsistencies in the individual departments' program usage as a mechanism to improve workers' behaviors and accountability, including supervisors' skill sets and coaching abilities. These inconsistencies were addressed by the licensee in PER 742931.

Comparison Summary

Comparing the focus group discussions with the inspection observations, there was a discrepancy noted. Specifically, the licensee's staff recognized accountability as having a positive impact on their performance. The team identified that reinforcement of desired behaviors and work practices through the use of direct observations and coaching had not been consistently implemented at BFN. In addition, the team observed issues with accountability impacting programs such as the CAP, Human Performance (HU) Clock Resets, and ePOP.

Specifically with respect to supervisor oversight, the team determined that, although improvements had been observed by the licensee and the NRC, reinforcement of the desired behaviors at the worker level via field observations and coaching had not been strongly implemented. The team considered this area as warranting a revision to the IIP related to the Safety Culture aspect of accountability.

Licensee Actions Identified to Revise IIP

The safety culture component for accountability affected multiple areas in the licensee's performance improvement plan and was specifically discussed in more detail in FPA 5, Corrective Action Program, in Section 6.1.4., FPA 1, Management and Leadership Standard, in Section 6.1.2., and FPA 10, Governance and Oversight in Section 6.1.5. of this report.

With respect to supervisor oversight, the team noted that the licensee's corrective actions in this area were individualistic and reactive and they did not have a systematic approach to address the issues observed in supervisor oversight. Specifically, the station did not methodically target and correct the latent organizational weaknesses of workforce and supervisors' work practices and behaviors that had continued to result in human performance errors and events. The team's concern with the lack of a systematic approach to address these issues would result in the licensee plateauing in their performance improvement initiatives with respect to safety culture and workforce behaviors. The team discussed these issues with the licensee who subsequently generated

PER 742931 to address safety culture continuous improvement and sustainability. The team reviewed the action plan that the licensee generated to address this issue and determined that it was appropriate to address the issues in the area of accountability and management oversight in the field.

4.5.2.11 **Continuous Learning Environment**

Focus Group Interview Summary

Focus group participants expressed some concerns about the continuous learning environment at BFN, specifically with regard to how knowledge is transferred at the site. When asked, most focus group participants were not aware that a formal knowledge transfer program existed at BFN. The focus group discussions expressed that there were senior employees retiring and by not having a formal knowledge transfer program there was a knowledge management challenge to the organization. Specific to the Maintenance organization, it was communicated that newly qualified staff were having difficulty regarding opportunities to shadow more senior qualified staff. There was a tendency to rely on a singular person who was proficient in a specific qualification to complete the work, thereby creating a void for on-the-job training for other qualified staff.

According to the interviews, although benchmarking was used more frequently across the site, management participation in benchmarking was higher compared to the rest of the organization. While staff had the ability to benchmark industry peers and generally, the feedback was viewed as positive and receptive, it was unclear whether there was a formal process for communicating the knowledge gained. It was also discovered that although there was a formal benchmarking program, staff were using a less rigorous process such as informal mentoring.

Team Observations

The team found that there was a procedure, which documented the fleet process for identifying, developing, and implementing plans to capture critical knowledge or adapt to the loss, BP-120, Rev. 0002, “Retaining Critical Knowledge.” However, the NRC did not find any indication of program implementation or knowledge of this program at BFN. This included HR, senior managers, and the work force.

During the inspection, the team reviewed Procedure, “NPG Benchmarking Program, NPG-SPP-03.1.12,” Rev. 0000, including the associated plans, and metrics. The team observed a formal process that required documentation of

Findings identified during benchmarking trips in a specific report and generated corrective actions to document deficiencies and lessons learned for station applicability and implementation. The procedure also required that the benchmarking report be distributed to affected individuals or organizations. However, the team noted a potential delta between the focus group discussions regarding the communication of benchmarking report findings to the work force and the procedure requirement to distribute the benchmarking report to affected groups.

The team identified a Finding of very low safety significance associated with the area of continuous learning environment, for the licensee's failure to establish qualified ultrasonic (UT) examination procedures. Specifically, the team identified four UT procedures that had not been qualified in accordance with the applicable ASME code section. Refer to Section 6.1.6.2.1 for additional details. The team considered this example of poor continuous learning environment due to the number of UT procedures found with the same procedure quality issue.

Comparison Summary

The team determined that the information received during the focus group discussions was consistent with the inspection observations in the area of continuous learning environment. Although both the knowledge transfer and benchmarking programs were formally documented in procedures, they were not fully implemented at BFN. This would explain why the focus groups were not aware of the formal knowledge transfer program or the results of different benchmarking activities. The team did not consider these issues with Continuous Learning Environment as more significant. At the time of the inspection, the team assessed the long-term sustainability, which was affected by the new programs and the lack of sufficient run-time, including the knowledge management process with respect to the issues identified in the area of Resources, as described in Section 4.5.2.2.

Licensee Actions Identified to Revise IIP

Continuous learning environment was identified as an FPA. The licensee developed corrective actions related to continuous learning. These corrective actions were reviewed and assessed under FPA 15, Continuous Learning Environment, in Section 6.1.6 of this report.

4.5.2.12 **Organizational Change Management**

Focus Group Interview Summary

A majority of focus group participants believed that site management took the time to “fix the plant” and “did it right the first time.” This was believed to be one of the most important changes to the organizational structure. In conjunction with that view, it was stated that TVA Corporate was providing the resources necessary to replace equipment. It was also noted that there was an attitude change by management that led to the perception that the management team was taking the time to understand the issues at BFN and put corrective actions in place. It was reported that the positive philosophy of the senior leadership team was permeating the site.

There were, however, some groups that were still lacking confidence in the sustainability of the new philosophy at the site. Specifically, some focus groups expressed concern that the current philosophy might change if the current senior management team changed. The focus group discussions indicated that there were concerns that a new management team would not adopt the current philosophy.

When the new management team was first assembled, there was a housekeeping initiative to clean the plant. Some employees reported that during that effort, tools were misplaced, or thrown away, and they believed it to be an ineffective effort because they were not sufficiently involved in the process. Staff from the maintenance department gave examples of how the housekeeping initiative negatively affected their timeliness with completing work, because specialty tools or parts had to be replaced.

The team discovered that there was a change management process being implemented, but when asked organizational change management questions, none of the focus group participants mentioned this process.

Team Observations

The team did not directly observe any conditions that would indicate the organizational change management was ineffective. The team reviewed the corrective actions to address management and leadership standards and alignment for the current management team at BFN.

Comparison Summary

The team determined that the information received during the focus group discussions with respect to a positive change in management philosophy was consistent with the inspection observations in the area of organizational change management. The concerns from the focus groups regarding the sustainability of these changes were also shared by the team. The reports from focus group participants regarding their frustration with some of the unanticipated outcomes of the housekeeping initiative were consistent with one of the issues in the 2013 INSCA assessment regarding a lack of input from staff before making changes. The team did not consider Organizational Change Management as an issue; at the time of the inspection, the team recognized challenges to long-term sustainability due to the new programs and the lack of sufficient run-time.

Licensee Actions Identified to Revise IIP

One aspect of change management, specifically management and supervisors getting staff input before making significant changes, was a remaining issue identified in the 2013 INSCA assessment. The corrective actions from 2011 to improve staff involvement in the change management process had not been fully effective. At the time of the 95003 inspection, corrective actions had not been developed for the 2013 INSCA.

Governance and oversight, along with leadership and management standards, were identified as a FPA. Corrective actions were developed to address issues identified in these areas. The corrective actions were reviewed and assessed under FPA 10, Governance and Oversight, Section 6.1.5, and FPA 1, Management and Leadership Standards, Section 6.1.2 of this report.

4.5.2.13 **Safety Policies**

Focus Group Interview Summary

The team concluded that BFN's employees perceived that the site and their management placed an appropriate emphasis on safety, versus the production mentality that previously existed at BFN. Focus group discussions indicated that management understood how the site got to the condition they were in by emphasizing short(er) outages and by allowing and tolerating equipment reliability issues. It was communicated by participants that the emphasis on safety was reinforced through various methods. For example, every meeting at the site started with a safety culture reading from TVA's Nuclear Fleet Focus, Building a Culture of Excellence, handbook. The participants also acknowledged that they would be supported by management to stop work when necessary.

Team Observations

The team did not directly observe any conditions that would indicate the safety policies were ineffective. The team observed multiple site meetings, pre-job briefs and turnovers, and work evolutions. The team observed the licensee's communication and emphasis on safety policies during online and outage activities.

Comparison Summary

The team determined that the information received during the focus group discussions was consistent with the inspection observations in the area of safety policies. Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture component of Safety Policies.

Licensee Actions Identified to Revise IIP

Governance and Oversight was identified as an FPA. Corrective actions were developed to address issues identified in this area. The corrective actions were reviewed and assessed under FPA 10, Governance and Oversight, Section 6.1.5. of this report.

4.5.2.14 **Procedure Quality and Adherence**

Focus Group Interview Summary

All focus group participants reported that there was an expectation for procedure use and adherence. The focus group discussions indicated that there was greater emphasis from the management team on having procedures physically out in the working space. Management encouraged staff to follow procedures; however, focus group discussions indicated that there were significant issues with procedure quality especially with TVA Corporate procedures. Some examples of issues included: 1) procedures not being specific to BFN; 2) procedures not being easy to change; and 3) procedures being cumbersome and difficult to use. Most of the procedures had multiple pages, and cross-references even for relatively skill-based tasks and routine work. As an example, when procedure changes were sent out for comment, focus group participants felt that input from BFN staff was not adequately considered, specifically compared to the rest of the fleet. In some organizations, the procedures contradicted each other. In some cases, there was conflicting information between corporate and site procedures; for example, when defining concurrent and independent verification. See Section 5.3.2., Procedure and Instruction Quality, for additional discussion on this topic. The procedures contained a large amount of information, guidance, and references, so they were relying on the procedures as a mechanism for informal knowledge transfer. The staff believed that these issues were being addressed by management, but staff understood that it will take time to make all the needed changes due to the vast number of procedures at the site.

There was confusion about how to change TVA Corporate procedures especially because the CAP process was site specific. The focus group discussion yielded inconsistent responses when asked how to change a procedure. Some indicated that they wrote SRs; some used a procedure change request process; and others went directly to the procedure owner. There was not a consistent use of a formal change process. There was also a concern about the backlog of procedure changes, and that changes were not made in a timely manner, because of the workload.

The focus group discussions indicated that the procedures were very dense because they were trying to over-proceduralize “tribal” knowledge. Some staff believed that skill of the craft tasks were being proceduralized when they did not need to be. Staff expressed concerns that procedures were too generic, and contain too many “if-then” statements, leading to opportunities for human error. As a result of too many options embedded in the procedure, staff had to do in-the-field decision making, which should have been completed before performing the task.

Team Observations

The team identified multiple examples of poor procedure quality and procedure adherence issues. In the area of procedure adherence, the team observations were previously discussed in Work Practices, Section 4.5.2.4 of this report.

The team identified four Findings related to procedure quality. First, the team identified in TVA Corporate Procedure, “Conduct of Operations,” OPDP-1, Rev. 26 and Rev. 27, April 8, 2013, inconsistent procedure standards with the usage of ‘should’ versus ‘shall’ and the application of verification practices. Refer to Section 5.2.2.2.3 for additional details. The second Finding, associated with procedure quality, was that TVA Corporate Procedure NPG-SPP-10.3, Rev.1, “Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, “Administrative Controls and Quality Assurance for Operational Phase Nuclear

Power Plants," verification requirements were not included in multiple abnormal operating instructions. This included AOI examples that directed the incorrect verification requirement for the associated work task; did not require concurrent verification during the performance of actions with irreversible consequences, and actions that were designated as critical steps did not require independent or concurrent verifications be performed. Refer to Section 5.3.2.2.1 for additional details.

The third Finding was a deficient acceptance criteria in the annual Main Battery 1 inspection Procedure, EPI-00248-BAT005, such that an adequate inspection of the battery bank could not be performed. Refer to Section 5.3.2.2.3 for additional details. The last Finding the team identified was the licensee's failure to translate the seismic uncertainties into the acceptance criteria and M&TE accuracy requirements into Procedure "RPS Circuit Protector Calibration/Functional Test For 3B1 and 3B2," 3-SR-3.3.8.2.1(B), Rev. 16. Refer to Section 5.2.2.2.4 for additional details.

In addition to the Findings, the team had additional observations with respect to procedure quality and work package instructions. The team observed that procedures "Chemistry Program," CI-13.1, and "Chemistry Control," SPP-5.3 stated that Action Level 1 warranted an improvement in operating practices; however, neither procedure required an SR to be generated if a parameter was returned within 96 hours. The licensee generated SR 728116 to address this issue.

While observing a maintenance activity, the team identified that Procedure TI-134, "Core Spray and Residual Heat Removal Room Coolers Air Flow," did not have clear guidance of all exact locations to hold a test probe; there was no guidance on how many data points to take; there was no location in the procedure to enter all flow measurements; and there was no acceptance criteria specified. The licensee generated SR 726887 to address these issues. In addition, the team identified out of date procedures on the refuel floor. For additional details and examples, refer to Procedure and Instruction Quality, FPA 12, in Section 5.3.2 of this report.

Comparison Summary

The team determined that the information received during the focus group discussions was consistent with the inspection observations in the area of procedure quality and adherence.

At the time of the inspection, the team discussed the Findings and individual observations with the licensee and they subsequently documented the issues in their corrective action program. However, at the time of the inspection, the team identified that BFN did not have a systematic plan to address the widespread procedure quality issues. As a result, the team identified procedure quality as an issue that warranted a revision to the IIP to ensure substantial and sustainable performance improvement would be achieved.

Licensee Actions Identified to Revise IIP

Procedure quality was identified as a FPA. Corrective actions were developed to address issues identified in this area. The corrective actions were reviewed and assessed under FPA 12, Procedure and Instruction Quality (Section 5.3.2). The team's concern regarding the lack of a systematic approach to address the widespread procedure quality issues was discussed with the licensee, who subsequently generated PERs 757451 and 742931 regarding a Safety Culture Improvement and Sustainability Plan to address safety culture continuous improvement and sustainability. The licensee also generated an action plan to address this issue and determined that it was appropriate to address the issues in the area of procedure quality PER 740212.

4.5.3 Safety Culture Observations Summary

Based on the focus group discussions, the team observed that there had been positive changes made at the site regarding communication of safety expectations and promotion of the importance of the site's safety culture. The team observed that the staff perceived an increased station focus on conservative decision making, stopping when unsure and following procedures. In addition, focus group discussions suggested that staff understood the importance of these behaviors; and they felt supported by management to exhibit these behaviors. The managers interviewed during the assessment provided information on safety policies and expectations that were generally consistent with the information gathered during the focus group interviews. The team found that this indicated an alignment in communications from the management team to the line organization.

However, the team's field observations indicated a lack of consistency in behaviors when personnel were actually performing the work. The team identified that the workforce, including supervisors, did not always stop when unsure; follow procedures; or write SRs when they identified an inconsistency in a procedure or work package. In addition, the team also identified supervisors were not consistently able to recognize these errors, intervene, or coach to correct behaviors.

The team identified issues in organizational characteristics and attitudes associated with five of the NRC's 13 safety culture components, as detailed in IMC 0310, "Components Within the Cross-Cutting Areas." The issues were identified in the safety culture components related to Decision Making and overall rigor; Work Control; Work Practices including human performance; Resources; and Procedure Use and Adherence; and Accountability, specifically supervisor and management oversight. In addition, the team identified an issue in the site's focus area of procedure and instruction quality. The observed issues were widespread among functional groups across the organization, including Operations, Engineering, Chemistry, Maintenance, and RP personnel.

Although the team observed some minor issues in the following safety culture components, Organizational Change Management, CAP, and Continuous Learning Environment, these components were not categorized by the team as issues warranting revisions to the IIP. However, at the time of the inspection, the team assessed that the long-term sustainability of improvements in these components due to the implementation of new programs and a lack of sufficient run-time would be challenged.

Based upon the assessment results, at the time of the inspection, the team did not identify issues of concern with the organizational characteristics and attitudes in the safety culture components of Operating Experience; Safety Policies; Self and Independent Assessments; the Environment for Raising Concerns; and Preventing, Detecting, and Mitigating Perceptions of Retaliation.

All of the issues identified in the referenced safety culture components were discussed with the licensee, and subsequently entered into BFN's CAP for resolution. The issues identified did not rise to the level of an immediate safety concern. Therefore, the team concluded that BFN's existing safety culture supports continued safe operation.

4.6 Nuclear Safety Culture Monitoring Panel/Site Leadership Team Meetings

4.6.1 Inspection Scope: The team assessed BFN's Nuclear Safety Culture Monitoring Panel (NSCMP) and Site Leadership Team (SLT) Semi-Annual Meeting to determine whether they were an effective avenue to identify and subsequently correct low-level precursors prior to the development of a larger safety culture issue. The team reviewed meeting minutes, procedures, and PERS. In addition, the team performed interviews and observed the first quarter 2013 NSCMP meeting.

4.6.2 Observations: No Findings of Significance were identified.

Based upon interviews, meeting observations, and documentation review, the team identified that the quarterly NSCMP and SLT meeting was not an effective avenue to catch and subsequently correct low-level precursors prior to the development of a larger safety culture issue. Although the team determined that the station procedure and meeting implementation met the expectations of NEI Guidance 09-07, "Fostering a Strong Nuclear Safety Culture," the team determined that the meeting content, structure, and personnel engagement were not adequately meeting the intent of the NEI guidance. More specifically, based on direct observations, the team's assessment of the effectiveness of the monitoring panel process as an adequate mechanism of sustainability for continued improvement of the station's safety culture was that the panel lacked rigor in discussing potential challenges to safety culture across the organization and within specific departments. The panel also lacked rigorous discussion of the effectiveness of new or ongoing corrective actions to address those challenges. The details were discussed below.

NSCMP/SLT On-Site Observations

During the onsite inspection, the team observed both the NSCMP and the SLT meetings and recognized that these meetings were very important to the ongoing monitoring of nuclear safety culture at the station. The team had concerns with the level of engagement and technical rigor among the members of the NSCMP, including the lack of time available to thoroughly discuss issues. Instead, the meeting was primarily a report-out on metrics. The team also had concerns with the lack of discussion and lack of challenges or questions from management regarding specific actions to address safety culture improvement opportunities during either the NSCMP or the SLT meetings. Although BFN had benchmarked other utilities during the development of their NSCMP and SLT guidance procedures, and the team did not identify any deficiencies in the procedures; it was unclear whether the benchmarking activities were effective.

NSCMP/SLT Documentation Review

A document review was performed for the last three NSCMP/SLT meeting minutes, including May 2013, October 2012, and March 2012. The review results indicated:

- Of the eight safety culture principles tracked, two of the principles have remained as 'Improvement Opportunities' for the eighteen month period reviewed. At the May 2013 NSCMP/SLT meetings, the team did not observe panel discussions that included timeliness, ownership, or effectiveness of current corrective actions, or the need to create additional corrective actions as a result of these two longstanding issues. The team also noted that associated corrective actions to address gaps were not referenced on the meeting agendas or the meeting minutes.

- Four of the eight principles had declined from ‘Acceptable’ in October 2012 to ‘Improvement Opportunity’ in May 2013. Three of the four had been in ‘Acceptable’ status since March 2012 and were now Improvement Opportunities. The team did not observe panel discussions regarding the first quarter 2013 decline in the status of these principles nor were there actions to address these issues documented in the agenda or minutes.

- In May 2013, “Decision-Making Reflects Safety First” was listed as a ‘Strength.’ This was the first Strength identified in the three agenda/meeting minutes reviewed. During the panel meeting, the team observed discussions regarding BFN’s outage performance and the organizational decisions made to extend the outage to work on equipment. The team had also heard similar positive comments related to outage related decision making during the focus group discussions. However, the team’s concern was that the licensee was performing a quarter-by-quarter snap shot of each of the eight principles individually and not evaluating the principles as inter-related with respect to performance over time. Specifically,” Questioning Attitude,” “Leaders Commitment to Safety,” and “Organization Learning is Embraced” were all noted as ‘Improvement Opportunities,’ while “Decision Making Reflects Safety First” was considered a ‘Strength.’

- To determine the station’s performance of the eight safety culture principles, the NSCMP received input from ten specific departments, each self-rating themselves in 35 categories. These department ratings were then incorporated into the station’s overall assessment of their performance by giving each principle a grade, for example, ‘Improvement Opportunity’, ‘Strength.’ The team reviewed the ten department inputs and identified the following:

    - In October 2012, Operations had one ‘Strength’ and seven ‘Improvement Opportunities’. In May 2013, Operations had two ‘Strengths’ and 18 ‘Improvement Opportunities’. The majority of the other departments either stayed approximately the same or slightly improved. The team did not observe during the meetings or identify in documentation where the meeting members had discussed this large quarterly decline or what corrective actions were needed to address this in Operations.

- In October 2012, Project Management had 23 'Strengths' and zero 'Improvement Opportunities'. In May 2013, PM had 20 'Strengths' and seven 'Improvement Opportunities'. Even with the slight decline, Project Management had been one of the highest self-rated departments with respect to safety culture. However, based upon site interviews, contractor performance and their human errors, including associated events, had continued to be a focus for BFN. The actual performance did not align with the high Project Management self-rated attributes. The team did not observe cross-discipline management challenges during the meetings.

<u>NSCMP/SLT Interviews</u>

Based upon an interview with the NCSMP chairman, the team identified:

- Each of the ten departments used subjective evidence to provide input into the applicable department's 35 attributes for the NSCMP, and

- The Nuclear Safety Culture – Site Dashboard, an attachment to the NCSMP, was performed by TVA Corporate on a quarterly basis. At the time of the inspection, there was no bases document to define how each of the categories were assigned or evaluated.

4.6.3 <u>Assessment Results</u>: Although no violation of regulatory requirements were identified, the implementation of the Nuclear Safety Culture Monitoring Board (NSCMP) and BFN Senior Leadership Team (SLT) was not effective as observed by the team. This was based on management interviews and documentation review. The NSCMP procedure itself was adequate but the meeting content, structure, and personnel engagement were not adequately meeting the intent of NEI 09-07, "Fostering a Strong Nuclear Safety Culture. The team did not consider the performance standards of this meeting as a quality indicator of sustainability for BFN's safety culture. This was communicated to BFN and subsequently BFN provided a Safety Culture Continuous Improvement and Sustainability Plan to address the issues in PERs 743538 and 757451. The team concluded that the Plan adequately reinforced the function of the NSCMP and SLT to monitor and cultivate a sustained and improved safety culture.

4.7 Fatigue Management Assessment

4.7.1 <u>Inspection Scope</u>: The team's independent safety culture assessment included the review of the licensee's fatigue management processes as a part of the evaluation of resource allocations concerning staffing levels. The review also included fatigue management program procedures, previous program audits, associated root causes, corrective actions, and gathering information through management interviews and focus groups.

4.7.2 Observations: No Findings of significance were identified.

The adequacy of staffing levels was affected by the restart of Unit 1. During the focus group interviews, the team heard repeatedly that the site was allocated sufficient staffing levels for a two-unit site but when Unit 1 was restarted, the staffing level numbers were not adjusted accordingly. Additionally, it was stated that site management did not properly retain qualified and highly experienced personnel in various positions and did not properly address attrition over the years.

As a part of the assessment and due to the staffing allocation issues indicated from the focus groups, the team reviewed the fatigue management program. After the regulations for fatigue management for specified personnel became effective in October of 2009, the site QA organization conducted an audit in September of 2010. The audit was conducted due to fleet issues with implementation and was documented in PER 215568. The results concluded that there was a programmatic failure in the implementation of fatigue management and work hour limits. The specific areas identified as unsatisfactory were the use of waivers from the rule, the verification of work hours, and the use of fatigue assessments.

There were two RCA performed, PER 255792, associated with inadequate implementation of TVA Corporate policies on fatigue management and the follow-up RCA, PER 322569, associated with the ineffective corrective actions to prevent recurrence from the initial audit findings. The first RCA identified the root cause as less than adequate management oversight. Significant attributes, which failed as barriers in the programmatic structure, were identified as written communications, work practices, change management, resource management training/qualification, and managerial methods. There was an immediate corrective action on the part of the SVP, who initiated a voluntary stop work on all overtime hours. The action also required all maintenance supervisors to read Procedure NPG-SPP-03.21 and sign that they understood the requirements prior to approving any further overtime for the shops. Other corrective actions included training, changing the overtime authorization form, establishing performance indicators, and requiring effectiveness reviews.

A follow-up audit was performed in February of 2011 by the licensee. This audit determined that BFN management had failed to take adequate corrective actions to prevent recurrence, and had not established clear program ownership with the appropriate level of management oversight and engagement. It was determined that management did not ensure procedural requirements were met or that there was sustained program compliance with regulations. In addition, due to 12 instances of non-compliances and the inadequate implementation of the correct actions associated with the initial RCA, the QA organization escalated the issue.

The second RCA, PER 322569, identified contributing causes as: no program owner identified; the owner of the initial RCA was not a subject matter expert (SME); corrective actions were not adequately documented; and actions requested by the CARB were never initiated but the associated PER, 306445, was closed. The corrective actions associated with the follow-up RCA included software and supervisor specific training; creation of a policy to ensure compliance; assignment of the SME for fatigue management; identifying workers who could potentially work under the provisions of Title10 Code of Federal Regulation (CFR) Part 26; and perform quarterly "snapshot" assessments.

Subsequently, there was an audit of all TVA sites in February 2012 to assess the fatigue management programs; and at that time, it was determined that there remained programmatic issues at BFN. The current SME in fatigue management at BFN was interviewed during the inspection who indicated that there were ongoing effectiveness reviews and there were plans to escalate actions associated with the fatigue management program. During the inspection, the team also reviewed samples from the various departments for the process of assigning overtime, including the review performed to ensure there were no violations that would result from scheduling. The regulatory aspects of the issues described in the licensee's RCAs and audits were addressed previously in NRC Inspection Reports 05000259/2010-0003, 05000260/2010-003, AND 05000296/2010-003, ML10210467.

4.7.3 Assessment Results: The team determined that the BFN fatigue management program was improving with a decrease in the use of waivers. The team noted that the current procedures addressed 10 CFR Subpart I rule provisions, although the team did not observe general practices for preventing worker fatigue for individuals not under the provisions of 10 CFR Part 26 Subpart I. Despite the current resource concerns mentioned previously in this report, the team did not identify examples that BFN had continued to exceed the work hour control limits or the repetitive use of waivers. The team identified that the site had not used waivers since 2012. The perception of the workers was that they do not work outside of work hour controls. However, this did not affect schedules and backlog assignments for individuals in engineering who may not perform duties that were under the purview of 10 CFR Part 26 Subpart I.

4.8 Summary and Conclusions

The team graded safety culture assessment was able to confirm that the results obtained from the 2011 Independent Nuclear Safety Culture Assessment (INSCA) were a reasonable characterization of the culture that existed at the site during that time period. The results of the 2011 assessment provided ample information about issues and low response rates or participation from site departments and organizations. BFN performed a critical review of the results and developed corrective actions to address the organizational issues and outlier organizations with low results. The team's graded safety culture assessment was also able to corroborate the results obtained from the more recent 2013 INSCA. The team found that employees perceived notable improvements in safety culture across the site. Employees had recognized a notable change in the overall focus of the site, from production-focus and an emphasis on doing the minimum required to keep the plant running, to a safety-focus and emphasis on making conservative decisions. Employees also indicated that they had greater trust in upper management and perceived an increased level of support for raising safety concerns and increased emphasis on raising standards for safe performance. Despite the overall improved safety culture, translating the safety culture beliefs into repeatable, sustainable safety culture behaviors still remained a challenge at BFN, based on direct team observations of routine activities being performed.

The team concluded that some BFN station personnel, who, for example operate plant equipment (operations and maintenance), including their immediate supervisors, continued to exhibit poor work practices, decision making, and problem identification. In addition, procedures directly related to safe plant performance continued to lack quality. Some of these latent issues have resulted in human performance errors, lack of issue recognition, a lack of healthy respect for safety significant issues and potential impacts, and inconsistent nuclear safety culture standards.

Based upon a review of the IIP and associated implementation of actions, the team observed that the station's focus had been primarily reactive and individual based; and lacked a systematic approach to improving work practices, decision making (rigor), supervisory oversight, and procedure quality that directly affect plant safety. As a result, the team observed a stratified layer existed between the new management philosophies and expectations and the daily staff performance of these expectations while performing normal duties and responsibilities. The team determined that there were competing administrative obligations of the supervisors field time and field observations and as a result supervisors did not always recognize poor work practices and did not always coach and correct.

The team identified seven specific areas of concern related to safety culture sustainability. These areas were observed in multiple departments at the station and may have affected BFN's ability to continue making performance improvement progress. Specifically, the team was concerned that the IIP warranted revision to ensure that the performance improvement initiative would not plateau or stagnate with respect to safety culture and work force behaviors. The five concerns are as follows with team observations referenced to support the conclusions:

Issue 1: Although employees exhibited attitudes that supported a positive safety culture, those behaviors were not consistently demonstrated, particularly by employees who were closest to the operation of the plant (individual contributors and supervisors).

Observations: Employees stated that there were positive changes made at the site; they were willing to stop when unsure and follow procedures; they understood the importance of these behaviors; and felt supported by management to exhibit these behaviors. However, field observations by the team indicated a lack of consistency in behaviors when actually performing activities, including routine duties and responsibilities. Employees did not always stop when unsure, follow procedures, or write SRs when they came across an inconsistency in their procedure or work package. In addition, supervisors were not consistently able to recognize these errors, intervene, or coach to correct behaviors. The deficiencies in work practices also include issues with decision making and rigor.

Issue 2: The work management process was not effectively implemented to facilitate coordination between departments. The lack of coordination may have contributed to quality issues with work packages, and affected the timeliness of performing work.

Observations: There were schedule delays observed over the course of the inspection as well as input from focus groups concerning schedule delays. Maintenance workers stated that repeatedly there would be work scheduled for completion though upon receipt of the work package, it was incomplete and therefore they would not be able do the job because the package was not adequate. This would happen even though packages were reviewed by the BFN 'Ready Ready' team. There were also issues communicated during the focus groups among the schedulers and planners concerning not coordinating with each other within the work management department at BFN.

Issue 3: Current resources may not be adequate to effectively manage the additional workload required to reduce backlogs and improve reliability at the station. In addition, the need for appropriate training and qualifications may create a gap between having enough staff and having enough qualified staff to meet work demands.

Observations: Focus group participants and managers expressed concerns that the current staffing levels were not appropriate for a three-unit BWR site. The Operations Department was concerned that given projected retirements and current failure rate for SRO licenses, there would not be enough SROs to meet more than minimum staffing requirements. The Engineering Department was currently supplemented by contractor staff to work down the backlog of design changes, and there was uncertainty expressed as to whether the complement of TVA staff could handle the full engineering workload once the contractors had left. The team observed that planned maintenance work was cancelled after operations tagged out safety-related equipment because maintenance did not have the right qualified staff to perform the work as scheduled. Focus group participants expressed a perception that because of the increased use of CAP, there were many low-level issues that were not being addressed because there were so many more high-priority issues backlogged in the system.

Issue 4: There was a recognized issue with the quality of procedures at the station however, there lacked a systematic process for improving procedure quality in an efficient manner.

Observations: Focus group participants expressed frustration with site procedures, particularly TVA Corporate procedures. Documentation reviews revealed deficiencies in the quality of procedures. The team identified multiple Findings of very low significance regarding procedure quality issues that were discussed throughout the report. In addition, the team observed multiple instances where employees failed to recognize the need to stop when a procedure was incorrect or unclear and failed to recognize the need to write an SR to document the issue in CAP. To address known procedure quality issues, the site established expectations to stop work, and identify procedure discrepancies so they could be subsequently resolved. Although this was an appropriate immediate action, this focus had been reactive and individual based and lacked a systematic approach to identification and resolving procedure quality issues.

Issue 5: Management and supervisors were not consistently reinforcing desired behaviors and work practices through the use of direct observations and coaching. In addition, the station lacked a systematic process to improve behaviors and work practices through supervisor oversight.

Observations: The team observed inconsistencies in the individual departments' observation program usage and supervisor oversight as mechanisms to improve workers' behaviors and accountability, including supervisors' skill sets and coaching abilities. In addition, employees in some departments commented during focus groups that supervisors were often in meetings. Supervisors also expressed concerns about getting out into the field as much as they wanted to because of the quantity of meetings they were required to attend.

In addition to the five areas of concern listed above, the team also identified two additional issues in the licensee's programs and actions that supported safety culture initiatives. The sixth issue was in the administration and oversight roles of the Nuclear Safety Cultured Monitoring Panel, as discussed in Section 4.6. of the Safety Culture Assessment. The seventh issue identified by the team was the administration and oversight of the BFN human performance (HU) plan, specifically the lack of strategic action plans and TVA Corporate oversight to address the station's long-standing HU issues. These gaps are discussed in more details in Sections 5.2.4., Human Performance Observations, and 6.1.5., Governance and Oversight.

Licensee Actions Identified to Revise IIP

Based upon the Findings and observations identified by the team, and the subsequent discussions with the licensee, BFN developed a safety culture action plan to address each area of concern, identified in PER 757451, titled "Safety Culture Continuous Improvement and Sustainability Plan" and PER 743724, for specific plan actions.

The Safety Culture Continuous Improvement and Sustainability Plan, Revision 001, dated July 22, 2013, stated that "in response to NRC observations, the Browns Ferry team recognizes that a systematic approach is warranted to ensure the effectiveness and sustainability of safety culture improvement efforts." The licensee categorized the team's safety culture observations into seven categories, which included existing IIP actions in progress or to be completed and additional actions being incorporated into the IIP to further drive sustainability of the identified safety culture improvement areas. The team reviewed the plan and determined it to be satisfactory based on the following corrective actions identified in the paper.

1) Attitudes of workers do not always match behaviors.

Actions in IIP:

- Strategic leadership performance management process,
- Leadership assessment process for supervisor and management alignment to the nuclear fleet fundamentals, and
- Establish initial and continuing training requirements, and develop and deliver training to provide expected behaviors for leaders and craft.

Additional Actions:

- SR 743392 to systematically evaluate (e.g., performance analysis) what action(s) are required to ensure that workers demonstrate and execute desired behaviors - specifically with regard to technical rigor and decision making. Evaluation will include necessary monitoring tools (metrics) that will be used to ensure desired results.
- Implement a communication strategy designed to inform and educate the workforce on the “frame of reference” issue, how that plays into the fragile state of BFN safety culture, and how BFN must move from a current state of “knowing the right behaviors” to a state where the right behaviors are engrained in the fabric of daily actions. (SR 742764 was written to track the specific actions for implementation),
- As an interim action BFN will provide additional HU oversight (e.g., resources, mentor, etc.) to drive implementation of the management observation program. (SR 742775 was written to track the specific actions for implementation), and
- Utilize metrics, such as the “All Six - All Summer HU event metrics”, HU error rate, etc. to provide ongoing, periodic communication of progress towards closing the gap between knowledge of the right behaviors and demonstrating them in the field. (SR 742775 and SR 743392).

2) Work management (WM) is not effectively implemented which affects plant equipment and results in quality issues.

Actions in IIP:

- Strategic Leadership Management Alignment for Executing WM,
- Procedure changes to strengthen risk management,
- Staffing of vacant WM and supporting positions,
- Training and seminars to raise primary participant knowledge level and reinforce roles in the process,

- Development of tools to support WM observations, and
- Develop a performance management procedure.

Additional Actions:

- Implement the WM Gaps to Excellence Plan, PER 6843,59,
    - Develop additional Performance Indicators to track accountability,
    - Use the observation program to reinforce roles, performance, and lessons learned,
    - Benchmark field work readiness verification methods,
    - Improve contingency planning to improve Maintenance Rule implementation and LCO management, and
    - Re-evaluate staffing for responsible task leads to ensure appropriate use of resources.

3) Staffing levels may not be adequate to effectively manage the workload related to performance improvement.

Actions in IIP:

- Revision of the Nuclear Business Management Process to require a more robust and dynamic process to evaluate and capture resource requirements and implement a periodic review of those requirements against the available and qualified resources,
- Assessment of the IIP actions against available resources and identification of adjustments required to accommodate the increased workload,
- Revise and implement workforce planning procedures and modify the hiring process to minimize the time required to fill positions, and
- Create metrics to monitor the heath of the hiring and workforce management process
- Add resource management elements to Integrated Trend Reviews.

Additional Actions:

- Perform a Gap Analysis of resource management actions, PER 706191, and
- Establish quarterly, stand alone “BFN Resources Review” meeting to assess the effectiveness of actions taken to resolve resource issues and the overall adequacy of BFN’s resource management, PER 734094.

4) The station lacks a systematic approach to improving quality of procedures in an efficient manner.

Actions in IIP:

- Completed additional causal analysis for Procedure and Instruction Quality, which resulted in actions to create and implement a comprehensive procedure upgrade project plan for the TVA Fleet and the BFN site; PER 680792 and PER 505709,
- The TVA Fleet plan for administrative procedures has been completed and includes identification of procedures requiring immediate upgrade to mitigate risk as well as a discussion of risk associated with the project completion timeline,
- Additional attributes have been added to the management observation database to capture behaviors associated with the preparation, revision, and field implementation of procedures and work packages,
- Assemble a cross-functional High Impact Team to develop the site procedure upgrade plan for site technical procedures similar to the Fleet plan,
- Develop and implement fleet metrics to monitor both procedure program performance and work instruction package quality, and
- Secure funding and complete implementation of both the Fleet and Site plans.

Additional Actions:

- Implement the interim procedure upgrade actions in accordance with PER 740212, and
- SR 743431 was written to establish additional interim fleet and site effectiveness review actions to coincide with milestone tracking actions to validate the check and adjust success criteria.

5) Management and supervisor field observations, which are important to achieving higher standards of performance excellence, are negatively impacted by competing management responsibilities.

Actions in IIP:

- Strategic leadership performance management process,
- Leadership assessment process for supervisor and management alignment to the nuclear fleet fundamentals,
- Establish initial and continuing training requirements, and develop and deliver training to provide expected behaviors for leaders and craft, and
- Develop a performance management procedure.

Additional Actions:

- Conduct a senior leadership team strategic alignment session to focus site priorities and resources on implementation of a more robust observation process, implementation of the WM Gaps to Excellence plan, and implementation of the Procedure Upgrade/Procedure Instruction Quality project, SR 743392,
- The BFN Human Performance manager will align the strategic Corporate and BFN Human Performance Plans and ensure department specific HU plans capture tactical actions to address identified Human Performance issues, PER 741783, and
- Implement the revised Performance Management process to conduct Leadership assessments for all BFN supervisors and managers, PER 516437.

6) Oversight and effectiveness in the implementation of the BFN NSCMP.

There were no existing IIP actions with respect to NSCMP.

Additional Actions:

- Expand the allotted time frame for the NSCMP meetings from one to two hours,
- Improve the overall level of engagement and rigor by NSCMP members,
- Improve the rigor in the trending and analysis reviews by the NSCMP,
- Solicit additional input from the NEI 09-07 Working Group for NSC,
- Become an active participant in the NEI 09-07 Working Group, and
- Participate as a member in the NEI 09-07 Subcommittee on NSC metrics.

7) TVA Corporate and BFN have been lacking in a strategic oversight approach to monitor and manage both corporate and the stations progress on HU initiatives.

There were no existing IIP actions with respect to TVA Corporate or BFN HU strategic oversight for BFN HU initiatives.

Additional Actions:

- Upon approval of TVA Corporate fiscal year (FY) 2014 HU business plan, enter actions into CAP for FY 2013 actions that will be carried over into FY 2014, SR 749025, and new FY 2014 actions, SR 749031,
- Upon approval of BFN FY 2014 HU business plan, enter actions into CAP for new FY 2014 actions, SR 749051,

- Develop a plan for TVA Corporate oversight of the BFN HU Improvement Plan tactical items, SR 749033, and
- Develop a COC oversight plan for the suite of HU procedure requirements, SR 749047.

5 Reactor Safety Strategic Performance Arena

5.1 Design

5.1.1 Inspection Overview

Based on risk insights from the individual plant evaluation (IPE), design reviews focused on the group of systems that support the containment heat removal function (i.e., residual heat removal, core spray (CS), RHR service water, and emergency equipment cooling water. The report refers to this group of systems as the vertical slice systems. The team reviewed design bases documents such as calculations and analyses to develop an understanding of the functional requirements for each system throughout the range of required operating conditions, including accident and abnormal conditions. The team focused on risk significant design aspects that could contribute to an increased frequency of initiating events, degradation of mitigation systems, or degradation of barrier integrity. The review covered the as-built design features of the selected system to verify its capability to perform its intended functions with a sufficient margin of safety. The team concentrated on review of system modifications as compared to the original system design. The team independently assessed the extent of risk significant design issues by performing the following inspection requirements and the overall inspection approach is referred to as a vertical slice inspection.

1. **Assessed the effectiveness of causal analysis and corrective actions for deficiencies involving design.** The team assessed whether evaluations were thorough and methodical, corrective actions adequately addressed the causes, adequacy of extent-of-condition reviews, timeliness of corrective actions, and adequacy of effectiveness reviews. The team reviewed Fundamental Problem Area (FPA) 16, PER 369800 - Red Finding associated with the 74-66 Low Pressure Coolant Injection (LPCI) valve failure, FPA-9, Technical Rigor, FPA-13, Equipment Programs and System Management, and FPA-14, Design and Configuration Control. The team also reviewed design engineering issues identified in quality assurance (QA) audit reports SSA1008 & SSA1209 - Design Engineering.

In addition, the team reviewed the following five recent design-related PERs associated with vertical slice system (RHR, CS, EECW, and RHRSW) components to ensure the licensee identified design issues and appropriately resolved them.

- 635860 (1B & 1D RHR room coolers cooling coil not exact match),
- 543136 (Incorrect motor operator calculations for 3-FCV-74-71, 57),
- 531079 (Fouling conditions of the 3D Diesel Heat Exchangers),
- 345374 (ICS point for RHRSW C Flow hi and hi/hi set-point incorrect), and
- 349889 (Incorrect friction factor table for Unit 1-FCV-60, 61, 74, 75).

2. **Selected several modifications for review and determined whether the system was capable of functioning as specified by the current design and licensing documents, regulatory requirements, and commitments for the facility.** The modifications were chosen based on their potential to significantly alter the system design and functional capability. The sample included vendor supplied products or services, because the licensee's ability to oversee vendor supplied services was an important aspect of design control. The team verified design calculations, compared the as-built design with current design basis requirements, verified whether the selected modifications introduced an unreviewed safety question, and verified adequacy of associated procedure changes.

The team reviewed the following modifications including a sample of recent commercial grade dedication packages:

- DCN 69907, Install New Motor Operators on Valves 3-FCV-074-0007 and 3-FCV-074-0030,
- DCN 40220, RHRSW Pumps Impeller Replacement,
- DCN 71061, Remove Vent and Drain Lines from RHR Pump Room Coolers 2A & 2D,
- DCN 61731, New Main Bank Transformers, Unit Station Service Transformer (USST)-3A and USST-3A differential relay 387SA,
- DCN 176376, Replacement of U3 GSU Transformers and USST 3A and Installation of a new U3 Spare GSU Transformer,
- DCN 70664, Revise Wiring So that the 43 Switch Prevents Spurious Start of EECW, Revision A,
- DCN 70132, Change Setpoint of Air Temperature Sensor for Drywell Bulkhead, Revision A,

- Temporary modification package TACF 0-10-004-067, and
- Commercial grade dedication packages Nos. AYD945BX1 (Double Row Cylindrical Bearings), ALC105WK0 (Single Row and Tapered Bearings), CTK65P-X0-BFN (Terminal Jacks), and CHM023A-R0-BFN (Pneumatic Power Pack).

The team assessed the following attributes for the modifications listed above:

- Completed in accordance with the licensee's procedure, policies, and license and design basis,
- Technically adequate and in accordance with applicable industry standards,
- Appropriately reviewed by applicable organizations (e.g., fire protection, environmental qualification, training) and approved by the appropriate level of supervision,
- Properly installed and tested,
- Associated procedures were appropriately revised or developed, and were appropriately addressed in the licensee maintenance program.

3. **Determined whether the system was operated consistent with design and licensing documents.** The team reviewed the permanent modifications and temporary modification described above to verify that operator training and actions were adequate for the permanent and temporary modifications listed above which required any changes to operator actions. Only the modifications implemented under DCN 71061 introduced the possibility of new operator actions requiring the control room operators to identify and shed unnecessary electrical loads in order to prevent EDG overloading condition during a Loss of Offsite Power (LOOP) event. Additionally, the team reviewed a sample of five operating procedures, five recent operating procedure revisions, and three maintenance procedure revisions associated with the vertical slice systems to verify procedures and training were consistent with current system design. The team verified that under all anticipated circumstances, the associated time critical operator actions could be performed in the required time-frame to mitigate design basis events.

4. **Evaluated the interfaces between engineering, plant operations, maintenance, and plant support groups.** The team reviewed the permanent and temporary modifications, and commercial grade dedication packages listed above to ensure design updates & interim controls were properly implemented, if required, and that vendor qualification was in accordance with licensee

procedures. The team also reviewed the following sample of five prompt operability determinations mainly associated with degraded conditions of vertical slice system components:

- PER 711398, Main Steam Vault Flood Protection Seals Do Not Match Design Drawings Emergency Core Cooling System(ECCS) Operability
- PER 704059, 20-30 dpm Leak on HPCI Vent Valve (HPCI Operability)
- PER 707543, Core Plate Plug 32-49E Not Secured Reactor Pressure Vessel (RPV) Operability
- PER 703979, Unacceptable Code UT Exam on RPV Nozzles (RPV Operability)
- PER 704527, Non-Service Induced Flaws on Core Spray System Loop II Weld (Core Spray System Operability

5.1.2 Equipment Programs and System Management (FPA 13 – EPSM)

5.1.2.1 Inspection Scope: The team assessed BFN's equipment programs and system management to determine whether they were sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The licensee diagnostic and Recovery Review identified Equipment Programs and System Management as a fundamental problem area (FPA 13). BFN performed an apparent cause evaluation for PER 547427 to determine the cause(s), extent-of-condition, and corrective actions to address this fundamental problem. The ACE problem summary stated that engineering programs and processes needed to drive and sustain high levels of equipment reliability were not implemented in a manner that would result in timely resolution of longstanding equipment problems or prevention of new problems. BFN also performed an Equipment Reliability Strategy assessment (PER 515388) that identified significant gaps and declining performance in engineering programs and processes used to monitor and respond to equipment reliability concerns.

The team interviewed BFN staff, attended meetings, and reviewed various documents and records as listed below to assess the effectiveness of engineering program management and system management. Specific inspection items included:

- Selected engineering program procedures including:
  - 0-TI-522, "Program for Implementing NRC Generic Letter 89-13,"
  - NPG-SPP-02.3, "Operating Experience,"
  - NPG-SPP-09.14, "NRC GL 89-13 Implementation,"

- NPG-SPP-09.16, “Plant Health Committee (PHC),” and
- NPG-SPP-09.16.1, “Structures, Systems, and Component (SSC) Health.”

- Selected system and engineering program health reports (2011-2013) including:
  - EECW system,
  - RHRSW system,
  - RHR system,
  - CS system,
  - Cooling Water,
  - Emergency core cooling system,
  - Heat exchanger (HX) component health,
  - NRC GL 89-13 program,
  - Buried cable program,
  - In-service testing program, and
  - PHC meeting minutes and presentation documents from January 1 to May 14, 2013.

- Selected engineering program audits and self-assessments were evaluated to determine whether 1) the scope of the assessment and extent-of-condition review was appropriate, 2) corrective actions adequately addressed causes, 3) timeliness of corrective actions was commensurate with safety significance, 4) selected corrective actions were adequately implemented, and 5) implementation of the corrective actions resolves the problem:

  - QA-BF-12-036, “Quarterly oversight report,”
  - BFN-ENG-F-11-003, “NRC GL 89-13 Program,”
  - BFN-ENG-F-12-001, “Surveillance Test Program,”
  - BFN-ENG-F-12-013, “Commercial Grade Item Acceptance & Dedication Program,”
  - BFN-ENG-S-12-020, “EECW Vulnerabilities,”
  - CRP-ENG-F-11-002, “Fleet Check Valve Program,”
  - CRP-ENG-S-11-005, “Effectiveness of BFN IST Program,”
  - CRP-ENG-F-12-001, “Flow-Accelerated Corrosion,”
  - CRP-ENG-F-12-002, “Buried Piping,”
  - CRP-ENG-F-12-009, “Fleet Equipment Reliability Program,”
  - CRP-ENG-F-12-014, “BFN Motors Program,”
  - CRP-ENG-F-12-015, “BFN Pumps Program,”
  - CRP-ENG-F-12-017, “Motor Operated Valve (MOV) Program,”
  - CRP-ENG-F-12-021, “BFN Breaker Program,”
  - CRP-ENG-F-12-026, “BFN Aging Management Program,”

- o SSA1011, “Engineering programs QA audit,”
- o SSA1207, “Materials & procurement QA audit,” and
- o SSA1213, “Engineering programs QA audit.”

- Interviewed selected system engineers and program owners.

- Attended the bi-weekly Plant Health Committee meeting the week of May 13, 2013 to determine whether the meeting: 1) was conducted in accordance with the licensee’s procedures; 2) reflected sound technical decision making; 3) communicated issues accurately; and 4) identified and addressed appropriate plant health issues.

In addition, the team evaluated the licensee’s apparent cause analysis (PER 547427) and related Equipment Reliability Strategy assessment (PER 515388) and a sample of ten associated corrective actions. Specifically the team evaluated whether: 1) completion of the analysis was in accordance with the licensee’s process; 2) a thorough and methodical process was used to complete the analysis; 3) the related licensee’s fundamental problem area adequately covered the related issues; 4) appropriate aspects of the analysis were carried through into the licensee’s Integrated Improvement Plan and the associated action plans; 5) corrective actions adequately addressed the causes; 6) timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) selected corrective actions were adequately implemented; 8) extent-of-condition and cause were adequately addressed; and 9) completed or planned effectiveness reviews were adequate. Documents reviewed are listed in the Attachment.

5.1.2.2 Observations: No Findings of Significance were identified.

The team observed several examples of effective programs and proactive engineer involvement in evaluating and managing system health. However, numerous examples of program deficiencies and inconsistent program implementation were also identified. BFN’s self-assessments were consistent with the team’s observations. A large number of actions to improve individual engineering programs were implemented within the last year and an equally large number of actions were being developed at the close of this inspection. Examples of the team’s observations are discussed below:

1. Program self-assessments were generally thorough and added significant value to the quality of engineering programs and their implementation. Examples included Buried Piping, In-service Testing, Check Valve,

Equipment Reliability, EECW, Pumps, Motor Operated Valves, and Breakers. Each of these self-assessments was critical and identified numerous deficiencies or learning opportunities.

2. Examples of deficient documentation of equipment inspections and trending of results for some engineering programs were identified (e.g., buried cable program, NRC Generic Letter 89-13 Service Water program, Heat Exchanger program, Motor program). The team found that BFN self-assessments had identified similar examples of deficient documentation of equipment inspections.

3. Three of twelve NRC GL 89-13 RHR heat exchanger inspections (2A RHR HX in 2009, 1A RHR HX in 2010, 1A RHR HX in 2012) reviewed, were inaccurately documented and evaluated. The team reviewed the 2010 and 2012 1A RHR HX as-found inspection results with engineers and determined the 1A RHR HX had remained operable. The 2012 2A RHR HX inspection results were evaluated separately as documented in NRC Inspection Report 05000259/2013003, 05000260/2013003, 05000296/2013003. As-found inspection data recorded on the evaluation forms did not consistently match photographs taken of the as-found HX condition. Based on follow-up interviews, the inspectors determined the inconsistent documentation and evaluation resulted from procedure deficiencies and knowledge deficiencies on the part of some engineers performing HX inspections (PER 728160). Although not a violation of regulatory requirements, the practice of permitting the same engineer to perform the as-found HX inspection, the as-left HX inspection, and the evaluation of inspection results increased the likelihood that HX degradation would not be identified and corrected in a timely manner (PER 734318).

4. The program and procedures for monitoring buried cable manholes, hand-holes, and vaults for moisture and submergence were deficient. Procedures did not verify drains were functioning, did not record as-found conditions, did not provide instruction for how to verify the dewatering system was operational, and did not trend the as-found results and establish a basis for inspection periodicity. The licensee entered these issues into the CAP for resolution (PERs 552170, 729861, 730766, and 730776 and SR 729864).

5. The backup EECW system engineer demonstrated a strong questioning perspective and identified several tertiary work order and procedure deficiencies associated with EECW flush procedures that were newly created and used. The issues were promptly entered into the CAP for resolution, PER 732158.

6. Several program managers had not completed qualifications for their assigned program role (e.g., HX, GL 89-13, Air operated Valve programs). Corrective actions included development of program-specific qualification plans and schedules for the various engineering programs.

7. Several program self-assessments (i.e., Check Valve, Equipment Reliability) stated that the programs were not properly implemented due to a lack of engineering resources. Large maintenance backlogs, deficient equipment life cycle management, and lack of implementing the single point vulnerability program were key factors that challenged equipment health and drove BFN's equipment management to be reactive instead of proactive.

8. The HX program self-assessment was thorough and identified significant deficiencies. However, several of the deficiencies were not entered into the CAP and as a result no action had been initiated to correct them.

9. Top 10 Action Plans were not reviewed and concurred on with regularity at the Plant Health Committee meetings as required by NPG-SPP-09.16, Equipment Reliability, Revision 4. The PHC chairman believed that the reason for this was that the committee focused on maintenance rule Yellow/Red systems due to the current large number of degraded systems. The team concluded the PHC lost some of its strategic, long look-ahead benefits by not reviewing the Top 10 lists.

10. Cable component health reports were incomplete and cursory. The reports didn't meet procedure requirements and didn't provide sufficient information to support meaningful assessment of cable condition by the PHC.

The regulatory aspects of these observations were assessed and in most cases, there were no violations of regulatory requirements. Where regulatory requirements existed, the violations were determined to be minor.

5.1.2.3 Assessment Results: The licensee's ACE (PER 547427) for FPA 13 identified the central cause of deficient engineering program and system management to be insufficient engineering staffing levels. Contributing causes included inadequate engineer experience and program knowledge, the CAP program was not effectively used to resolve external assessment findings, and BFN management did not consistently execute their responsibilities to support engineering program implementation. The team's independent assessment of the ACE and supporting documents determined the licensee had appropriately identified the apparent causes that led to the site challenges described under FPA 13.

Based on interviews, equipment walk downs, review of staffing and equipment performance, and review of various engineering program documents the team determined the licensee had made significant progress toward addressing issues pertaining to Equipment Programs and System Management. Additional discussion of actions that have been taken to address engineering resource challenges is documented in Section 6.1.3, Resource Management. Appropriate corrective actions were established to address the causes, actions were properly prioritized in the licensee's Integrated Improvement Plan, and effectiveness reviews were scheduled where appropriate. The team concluded that engineering made significant progress towards addressing Equipment Program and System Management deficiencies. In addition the engineering related performance metrics established to monitor equipment program health were adequate to prevent a decline in safety that could result in unsafe operation and for the licensee to maintain a sustainable path toward further improvement in the area of Equipment Programs and System Management.

5.1.3 **Design and Configuration Control (FPA 14 – DCC)**

5.1.3.1 Inspection Scope: The team assessed the licensee's application of design and configuration control as applied at the TVA Corporate and station level to determine whether it was sufficient to prevent a decline in performance that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The licensee's diagnostic and Recovery Review identified Design and Configuration Control as a fundamental problem area (FPA 14). BFN performed an apparent cause evaluation for PER 543132 to determine the cause(s), extent-of-condition, and corrective actions to address this fundamental problem. The ACE problem summary stated that management of design bases including key inputs, expected results, and outputs was not adequate. In addition, the ACE problem statement stated that configuration documentation and control (e.g., drawings, calculations, procedures, change backlog, modification packages, observations, and long standing clearances) challenged reliable plant operations.

The team interviewed selected members of the licensee's engineering staff, from both the TVA Corporate level and the station to gain a working understanding of any pervasive underlying design and configuration control issues existing at the station. Additionally, the team evaluated the following:

- Problem statement as described above and examples of station issues identifying lack of design and configuration control,
- Apparent and contributing causes identified by the licensee for lack of design and configuration control as identified in ACE PER 543132,
- Licensee response and associated actions related to industry and internal operating experience associated with design and configuration control issues,
- Internal and external audits and assessments related to design and configuration control,
- Corrective actions implemented and/or planned to address station design and configuration control issues and the effectiveness of these corrective actions,
- Effectiveness of measurement tools, such as performance metrics and observations, and
- Several design and configuration control products such as prompt operability determinations, commercial grade dedication packages, permanent and temporary modification design packages, engineering self-assessments, and PERs associated with engineering design issues.

The team evaluated the licensee's apparent cause evaluation related to the licensee's fundamental problem area 14, Design and Configuration Control. Specifically the team evaluated whether: 1) completion of the analysis was in accordance with the licensee's process; 2) a thorough and methodical process was used to complete the analysis; 3) the related licensee's fundamental problem area adequately covered the related issues; 4) appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) corrective actions adequately addressed the causes; 6) timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) selected corrective actions were adequately implemented; 8) extent-of-condition and cause were adequately addressed; and 9) completed or planned effectiveness reviews were adequate.

Documents reviewed are listed in the Attachment.

5.1.3.2 Observations and Findings: The team identified two findings of very low safety significance.

5.1.3.2.1 **Failure to Perform Evaluation of Non-Conforming Material during Commercial Grade Dedication of Safety-Related Bearings**

Although this Finding was documented under the Design and Configuration Control FPA, aspects of this Finding also related to other FPAs. Specifically, FPA 9 Technical Rigor (Section 5.1.4) for licensee's lack of technical rigor in justifying acceptance of non-conforming bearings for application in safety-related components (PER 729646). This issue was also related to configuration control as described in Section 5.5.4. Although not explicitly described in the report, the team also determined that aspects of this issue were related to FPA 6, Procedure Use and Adherence (Section 5.2.2) for the licensee's failure to follow Section 3.3.6 of Procedure NPG-SPP-04.2, "Material Receipt and Inspection," Rev. 2. The regulatory significance of these performance issues were addressed in the Finding below.

5.1.3.2.1.a Introduction: The team identified a Green non-cited violation of 10 CFR 50 Appendix B, Criterion III, Design Control in that the licensee did not adequately evaluate a commercial grade dedication (CGD) of bearings prior to installing the bearings in a safety-related low pressure coolant injection motor generator (MG) set. Specifically, BFN did not perform an acceptance evaluation as required by Section 3.2.6 of NPG-SPP-04.2, "Material Receipt and Inspection," Rev. 2.

5.1.3.2.1.b Description: The team reviewed five CGD packages, which evaluated commercially procured parts for use in safety-related applications. The team identified an issue of concern related to CGD package No. AYD945B, which involved dedication of nine safety-related bearings procured from two different vendors. Specifically, CGD package No. AYD945B listed material of construction and hardness as critical characteristics for acceptance of the bearings for safety-related use. The material of construction and hardness were determined by laboratory testing for three of the nine procured bearings and the results were included in the CGD package.

The team found that the two test sample bearings procured from the first vendor did not pass the acceptance criteria for material of construction pertaining to the chromium concentration. In addition, the sample bearing procured from the second vendor failed the material hardness acceptance criteria. Despite the failure to meet acceptance criteria exhibited by all three test sample bearings, the licensee had accepted the remaining six bearings for use without an evaluation documenting the technical justification for acceptance. Licensee staff informed the team that acceptance of the bearings was based on 'engineering judgment' by the engineer that was performing this CGD. Procedure NPG-SPP-04.2, "Material Receipt and Inspection," Rev. 2, Section 3.2.6, required, in part, that an accept-as-is evaluation be performed during disposition of items that do not meet critical characteristic acceptance criteria and a PER be written to document this evaluation. The team found no PER or accept-as-is evaluation was written to disposition use of the remaining six bearings.

Two of the accepted-for-use bearings were subsequently installed in the 3EN LPCI MG set, which provided normal power to the 480V RMOV Board 3E, which was required for Unit 3 RHR Loop II LPCI mode operability. The failure to evaluate acceptance of the procured bearings resulted in a loss of design control for the 3EN LPCI MG set. The licensee reviewed material and maintenance records and determined the non-conforming bearings accepted by CGD package No. AYD945B had not been installed in any other safety-related applications. The licensee documented this issue of concern in PER 729646, performed an operability determination, and concluded the 3EN LPCI MG set and Unit 3 RHR Loop II LPCI remained operable. The team determined the operability determination was technically adequate.

5.1.3.2.1.c Analysis: The team determined that BFN's failure to perform an accept-as-is evaluation and initiate a PER to assess a non-conforming CGD material condition as required by NPG-SPP-04.2 was a performance deficiency (PD). The Finding was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Additionally the Finding was similar to Example 5.c in Appendix E of IMC 0612. Specifically, the PD resulted in two non-conforming bearings being installed in the 3EN LPCI MG set.

The team evaluated the significance of this Finding using IMC 0609, Appendix A, The Significance Determination Process (SDP) for Findings At-Power, dated June 19, 2012. The Finding was of very low significance because the Finding was a design qualification deficiency and the affected SSC (3EN LPCI MG set) maintained its operability. This Finding had a cross-cutting aspect in the area of Human Performance, Decision Making because the licensee did not use conservative assumptions when making the decision to accept non-conforming commercial grade bearings for safety-related use, such that nuclear safety was supported. [H.1 (b)]

5.1.3.2.1.d Enforcement: Title 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that design control measures provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program. Section 3.2.6 of Procedure NPG-SPP-04.2, required, in part, that an accept-as-is evaluation be performed during disposition of items that do not meet critical characteristic acceptance criteria and a PER be written to document this evaluation.

Contrary to the above, on January 15, 2013, the licensee's design control measures did not properly verify the adequacy of the design of the bearings that were commercial grade dedicated and subsequently installed in the safety-related 3EN LPCI MG set. Specifically, during review of laboratory test results for CGD package No. AYD945B the licensee did not perform an acceptance evaluation of the procured bearings which did not meet the critical material attribute acceptance criteria.

The licensee subsequently initiated prompt corrective actions which included an evaluation of acceptance of the installed bearings, a LPCI operability determination, and an extent-of-condition review. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as PER 729646, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000296/2013011-01, Failure to Perform Evaluation of Non-conforming Material during Commercial Grade Dedication of Safety-Related Bearings.

5.1.3.2.2 **Failure to Follow Procedure during Implementation of Plant Modifications under DCNs 69466 and 69467**

Although this Finding was documented under the Design and Configuration FPA, the team also determined this issue was related to the FPA 4 and 6. Specifically FPA 6 Procedure Use and Adherence (Section 5.2.2) for the licensee's failure to follow Section 3.2.17 of Procedure NPG-SPP-09.3, Rev. 0013, "Plants Modifications and Engineering Change Control," and this issue was also related to configuration control as described in Section 5.5.4. Although not explicitly described in the report, the team also determined that aspects of this issue were related to FPA 4, Work Management (Section 5.5.2) SR 739929 and PER 740729. The regulatory significance of these performance deficiencies was addressed in the Finding below.

5.1.3.2.2.a Introduction: The team identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, for the licensee's failure to follow Procedure NPG-SPP-09.3, "Plant Modifications and Engineering Change Control," Rev. 13, Section 3.2.17 during implementation of plant modifications under Design Change Notices 69466 and 69467. Specifically, the Vice President (VP) of Engineering's approval was not obtained prior to leaving these DCNs in a partially implemented status for a period longer than two refueling outages.

5.1.3.2.2.b Description: The team identified an issue of concern with DCNs 69466 and 69467 that were issued for the replacement of Core Spray and Residual Heat Removal Room Cooler Fan Motors and Fans for Units 2 and 3, respectively. Each of these DCNs included multiple stages. A few stages of each DCN were completed shortly after the DCNs were issued in 2010. These partially implemented DCNs remained in that status for greater than two refueling outages, since 2010 when the DCNs were issued. Section 3.2.17 of Procedure NPG-SPP-09.3, "Plant Modifications and Engineering Change Control," Rev. 13, required that, "To maintain effective configuration control, DCN packages shall not remain in unimplemented, partially implemented, or NUMAS status beyond two refueling outages, without approval of the VP of Engineering. Extension beyond that time will require specific case-by-case justification for approval."

The team identified that the licensee did not have any documented justification or approval for leaving these DCNs in partially implemented status for an extended period of time. The team determined the absence of justification and approval for keeping DCNs 69466 and 69467 in the partially implemented status for a period extending over two refueling outages, created the potential for a loss of configuration control of the RHR and CS systems. Specifically, the potential impacts to system design and configuration pertaining to leaving the DCNs in a partially implemented status were not evaluated for an extended period of time.

5.1.3.2.2.c Analysis: The team determined the licensee's failure to follow Procedure NPG-SPP-09.3, "Plant Modifications and Engineering Change Control," Rev. 13, Section 3.2.17 during implementation of modifications under DCNs 69466 and 69467 was a performance deficiency. The PD was more than minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Absence of justification and approval for keeping DCNs 69466 and 69467 in the partially implemented status for an extended period extending over two refueling outages, created the potential for a loss of configuration control of the RHR and CS systems. Specifically, the potential impacts to system design and configuration pertaining to leaving the DCNs in a partially implemented status were not evaluated for an extended period of time after modification implementation began.

The team evaluated the significance of this Finding using IMC 0609, Appendix A, The Significance Determination Process for Findings At-Power, dated June 19, 2012. The team determined the Finding was of very low significance (Green) because the Finding was not a design or qualification deficiency, and it did not result in an actual loss of one or more trains of the RHR or CS systems and/or their function. The Finding had a cross-cutting aspect in the area of Human Performance, Work Control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of partially implemented DCNs on the plant. [H.3 (b)]

5.1.3.2.2.d Enforcement: Title 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Procedure NPG-SPP-09.3 requires that, "To maintain effective configuration control, ECP/DCN packages shall not remain in unimplemented, partially implemented, or NUMAS status beyond two refueling outages, without approval of the Vice President of Engineering. Extension beyond that time will require specific case-by-case justification for approval."

Contrary to the above, following initiation of modifications to the RHR and CS systems in 2010, the licensee did not document justification and obtain approval from the VP of Engineering for leaving DCNs 69466 and 69467 in the partially implemented status beyond two refueling outages. The licensee entered the issue into their corrective action program as SR 739929 and PER 740729 and recommended actions to evaluate completion or cancellation of the remaining portions of DCNs 69466 and 69467. Because this violation was of very low safety significance and was entered into the licensee's corrective action program as SR 739929 and PER 740729, it was treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000260/2013011-02 and 05200296/2013011-02, Failure to Follow Procedure during Implementation of Modifications to the Residual Heat Removal and Core Spray Systems.

5.1.3.2.3 Other Observations: The licensee's ACE associated with the Design and Configuration Control FPA identified two apparent causes: 1) less than adequate accountability for the rigorous application of the procedural guidelines; and 2) the project planning process did not adequately plan and fund DCN closures and drawing updates. The team's independent assessment of the ACE and supporting documents concluded that the licensee had appropriately identified the apparent causes that led to several site challenges, eventually culminating into a fundamental problem area within Design and Configuration Control. The team noted that a lack of resources was an underlying contributor to past issues involving DCC especially with regards to backlogs in engineering design change packages and engineering drawing updates. The team concluded the licensee had made significant progress towards addressing issues pertaining to DCC at the station and that the metrics established by the licensee to monitor the health of DCC were adequate for the licensee to maintain a sustainable path towards further improvement in the area of DCC.

As of September 2012, BFN estimated the total volume of engineering design backlog items to be 5 years of work if performed by BFN staff. Actions identified in the IIP included hiring contactor resources to work down the ECP backlog and revision of fleet modification processes to ensure future engineering design change package closure documentation was included in work scope performed by contract labor rather than assigning this to onsite BFN engineering staff. The team verified these actions were implemented, and at the close of this inspection approximately 80 percent of the design backlog items had been completed.

5.1.3.3 Assessment Results: The team determined that BFN implemented reasonable actions, to date, to reduce and manage the design engineering backlog at levels appropriate to support safe plant operation. It was also determined that the actions were sufficient to prevent a decline in performance and that these actions were adequate to address the apparent cause evaluation for FPA 14. While progress was notable, the team determined that several related IIP actions were not fully implemented or had not had sufficient run-time to support the team's assessment of sustainability. Continued implementation of the IIP actions was warranted on this fundamental problem area to ensure that substantial and sustainable performance improvement is achieved.

In addition, the team concluded that the Findings associated with design and configuration control, reveal underlying performance issues in the areas of technical rigor and procedure adherence. Hence, although the licensee had made progress towards improving and sustaining Design and Configuration Control (DCC), the team concluded that concurrent improvement and sustainability in the areas of technical rigor and procedure adherence are crucial to achieving sustained DCC improvement at BFN.

5.1.4 **Technical Rigor (FPA 9 – TR)**

5.1.4.1 Inspection Scope: The team assessed the licensee's technical rigor as applied at the TVA Corporate and station level to determine whether it was sufficient to prevent a decline in performance that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The licensee's diagnostic investigation and Recovery Review identified Technical Rigor as a fundamental problem area (FPA 9). BFN performed an apparent cause evaluation (ACE) PER 543131 to determine the cause(s), extent-of-condition, and corrective actions to address this fundamental problem. The ACE problem summary stated that insufficient technical rigor from engineering had resulted in rework, engineering design basis documentation flaws, and/or mis-configurations requiring additional work and resources.

The team interviewed selected members of the licensee's engineering staff, from both the TVA Corporate level and the station, to gauge the level of experience and expertise of station engineering personnel. Additionally, the team evaluated the following:

- Problem statement as stated above and examples of station issues identifying lack of technical rigor pertaining in large part to engineering products,
- Apparent and contributing causes identified by the licensee for lack of technical rigor as identified in ACE PER 543131,
- The licensee's response and associated actions related to industry and internal operating experience related technical rigor issues,
- The internal and external audits and assessments related to technical rigor,
- Corrective actions implemented and/or planned to address station technical rigor issues and the effectiveness of these corrective actions,
- The effectiveness of measurement tools, such as metrics and observations, and
- Several engineering products such as prompt operability determinations, commercial grade dedication packages, permanent and temporary modification design packages, engineering self-assessments, and PERs associated with engineering design issues.

The team evaluated the licensee's apparent cause analysis related to the licensee's Fundamental Problem Area 9, "Technical Rigor". Specifically the team evaluated whether: 1) completion of the analysis was in accordance with the licensee's process; 2) a thorough and methodical process was used to complete the analysis; 3) the related licensee's fundamental problem area adequately covered the related issues; 4) the appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) the corrective actions adequately addressed the causes; 6) the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) selected corrective actions were adequately implemented; 8) the extent-of-condition and cause were adequately addressed; and 9) the completed or planned effectiveness reviews were adequate. Documents reviewed are listed in the Attachment.

5.1.4.2 Observations and Findings: The team identified a Severity Level IV non-cited violation.

5.1.4.2.1 Failure to Perform 10 CFR 50.59 Evaluation for Intergranular Stress Corrosion Cracking Examination on ASME Code Class 1 Piping Weld

Although this finding was documented under the FPA of Technical Rigor, the team also determined the Finding was related to the FPAs of Operational Focus and Decision Making (FPA 2), Section 5.4.2 for the licensee's failure to make conservative decisions regarding disposition of unknown examination conditions during UT examination of IGSCC susceptible welds at the station.

5.1.4.2.1.a Introduction: The team identified a Severity Level IV non-cited violation (NCV) of 10 CFR 50.59, Changes, Tests, and Experiments, for the licensee's failure to perform an evaluation of a change to the facility as described in the Updated Final Safety Analysis Report and an associated Green Finding for the licensee's failure to perform an acceptable Ultrasonic examination in accordance with American Society of Mechanical Engineers (ASME) Code, Section XI requirements. This change resulted in a departure from the method of evaluation used to inspect for IGSCC in reactor coolant pressure boundary components at BFN as described in the UFSAR and therefore required a 10 CFR 50.59 evaluation.

5.1.4.2.1.b Description: On March 22, 2013, the licensee performed UT examination on Unit 2 on weld DRHR-2-12 to satisfy the requirements of BWRVIP-75-A, Technical Basis for Revisions to Generic Letter 88-01, for the detection of IGSCC in reactor coolant pressure boundary components at BFN. Weld DRHR-2-12 was a 24" diameter stainless steel weld that consisted of a flued head penetration to a cast stainless steel valve and was part of the RHR injection line above the torus. The UT examination report documented that only 50 percent of the required examination volume was examined using qualified UT examination techniques. The reason documented in the report for obtaining 50 percent weld volume examination coverage was that only a single-sided (as opposed to dual-sided) UT examination could be performed due to cast stainless steel material on one side of the weld. Ultrasonic examination technology used in the examination was not qualified to detect flaws if the UT examination was performed on cast stainless material. However, no further evaluation was documented to analyze the material condition of the 50 percent of the weld that had not been examined. Therefore, the team concluded that the licensee failed to meet the ASME Code required coverage requirement of essentially 100 percent (i.e., greater than or equal to 90 percent).

Browns Ferry UFSAR Section O.1.10 described the BFN Boiling Water Reactor Stress Corrosion Cracking (BWRSCC) Program. This program stated that, "The BWRSCC Program manages intergranular stress corrosion cracking in reactor coolant pressure boundary components made of stainless steel. The BWRSCC Program is consistent with NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," and Nuclear Regulatory Commission Generic Letter 88-01, "NRC Position on Intergranular Stress Corrosion Cracking in BWR Austenitic Stainless Steel Piping," and its Supplement 1." The Program included, in part: (b) Inspections to monitor IGSCC and its effects.

Generic Letter 88-01 (GL 88-01) contained the NRC staff position on requirements for inspection of IGSCC in BWR piping welds. Specifically, Attachment A of GL 88-01 stated that examinations performed under the Scope of GL 88-01 letter should comply with the applicable Edition and Addenda of the ASME Code, Section XI, as specified in paragraph (9), "Inservice Inspection Requirements" of 10CFR50.55a, Codes and Standards, or as otherwise approved by the NRC.

ASME Code Case N-460 (CC N-460) clarified the Code Committee's position on acceptable examination coverage when required examination coverage cannot be obtained due to interference. Code Case N-460 stated, in part, that a reduction in examination coverage on any Class 1 or Class 2 weld may be accepted provided the reduction in coverage for that weld was less than 10 percent. The applicable examination records shall identify both the cause and percentage of reduced examination coverage. That is, when there was interference during an UT examination, the examination was only acceptable if greater than or equal to 90 percent coverage was obtained. Because the licensee did not obtain the required minimum 90 percent examination volume coverage during UT examination of DRHR-2-12, the licensee did not meet CC N-460 or the NRC staff position on inspection requirements for detecting IGSCC in BWR austenitic pipe welds as described in GL 88-01. As a result, the UT examination of DHR-2-12 introduced a departure from the inspection methodology described in GL 88-01 that was referenced under the BFN BWRSCC Program as described in UFSAR Section O.1.10.

The licensee did not perform 10 CFR 50.59 applicability, screening, and evaluation for this departure from the IGSCC inspection methodology. The team concluded that the limited examination of weld DRHR-2-12 (50 percent of required exam coverage) required a 10 CFR 50.59 evaluation in accordance with the guidance established in NEI 96-07, "Guidelines for 10 CFR 50.59 Implementation." The team also concluded that this departure from the inspection methodology as described in the UFSAR was a departure in the non-conservative direction because less than the required examination volume coverage was obtained during the IGSCC UT examination. Additionally, there were similar weld configurations on Units 1 and 3 that required the application of the 10 CFR 50.59 screening process. The team determined that performing the 10 CFR 50.59 process would require thorough extent-of-condition reviews that would address weld configuration of other Units.

5.1.4.2.1.c Analysis: The licensee's failure to perform an evaluation to determine if a license amendment request was required following a departure from weld examination methodology as described in the UFSAR was a violation of 10 CFR 50.59 and the failure to perform an acceptable examination in accordance with the applicable ASME Code, Section XI requirements was the associated performance deficiency. The team evaluated this issue using the traditional enforcement process, including NRC Enforcement Policy, Supplement I, Reactor Operations, because this PD had the potential to impact the NRC's ability to perform its regulatory function. This violation was associated with a Finding that was evaluated by the SDP and communicated with SDP color representative of the safety impact of the deficient licensee performance. The SDP, however, does not specifically consider the regulatory process impact. Thus although related to a common regulatory concern, it was necessary to address the violation and Finding using different processes to correctly reflect both the regulatory importance of the violation and the safety significance.

The team determined the underlying PD was more than minor and a Finding, because the PD affected the Barrier Integrity Cornerstone and if left uncorrected, could become a more significant safety concern. Absent NRC identification of this PD, the licensee could have continued to perform UT examinations to detect IGSCC on safety-related components without obtaining the minimum required examination volume. This could result in IGSCC susceptible welds on ASME Code Class 1 piping being only partially examined for IGSCC flaws and could lead to safety-related components with potentially unacceptable service-induced flaws not detected during UT examinations being returned to service. The team evaluated the Finding's significance in accordance with IMC 0609, Appendix G, Shut-down Operations Significance Determination Process, because the PD occurred while Unit 2 was in cold shutdown. The team reviewed IMC 0609, Appendix G, Attachment 1, Checklists 5, 6, 7, and 8 and determined this Finding did not require a quantitative assessment. Therefore the Finding screened as having very low safety significance.

The team determined the violation was more than minor because of reasonable likelihood the departure from weld inspection methodology as described in the UFSAR would have required Commission review and approval prior to implementation. The team concluded that the violation of 10 CFR 50.59 was a Severity Level IV because the underlying PD screened Green under the SDP. The team also concluded that this Finding had a cross-cutting aspect in the area of Human Performance, Decision Making, because the licensee did not make safety-significant or risk-significant decisions using a systematic process when faced with uncertain or unexpected plant conditions, to ensure safety was maintained. [H.1 (a)]

5.1.4.2.1.d <u>Enforcement</u>: Title 10 CFR 50.59, Changes, Tests and Experiments, states in part, that a licensee may make changes in the facility as described in the final safety analysis report (as updated) without obtaining a license amendment pursuant to 10 CFR 50.90 only if the change does not result in a departure from a method of evaluation described in the final safety analysis report (as updated) used in establishing the design bases or in the safety analyses.

Contrary to the above, on March 22, 2013, the licensee made changes to the facility as described in the final safety analysis report without performing a 10 CFR 50.59 evaluation to determine if a license amendment request was required for a change that resulted in a departure from a method of evaluation described in the UFSAR used in establishing the design bases or in the safety analyses. Specifically, the licensee performed a UT examination of the DRHR-2-12 weld to detect for IGSCC under BWRSCC Program as described in UFSAR Section O.1.10. Section O.1.10 of the UFSAR stated the BWRSCC program was consistent with GL 88-01. However, on March 22, 2013, the licensee did not meet the volumetric examination requirements described in GL 88-01 and therefore, departed from a method of evaluation as described in the UFSAR and did not perform a 10 CFR 50.59 evaluation to determine if the change would have required a license amendment request. Because the underlying Finding associated with this violation was of very low safety significance and was entered into the corrective action program as SR 743380 and PER 744849 this violation was being treated as a Severity Level IV NCV consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000260/2013011-03, Failure to Perform 10 CFR 50.59 Evaluation or Intergranular Stress Corrosion Cracking Examination on ASME Code Class 1 Piping Weld

5.1.4.2.2 Other Observations: The team identified several additional examples of lack of technical rigor that were being applied during this inspection to technical products from engineering and other organizations at the station such as operations, maintenance, and CAP. These examples of issues with technical products included one immediate operability determination from operations, two preventive maintenance (PM) deferrals from maintenance, six service requests, three lower tier apparent cause evaluations, one engineering procedure revision, and one engineering evaluation as described below:

1. PM Deferral 686634 and PM Deferral 506529 did not provide adequate technical justification for why the PMs could be deferred, and were not performed in accordance with Procedure NPG-SPP-06.2, “Preventive Maintenance,” Revision 4. This is an example of a lack of technical rigor by engineering personnel in that the evaluations did not contain enough technical information to justify why the PM task could be deferred. In both cases the PM Deferrals did not contain sufficient technical information to support the deferral conclusions. The licensee wrote SR’s 722931 and 725628 to address these two deficient PM deferrals and initiated PER 723646 to develop additional corrective actions associated with PM deferral. No violations of regulatory requirements occurred.

2. The licensee unsecured three seismically mounted control room ceiling light diffusers and slid them over the top of other light diffusers while performing Surveillance Procedure 0-SR-3.3.7.1.4, “Control Room

Ventilation Logic System Functional Test-Radiation Monitors." This action created a seismic missile hazard that could have impacted control room ventilation damper actuators. The immediate determination of operability for PER 730443, "NRC Identified Main Control Room Ceiling Panels," did not address the seismic missile hazard posed by the unsecured ceiling light diffusers. See Section 5.2.4.2.1 for a detailed description and regulatory significance.

3. The team identified several examples of lack of technical rigor in the area of problem identification and resolution. These examples focused on the quality of service requests and lower-tier apparent cause evaluations generated by the site. See Section 6.1.4, Corrective Action Program, for detailed observations.

4. The revision to Procedure EPI-00248-BAT005,"Annual Inspection of 250V DC Main Battery Banks 1, 2, 3 and Associated Chargers" (Revision 19), which changed the inter-cell resistance measurement method, was not thorough or rigorous. Specifically, BFN staff did not identify the need to revise the inter-cell resistance acceptance criteria to correspond to the new measurement method and locations. See Section 2.2.3, Procedure and Instruction Quality, for a detailed description and regulatory significance.

5. The initial licensee evaluation of the RHRSW air relief valves (ARV) freeze protection deficiency was not rigorous, because it did not address the potential for ice to block the ARV vent path, the potential of a resulting water hammer transient to damage the RHRSW system, worst case river level, RHRSW check valve leakage conditions, adequacy of RHRSW ARV freeze protection, or the potential misclassification of the ARV as non safety-related (SR 732519). See Section 6.1.4.2.1, Corrective Program Observations, for a detailed description and regulatory significance.

6. The licensee lacked technical rigor in justifying acceptance of non-conforming bearings for use in safety-related components during commercial grade dedication of commercially procured bearings (PER 729646). See Section 5.1.3.2.1, for a detailed description and regulatory significance.

7. The team observed the outside rounds operator flush strainers for circulation water bearing coolers. The flush was necessary several times a day while biocide injection was in progress to ensure adequate

system flow rates were maintained. The procedure that the operator used did not contain instructions for flushing the strainer with temporary alteration TAF 1-09-001-023 in place. The operator correctly stopped and called the control room when the procedure instructions did not work with the temporary alteration installed. However, the operator could not answer the team's question of how this activity was done previously when using this procedure.

5.1.4.3 Assessment Results: The team's independent assessment of the Technical Rigor (FPA 9) ACE and supporting documents concluded that the licensee had appropriately identified the apparent causes that led to several site challenges, eventually culminating into a fundamental problem area associated with Technical Rigor. The apparent causes were: 1) lack of accountability exercised by leaders for existing barriers and Knowledge Worker Human Performance Tools; and 2) inconsistent proficiency and experience level of personnel preparing technical documents and ineffective implementation of the Knowledge Worker Human Performance Tools.

The team concluded that the licensee made progress towards addressing issues of technical rigor being applied to products delivered by the engineering organization at the station. The metrics established by the licensee to monitor health of engineering technical rigor at the station were adequate and should allow the licensee to maintain a sustainable path towards further improvement in the area of technical rigor at the station. The team also concluded that the licensee had developed enhanced guidance on leadership excellence pertaining to Knowledge Worker Human Performance accountability as well as developing a Knowledge Worker Human Performance Tools procedure to effectively implement Knowledge Worker Human Performance Tools amongst the licensee's staff. However, the FPA 9 ACE scope did not include a thorough review of technical rigor as it applied to other organizations at the station including maintenance, operations, and CAP to ensure a high level of technical rigor was obtained and maintained station-wide and not just achieved by the engineering organization.

In addition, the team concluded that the 10 CFR 50.59 violation described above revealed technical rigor deficiencies that crossed several organizations at the station including engineering, licensing, and Inservice inspection (ISI). Therefore, the team also concluded the licensee had not approached technical rigor at BFN holistically, in that, BFN failed to effectively determine why site-wide technical rigor was not consistently applied. For example, after the team identified an issue concerning an RHR weld examination coverage disposition and a potential associated 10 CFR 50.59 violation, the BFN licensing organization did not provide adequate regulatory technical rigor to support engineering and ISI technical rigor efforts in the final disposition of the examination results.

The team concluded that continued BFN management emphasis on technical rigor across the station was warranted to reduce the occurrence of issues described in the observations described above. The licensee addressed this team conclusion in their Safety Culture Continuous Improvement and Sustainability Plan, PERs 757451 and 743724 that included actions to address the need to approach each fundamental problem area, including Technical Rigor, more holistically at the site. Specifically, the licensee included additional actions in the Safety Culture Action Plan that provided a holistic approach that systematically evaluated what action(s) were required to ensure that workers demonstrate and execute desired behaviors more consistently, including technical rigor and decision making at the site. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement of the FPA.

5.1.5 **Summary and Conclusion**

In summary, the team reviewed the apparent cause evaluations (ACEs) and supporting documents for the fundamental problem areas (FPAs) of Equipment Programs and System Management, Technical Rigor, and Design and Configuration Control. The licensee-identified apparent causes included inexperienced staff, inadequate engineering staffing level, and lack of accountability for procedure adherence. The team's independent assessment of these FPA ACEs concluded the licensee had appropriately identified the associated apparent causes. The team also reviewed a sample of the corrective actions associated with these ACEs and concluded that the implemented and planned corrective actions were sufficient to prevent a decline in safety that could result in unsafe operations. Although the team had some findings and observations related to the areas of Equipment Programs and System Management, the implemented and proposed actions in the IIP for these FPAs were appropriate to promote sustained improved performance. This included additional actions to address issues related to Technical Rigor across the site. The team concluded that the licensee had adequately addressed the multitude of challenges at the site in their Safety Culture Continuous Improvement and Sustainability Plan (PERs 757451 and 743724) that formed the bases of the design related fundamental problem areas experienced at the site to prevent a decline in performance. Nonetheless completion of the planned and revised actions associated with the FPA as contained in the IIP is essential to sustained performance improvement.

5.2 Human Performance

5.2.1 Inspection Overview: As prescribed by IP 95003, the team's human performance inspection activities included the fundamental problem areas of Procedure Use and Adherence FPA 6, and Ownership and Accountability FPA 11. The team reviewed and observed the licensee's performance in a wide range of plant processes and activities for these FPAs. The team identified six Findings of very low safety significance.

5.2.2 Procedure Use and Adherence (FPA 6 – PU&A)

5.2.2.1 Inspection Scope: The team reviewed documents and performed inspection activities associated with procedure use and adherence during start up and power operations at BFN Units 1, 2, and 3 including:

- Conduct of operations,
- Peer checks, independent verifications, and concurrent verifications,
- System operability surveillance testing,
- Equipment clearances and tagouts,
- Control room alarm responses,
- Normal and abnormal equipment operation,
- Operability and functionality determinations,
- Protected equipment,
- Preventative and corrective equipment maintenance, and
- The corrective action program.

The team reviewed BFN PER 484548, "Continued Trend in Repetitive Issues Associated with Procedure Use and Adherence and RCA Report," Revision 1, and PER 543135, "GAP Analysis of Procedure Use and Adherence Root Cause Analysis Report," Revision 1. The team assessed the root and contributing causes of risk significant deficiencies associated with each PER to determine if they were comprehensive and sustainable. The team's objective was to determine whether the licensee's completed and planned corrective actions, were effective in achieving sustainable improvements in procedure use and adherence.

In the operations inspection area for surveillance testing, the team verified:

- Completion was in accordance with the licensee's procedures, policies, operating license, and design bases,
- Completion was technically adequate and in accordance with industry standards as applicable, and
- Results were appropriately reviewed and discrepancies were appropriately identified and addressed in a technically sound manner and in accordance with the licensee's process and procedures.

In the area of operations assessment and audits, the team verified:

- The adequacy of the extent of condition,
- The adequacy of corrective actions in addressing the causes of the identified condition and the adequacy of effectiveness reviews to assess plant progress toward correction of the identified deficiencies,
- The priority of corrective action was commensurate with the safety significance,
- Corrective action implementation resolved the problem,
- The scope (breadth and depth) of the assessment was appropriate,
- That the licensee analyzed the corrective actions to understand trends and areas of concern,
- By walkdowns, interviews, and procedure/program reviews, that the corrective actions were implemented and maintained in accordance with procedures, and
- Declining trends were arrested by the corrective actions taken.

For observations of work activities or meetings related to the operations inspection area, the team verified:

- The activity or meeting was completed in accordance with the licensee's program and procedures,
- The meeting reflected sound technical decision making,
- Adequate communication was demonstrated both inter-departmentally and across departments, and
- Discrepancies were identified and addressed in accordance with the licensee's processes and procedures.

Documents reviewed are listed in the Attachment.

5.2.2.2 Observations and Findings: The team identified five findings of very low safety significance.

5.2.2.2.1 Two BFN Assistant Unit Operators Closed and Danger Tagged the A1 RHRSW Pump Manual Discharge Valve Instead of the Required A2 RHRSW Pump Discharge Valve

Although this finding was documented under the FPA 6 Procedure Use and Adherence, the team determined that, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Operational Focus and Decision Making (FPA 2) (Section 5.4.2),
- Work Management (FPA 4) (Section 5.5.2), and
- Technical Rigor (FPA 9) (Section5.1.4).

In addition, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) and Configuration Control (Section 5.5) described in this report.

5.2.2.2.1.a Introduction: A self-revealing Green NCV of TS 5.4.1, “Procedures”, was identified when BFN’s clearance and tagging application related to the planned A2 residual heat removal service water pump maintenance was not applied or verified properly as required by TVA Corporate procedures. Two BFN AUOs closed and danger tagged the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump discharge valve on May, 6, 2013. The error resulted in the unplanned inoperability of the A1 RHRSW pump with the A2 RHRSW pump inoperable for planned maintenance.

5.2.2.2.1.b Description: The team determined that BFN’s clearance and tagging application related to the planned A2 residual heat removal service water (RHRSW) pump maintenance was not properly applied and verified as required by TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, “Clearance Procedure to Safely Control Energy,” and NPG-SPP-10.3, Rev.1, “Verification Program." Two BFN assistant unit operators (AUOs) closed and danger tagged the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump discharge valve. The two AUOs signed and dated that the planned A2 (actually A1) RHRSW pump manual discharge valve was manually closed and the danger tag was applied on May, 6, 2013, at 10:33 am. The A2 RHRSW pump tagout number 0-TO-

2013-001, and clearance number 0-023-008 included the application of nine red danger tags for the planned A2 RHRSW pump impeller adjustment maintenance activity.

The tagout required the AUO's to close the A2 RHRSW pump manual discharge valve and apply a red danger tag using self-checking, peer checking, and concurrent verification human error prevention processes. The concurrent verification procedure required that both AUOs perform the actions to close the A2 pump manual discharge valve in the safety-related river water intake structure, and verify the danger tag is applied to the correct valve blocking point. Both AUO's failed to perform proper self-checking and concurrent verification checking requirements when they closed the A1 RHRSW pump manual discharge valve and applied the red danger tag that was written for the A2 RHRSW pump. Both AUO's signed the clearance document for danger tag No. 1435, valve O-SHV-023-0507, "RHR SW PMP A2 DISCH INTAKE EL 565 A RHRSW."

The A1 RHRSW pump discharge valve tagging error became self-revealing when the Unit 1 control room reactor operator (RO) started the A1 RHRSW pump to perform Surveillance Test, 1-SR-3.5.1.6(RHR I), "Quarterly RHR System Rated Flow Test – Loop I." After starting the 1A RHRSW pump, the RO immediately opened the 1A RHRSW heat exchanger outlet valve. With the 1A RHRSW manual discharge valve tagged closed, the control room received the "RHRSW Header Pressure Low" alarm on all three Units. The RHRSW pressure dropped to zero pounds per square inch (psig). The RO closed the 1A RHRSW heat exchanger outlet valve and system pressure recovered. An AUO responded to the 1A RHRSW pump river water intake structure and noted that the 1A RHRSW pump manual discharge valve was full closed with a red danger tag attached to the valve handwheel.

Operations removed the danger tag and re-opened the 1A RHRSW pump manual discharge valve. Operations declared the A1 RHRSW pump and Units 1, 2, and 3 RHR heat exchangers inoperable from 9:45 am thru 9:45 pm on May 6, 2013. Operations performed a fill and vent of the RHRSW header to ensure all air was removed from the system and to restore all three RHRSW heat exchangers to an operable condition.

5.2.2.2.1.c Analysis: The team determined that the BFN AUO's that closed and danger tagged the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump discharge valve failed to follow TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely

Control Energy," and NPG-SPP-10.3, Rev.1, "Verification Program." Specifically, the AUOs did not use proper self-checking, peer checking, and concurrent verification human error prevention processes for the clearance tag application which constituted a performance deficiency that was reasonably within BFNs ability to foresee, correct, and could have been prevented.

This Finding was more than minor because it was associated with the human performance attribute of the Mitigating System cornerstone because the AUOs tagged the wrong RHRSW pump discharge valve and the error affected the Mitigating System cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating event to prevent undesirable consequences. Using Inspection Manual Chapter 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, "The Significant Determination Process (SDP) for Findings At-Power," the team determined that this Finding was of very low safety significance because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time. The team determined that this Finding had a cross-cutting aspect in the area of Human Performance, Work Practices, because BFN AUOs did not use proper self-checking and peer checking human error prevention techniques to prevent the inadvertent closure and danger tagging of the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump valve during the application of a tagging clearance. [H.4(a)]

5.2.2.2.1.d <u>Enforcement</u>: TS 5.4.1, "Procedures," states that written procedures shall be established, implemented, and maintained covering the following activities: a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 1.c. Administrative Procedures, "Equipment Control (e.g., locking and tagging). Contrary to the above, the team determined that BFN's clearance and tagging application related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy," and NPG-SPP-10.3, Rev.1, "Verification Program." Specifically, both AUO's failed to perform proper concurrent verification requirements stated in NPG-SPP-10.3, Section 3.3.1 C. and D., "the performer and verifier shall: 1) locate the component; and 2) identify each unique identifier on the component label." The AUOs closed the A1 RHRSW pump manual discharge valve, O-SHV-023-0503, and applied the red danger tag No. 1435 that was written for the A2 RHRSW pump manual discharge valve, O-SHV-023-0507. The incorrect valve was tagged closed at 10:33 am on May 6, 2013. The 1A RHRSW pump was subsequently declared inoperable at 9:45 am on May 6, 2013, and had remained inoperable for 12 hours. Because this Finding was of very low safety significance and it was entered into the licensee's CAP via SR 722559 and PER 722859, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC's Enforcement Policy and is identified as NCV 05000259, 260, 296/20130011-04, Two BFN Assistant Unit Operators Closed and Danger Tagged the A1 RHRSW Pump Manual Discharge Valve Instead of the Required A2 RHRSW Pump Discharge Valve.

5.2.2.2.2 **Maintenance Personnel Not Following Clearance Procedure**

Although this finding was documented under the FPA 6 Procedure Use and Adherence, the team determined that aspects of this issue were related to FPA 2 Operational Focus and Decision Making as described in Section 5.4.2, and FPA 11, Ownership and Accountability as described in Section 5.2.3. In addition, although not explicitly discussed in the report, this issue was also related to the following FPAs:

- Work Management (FPA 4) (Section 5.5.2),
- Technical Rigor (FPA 9) (Section 5.1.4), and
- Governance and Oversight (FPA 10) (Section 6.1.5).

Furthermore, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) and Configuration Control (Section 5.5) described in this report.

5.2.2.2.2.a Introduction: An NRC identified Green NCV of TS 5.4.1, "Procedures," occurred when a BFN maintenance Primary Authorized Employee (PAE) did not verify that all of the blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW pump planned maintenance. The PAE's decision to only verify two of nine clearance components was a violation of TVA's Clearance Procedure to Safely Control Energy. The PAE did not verify or recognize that the A1 RHRSW pump manual discharge valve was tagged closed instead of the required A2 RHRSW pump discharge valve on May, 6, 2013.

5.2.2.2.2.b Description: The team evaluated BFNs work coordination actions related to the planned maintenance on the A2 RHRSW pump. The maintenance department was scheduled to perform a pump impellor gap adjustment to compensate for the change in river water temperature. The work required that the pump was uncoupled from the electric motor. The A2 RHRSW pumps is a safety-related river water cooling pump that supplies the “A” RHR heat exchanger cooling for all three Units. The A1 RHRSW pump also supplies the same RHR heat exchangers for the division one cooling loop.

The A2 RHRSW pump was tagged out of service on May 6, 2013, at 10:33 am. Unknown to the work control center, operations, and maintenance departments, the assistant unit operators closed and danger tagged the A1 RHRSW pump manual discharge valve instead of the required A2 RHRSW pump discharge valve. After tagout 0-TO-2013 -0001 was applied, the maintenance Primary Authorized Employee did not verify that all of the blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW pump planned maintenance.

The team questioned the PAE’s decision to only walk down and verify the A2 RHRSW pump motor electrical breaker and associated control power fuses. The PAE did not verify that danger tag No. 1435, “RHR SW PMP A2 DISCH INTAKE EL 565 A RHRSW,” for A2 RHRSW pump manual discharge valve, O-SHV-023-0507, was applied to the correct valve and that the A2 valve was closed. The PAE replied that “he correctly verified the tags directly related to his task, he walked down the breaker and fuses as required by Procedure NPG-SPP-10.2, Section 3.3.5. C. The work did not require flow to be isolated.”

The team reviewed TVA Procedure NPG-SPP-10.2, “Clearance Procedure to Safely Control Energy,” Rev. 5, Section 3.3.5 C. and D. Procedure Section C. and D., state, in part, that “the PAE physically walks down the clearance to determine if energy isolating devices are controlled to prevent introduction of hazardous energy to the equipment on which the PAE will perform maintenance. The walk down shall be completed and the clearance held prior to the PAE or any authorized employee start to work on the equipment under the clearance. The PAE documents that the clearance has been read and understood, the walk down is complete, that the clearance boundary is adequate and the work can be safely performed by signing onto the clearance.” Procedure NPG-SPP-10.2 did not provide written allowance for the PAE to perform a partial walkdown and verification of the clearance tagout blocking components. After discussion with maintenance and station management, the team was informed that the required standard was to perform a walkdown and verify all blocking components included in the clearance tag list; with no exception allowed.

In addition, the A1 and A2 RHRSW Incident Prompt Investigation evaluation approved on May 9, 2013, by site management, concluded that and initial procedure implementation was acceptable, and did not identify that the Maintenance PAE did not follow the requirements of Procedure NPG-SPP-10.2, Rev. 5, “Clearance Procedure to Safely Control Energy.” The PAE did not walk down and verify that all nine danger tags for the A 2 RHRSW planned pump maintenance work on May 6, 2013, were applied correctly on all tagout components. The investigation did not highlight the seriousness of protecting the safety of station personnel and Station and Maintenance Department management accepted the maintenance supervisor’s (PAE) reason to only perform a partial verification of the A2 RHRSW pump motor electrical power supply and associated fuses.

The A1 RHRSW pump discharge valve tagging error became self-revealing when the Unit 1 control room reactor operator started the A1 RHRSW pump to perform Surveillance Test, 1-SR-3.5.1.6 (RHR I), “Quarterly RHR System Rated Flow Test – Loop I.” After starting the 1A RHRSW pump, the RO immediately opened the 1A RHRSW heat exchanger outlet valve. With the 1A RHRSW manual discharge valve tagged closed, the control room received the “RHRSW Header Pressure Low” alarm on all three Units. The RHRSW pressure dropped to zero pounds psig. The RO closed the 1A RHRSW heat exchanger outlet valve and system pressure recovered. An AUO responded to the 1A RHRSW pump river water intake structure and noted that the 1A RHRSW pump manual discharge valve was full closed with a red danger tag attached to the valve handwheel.

Operations removed the danger tag and re-opened the 1A RHRSW pump manual discharge valve. Operations declared the A1 RHRSW pump and Units 1, 2, and 3 RHR heat exchangers inoperable from 9:45 am thru 9:45 pm on May 6, 2013. Operations performed a fill and vent of the RHRSW header to ensure all air was removed from the system and to restore all three RHRSW heat exchangers to an operable condition.

The maintenance PAE missed an opportunity to identify that the A2 RHRSW pump manual discharge valve was not closed and danger tagged as required and that the A1 RHRSW pump discharge valve was inadvertently closed with the A2 pump red danger tag applied to the valve handwheel.

5.2.2.2.2.c <ins>Analysis</ins>: The team determined that the failure of the BFN maintenance PAE to verify that all the blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW planned maintenance was a performance deficiency. The team determined that this deficiency was reasonably within BFNs ability to foresee, correct, and could have been prevented.

This Finding was more than minor because, if left uncorrected the BFN Maintenance Supervisor's failure to follow the clearance and tagging procedure requirement to verify all danger tag blocking points, he only verified two of nine danger tags, for the A 2 RHRSW planned pump the performance deficiency would have the potential to lead to a more significant safety concern, such as more severe plant transients, engineered safeguard system malfunctions, and a higher probability of personnel injury.

The Finding was determined to be of very low safety significance (Green) in accordance with Inspection Manual Chapter (IMC) 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, "The Significant Determination Process (SDP) for Findings At-Power," because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time.

The team identified a cross-cutting aspect in the Work Practices component of the Human Performance area. Specifically, the licensee ensures supervisory and management oversight of work activities such that nuclear safety is supported. [H.2(c)]

5.2.2.2.2.d Enforcement: TS 5.4.1, "Procedures," states that written procedures shall be established, implemented, and maintained covering the following activities: a. The applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978, Section 1.c. Administrative Procedures, "Equipment Control (e.g., locking and tagging). Contrary to the above, the team determined that the BFN maintenance Primary Authorized Employee' s clearance and tagging application verification, for Clearance Order No. 0-023-008, related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedure NPG-SPP-10.2, "Clearance Procedure to Safely Control Energy," Rev. 5, Section 3.3.5 C. and D. Procedure Section C. and D., state, in part, that "the PAE physically walks down the clearance to determine if energy isolating devices are controlled to prevent introduction of hazardous energy to the equipment on which the PAE will perform maintenance. The walk down shall be completed and the clearance held prior to the PAE or any authorized employee start to work on the equipment under the clearance. The PAE documents that the clearance has been read and understood, the walk down is complete, that the clearance boundary is adequate and the work can be safely performed by signing onto the clearance."

Specifically, the maintenance PAE failed to verify that red danger tag, No. 1435, "RHR SW PMP A2 Discharge Valve O-SHV-023-0507, Intake EL 565 A RHRSW Pump Room, was applied to the correct valve and that the A2 RHRSW pump manual discharge valve was closed. At 1:09 pm on May 6, 2013, the Unit 1 control room reactor operator started the 1A RHRSW pump; the RO immediately secured the A1 RHRSW pump when the control room received the "RHRSW Header Pressure Low" alarm on all three Units. An AUO responded to the 1A RHRSW pump river water intake structure and noted that the 1A RHRSW pump manual discharge valve was full closed with the A2 RHRSW pump red danger tag attached to the valve handwheel. The A2 RHRSW pump manual discharge valve was found full open and not danger tagged as required by the clearance order. Because this Finding was of very low safety significance and it was entered into the licensee's CAP via SR 722984 and PER 724067, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC's Enforcement Policy and is identified as 05000259, 260, 296/2013-011-05, Maintenance Personnel Not Following Clearance Procedure.

5.2.2.2.3 **Conduct of Operations Procedure Violation**

Although this finding was documented under the FPA 6 Procedure Use and Adherence, the team determined that aspects of this issue were related to FPA 2 Operational Focus and Decision Making as described in Section 5.4.2, and FPA 4, Work Management as described in Section 5.5.2. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Technical Rigor (FPA 9) (Section 5.1.4),
- Governance and Oversight (FPA 10) (Section 6.1.5), and
- Procedure and Instruction Quality (FPA – 12) Section 5.3.2).

Furthermore, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) and Configuration Control (Section 5.5) described in this report.

5.2.2.2.3.a Introduction: The team identified a Green, non-cited violation of Technical Specification (TS) 5.4.1, "Procedures." The team determined that assistant unit operators' failure to comply with TVA Procedure OPDP-1, "Conduct of Operations," Rev. 26, related to the missing A1 RHRSW pump discharge valve label plate and the AUO's inadequate walkdown of the A1 RHRSW pump prior to the planned quarterly surveillance test pump start on May 6, 2013. The errors contributed to the unplanned inoperability of the A1 RHRSW pump with the A2 RHRSW pump inoperable for planned maintenance.

5.2.2.2.3.b Description: The team evaluated BFNs work coordination actions related to the planned maintenance on the A2 RHRSW pump and the subsequent planned quarterly surveillance test for the A1 RHRSW pump. The A1 and A2 RHRSW pumps are safety-related river water cooling pumps that supply the "A" RHR heat exchanger cooling for all three Units.

The A2 RHRSW pump was tagged out of service on May 6, 2013, at 10:33 am. The two AUOs assigned to the A2 RHRSW pump tagout noticed that the pump discharge valve identification label was not attached to the valve. Unknown to the AUOs at the time, the missing identification label was not for the A2 pump, but for the A1 RHRSW pump discharge valve. The AUOs failed to comply with Procedure OPDP-1, "Conduct of Operations," Rev. 27, Section 4.2 K. because they did not stop the A2 RHRSW pump clearance application to correct the valve label issue. When a missing or incorrect component identification label is discovered, OPDP-1 procedure states, in part, that "the Operator should stop to seek clarification to ensure the correct component is being manipulated. Actions shall be initiated to correct the information such as installation of a temporary label."

The BFN work control center and Unit 1 control room operators elected to perform the A1 RHRSW pump Surveillance Test, 1-SR-3.5.1.6(RHR I), "Quarterly RHR System Rated Flow Test – Loop I." Prior to the A1 RHRSW pump start Procedure OPDP-1, "Conduct of Operations," Rev. 27, Section 4.2 M., states, in part, that "a field operator shall be dispatched during normal planned operations to monitor associated equipment startup, notifying the control room of any abnormalities." The AUO did not enter the RHRSW intake structure as required by Procedure OPDP-1, to monitor the A1 RHRSW pump and system alignment prior to the planned surveillance test. The AUO missed an opportunity to identify that the A1 RHRSW pump discharge valve was inadvertently closed with a red danger tag applied to the valve handwheel during the A2 RHRSW pump tagout that was applied earlier in the day shift at 10:33 am.

The A1 RHRSW pump discharge valve tagging error became self-revealing when the Unit 1 control room reactor operator started the pump at 1:09 pm on May 6, 2013. After starting the 1A RHRSW pump, the RO immediately opened the 1A RHRSW heat exchanger outlet valve. With the 1A RHRSW manual discharge valve tagged closed, the control room received the "RHRSW Header Pressure Low" alarm on all three Units. The RHRSW pressure dropped to zero pounds psig. The RO closed the 1A RHRSW heat exchanger outlet valve and system pressure recovered. An AUO responded to the 1A RHRSW pump river water intake structure and noted that the 1A RHRSW pump manual discharge valve was full closed with a red danger tag attached to the valve handwheel.

Operations removed the danger tag and re-opened the 1A RHRSW pump manual discharge valve. Operations declared the A1 RHRSW pump and Units 1, 2, and 3 RHR heat exchangers inoperable from 9:45 am thru 9:45 pm on May 6, 2013. Operations performed a fill and vent of the RHRSW header to ensure all air was removed from the system and to restore all three RHRSW heat exchangers to an operable condition.

In addition to the prior two Procedure OPDP-1, "Conduct of Operations," Rev. 26, February 8, 2013, procedure adherence examples, the team also identified numerous errors and existing inconsistent standards that did not comply with NRC regulations and TVA procedure requirements. The inconsistent TVA Corporate procedure adherence standards; inconsistent self, peer, independent verification, and concurrent verification standards; and the poor quality of the TVA Conduct of Operations written and approved procedure, did not provide BFN, Watts Barr, and Sequoyah sites with current nuclear standards that provide all TVA personnel with high procedure adherence and quality standards to ensure the continued safe plant operation that meets regulatory requirements and industry standards. For example:

- Procedure OPDP-1, Rev. 26, included inconsistent standards within the procedure related to procedure adherence and peer checking. The differences included the term "should" in certain sections and the term shall in a different section for the same activity. Specifically, Procedure OPDP-1, Rev. 26, Section 3.9, "Ownership of Operations Procedures, stated, in part, that "Equipment should only be operated with approved procedures, clearances, or other approved documents as appropriate to maintain configuration control. When problems with procedures are identified, a change should be requested." Section 5.1, "Procedure Adherence," 5.1 .1 B., stated, in part, that "Immediate operator actions required to place the plant in a stable condition during a transient will be performed from memory." Section 5.1 D., stated, in part, that "Plant equipment shall be operated in accordance with written approved procedures as discussed in Procedure NPG-SPP-01.2, "Administration of Site Technical Procedures."

- Procedure OPDP-1, Rev. 26, Section 4.2 M., stated, in part, that "Plant announcements should be made for starting or stopping major equipment, such as starting and stopping pumps, a field operator should be dispatched to monitor associated equipment startup and shutdown and notify the control room of any abnormalities." After the team questioned the use of "should," the procedure was revised to a "shall" requirement. Procedure OPDP-1, Rev. 27, Section 4.2 M., now states, in part, that "a field operator shall be dispatched during normal planned operations to monitor associated equipment startup, notifying the control room of any abnormalities."

- Procedure OPDP-1, Rev. 26, Section 7.2 2, states, in part, that "Peer Checking should be used for all Main Control Room equipment manipulations." "Peer Checks are desired but not required for actions necessary to mitigate a transient such as AOI immediate actions, actions to stabilize the plant during degraded conditions, or EOI directed actions."

- Procedure OPDP-1, Attachment 8, "Peer Check Exemption List," dated June 10, 2011, contains the activities and procedures that are exempt from performing Peer checks. The exemption list includes actions in the Abnormal Operating Instructions (AOIs) and Emergency Operating Instructions (EOIs). The AOI peer check exemptions were not consistent with the TVA Corporate Procedure NPG-SPP-10.3, "Verification Program," Rev. 1, and NRC regulatory requirements.

Shift Manager Emergency Declaration does not require a peer check by a second SRO.

In response to the team's feedback, TVA revised Procedure OPDP-1, "Conduct of Operations," Rev. 27, to provide more consistent procedure adherence and peer checking standards. The new procedure was reviewed and approved by the TVA Corporate Functional Area Manager and all three site sponsors, including BFN, on April 8, 2013.

5.2.2.2.3.c Analysis: The team determined that the failure of station operators to follow the Conduct of Operations procedure was a performance deficiency that was reasonably within TVA's ability to foresee and correct and could have prevented the A1 RHRSW pump start with the manual discharge valve inadvertently danger tagged closed. This Finding was more than minor because, if the operator procedure use and adherence is left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern such as a more severe plant transient or engineered safeguard system actuation or malfunction.

Additionally, this issue is similar to Example 4.e in IMC 0612, Appendix E, "Examples of Minor Issues," in that the recent A1 RHRSW pump discharge valve was missing the identification label plate. The AUOs did not stop the A2 RHRSW pump clearance application to correct the valve label issue as required by TVA Corporate Procedure OPDP-1. The failure was a missed opportunity to identify that the AUOs were tagging the wrong valve. Using Inspection Manual Chapter 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, "The Significant Determination Process (SDP) for Findings At-Power," the team determined that this Finding was of very low safety significance because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time.

The team determined that this Finding had a cross-cutting aspect in the area of Human Performance, Work Control. Specifically, the licensee plans and coordinates work activities, consistent with nuclear safety. In addition, the licensee appropriately coordinates work activities by incorporating actions to address: the impact of changes to the work scope or activity on the plant and human performance, the impact of the work on different job activities, and the need for work groups to maintain interfaces with offsite organizations, and communicate, coordinate, and cooperate with each other during activities in which interdepartmental coordination is necessary to assure plant and human performance, the need to keep personnel apprised of work status, the operational impact of work activities, and plant conditions that may affect work activities. [H.3(b)]

5.2.2.2.3.d Enforcement: TS 5.4.1, "Procedures," states that written procedures shall be established, implemented, and maintained covering the following activities: a. The applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978, Section 1.c. Administrative Procedures, "Equipment Control." Contrary to the above, the team determined that two tasks associated with BFN's planned A2 RHRSW pump maintenance and subsequent A1 RHRSW surveillance test pump start were not implemented properly as required by TVA Corporate Procedure OPDP-1, “Conduct of Operations,” Rev. 26, Sections 4.2 K. and M., related to the missing A1 RHRSW pump discharge valve identification label plate and the AUO’s pre-start equipment walkdown of the A1 RHRSW pump start.

Specifically, the A2 RHRSW pump was tagged out of service on May 6, 2013, at 10:33 am. The two AUOs assigned to the A2 RHRSW pump tagout noticed that the pump discharge valve identification label was not attached to the valve. Unknown to the AUOs at the time, the missing identification label was not for the A2 pump, but for the A1 RHRSW pump discharge valve. The AUOs failed to comply with Procedure OPDP-1, “Conduct of Operations,” Rev. 27, Section 4.2 K. because they did not stop the A2 RHRSW pump clearance application to correct the valve label issue. When a missing or incorrect component identification label is discovered, OPDP-1 procedure states, in part, that “the Operator should stop to seek clarification to ensure the correct component is being manipulated. Actions shall be initiated to correct the information such as installation of a temporary label.”

Also, prior to the A1 RHRSW pump start at 1:09 pm on May 6, 2013, Procedure OPDP-1, “Conduct of Operations,” Rev. 27, Section 4.2 M., states, in part, that “a field operator shall be dispatched during normal planned operations to monitor associated equipment startup, notifying the control room of any abnormalities.” The AUO did not enter the RHRSW intake structure as required by Procedure OPDP-1, to monitor the A1 RHRSW pump and system alignment prior to the planned surveillance test. The AUO missed an opportunity to identify that the A1 RHRSW pump discharge valve was inadvertently closed with a red danger tag applied to the valve handwheel during the A2 RHRSW pump tagout that was applied earlier in the day shift at 10:33 am.

Because this Finding was of very low safety significance and it was entered into the licensee’s CAP via PERs 135161, 701486, and 722859 and SR 722559, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC’s Enforcement Policy and is identified as 05000259, 260, 296/2013011-06, Conduct of Operations Procedure Violation.

5.2.2.2.4 **Failure to Adequately Implement Procedure 3-SR-3.3.8.2.1(B)**

Although this finding was documented under the FPA 6 Procedure Use and Adherence, the team determined that aspects of this issue were related to FPA 7 Equipment Performance, Monitoring and Trending as described in Section 5.4.3. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Operational Focus and Decision Making (FPA 2) (Section 5.4.2),
- Work Management (FPA 4) (Section 5.5.2),
- Technical Rigor (FPA 9) (Section 5.1.4), and
- Governance and Oversight (FPA 10) (Section 6.1.5).

Furthermore, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) described in this report.

5.2.2.2.4.a Introduction: The team identified a Green NCV of Technical Specification 5.4.1, which requires written procedures be established, implemented, and maintained covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, including surveillance tests. The licensee failed to implement the procedure, when the licensee failed to use approved M&TE to measure the underfrequency relay settings during the performance of the Reactor Protection System (RPS) circuit protector calibration surveillance procedure.

5.2.2.2.4.b Description: The licensee implemented Procedure 3-SR-3.3.8.2.1(B), "RPS Circuit Protector Calibration/Functional Test For 3B1 And 3B2," Rev. 16, to verify the operability of the RPS circuit protectors 3B1 and 3B2 in conformance with TS Surveillance Requirements 3.3.8.2.1, 3.3.8.2.2, and 3.3.8.2.3. This surveillance frequency was 184 days. On April 24, 2013, the licensee completed 3-SR-3.3.8.2.1(B) and recorded the surveillance as satisfactory. The team reviewed the completed procedure, and noted that the licensee marked through the frequency counter M&TE and recorded "Not Applicable" in Section 5.0 "Special Tools and Equipment Recommended." Additionally, the team noted that the licensee recorded "Not Applicable" for the frequency counter M&TE identification number and calibration due date. The team also noted that the steps in the procedure requiring the use of the frequency counter were marked as complete and recorded satisfactorily.

Subsequent to the team questioning the proper implementation of the procedure, the licensee determined that the maintenance technicians used a digital multimeter to record the underfrequency relay settings, but the multimeter was not considered qualified M&TE for performing this procedure. The licensee performed an immediate determination of operability that stated that the surveillance procedure had been performed satisfactorily in February of 2013, and that the April 2013 performance found that a change was not required to instrument settings. Although the April 2013 performance of the surveillance was not a valid test, the results of the previous surveillance was still valid and within the periodicity of 184 days to meet TS requirements. The team concluded that the licensee failed to follow Procedure 3-SR-3.3.8.2.1(B) when they did not use qualified M&TE to measure the underfrequency relay settings as specified in the procedure. The licensee entered this issue into their corrective action program as problem evaluation report (PER) 731144.

5.2.2.2.4.c Analysis: The licensee's failure to use approved M&TE to measure the underfrequency relay settings during the performance of the RPS circuit protector calibration surveillance procedure was a performance deficiency. The performance deficiency was determined to be more than minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern. Specifically, the licensee could have taken credit for this invalid surveillance and failed to perform the next surveillance in the periodicity required by TS. This could have affected the TS operability of the relays. The team used IMC 0609, Att. 4, "Initial Characterization of Findings," issued June 19, 2012, for mitigating systems, and IMC 0609, App. A, "The Significance Determination Process (SDP) for Findings at Power," issued June 19, 2012, and determined the Finding to be of very low safety significance because the Finding did not result in the loss of functionality or operability of a structure, system, or component. The team identified a crosscutting aspect in the work practices component of the Human Performance area; because the licensee did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures [H.4(b)].

5.2.2.2.4.d Enforcement: Unit 3 TS 5.4.1, requires, in part, that written procedures be established, implemented, and maintained covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, Section 8, specifies, Procedures for Control of M&TE and for Surveillance Tests, Procedures, and Calibrations. Procedure 3-SR-3.3.8.2.1(B) required the use of a frequency counter to measure the underfrequency relay settings. Contrary to the above, since April 24, 2013, the licensee failed to adequately implement Surveillance Procedure 3-SR-3.3.8.2.1(B) by not utilizing a frequency counter to measure the underfrequency relay settings. Because this violation was determined to be of very low safety significance (Green) and has been entered into the licensee's CAP as PERs 731144, 730495 and 732359, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as 05000259, 260, 296/2013011-07, "Failure to Adequately Implement Procedure 3-SR-3.3.8.2.1(B)."

5.2.2.2.5 **Failure to Manage Emergent Risk Condition during RHRSW A1 and A2 Inoperability**

Although this finding was documented under the FPA 6 Procedure Use and Adherence, the team determined that aspects of this issue were related to FPA 2 Operational Focus and Decision Making as described in Section 5.4.2. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Work Management (FPA 4) (Section 5.5.2),
- Technical Rigor (FPA 9) (Section 5.1.4), and
- Governance and Oversight (FPA 10) (Section 6.1.5).

Furthermore, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) and Configuration Control (Section 5.5) described in this report.

5.2.2.2.5.a Introduction: The team identified a self-revealing, Green non-cited violation of 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," due to BFN's failure to adequately manage the impact of an emergent risk condition related to the A1 residual heat removal service water quarterly surveillance test. BFN recognized the online maintenance risk condition however, failed to implement appropriate risk management actions (RMAs) in accordance with Procedure BFN-ODM-4.18, "Protected Equipment." BFN entered this issue into their corrective action program as SR 730356. Specifically, on May 6, 2013, with the A2 RHRSW pump inoperable for planned maintenance, the A1 RHRSW pump was declared inoperable during the A1 RHRSW pump quarterly test. An assistant unit operator tagging error related to the A2 RHRSW pump maintenance resulted in the AUOs closing and danger tagging the A1 pump manual discharge valve instead of the required A2 pump discharge valve.

5.2.2.2.5.b <u>Description</u>: On the morning of May 6, 2013, at 10:33 am, BFN removed the A2 RHRSW pump from service for a planned maintenance outage. While applying a clearance for the A2 RHRSW pump, the AUOs inadvertently closed and danger tagged the A1 RHRSW pump discharge valve. At 1:04 pm, the control room operators started the A1 RHRSW pump to perform the quarterly surveillance test. The 1A RHRSW pump was started and the 1A RHRSW heat exchanger discharge valve was opened to allow flow through the system. Upon opening the 1A RHRSW heat exchanger discharge valve, the 1A RHRSW header pressure dropped to zero pounds per square inch (psig) due to the 1A RHRSW pump manual discharge valve being closed and the heat exchangers discharge valve being open. BFN recognized the abnormal A1 pump start indications and the identified the closed pump discharge valve. The applicable TS seven day LCOs were entered for all three "A" RHR loops for each Unit and the A1 RHRSW pump was declared inoperable and the Unit 1, 2, and 3 TS LCOs were entered for 3.7.1, Action C, two RHRSW pumps, and TS LCOs 3.6.2.3.A, 3.6.2.4.A, and 3.6.2.5.A, for containment spray and cooling systems.

BFN identified that with the A1 and A2 RHRSW pumps inoperable simultaneously, that the plant was in an elevated risk condition. However, the BFN staff failed to perform the procedurally required risk management actions in accordance with the Operations Directive Manual Procedure BFN-ODM-4.18, "Protected Equipment," Section 2.2 B.1., 4, and 6. Specifically, Procedure BFN-ODM-4.18 requires, in part, that if the A1 and A2 RHRSW pumps are out of service then emergency diesel generators "A" and "B" need to be protected. Contrary to the above, the A1 and A2 RHRSW pumps were declared inoperable on May 6, 2013, for 12 hours and BFN did not protect EDGs "A" and "B" or any of the additional six RHRSW pumps. Furthermore, with EDGs "A" and "B" not protected, additional preventive measures to authorize work on or near the equipment in accordance with Procedure BFN-ODM-4.18 would not have been implemented to effectively manage the emergent online risk condition. The licensee documented the issue into their corrective action program as SR 730356.

5.2.2.2.5.c <u>Analysis</u>: The team determined that BFN's failure to implement risk management actions for an emergent risk condition that was self- revealing during the A1 RHRSW pump quarterly test concurrent with the A2 RHRSW pump planned maintenance was a performance deficiency. The Finding was determined to be more than minor because if the performance deficiency was left uncorrected it had the potential to lead to a more significant safety concern. Specifically, the failure to take adequate RMAs could have led to unplanned inoperability of redundant TS or risk significant mitigating systems being relied upon to respond to initiating events to prevent undesirable consequences. The performance deficiency was also determined to be more than minor since it is similar to more than minor Example 7.e of Inspection Manual Chapter 0612, Appendix E, "Examples of Minor Issues," because BFN failed to implement additional RMAs as required by their risk assessment and protected equipment procedure requirements.

The Finding was evaluated in accordance with Appendix K, Maintenance Risk Assessment and Risk Management Significance Determination Process, of IMC 0609, "Significance Determination Process." The team, in consultation with the team senior risk analyst, performed a Phase 1 analysis and concluded that the incremental core damage probability deficit for the A1 and A2 RHRSW pumps, with an out-of service time of 12 hours, was less than 1E-6. The dominant sequences result from the loss of offsite power and loss of various 480 Volt AC boards, and the failure of suppression pool cooling and late injection. Therefore, the Finding was determined to be of very low safety significance.

This Finding has a cross-cutting aspect in the area of Human Performance, Work Control, because BFN failed to implement immediate RMAs and communicate to the station personnel the change in plant risk condition and protected equipment requirements that may affect work activities. [H.3(b)]

5.2.2.2.5.d Enforcement: 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires, in part, that the licensee shall assess and manage the increase in risk that may result from maintenance activities. Contrary to the above, on May 6, 2013, BFN did not adequately manage the impact of the increase in the emergent risk condition during the self-revealing inoperability of the A1 RHRSW pump quarterly surveillance test. Specifically, on May 6, 2013, for 12 hours, the A1 and A2 RHRSW pumps were both recognized to be inoperable during the A1 RHRSW pump quarterly test. BFN recognized the online maintenance risk condition; however, failed to implement appropriate RMAs in accordance with Procedure BFN-ODM-4.18, "Protected Equipment." Because this issue is of very low safety significance and BFN entered this issue into their corrective action program as SR 730356 and PERs 722859 and 731570, this Finding is being treated as an NCV consistent with the NRC Enforcement Policy and is identified as NCV 0500025, 260, 296/

2013011-08, Failure to Manage Emergent Risk Condition during A1 and A2 RHRSW Inoperability.

5.2.2.2.6 Other Observations: The team evaluated the licensee's causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee's program, that it utilized a through and comprehensive method in determining the causes, contributing causes, extent of cause, and extent of condition. The team assessed that the corrective actions implemented and or planned addressed the identified causes, and were reasonable.

The team identified that the licensee failed to follow Procedure NPG-SPP-09.3, "Plant Modifications and Engineering Change Control," Revision 0012, during the implementation of modifications to the RHR and CS room cooler fan and fan motor, design change notices (DCNs) 69466 and 69467. Additional details and regulatory significance were included in report Section 5.1.3.2.2.

The team also identified the failure to follow Procedure NPG-SPP-09.3, "Plant Modifications and Engineering Change Control," Rev. 0012, Section 3.2.17, during commercial grade dedication of bearings procured for safety-related applications for a LPCI MG set at the station. Additional details and regulatory significance are included in report Section 5.1.3.2.2.

TVA identified repetitive issues associated with procedure use and adherence (PU&A). In January 2013, BFN completed a root cause analysis, "Continued Trend in Repetitive Issues Associated with Procedure Use and Adherence," PER 484548. BFN identified the following root cause: "The inconsistent enforcement of PU&A by site leadership has created a culture that does not value verbatim compliance with procedures."

BFN implemented a PU&A awareness program in October 2011 that included banners, posters, a "good catch" program, and expectations for increased first line supervisor (FLS) reinforcement of PU&A fundamentals. Between October 2012 and January 2013, BFN management completed 24 high level interim actions to implement TVA PU&A initiatives. Although, the licensee concluded in their root cause analysis that corrective actions have been provided to prevent recurrence and strengthen barriers to ensure sustainability, PU&A issues have continued.

The team identified multiple Findings and observations that demonstrated TVA's ineffective corrective actions taken to ensure BFN and industry PU&A standards were met. This included Findings in the limited use of fundamental human performance tools by all organizations, lack of manager and supervisor oversight to enforce PU&A standards, inconsistent procedure use and adherence standards in TVA Corporate and site procedures, BFN acceptance of sub-standard procedures, and frequent examples of station personnel errors related in the PU&A area. Although the insights obtained through focus group interviews indicated that there was an increased emphasis on PU&A at BFN, they also indicated that there was inconsistent management and supervisor oversight and reinforcement of PU&A standards. The licensee addressed these concerns in the Safety Culture Continuous Improvement and Sustainability Plan captured in the CAP as PER 757451 and 743724.

5.2.2.3 Assessment Results: The team concluded that BFN management had communicated procedure use and adherence expectations to BFN site personnel. A majority of the site personnel understood and could recite procedure use and adherence expectations. However, the team observed a high number of procedure use and adherence errors and plant events that occurred as a result of these errors at BFN. The team concluded that station management did not methodically address and correct latent organizational human performance weaknesses, including procedure use and adherence and the limited use of human error prevention verification tools and practices in the IIP. Nonetheless, the measures developed to revise the IIP as a result of the team's observations as described in the licensee's Safety Culture Continuous Improvement and Sustainability Plan (PERs 757451 and 743724) provided a site-wide systematic approach to improve procedure use and adherence and related human performance issues. In addition, for continued sustainability and substantial improvement of the FPA, implementation of the corrective actions in place and those revised in the IIP was considered to be essential.

5.2.3 Ownership and Accountability (FPA 11 – IRP)

5.2.3.1 Inspection Scope: As a result of the NRC issued RED Finding in 2011, TVA performed a diagnostic investigation of BFN programs and processes and identified in 2012 that the station had an inappropriate reliance on processes, in that the station failed to have sufficient ownership, follow through and accountability to drive problems to resolution. Therefore, BFN established this as a fundamental problem area under Inappropriate Reliance on Processes, performed an apparent cause evaluation, and developed corrective actions. The apparent cause was identified as the BFN leadership had not held process owners and stakeholders accountable to their roles and responsibilities to ensure people work together to effectively implement station programs/processes.

The team evaluated the apparent cause analyses and the related BFN Fundamental Problem Area 11, Inappropriate Reliance on Processes. Specifically, the team evaluated: 1) the completion of the analysis was conducted in accordance with BFN's process requirements; 2) that a thorough and methodical evaluation process was used to complete the analysis; 3) that BFN's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into BFN's Integrated Improvement Plan (IIP) and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selective corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

The team also conducted focused interviews with individuals from several organizations that were in management and non-management positions, as well as a cross section of station personnel that were working in the field to verify that the corrective actions put in place were effective in contributing to the improvement of station performance in this area. Specifically, the team focused on whether the individuals knew and understood their roles and responsibilities, the level of authority they had in making decisions out in the field, and the accountability standards that were implemented.

As a method of measuring performance in the fundamental problem areas, BFN established performance indicators with associated quantitative criteria. The team reviewed BFN's performance indicators for the fundamental problem area to ensure the performance metrics would effectively measure the appropriate breadth and depth, and assess whether BFN's performance would be sustainable going forward. The team also reviewed the performance indicators basis documentation and analysis, as well as inputs to verify accurate performance metric results and conclusions.

5.2.3.2 Observations: No Findings of significance were identified.

The team identified a couple issues in the organization's implementation of ownership and accountability. The American Society of Mechanical Engineering in-service testing of the BFN Unit 2 SLC pumps was performed in March 2013, with vibration test equipment that was not calibrated over the code required range of 2.88-1000Hz. The licensee was aware of the range requirement in 2012 and on February 12, 2013 requested vibration equipment be calibrated over the correct range. The station did not to control the procedure that would preclude performing the surveillance with improperly calibrated test equipment. This was documented in SR 729845. The team noted that the SLC pumps operate at a frequency for which the vibration analyzer calibration remained accurate. The team determined that this issue was a minor violation of regulatory requirements, in accordance with IMC 0612

The maintenance department failed to perform a complete investigation of the maintenance supervisor not performing a complete walkdown of the clearance tag hung to support a RHRSW pump impeller adjustment. After being questioned by the team, a review was performed by the licensee and determined that in accordance with NPG-SPP-18.2.3, Appendix B, Section 3, a maintenance department clock reset should have occurred. This was documented in SR 728456. See Section 5.2.2.2.2 for a detailed description and regulatory significance.

The team assessed that BFN had performed a thorough cause analysis that adequately captured the causes of the inappropriate reliance on processes' prior issues in adequately identifying roles and responsibilities, and implementing accountability measures against those roles and responsibilities. BFN developed corrective actions that adequately addressed the causes, implemented the corrective actions to address the issues, and established indicators to continually measure the implementation of the corrective actions.

5.2.3.3 Assessment Results: The team performed a program review and onsite observations of the aspects contained in BFN's fundamental problem area associated with ownership and accountability to assess the licensee's understanding of the problems this area and the effectiveness the corrective actions implemented to date. In general, the team identified improved performance in this area by identifying process owners' roles and responsibilities and holding those owners accountable to their roles and responsibilities.

The team recognized an improved performance in the inappropriate reliance on processes area; however, BFN must continue to gain alignment down through all levels of the organization in ownership and accountability. Specifically, several of the observations described above involve ownership and accountability examples at the first-line supervisor and worker levels. These were examples that reiterate the need for management's continued focus and attention to implement the IIP in order to continue to improve station performance.

Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement of the FPA.

5.2.4 **Human Performance Observations**

5.2.4.1 Inspection Scope: The team reviewed documents and performed inspection activities associated with station human performance during start up and power operations at BFN Units 1, 2, and 3. The team:

- Evaluated data from the licensee's CAP, LERs, and audits, to determine if human performance issues had contributed to performance issues,
- Determined if the problems were reviewed by the appropriate level of management and prioritized according to their safety significance,
- Evaluated whether the corrective actions were technically correct and implemented in a timely manner,
- Assessed human performance corrective action commitments as they related to identified gaps and causes documented in analyses products. Corrective actions included: training development and presentation, associated procedure revisions, change management plans, oversight and enforcement, metrics and trending, and through the direct observations of personnel performance; and
- Evaluated TVA Corporate, station, and department human performance improvement plans for short and long-term program initiatives and systematic approach to station-wide human performance gaps.

Activities and areas the team considered for the inspection included:

- Specific problem areas and issues identified by inspections to determine if concerns existed in the human performance cross-cutting area components as detailed in IMC 0310, "Components within the Cross-Cutting Areas,"
- A tour of the plant to note indications of potential error-likely situations (operator workarounds, unapproved job aids or markings, and Human-System interfaces including work area design, accessibility, and labeling per guidance contained in IP 71841, "Human Performance,")
- A sample of written logs and shift status reports to verify that they:
  - Provided sufficient detail to allow a full understanding of operationally significant matters, including abnormal occurrences or test results and any compensatory measures taken, and
  - Described changes in plant or equipment status.

- A sample of documentation for review of completeness, accuracy, human performance tool usage, PERs written if applicable, and rigor applied for technical decision making steps. Documents included:
  - Maintenance work packages and testing procedures,
  - Operations' surveillances and procedures;,
  - Operability reviews,
  - Engineering evaluations, and
  - Work control schedules and associated risk management.
- A review of the December 2012 reactor scram due to a SRO human performance error with no use of peer checking,
- A review and assessment of the following components, as related to human performance observations:
  - Decision Making/ Rigor, specifically:
    - The roles and authorities of personnel were clearly defined and understood,
    - Operational decisions and their bases were communicated,
    - Interdisciplinary input and reviews of safety-significant or risk-significant decisions was sought,
    - Decision-making was systematic when personnel faced uncertain or unexpected plant conditions,
      - Conservative assumptions used and possible unintended consequences considered,
      - Whether station personnel proceeded in the face of uncertainty or unexpected conditions, and
      - Assessed whether the operators exhibited attentiveness and were pro-active when assessing plant conditions that may indicate a safety concern.
  - Work Practices-whether personnel work practices support human performance. The team observed activities of station licensed and non-licensed personnel; which included:
    - Verified that procedural requirements were met and that procedures were implemented using the correct level of use (i.e. continuous, reference, etc.),
    - Assessed whether Technical Specification and/or procedure prerequisites were executed,
    - Determined whether deficiencies were resolved using the corrective action program rather than implementing their own workarounds,
    - During evolutions, tests, and response to annunciators, determined whether operator actions or compensatory measures were required due to degraded equipment or plant conditions,

  - Determined that human error prevention techniques, such as holding pre-job briefings, self and peer checking, and proper documentation of activities, were used commensurate with the risk of the assigned task, such that work activities were performed safely, and
  - Determined whether individuals were knowledgeable about the current state of structures, systems, and components, equipment performance, and the impact of ongoing work activities.
- Supervisor Oversight:
  - Determined if supervisors were providing in-field oversight of routine and high risk activities,
  - Determined whether supervisory and management oversight of work activities, including contractors, was effective in driving workforce behavior changes,
  - Determined if station was utilizing observation program results for trending purposes; and
  - Assessed corrective actions as a result of station program trending.

5.2.4.2 Observations and Findings: The team documented one Finding of very low safety significance in this section.

5.2.4.2.1 Failure to Control a Modification to the Seismically Mounted Control Room Ceiling Light Diffusers

Although this finding was documented under the general concept of Human Performance, the team determined that aspects of this issue were related to FPA 9 Technical Rigor as described in Section 5.1.4. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Operational Focus and Decision Making (FPA 2) (Section 5.4.2),
- Work Management (FPA 4) (Section 5.5.2),
- Procedure Use and Adherence (FPA 6) (Section 5.2.2),
- Governance and Oversight (FPA 10) (Section 6.1.5), and
- Procedure and Instruction Quality (FPA 12) (Section 5.3.2).

Furthermore, the team recognized that this issue was related to the general area of Configuration Control (Section 5.5) described in this report.

5.2.4.2.1.a Introduction: The team identified a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to control deviations from the as-built control room envelope design for seismically mounted ceiling light diffusers in accordance with instructions that assure quality standards are controlled. Specifically, the licensee unsecured three seismically mounted control room ceiling light diffusers and slid them over the top of other light diffusers creating a seismic missile hazard that could have impacted control room ventilation damper actuators and potentially impacted main steam isolation valve (MSIV) controls located below the moved light diffusers.

5.2.4.2.1.b Description: On May 18, 2013, BFN personnel unsecured three seismically mounted control room ceiling light diffusers and slid them over the top of other light diffusers. This degraded condition existed for 6 days during the performance of Surveillance Procedure 0 SR-3.3.7.1.4, “Control Room Ventilation Logic System Functional Test-Radiation Monitors.” Removing the diffusers provided visual access to control room ventilation damper actuators that were cycled during the test. Although the test duration was planned for approximately three hours, the ceiling light diffusers remained in a degraded condition for 6 days due to test delays. When challenged by the team that un-securing and sliding the light diffusers over other diffusers was not removal as specified by the procedure, the licensee developed an operability determination concluding that sliding the diffusers constitutes safe removal. The team challenged the operability determination due to a lack of technical rigor in that it failed to account for the seismic missile hazard the loose diffusers posed to the control room ventilation damper actuators. Once the licensee understood that unfastening ceiling light diffusers and sliding them over top of other diffusers was creating an unanalyzed modification, the licensee removed the ceiling diffusers from the overhead and placed them in a seismically safe location. The licensee also initiated procedure change request (PCR) 13002049 to change the procedure wording to precisely state that to remove the diffusers means to completely remove the diffusers from the ceiling and place them at a location other than on top of adjacent panels to ensure seismic requirements are met. The team identified a lack of technical rigor in the operability determination was entered into the in the CAP process. (PERS 730443, 731524 and 741812)

5.2.4.2.1.c Analysis: The failure to control a modification of the seismically mounted control room ceiling light diffusers was a performance deficiency. The PD was more than minor because it was associated with the design control attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Using Inspection Manual Chapter 0609.04, “Phase 1-Initial Screening and Characterization of Findings,” the team determined that the

Finding had very low safety significance because the Finding only represents a degradation of the radiological barrier function for the control room.

This Finding has a crosscutting aspect in the area of human performance because the licensee did not define and effectively communicate expectations regarding procedural compliance and that personnel follow procedures. [H.4.(b)]

5.2.4.2.1.d <u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified that deviations from such standards are controlled.

Contrary to the above, the licensee failed to control deviations from the as built control room envelope design for seismically mounted ceiling light diffusers in accordance with instructions that assure applicable quality standards are controlled. Specifically, during the performance of Surveillance Test 0-SR-3.3.7.1.4, “Control Room Ventilation Logic System Functional Test-Radiation Monitors,” pre-requisite step four, the licensee slid three light diffusers over the top of other light diffusers creating seismic missile hazards that could have impacted control ventilation system damper actuators and potentially impacted main steam isolation valve controls located below the moved light diffusers.

The licensee subsequently took corrective actions which included a procedure clarification to completely remove the specified ceiling light diffusers and place them at a location that would not create a seismic impact. Because this violation was of very low safety significance, and was entered into the licensee’s corrective action program as PERs 730443, 731524 and 741812, this issue is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000259, 260, 296/2013011-09, Failure to control a modification to the seismically mounted control room ceiling light diffusers.

5.2.4.2.2 <u>Other Observations</u>: The team reviewed corrective actions associated with station initiatives to improve human performance. Corrective actions were a result of licensee identified issues and associated root causes and apparent cause analyses; internal and external audits and assessments, including and industry actions from operating experience, benchmarking, peer groups, or SOERs. In addition to the corrective action program and its associated tracking processes, some actions were also tracked through the IIP and the TVA Corporate and BFN Station Human Performance Business Plans.

The team acknowledged the station had improved in the overall area of human performance. The team also noted that BFN had extensive corrective actions in place, both completed and in-progress, to address the human performance gaps that the licensee determined needed to be addressed. The team observed that the analyses products and high priority corrective actions were reviewed by the appropriate level of site management and prioritized according to their safety significance or performance area gaps. The corrective actions, in general were timely for the required resources, process changes, and behavior changes needed to complete the associated actions. The team also noted that the corrective actions in general were technically adequate to address the individual causes identified from the multiple inputs discussed above. However, the team identified in the areas of decision making and rigor; worker practices, specifically human performance; and supervisory oversight; that the licensee did not have a systematic approach that comprehensively addressed the continued station-wide issues in these areas. Specifically, without a systematic approach to address these issues, the team was concerned that BFN's performance improvement in these areas may not achieve substantial and sustainable performance improvement. This was previously discussed in Section 4.5, NRC Independent Safety Culture Observations, and will be further expanded on in this section.

The team assessed BFN's human performance corrective actions which included training lesson plans for human performance and technical human performance including decision making and rigor. The team reviewed station meeting and stand-down presentations, associated procedure revisions, change management plans, oversight and accountability processes, and metrics and trending. The team also performed direct observations of personnel and process performance to assess corrective action effectiveness. As part of the plant and control room walk downs, the team reviewed areas for conditions that could potentially lead to job-task errors and human performance related events. This focus included operator workarounds, unapproved job aids or markings, potential adverse environmental conditions, and Human-System interfaces including work area design, accessibility, and labeling concerns. The team did not identify any issues of safety significance; however, observations were made and discussed with the licensee, who in turn generated SRs to address the issues.

The team reviewed the circumstances of the December 22, 2012, BFN Unit 2 reactor scram. The human performance issues of this event were discussed in the Finding, Inadequate Corrective Actions to Address Programmatic Procedure Quality Issues, in Section 5.3.2.2.2

The team reviewed TVA Corporate procedures for human performance including "Human Performance Program," NPG-SPP-18.2, Rev. 0000; "Human Performance Tools," NPG-SPP-18.2.2, Rev. 0005; "Human Performance Program Health Monitor," NPG-SPP-02.6, Rev. 0001; "Oversight of the Human Performance Program," NPG-SPP-18.2.1, Rev. 0006; and "Integrated Trend Review (ITR)," NPG-SPP-02.8, Rev. 0004. The team determined that overall the procedures in place supported a programmatic structure for roles and responsibilities, both at corporate and the station; for workforce knowledge and usage of human error prevention techniques; for management and process oversight; and for identification of potential human performance related trends.

The team did identify some areas of concern with respect to the procedures. The roles and responsibilities described in the Procedure NPG-SPP-18.2 were not consistently observed by the team when observing station personnel conduct routine responsibilities and duties during the inspection. These observations included corporate and the station implementation of responsibilities. The team's observations with respect to BFN were documented in this section. Additional concerns with respect to TVA Corporate's roles and responsibilities for the human performance program are discussed in more detail in Section 6.1.5, Governance and Oversight.

The team reviewed short-term and long-term action plans for BFN's human performance program initiatives. As part of the documentation, the team reviewed the Site HU business plan for 2013-2017, "HU Performance (Site Clock Resets) Gap Analysis," and the associated corrective actions listed in BFN CAP. The Team also reviewed the TVA Corporate fleet HU Business Plan for 2013-2017. The team identified that the actions in the TVA Corporate plan, both for TVA Corporate and sites actions, were not tracked in CAP. This was discussed with the Corporate Functional Area Manager (CFAM) who entered this issue into CAP under SRs 749025 and 749031.

For short-term action plans, the team specifically reviewed the associated CAP actions that had been scheduled or completed in 2012 and 2013. The team reviewed corrective actions associated with HU related RCAs and FPAs, including HU related actions tracked in BFN's IIP; however, the licensee did not have a stand-alone FPA to address station worker practices and human performance. For long-term action plans, the team focused on long-term corrective actions associated with PERs, RCAs, the ITR, and IIP actions to determine whether the actions that were currently planned and in place would address long-term improvement actions for sustainability.

The team also reviewed BFN's RCA for PER 505709, "Potential Trend in the Human Performance Cross-Cutting Aspect H.2.c." The licensee concluded that the two root causes associated with continued human performance related NRC Findings were:

1. BFN leaders were not aligned around a common set of standards and goals (picture of excellence) such that the leadership influence required to change behaviors had not been effective and efforts to improve leadership capability had not achieved desired results; and

2. Accountability had been ineffectively implemented at BFN, which had resulted in consequential events and impacts to nuclear safety. Although the team determined that the identified root causes were adequate, the corrective actions assigned were focused on senior management alignment and standards improvement; procedure quality improvement initiatives; and CAP program improvements. There were a couple actions focused at mid/lower level management and supervisor level, which included the development of a first line supervisor peer team, Compliments and Concerns alignment meetings, and development of an observation schedule. However, none of the actions specifically targeted mid/lower level management, supervisors, and workforce alignment around a set of standards and goals (picture of excellence) to change behaviors or the use of accountability at the supervisor or peer-to-peer workforce level.

The team determined that although the station had extensive corrective actions, the licensee lacked a systematic approach to addressing continued HU issues. Specifically, the actions created were primarily reactive, a result of an individual event or cause, and targeted at specific work groups. For example, in the 2013 second quarter ITR report, BFN identified human performance weaknesses as a station-wide trend. There were six associated PERs and analyses products written for Operations, Maintenance, RP, Chemistry, and Performance Improvement (Licensing). The PERs had been written due to externally identified issues or licensee identified negative trends in human performance. The ITR report documented only that human performance improvement was an on-going station initiative since the second quarter of 2012 and documented the initiative status as "ongoing actions and coaching." As a result, the team determined that the licensee did not have a systematic approach to comprehensively address the continued issues in the area of supervisor and workforce behaviors and that the licensee's actions were not addressing long-term performance improvement and sustainability. The lack of a systematic approach was discussed with the licensee, who subsequently worked with TVA Corporate to generate SRs 740658 and 749033 to address this concern. Subsequently the licensee generated a Safety Culture Continuous Improvement and Sustainability Plan covered by PERs 757451 and 743724.

In addition to the station's plans, the team also identified that BFN did not utilize department human performance improvement plans to strategically identify and correct department weaknesses. Specifically, Procedure NPG-SPP-18.2.1, Section 3.3, stated that HU work practices and supervisory oversight shall be addressed in the department level improvement plans in accordance with Procedure NPG-SPP-02.8, "Integrated Trend Review." The team reviewed the 2013 second quarter ITR report. The team noted that each of the departments identified "Top Issues" and associated PERs documented in the report. However, the team found that each department did not have a specific improvement plan that strategically addressed department gaps, or HU work practices and supervisory oversight. The lack of department human performance improvement plans was discussed with the licensee, who subsequently generated SR 740668 to address this concern.

As part of the licensee's human performance initiatives, BFN had multiple corrective actions associated with an observation program. Although BFN had an observation program for several years, TVA Corporate utilized a new program in 2012 and was taking actions to tailor the program to the TVA fleet needs. These actions included developing specific software reports for better trending and creating specific observation attributes in the software to assist the observer and management in identifying and correcting specific behaviors or work practices. In addition to software changes, corrective actions existed to implement training for management observers, and to utilize observation results for different mechanisms such as improved trending, metrics, and crew Management Review Meetings (MRM). The team determined that overall the actions in place supported a programmatic structure for performing work practice and behavior observations; however, because many of the actions were still in progress, the team was not able to determine long-term sustainability for this observation program. In addition, the team noted that although programmatic corrective actions existed to address the observation program itself, the licensee did not have a systematic approach to addressing supervisors' behaviors and abilities. Specifically, the team noted supervisors were not consistently able to recognize the errors, intervene, or coach to correct behaviors. The licensee was addressing these issues in SRs 742764, 742775, and 742931.

In the area of decision making and rigor, worker practices, and supervisory oversight, the team observed multiple examples of poor workforce performance, including the identification of several Findings of very low safety significance. The team's field observations indicated a lack of consistency in behaviors when personnel were actually performing the work. The team identified that the workforce, including supervisors, did not always stop when unsure; follow procedures; or write SRs when they identified an inconsistency in a procedure or work package. In addition, the team also identified supervisors were not consistently able to recognize these errors, intervene, or coach to correct workforce behaviors. Specific observation examples and Findings related to the individual safety culture component examples are documented in Section 4.5. 2.1 for Decision Making (Rigor), Section 4.5.2.4 for Work Practices, and Section 4.5.4.2.10 for Accountability as this section related to supervisor oversight. The concerns with the attitudes of workers do not always match in-field behaviors was discussed with the licensee, who subsequently generated SRs 743392, 742765, and 742775 to address this concern.

5.2.4.3 Assessment Results: The team's programmatic review of BFN's human performance program concluded that although corrective actions had been implemented, and improvements observed by the licensee and the team, site-wide issues in human performance still occurred. The team determined, through direct observation of activities conducted by individuals in the plant, that the BFN corrective actions were focused on 'fixing' each occurrence versus applying actions that were broader in scope, such that they would not only resolve the specific issue that occurred, but would be applied across the departments and organizations to prevent similar occurrences. The team's review did not identify a structured systematic or comprehensive approach at BFN or TVA Corporate to address the overall issue of human performance errors that continued to occur.

The team noted that a fleet Business Plan existed for Corporate and BFN's human performance improvement initiatives however, these plans provided high level strategic actions only and tactical implementation actions did not exist, such that there was no guidance or oversight given to complete these actions. In addition, the station did not methodically target and correct the latent organizational weaknesses with human performance, including procedure use and adherence and verification practices. The team found that BFN did not have department human performance plans. The health and organizational oversight for station human performance initiatives was provided by a quarterly meeting with department directors or designees and based on document review and interviews the team determined that the licensee did not intrusively identify department and station human performance issues. The team concluded that the lack of a systematic and comprehensive action plan allowed for continued human performance errors and events at BFN.

Based upon the safety culture assessment, the team recognized that by not having a systematic approach that develops a comprehensive plan to address the continuing human performance errors, BFN could plateau in their performance improvement initiatives with respect to safety culture and workforce behaviors. The team observed that the staff directly performing activities in the plant, including their immediate first line supervisors, continued to exhibit poor work practices. These work practice issues involved human performance, rigor and decision making, and supervisory oversight. In addition, procedures directly related to safe plant performance continued to lack quality. The team's review of the independent safety culture assessment and the team performance of focus group interviews, determined that BFN's plans and actions were adequate with regard to organizational alignment through communications and resulting in consistency in message. Based upon Findings and observations, the team concluded that BFN had not established a consistent strategic focus on behaviors and work practices and across all levels of the workforce. Therefore, a barrier existed between the new management philosophies and expectations and the daily staff performance. As a result of the team's observations, the licensee generated a Safety Culture Continuous Improvement and Sustainability Plan covered by several SRs and PERs most relevant were PERs 757451 and 743724.

5.2.5 Summary and Conclusions

The team observed that the licensee had improved in the overall station performance as a result of actions taken in the areas of procedure use and adherence, ownership and accountability, and human performance. The team also noted that BFN had extensive corrective actions in place, both completed and in-progress. In some areas, the team was not able to verify the effectiveness of the BFN's actions because they had not been implemented long enough to determine whether long-term performance improvement would achieve sustained performance improvement.

In the area of Human Performance, the team concluded that some BFN station personnel who directly manipulate the plant, including the first line supervisors, continued to exhibit poor work practices in human performance including procedure use and adherence, decision making, and supervisory oversight.

Based upon a review of the IIP and associated actions, the team concluded that the station's focus had been reactive and individual based, in that the actions were focused on 'fixing' each occurrence versus applying actions that were broader in scope, such that they would not only resolve the specific issue that occurred, but would be applied across the departments and organizations to prevent similar occurrences; and lacked a systematic approach to improving work practices, decision making (rigor), and supervisory oversight to ensure long-term corrective actions were effective for performance improvement sustainability. These team identified issues and observations warranted revision to the licensee's IIP. These observations and conclusions were discussed with the licensee who subsequently concurred with the Findings and developed an action plan to address the issues in the CAP to ensure substantial and sustained improvement. Furthermore, for sustainability and substantial human performance improvement, implementation of the IIP corrective actions in place and completion of the remaining IIP corrective actions is essential.

5.3 Procedure Quality

5.3.1 Inspection Overview

The team's procedure quality inspection activities included the fundamental problem areas of Procedure and Instruction Quality, FPA 12, and Training, FPA 20. The team utilized a sampling method to review and observe the licensee's performance in a wide range of plant processes and activities for these FPAs. The team identified four Findings of very low safety significance.

5.3.2 Procedure and Instruction Quality (FPA 12 – PIQ)

5.3.2.1 <u>Inspection Scope</u>: The team reviewed documents and performed inspection activities associated with procedure instruction and quality during start up and power operations at BFN Units 1, 2, and 3 including:

- A review of PER 680972, "Procedure and Work Instruction Quality,"

- A review of PER 552135, “Preliminary GAP Analysis of Procedure Instruction and Quality,”
- An assessment of the effectiveness of the corrective actions related to procedure quality deficiencies,
  - o Reviewed PERs and independently selected several procedure revisions to evaluate procedure quality.
- An evaluation of TVA Corporate and BFN site procedure development and revision processes,
- A review of several procedures during operator daily activities,
  - o Observed planned and emergent operations evolutions that include accompanying Assistant Unit Operators during daily plant tours and log keeping for each building that spanned across all three units, and
  - o Performed dedicated control room observations on multiple shifts and weekends that spanned across all three units.
- An assessment of training on new and revised procedures,
  - o Reviewed the associated controlling procedures, policies, and industry standards,
  - o Reviewed training provided for recently developed or revised procedures;
  - o Assessed whether training was completed in accordance with the licensee’s processes and procedures,
  - o Evaluated the training of new or recently revised procedures in the requalification training process,
  - o The team evaluated dynamic simulator scenarios related to procedures that contributed to recent plant events, and
  - o Reviewed selected PERs related to procedure training and assessed the effectiveness of the corrective actions and the associated extent of condition review.
- An evaluation to the extent procedure quality has contributed to previously identified performance issues.
- An evaluation of the technical adequacy of operation and maintenance procedures,
  - o Determined if the procedure steps achieved the required system performance,
  - o Determined if the procedure accomplished the activity in accordance with the system design and associated regulatory requirements,
  - o Verified whether operations and maintenance procedure critical task steps included quality verification signatures or initials, and
  - o Verified maintenance procedures included vendor manual requirements and references.
- A review to verify that personnel had the ability to reference up-to-date revisions and accurate copies of documents,

- A review to verify that procedure changes were in accordance with licensee processes and regulatory requirements including 10 CFR 50.59,
- A review of procedures for proper approval and compliance with technical specification requirements, and accepted human factors principles, and
- A review of night orders and work orders for unapproved implementation of temporary procedures.

5.3.2.2 Observations and Findings: Four Findings of very low safety significance were identified and documented in this section.

5.3.2.2.1 **Requirements for Concurrent Verification, Independent Verification, and Peer Checks**

Although this finding was documented under the FPA 12 Procedure and Instruction Quality, the team determined that aspects of this issue were related to FPA 20 Training as described in Section 5.3.3. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Operational Focus and Decision Making (FPA 2) (Section 5.4.2),
- Work Management (FPA 4) (Section 5.5.2),
- Procedure Use and Adherence (FPA 6) (Section 5.2.2),
- Technical Rigor (FPA 9) (Section 5.1.4), and
- Governance and Oversight (FPA 10) (Section 6.1.5).

Furthermore, the team recognized that this issue was related to the general areas of Human Performance (Section 5.4.2) and Configuration Control (Section 5.5) described in this report.

5.3.2.2.1.a Introduction: The team identified a Green NCV of TS 5.4.1, "Procedures," because BFN did not ensure TVA Corporate and site procedure requirements for Concurrent Verification, Independent Verification, and Peer Checks are not consistently applied to plant procedures, instructions, and work documents as required by TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants."

5.3.2.2.1.b Description: The team performed a random sample of operations and maintenance procedures, instructions, and work documents to determine if the requirements for concurrent verifications (CVs), independent verifications (IVs), and peer checks were consistently applied. The team determined that BFN's requirements for CVs, IVs, and peer checks are not consistently applied to plant procedures, instructions, and work documents as required by TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," Rev. 1, and regulatory requirement American National Standards Institute (ANSI) N18.7-1976 American Nuclear Society (ANS)-3.2, Section 5.2.6, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants." For example, the following list of documents did not include the required or proper verification human performance tools; including the individual's signature or initials when the verification actions were performed:

Procedure AOI-1-1, "Relief Valve Stuck Open," did not include CVs for the procedure steps that are performed, in Attachment 1, to close a stuck open Safety Relief Valve (SRV) when multiple fuses are removed in energized electrical panels to close the SRV(s). Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.2, requires CVs for "actions with irreversible consequences" such as industrial safety when an individual could sustain an injury or death. Also, Section 3.4.5, "Example," includes required CVs during the "removal or installation of fuses."

Procedure 1-AOI-99-1, "Loss of Power to One RPS Bus," Rev. 20, does not include IVs\CVs for the procedure critical action steps that are performed. For example, Section 4.2, steps 7.4, 9.2, 9.3, 9.4.1, 9.5.1, 9.5.2, 9.6.1, 9.6.2, 9.7, 9.9, 10.2, 10.3, 10.4.1, 10.5.1, 10.5.2, 10.6.1, 10.6.2, 10.7, 10.9,11.2, 11.3, 11.4, 13.1, 13.3, 15.1, 15.2, 16.1, and 16.2. did not include the required CVs or IVs.

Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.5. required CVs for actions with irreversible consequences such as a potential reactor trip (scram), reduction in power, or equipment damage. Procedure 2-OI-99, "Reactor Protection System," did not include IVs\CVs for all critical steps; 2-OI-99 was used to re-energize the RPS 2B bus by operations. The combination of inadequate procedure steps and operator errors ultimately resulted in the December 2012 U2 scram. Details regarding this event were documented in NRC Inspection Report 05000259, 260, 296/2013002 ML13134A237.

Procedure NPG-SPP-10.3, Section 3.4.1, "Clearance Activities," states that "verification is required for all clearance (hold order) activities (except when verification during clearance release was waved as allowed by Section

3.4.3 B.; for example, exempted activities include significant radiation exposure greater than 10 millirem, and during emergency conditions when imminent danger to plant or personnel requires rapid personnel action). IVs or CVs shall be used as specified in Section 3.4.4 or 3.4.5."

Procedure NPG-SPP-10.3, Section 3.4.4.G, "Independent Verification Requirements," stated that IVs were required when placing and removing clearance tags. There was an exception to use CVs for verification of throttle valve positions and locked valve positions. Three clearance and tagging orders reviewed by the team included CVs for all danger tags applied and removed.

On February 23, 2013, maintenance instrumentation and control technicians performed Surveillance test Procedure 3-SR-3.3.8.2.1(B), "RPS Circuit Protector Calibration/Functional Test For 3B1 And 3B2," Rev. 16, to verify the operability of the RPS circuit protectors 3B1 and 3B2. The team identified that the "as left" protective relay calibration settings did not include IV or CV verification criteria as required by Procedure NPG-SPP-10.3, Rev.1, "Verification Program."

In addition to the previous examples that require IVs or CVs, The team noted that Procedure NPG-SPP-10.3, Appendix "A," includes a list of 35 BFN systems that were required to included energize the RPS 2B bus by operations. The combination of inadequate procedure steps and operator errors ultimately resulted in the December 2012 U2 scram.

Procedure NPG-SPP-10.3, Section 3.4.1, "Clearance Activities," stated that "verification is verifications for procedures, instructions, and work documents." A majority of the Appendix "A" systems did not include the required IVs or CVs for "critical steps" within the system documents. The missing procedure verification human performance error prevention tools have contributed to recent and historical reactor scrams, plant transients, power reductions, unexpected safety system actuations, unplanned safety system and risk significant system unavailability and rework.
The team also noted that multiple TVA Corporate verification procedures have added to the site personnel's misunderstanding and inconsistent use of IVs, CVs, and peer checking requirements. During the on-site inspection, the team provided initial observations, Findings, and adverse trends to the corporate manager responsible for human performance error prevention processes and tools.

In response to the team's feedback, TVA initiated an Apparent Cause Evaluation associated with PER 707531, dated May 2, 2013. The ACE provided a detailed assessment of verification programmatic problems, examples of verification procedure inconsistencies and implementation issues, and reasonable corrective actions to minimize the human performance errors related to verification program and process issues. Specifically, three existing TVA Corporate procedures that provided verification program requirements were combined into one procedure that provides consistent verification standards and implementation requirements. In addition, training was planned for all BFN employees who perform verification activities.

5.3.2.2.1.c Analysis: The team identified that BFN's failure to incorporate Concurrent Verification, Independent Verification, and Peer Check requirements in plant procedures, instructions, and work documents as required by TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," is a performance deficiency that was reasonably within BFNs ability to foresee, correct, and could have been prevented.

This Finding was more than minor because, if BFN site verification procedure requirement issues and adherence are left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern, such as more severe plant transients or engineered safeguard system actuations or malfunctions. Additionally, this issue is similar to IMC 0612, Appendix E, "Examples of Minor Issues," example 4.b, in that the recent inadequate use of human performance error prevention tools (self-checking, peer checking, IVs and CVs) have resulted in a reactor scram or other transients.

The Finding was determined to be of very low safety significance in accordance with Inspection Manual Chapter 0609, Attachment 4, "Phase 1– Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, "The Significant Determination Process (SDP) for Findings At-Power," the team determined that this Finding was of very low safety significance because it did not represent an actual loss of safety function or safety systems out of service for greater than the TS allowed outage time.

The team identified a cross-cutting aspect in the Human Performance area, Resources component, because the licensee did not ensure that procedures were available and adequate to assure nuclear safety.

Specifically, accurate and up-to-date procedures, work packages, and correct labeling of components. [H.2(c)]

5.3.2.2.1.d <u>Enforcement</u>: TS 5.4.1, "Procedures," states that written procedures shall be established, implemented, and maintained covering the following activities: TS 5.4.1 a. The applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978, Section 1.b. and c. Administrative Procedures, "Authorities and Responsibility for safe Operation and Shutdown," and "Procedure Review and Approval." Contrary to the above, the team determined that TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," verification requirements were not included in abnormal operating instruction AOI-1-1, "Relief Valve Stuck Open," did not include CVs for the procedure steps that were performed, in Attachment 1, to close a stuck open Safety Relief Valve when multiple fuses are removed in energized electrical panels to close the SRV(s). Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.2., requires CVs for "actions with irreversible consequences" such as industrial safety when an individual could sustain an injury or death. Also, Section 3.4.5, "Example," includes required CVs during the "removal or installation of fuses." Also, Procedure 1-AOI-99-1, "Loss of Power to One RPS Bus," Rev. 20, did not include IVs\CVs for the procedure critical action steps in Section 4.2, Steps 7.4, 9.2, 9.3, 9.4.1, 9.5.1, 9.5.2, 9.6.1, 9.6.2, 9.7, 9.9, 10.2, 10.3, 10.4.1, 10.5.1, 10.5.2, 10.6.1, 10.6.2, 10.7, 10.9,11.2, 11.3, 11.4, 13.1, 13.3, 15.1, 15.2, 16.1, and 16.2.

Procedure NPG-SPP-10.3, Section 3.4.1, "Clearance Activities," states that "verification is required for all clearance (hold order) activities (except when verification during clearance release is waved as allowed by Section 3.4.3 B.). Procedure NPG-SPP-10.3, Section 3.4.4, "Independent Verification Requirements," G., IVs were required when placing and removing clearance tags. The team identified that Clearance number 0-023-008 for RHRSW A2 pump maintenance used CVs for all nine tagged component applications and removal steps instead of the required IVs.

Because this Finding was of very low safety significance and it was entered into the licensee's CAP via SRs 722559, 726755, and PERs 707531, 722859 and 727405 this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC's Enforcement Policy and is identified as NCV 05000259, 260, 296/2013011-10, Requirements for Concurrent Verification, Independent Verification, and Peer Checks.

5.3.2.2.2 **Inadequate Corrective Actions to Address Programmatic Procedure Quality Issues**

Although this finding was documented under the FPA 12 Procedure and Instruction Quality, the team determined that aspects of this issue were related to FPA 20 Training as described in Section 5.3.3 and the general aspect of Human Performance as described in Section 5.2.4. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPAs:

- Operational Focus and Decision Making (FPA 2) (Section 5.4.2),
- Work Management (FPA 4) (Section 5.5.2),
- Corrective Actions Program (FPA 5) (Section 6.1.4),
- Procedure Use and Adherence (FPA 6) (Section 5.2.2.),
- Technical Rigor (FPA 9) (Section 5.1.4), and
- Governance and Oversight (FPA 10) (Section 6.1.5).

5.3.2.2.2.a Introduction: The team identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," in that BFN failed to take corrective action to preclude repetition of a significant condition adverse to quality regarding procedure quality. Specifically, BFN had unsuccessfully implemented corrective actions to address a condition which the licensee identified as a significant condition adverse to quality involving inadequate procedures that resulted in a significant contributor to plant performance issues. The team identified multiple inadequate procedures across most BFN departments during the inspection document review and onsite inspection. BFN had conducted three root causes, developed and implemented numerous corrective actions however; procedural deficiencies had still contributed to plant shutdowns, unplanned component unavailability, and rework activities. BFN documented the issue in PER 680792.

5.3.2.2.2.b Description: Prior to the team's onsite inspection, BFN identified in their performance improvement plan that the site continued to maintain below standard procedures which resulted in a significant contributor to plant performance issues. In response, BFN performed a root cause, Procedure Use and Adherence and Work Practices, Human Performance Shortfalls (PER 484548). PER 484548 identified that a significant condition adverse to quality (SCAQ) existed involving workers' perception of production over other station processes, including procedure use and adherence (PUA), and has resulted in the inability to identify and correct issues needed to reverse the continued negative PUA trend and that the cause of the SCAQ could be attributed to the inconsistent enforcement of PUA by site leadership that created a culture which does not value verbatim procedure compliance. Corrective actions to address PUA and prevent recurrence were closed before the actions resolved PUA issues. BFN subsequently developed and implemented corrective actions to preclude repetition. The PER also developed and implemented corrective actions to prevent repetition of the SCAQ, which included but were not limited to issuance of a monthly “Key Issues Station Communication Bulletin” for the April 2012 thru December 2012 period; a read and sign document was issued for PUA “Condition of Employment” to all station managers and first line supervisors; and the document required the enforcement of procedure verbatim compliance and the need to support workers when procedure quality issues challenged execution of the procedure.

The team performed a detailed evaluation of the licensee’s root cause and effectiveness of corrective actions to address the significant condition adverse to quality. In accordance with BFN Quality Assurance Plan, TVA-NQA-PLN89-A, a programmatic deficiency was defined as a SCAQ. Therefore, the team evaluated the procedure quality deficiency as a programmatic deficiency and the corrective actions must address the SCAQ and prevent repetition. The team determined that the corrective actions identified and implemented had not prevented additional plant performance issues due to procedure quality issues. In addition, the team identified the root cause was deficient in identifying and correcting fundamental inadequacies in the TVA Corporate level procedures such as Procedure OPDP-1, “Conduct of Operations,” and Procedure NPG-SPP-10.3, “Verification Program.”

The team identified multiple examples of inadequate procedures that resulted in plant performance issues. The inadequate procedures have contributed to a loss of shutdown and spent fuel pool cooling, unexpected safety system actuations, unplanned safety system unavailability and rework. For example:

A contributing cause to the Unit 2 reactor scram that occurred on December 22, 2012, was the adequacy of the procedure used to restore power to the 2B reactor protection system (RPS) bus that tripped. Operating Instruction 2-OI-99, “Reactor Protection System,” contained action steps that included both RPS “A” and “B” performance steps in the same sentence. The procedure contained poor human factored formatting and contributed to the operator error when the running “A” RPS motor generator was deenergized instead of restoring the 2B RPS bus, causing a full reactor scram. BFN revised the procedure to correct the use of "A" and "B" component actions in the same procedure step. However, the team identified that the revised procedure still did not meet ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," and TVA corporate procedure NPG-SPP-10.3, Rev.1, "Verification Program," requirements because the revised procedure did not include Concurrent Verification (CV) and Independent Verification (IV) criteria for action steps that could result in a loss of RPS power and unplanned automatic reactor scram. Specifically, 1-AOI-99-1, "Loss of Power to One RPS Bus," Rev. 20, did not include IVs\CVs for the procedure critical action steps in Section 4.2, Steps 7.4, 9.2, 9.3, 9.4.1, 9.5.1, 9.5.2, 9.6.1, 9.6.2, 9.7, 9.9, 10.2, 10.3, 10.4.1, 10.5.1, 10.5.2, 10.6.1, 10.6.2, 10.7, 10.9,11.2, 11.3, 11.4, 13.1, 13.3, 15.1, 15.2, 16.1, and 16.2. (The regulatory aspects of the December 22, 2012, scram were documented in NRC Inspection Report 05000259, 260, 296/2013002 ML 13134A237.)

BFN's clearance and tagging application related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy," and NPG-SPP-10.3, Rev.1, "Verification Program." Specifically, both AUO's failed to perform proper concurrent verification requirements stated in NPG-SPP-10.3, Section 3.3.1 C. and D., "the performer and verifier shall: 1) locate the component, and 2) identify each unique identifier on the component label." The AUOs closed the A1 RHRSW pump manual discharge valve, O-SHV-023-0503, and applied the red danger tag No. 1435 that was written for the A2 RHRSW pump manual discharge valve, O-SHV-023-0507. The incorrect valve was tagged closed at 10:33 am on May 6, 2013. The 1A RHRSW pump was subsequently declared inoperable at 9:45 am on May 6, 2013, and had remained inoperable for 12 hours.

A BFN maintenance Primary Authorized Employee' s (PAEs) clearance and tagging application verification, for Clearance Order No. 0-023-008, related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedure NPG-SPP-10.2, "Clearance Procedure to Safely Control Energy," Rev. 5, Section 3.3.5 C. and D. Procedure Section C. and D., stated, in part, that "the PAE physically walks down the clearance to determine if energy isolating devices are controlled to prevent introduction of hazardous energy to the equipment on which the PAE will perform maintenance. The walk down shall be completed and the clearance held prior to the PAE or any authorized employee start to work on the equipment under the clearance." The PAE failed to verify that red danger tag, No. 1435, "RHR SW PMP A2 Discharge Valve O-SHV-023-0507, was applied to the correct valve and that the A2 RHRSW pump manual discharge valve was closed.

TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," verification requirements were not included in abnormal operating instruction AOI-1-1, "Relief Valve Stuck Open." The procedure did not include concurrent verifications (CVs) when attempting to close a stuck open Safety Relief Valve. The procedure requires operators to remove multiple fuses that are located in energized electrical panels to close the SRV(s). Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.2., requires CVs for "actions with irreversible consequences" such as industrial safety when an individual could sustain an injury or death. Also, Section 3.4.5, "Example," includes required CVs during the "removal or installation of fuses."

The team's review of TVA corporate procedure OPDP-1, "Conduct of Operations," Rev. 26, issued on February 8, 2013, identified numerous errors and existing inconsistent standards that did not comply with NRC regulations and TVA procedure requirements. The inconsistent TVA Corporate procedure adherence standards; inconsistent self, peer, independent verification, and concurrent verification standards; and the poor quality of the TVA Conduct of Operations written and approved procedure, did not provide BFN, Watts Barr, and Sequoia sites with current nuclear standards that provide all TVA personnel with high procedure adherence and quality standards to ensure the continued safe plant operation that meets regulatory requirements and industry standards. For example, OPDP-1, Rev. 26, included inconsistent standards within the procedure related to procedure adherence and peer checking. The differences included the term should in certain sections and the term shall in a different section for the same activity. Specifically, Procedure OPDP-1, Rev. 26, Section 3.9, "Ownership of Operations Procedures, stated, in part, that "Equipment should only be operated with approved procedures, clearances, or other approved documents as appropriate to maintain configuration control. Section 5.1, "Procedure Adherence," 5.1 .1 B., stated, in part, that "Immediate operator actions required to place the plant in a stable condition during a transient will be performed from memory." Section 5.1 D., stated, in part, that "Plant equipment shall be operated in accordance with written approved procedures" as discussed in Procedure

NPG-SPP-01.2, “Administration of Site Technical Procedures.” In addition, TVA procedure NPG-SPP-01.2, “Administration of Site Technical Procedures,” Rev. 7, effective October 5, 2012, Section 3.1.1.H, “Procedure Users Responsibilities”, states “Make every effort to perform “should” statements in procedures. The decision to not perform a “should” statement must not be made by the field performer alone, but will be discussed with the performer’s supervisor or manager. A “Should” is considered a “Shall” unless a specific exemption is met.” In response to the team’s feedback, TVA revised Procedure OPDP-1, “Conduct of Operations,” Rev. 27, to provide more consistent procedure adherence and peer checking standards. The new procedure was reviewed and approved by the TVA Corporate Functional Area Manager and all three site sponsors, including BFN, on April 8, 2013.

The team determined that assistant unit operators’ (AUOs) failure to comply with Procedure OPDP-1, Rev. 26, “Conduct of Operations,” Sections 4.2.K. and M., related to the missing A1 RHRSW pump discharge valve label plate and the AUO’s inadequate walkdown of the A1 RHRSW pump prior to the planned quarterly surveillance test pump start on May 6, 2013, were also examples of inadequate corrective actions that failed to preclude repetition of the SCAQ.

The licensee acknowledged the deficiencies in the initial fundamental root cause, PER 484548, and the associated corrective actions did not effectively address the procedure quality issues and documented the issue under PER 680792. BFN performed a root cause analysis and developed corrective actions to address the deficiencies identified by the team. Furthermore, BFN developed a procedure upgrade project that will perform a risk based prioritized approach to revise deficient station procedures under SR 739429.

5.3.2.2.2.c Analysis: The team determined that the failure to implement successful corrective actions to address inadequate station procedures was a significant contributor to the continued elevated number of plant performance issues and is a performance deficiency that was within BFN’s ability to foresee and correct. The Finding was determined to be more than minor because it is associated with the human performance attribute of the initiating events cornerstone and adversely affected the cornerstone objective to limit this likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using Inspection Manual Chapter 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” the team determined that the Finding was of very low safety significance because it did not cause a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition (e.g. loss of condenser, loss of feedwater). The team concluded that the Finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because BFN did not thoroughly evaluate the extent of condition associated with inadequate procedures such that the corrective actions resolved the issue and prevented repetition. [P.1(c)]

5.3.2.2.2.d Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," required, in part, for significant conditions adverse to quality that measures shall assure that the cause of the condition is determined and corrective actions are taken to preclude repetition.

Contrary to the above, BFN failed to determine the cause of an SCAQ and failed to take corrective action to preclude repetition of a significant condition adverse to quality regarding procedure quality. Specifically, in January 2012, as a result of numerous plant shutdowns, unplanned equipment unavailability, and component rework activities, BFN performed a root cause analysis of Procedure Use, Adherence and work practices, and Human Performance Shortfalls (PER 484548). The results of PER 484548 identified an SCAQ that involved workers' perception of production over other station processes, including procedure use and adherence (PUA), and has resulted in the inability to identify and correct issues needed to reverse the continued negative PUA trend. BFN concluded that the causes of the SCAQ were related to the inconsistent enforcement of PUA by site leadership that created a culture which does not value verbatim procedure compliance. Corrective actions to address PUA and prevent recurrence were closed before the actions resolved PUA issues. BFN subsequently developed and implemented corrective actions to preclude repetition.

The corrective actions included, but were not limited to, issuance of a monthly "Key Issues Station Communication Bulletin" for the April 2012 thru December 2012 period. A read and sign document was issued for PUA "Condition of Employment" to all station managers and first line supervisors. The document required the enforcement of procedure verbatim compliance and the need to support workers when procedure quality issues challenged execution of the procedure.

However, the team determined that BFN failed to identify that another cause of the SCAQ was inconsistent written procedure adherence standards, both within individual and across multiple corporate and site procedures. The team concluded that BFN's corrective actions failed to preclude repetition, as evidence by a recurrence of plant shutdowns, unplanned component unavailability, and rework activities related to procedural deficiencies. For example:

- A contributing cause to the Unit 2 reactor scram that occurred on December 22, 2012, was the adequacy of the procedure used to restore power to the 2B reactor protection system (RPS) bus that tripped. Operating Instruction 2-OI-99, "Reactor Protection System," contained action steps that included both RPS "A" and "B" performance steps in the same sentence. The procedure contained poor human factored formatting and contributed to the operator error when the running "A" RPS motor generator was deenergized instead of restoring the 2B RPS bus, causing a full reactor scram. BFN revised the procedure to correct the use of "A" and "B" component actions in the same procedure step. However, the team identified that the revised procedure still did not meet ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," and TVA corporate procedure NPG-SPP-10.3, Rev.1, "Verification Program," requirements because the revised procedure did not include Concurrent Verification (CV) and Independent Verification (IV) criteria for action steps that could result in a loss of RPS power and unplanned automatic reactor scram. Specifically, 1-AOI-99-1, "Loss of Power to One RPS Bus," Rev. 20, did not include IVs\CVs for the procedure critical action steps in Section 4.2, Steps 7.4, 9.2, 9.3, 9.4.1, 9.5.1, 9.5.2, 9.6.1, 9.6.2, 9.7, 9.9, 10.2, 10.3, 10.4.1, 10.5.1, 10.5.2, 10.6.1, 10.6.2, 10.7, 10.9,11.2, 11.3, 11.4, 13.1, 13.3, 15.1, 15.2, 16.1, and 16.2.

- BFN's clearance and tagging application related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedures NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy," and NPG-SPP-10.3, Rev.1, "Verification Program." Specifically, both AUO's failed to perform proper concurrent verification requirements stated in NPG-SPP-10.3, Section 3.3.1 C. and D., "the performer and verifier shall: 1) locate the component; and 2) identify each unique identifier on the component label." The AUOs closed the A1 RHRSW pump manual discharge valve, O-SHV-023-0503, and applied the red danger tag No. 1435 that was written for the A2 RHRSW pump manual discharge valve, O-SHV-023-0507. The incorrect valve was tagged closed at 10:33 am on May 6, 2013. The 1A RHRSW pump was subsequently declared inoperable at 9:45 am on May 6, 2013, and had remained inoperable for 12 hours.

- A BFN maintenance Primary Authorized Employee' s (PAEs) clearance and tagging application verification, performed on May 6, 2013, for Clearance Order No. 0-023-008, related to the planned A2 RHRSW pump maintenance was not implemented properly as required by TVA Corporate Procedure NPG-SPP-10.2, "Clearance Procedure to Safely Control Energy," Rev. 5, Section 3.3.5 C. and D. Procedure Section C. and D., state, in part, that "the PAE physically walks down the clearance to determine if energy isolating devices are controlled to prevent introduction of hazardous energy to the equipment on which the PAE will perform maintenance. The walk down shall be completed and the clearance held prior to the PAE or any authorized employee start to work on the equipment under the clearance. The PAE failed to verify that red danger tag, No. 1435, "RHR SW PMP A2 Discharge Valve O-SHV-023-0507", was applied to the correct valve and that the A2 RHRSW pump manual discharge valve was closed.

- TVA Corporate Procedure NPG-SPP-10.3, Rev.1, "Verification Program," and regulatory requirement ANSI N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for Operational Phase Nuclear Power Plants," verification requirements were not included in abnormal operating instruction AOI-1-1, "Relief Valve Stuck Open." On May 20, 2013, the team observed a licensed operator dynamic simulator scenario to evaluate the operators' and simulated plant responses. The simulator scenario included a stuck open safety relief valve (SRV) malfunction and the licensed operators' implementation of procedure AOI-1-1. The procedure did not include concurrent verifications (CVs) for the simulated task of removing fuses when attempting to close the stuck open Safety Relief Valve. The procedure required operators to remove multiple fuses that were located in energized electrical panels to close the SRV(s). Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.2., required CVs for "actions with irreversible consequences", such as industrial safety when an individual could sustain an injury or death. Also, Section 3.4.5, "Example," included required CVs during the "removal or installation of fuses."

- The team's review of TVA corporate procedure OPDP-1, "Conduct of Operations," Rev. 26, issued on February 8, 2013, identified numerous errors and existing inconsistent standards that did not comply with NRC regulations and TVA procedure requirements. The inconsistent TVA Corporate procedure adherence standards; inconsistent self, peer, independent verification, and concurrent verification standards; and the poor quality of the TVA Conduct of Operations written and approved procedure, did not provide BFN, Watts Barr, and Sequoia sites with current nuclear standards that provide all TVA personnel with high procedure adherence and quality standards to ensure the continued safe plant operation that meets regulatory requirements and industry standards. For example, OPDP-1, Rev. 26, included inconsistent standards within the procedure related to procedure adherence and peer checking. The differences included the term should in certain sections and the term shall in a different section for the same activity. Specifically, Procedure OPDP-1, Rev. 26, Section 3.9, "Ownership of Operations Procedures, stated, in part, that "Equipment should only be operated with approved procedures, clearances, or other approved documents as appropriate to maintain configuration control. Section 5.1, "Procedure Adherence," 5.1 .1 B., stated, in part, that "Immediate operator actions required to place the plant in a stable condition during a transient will be performed from memory." Section 5.1 D., stated, in part, that "Plant equipment shall be operated in accordance with written approved procedures" as discussed in Procedure NPG-SPP-01.2, "Administration of Site Technical Procedures." In addition, TVA procedure NPG-SPP-01.2, "Administration of Site Technical Procedures," Rev. 7, effective October 5, 2012, Section 3.1.1.H, "Procedure Users Responsibilities", states "Make every effort to perform "should" statements in procedures. The decision to not perform a "should" statement must not be made by the field performer alone, but will be discussed with the performer's supervisor or manager. A "Should" is considered a "Shall" unless a specific exemption is met." In response to the team's feedback, TVA revised Procedure OPDP-1, "Conduct of Operations," Rev. 27, to provide more consistent procedure adherence and peer checking standards. The new procedure was reviewed and approved by the TVA Corporate Functional Area Manager and all three site sponsors, including BFN, on April 8, 2013.

- The team determined that assistant unit operators' (AUOs) failure to comply with Procedure OPDP-1, Rev. 26, "Conduct of Operations," Sections 4.2 K. and M., related to the missing A1 RHRSW pump discharge valve label plate and the AUO's inadequate walkdown of the A1 RHRSW pump prior to the planned quarterly surveillance test pump start on May 6, 2013, were also examples of inadequate corrective actions that failed to preclude repetition of the SCAQ.

Because this violation was of very low safety significance and was entered into BFN's corrective action program under PERs 680792 and 740212, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC enforcement policy. This NCV is identified as 05000259; 260, 296/2013011-11, Inadequate Corrective Actions to Address Programmatic Procedure Quality Issue.

5.3.2.2.3 **Deficient Acceptance Criteria for Main Battery Bank 1 Inspection**

Although this Finding was documented under the FPA 12 Procedure and Instruction Quality, aspects of this Finding also related to other FPAs, specifically, FPA 7 Equipment Performance, Monitoring and Trending (Section 5.4.3). In addition, although not explicitly described in the report, the team also determined this issue was related to Technical Rigor (Section 5.14) and Work Management (Section 5.5.2). Specifically, Procedure EPI-00248-BAT005 was deficient since replacement of main battery bank 1 in 2009, because the procedure contained outdated and non-conservative acceptance criteria (SR 731341). Work planning for the main battery bank 1 replacement (WO 08-716659) and the procedure revision that changed the inter-cell resistance measurement method were not thorough or rigorous. On both occasions BFN staff did not identify the need to revise inter-cell resistance acceptance criteria. The regulatory significance of these performance elements was addressed in the Finding below.

5.3.2.2.3.a <u>Introduction</u>: The team identified a Green NCV of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, for the licensee's failure to incorporate appropriate quantitative acceptance criteria into a station battery inspection procedure. Specifically, Procedure EPI-00248-BAT005, "Annual Inspection of 250V DC Main Battery Banks 1, 2, 3 and Associated Chargers," Revisions 18 and 19 did not provide the correct acceptance criteria for the battery bank connection resistance results.

5.3.2.2.3.b Description: In December 2009, BFN performed work order 08-716659 to replace main bank battery 1 due to the battery reaching the end of serviceable life. Main bank battery 1 was a safety-related 250V DC power source for onsite safety-related DC loads. As part of the battery replacement activity, electricians performed baseline resistance measurements for the new battery connections. In accordance with WO 08-716659 and Institute of Electrical and Electronic Engineers (IEEE) Std. 450-2002, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications, the baseline resistance readings were recorded for use as acceptance criteria for future annual testing to validate battery connection health and identify conditions adverse to quality. The new baseline resistance readings were provided to the Procedures Group for incorporation as acceptance criteria in Procedure EPI-00248-BAT005.

The team reviewed records for the 2011 and 2012 annual battery inspections and identified that Procedure EPI-00248-BAT005 had not been revised to incorporate the new connection resistance acceptance criteria. The previous acceptance criteria were, in part, non-conservative. The team reviewed the 2013 annual battery inspection records and noted that the inspection procedure had been revised to include the new, post-battery installation, resistance acceptance criteria. However, the inter-cell resistance measurement method was also revised in June 2012 and the new acceptance criteria were not valid for inter-cell resistance data collected using the new method. The team determined the acceptance criteria in the 2013 annual inspection procedure were incorrect and non-conservative. Based on interviews, the team determined station personnel had not considered the need to establish revised baseline resistance and acceptance criteria when they revised the inter-cell resistance measurement method. Engineers reviewed the most recent main battery bank 1 resistance values with the team and concluded the battery remained operable. BFN entered the issue into their CAP under SR 731341 to evaluate extent-of-condition on other station batteries and correct the associated battery inspection procedures.

5.3.2.2.3.c Analysis: The team determined that BFN's failure to establish correct quantitative acceptance criteria after main bank battery replacement and after changing the battery inspection methodology in the annual battery test inspection procedure was a performance deficiency. The performance deficiency was determined to be more than minor and a Finding because it was associated with the procedure quality attribute of the Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process for Findings At-Power" dated June 19, 2012, the team determined that the Finding was of very low safety significance because it was not a design or qualification deficiency and did not result in an actual loss of system and/or function. The team concluded that the Finding had a cross-cutting aspect in the area of Human Performance, Resources - Procedures, because BFN did not provide accurate and up-to-date procedures for the inspection of safety-related station batteries. [H.2(c)]

5.3.2.2.3.d Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed and accomplished by documented procedures that shall include appropriate quantitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, since January 1, 2011, BFN did not prescribe correct quantitative acceptance criteria in the annual battery inspection Procedure, EPI-00248-BAT005, such that adequate main battery bank 1 inspection could be accomplished. Prompt corrective actions included determination that main battery bank 1 remained operable and entry of the issue into the CAP. Because this violation was of very low safety significance and was entered into the licensee's CAP as SR 731341 and PER 732511, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000259/2013011-12, Deficient Acceptance Criteria for Main Battery Bank 1 Inspection.

5.3.2.2.4 **Failure to Translate the Design into Procedure 3-SR-3.3.8.2.1(B)**

Although this finding was documented under the FPA 12 Procedure and Instruction Quality, the team determined that aspects of this issue were related to FPA 7 Equipment Performance Monitoring and Trending as described in Section 5.4.3. In addition, although not explicitly discussed in the report, this issue was also related to the following the FPA:

- Technical Rigor (FPA 9) (Section 5.1.4).

5.3.2.2.4.a Introduction: The team identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to translate seismic uncertainties into acceptance criteria and measuring and test equipment accuracy requirements into the RPS circuit protector calibration surveillance procedure.

5.3.2.2.4.b Description: The RPS electric power monitoring system was provided to isolate the RPS bus from the motor generator set or an alternate power supply in the event of over voltage, under voltage or under frequency. This safety-related system protected the loads connected to the RPS bus against unacceptable voltage and frequency condition and forms an important part of the primary success path of the essential safety circuits. Calculation ED-Q2249-890238, “RPS Circuit Timers, Setpoint and Scaling Calculation,” Rev. 3, determined the accuracy of the RPS instrument loops associated with the RPS circuit timers. The team noted that the calculation included uncertainty for the effects of a seismic event, but then incorrectly excluded it when calculating the as-found setpoint of four seconds. The licensee then failed to translate this uncertainty into the acceptance criteria of Procedure 3-SR-3.3.8.2.1(B), “RPS Circuit Protector Calibration/Functional Test For 3B1 and 3B2,” Rev. 16. Additionally, the team noted that a previous revision of the same calculation had accounted for the seismic uncertainty and determined that the setpoint for the RPS circuit timers as found setting should be 3.67 seconds.

Subsequent to the team questioning the licensee’s incorrect exclusion of the error associated with the effects of a seismic event on the RPS circuit timers in Calculation ED-Q2249-890238, the licensee performed a past operability evaluation. The past operability evaluation evaluated the past 3 years of surveillances for the RPS circuit timers, and concluded that all of the similar timers for Units 1, 2, and 3 had stayed within the more restrictive as left allowances of 3.67 seconds. The team concluded that the licensee failed to translate the uncertainty associated with a seismic event into the as found acceptance criteria of Procedure 3-SR-3.3.8.2.1(B). The licensee entered this issue into their CAP as problem evaluation report (PER) 723605.

In addition to Calculation ED-Q2249-890238, the team reviewed Calculation ED-Q2099-890137, “RPS Circuit Protector Under Frequency Relay Setpoint And Scaling Calculation,” Rev. 0, and Calculation ED-Q2249-880643, “RPS Circuit Protector Under Voltage and Over Voltage Relay Setpoint And Scaling Document,” Rev. 0, which determined the assumed accuracy of the M&TE used to measure the under voltage, over voltage, under frequency, and their associated time delays, for the purpose of determining the proper setpoints that would not exceed safety or operational limits. The team noted that Procedure 3-SR-3.3.8.2.1(B) did not prescribe M&TE accuracy requirements.

Subsequent to the team questioning the appropriateness of the M&TE accuracy requirements not being specified in Procedure 3-SR-3.3.8.2.1(B), the licensee performed a prompt determination of operability (PDO). The PDO evaluated the stated accuracies of the M&TE used to complete Procedure 3-SR-3.3.8.2.1(B) and determined that while the M&TE used to measure the as-found values for the time delay relay and under frequency relays were within the accuracy requirements assumed in Calculations ED-Q2249-890238 and ED-Q2099-890137, the M&TE used to measure the as-found values for the under voltage and over voltage relays did not have a stated accuracy that met the accuracy requirements assumed in Calculation ED-Q2249-880643. The licensee then reviewed the actual calibration results of the M&TE used to measure the as-found under voltage and over voltage relays and determined that it was within the accuracy requirements assumed in the calculation. The team concluded that the licensee failed to translate the required accuracy of the M&TE needed to perform the surveillance into Procedure 3-SR-3.3.8.2.1(B). The licensee entered this issue into their CAP as PER 730495.

5.3.2.2.4.c Analysis: The licensee's failure to translate seismic uncertainties into acceptance criteria and M&TE accuracy requirements into the Reactor Protection System circuit protector calibration surveillance procedure was a performance deficiency. The performance deficiency was determined to be more than minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern. Specifically, the setpoint for the RPS circuit protector time delay relays could be recorded as satisfactory, but actually be above the TS operability limit. Additionally, the M&TE used to perform Procedure 3-SR-3.3.8.2.1(B) could be outside of the accuracy assumed in the licensee's calculations, resulting in the RPS circuit protector under voltage and overvoltage relays being recorded satisfactory, but actually be above or below the TS operability limits. The team used IMC 0609, Att. 4, "Initial Characterization of Findings," issued June 19, 2012, for mitigating systems, and IMC 0609, App. A, "The Significance Determination Process (SDP) for Findings at Power," issued June 19, 2012, and determined the Finding to be of very low safety significance because the Finding did not result in the loss of functionality or operability of a structure, system, or component. The team did not identify a cross-cutting aspect because this performance deficiency has existed since 2006 and was not indicative of current licensee performance.

5.3.2.2.4.d <u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that the design bases are correctly translated into procedures. Contrary to the above, since November 28, 2006, the licensee failed to translate seismic uncertainties into acceptance criteria and M&TE accuracy requirements into Procedure 3-SR-3.3.8.2.1(B), "RPS Circuit Protector Calibration/Functional Test For 3B1 And 3B2," Rev. 16. Because this violation was determined to be of very low safety significance and has been entered into the licensee's CAP as PERs 730495, and 723605, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000259, 260, 296/2013011-13, Failure to Translate the Design Into Procedure 3-SR-3.3.8.2.1(B).

5.3.2.2.5 <u>Other Observations</u>: Based on the team's review of the licensee's causal analysis for the FPA associated with the Procedure and Instruction Quality and the several team identified observations and Findings related to procedure quality issues, the team concluded that the IIP did not have a systematic approach to resolving procedure quality issues. As a result TVA initiated a site-wide Procedure Upgrade Project. This project was a revision to the IIP intended to ensure that substantial and sustainable improvement will be made in this area of procedure quality. The project was developed to use a risk based approach to define a priority and implementation timeline of procedure changes. The timeline will include due dates that are clearly defined and measurable. The procedure revisions will include established standards for procedure upgrades during the work control T-week process, verbal alignment to industry standards (should, shall, may), appropriate criteria for Notes and Cautions, criteria for procedure step validation, and training. TVA's commitment to establish and maintain the required resources, project management, and funding from start to finish is vital to the success of the procedure upgrade project.

Section 5.3.2.2.1 described the team's Finding regarding the requirements for concurrent verification, independent verification, and peer checks. BFN planned to complete a cause analysis to identify the cause, and establish corrective actions that adequately addresses the controlling procedures and includes a list of affected implementing procedures and a schedule for correcting the affected implementing procedures.

Inservice Inspection (ISI) Ultrasonic Examination Procedures N-UT-76, N-UT-64, N-UT-65, N-UT-78, N-UT-82, and N-UT-84 were not qualified in accordance with applicable ASME Code Section XI, Appendix VIII requirements. See Section 6.1.6, “Continuous Learning Environment,” for details and regulatory significance.

The team identified that the Procedure NPG-SPP-06.10, NPG “Fix it Now (FIN) team Process,” possessed procedural quality issues. The procedure contained several vague and/or ambiguous steps that direct the implementation and execution of the BFN Fix-It-Now program. As a result of the teams’ observations, BFN wrote SR 716904 and subsequently PER 717278 to address the procedural quality issues associated with NPG-SPP-06.10, NPG Fix it Now (FIN) team Process. These issues did not constitute violations of NRC requirements.

Procedure 0-GOI-200-1, “Freeze Protection Inspection,” Revision 73, was deficient because it did not provide instruction to verify that heat trace control circuit cabinets were properly secured to keep water out. In addition, the procedure did not provide written criteria that operators could use to verify insulation was properly installed on the RHRSW air release valves. Consequently, when operators performed Procedure 0-GOI-200-1 prior to the onset of cold weather, they did not identify and correct degraded cold weather protection equipment conditions including missing insulation on two RHRSW air release valves and several loose heat trace cabinet covers that permitted water into the cabinets. These conditions could challenge RHRSW operability during extended periods of extreme cold weather. This was discussed further in Section 6.1.4.2.1 of this report.

The team observed a pre-job brief for WOs to perform Surveillance Instructions 1/2/3-SI-4.6.B.1.4, “Reactor Coolant Chemistry.” The WO did not reference Chemistry Instruction CI-13.1, Chemistry Program, even though the data taken during the performance of 1/2/3-SI-4.6.B.1.4, “Reactor Coolant Chemistry,” would be used to complete Chemistry Instruction CI-13.1, Chemistry Program. The Chemistry Technicians stated that they just knew to complete Chemistry Instruction CI-13.1, “Chemistry Program,” after they performed 1/2/3-SI-4.6.B.1.4, Reactor Coolant Chemistry. BFN documented this issue in SR 729857.

5.3.2.3 Assessment Results: BFN has conducted root causes, developed and implemented numerous corrective actions; however, procedural deficiencies continued to contribute to plant shutdowns, unplanned component unavailability, and rework activities. Interviews with BFN staff revealed dissatisfaction with procedure/instruction quality. The team concluded that based on the Findings and observations related to procedure quality issues warranted a revision to the IIP.

In response to the team's conclusion, BFN developed a plan for a procedure upgrade project, including interim actions to address team identified issues that were not addressed in the IIP for the procedure and instruction quality FPA. Moreover, the team concluded that for continued sustainability and substantial improvement of the FPA, implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential. The team concluded that additional time was needed to determine if these actions can improve and sustain BFN procedure quality.

5.3.3 **Training (FPA 20 – TRN)**

5.3.3.1 Inspection Scope: The team reviewed documents and performed inspection activities associated with training at BFN Units 1, 2, and 3 including:

- A review of PER 629212, "Engineering knowledge and skill weaknesses related to station transients and events not being thoroughly identified and evaluated,"
  - o Verified that completion was in accordance with the licensee's processes and used a through and methodical process to complete the evaluation,
  - o Verified the problem area covered the issues and that appropriate aspects of the analysis were carried through into the Integrated Improvement Plan and the associated action plans,
  - o Verified corrective actions adequately addressed the causes and were appropriately completed or planned to be completed,
  - o Reviewed the adequacy of completed effectiveness reviews,
- A review of PER 579250,"Unqualified Tasks performed by personnel in Maintenance and Technical Training Program,"
  - o Verified that completion was in accordance with the licensee's processes and used a through and methodical process to complete the evaluation,
  - o Verified the problem area covered the issues and that appropriate aspects of the analysis were carried through into the Integrated Improvement Plan and the associated action plans,
  - o Verified corrective actions adequately addressed the causes and were appropriately completed or planned to be completed,
  - o Reviewed the adequacy of completed effectiveness reviews,
- A review of PER 65251, 95003 Training "GAP Analysis", and
- Observations of simulator training.

5.3.3.2 Observations: No Findings were identified.

The team reviewed the licensee's GAP analysis related to training and determined the methods used and results to be sound. The team observed and evaluated two licensed operator dynamic simulator scenarios to determine the operators' and simulated plant responses. The simulator scenarios included malfunctions that were related to recent plant events and procedures that were known to have deficiencies. For example, Procedure AOI-1-1, "Relief Valve Stuck Open," did not include CVs for the procedure steps that are performed, in Attachment 1, to close a stuck open Safety Relief Valve when multiple fuses were removed in energized electrical panels to close the SRV(s). Procedure NPG-SPP-10.3, Section 3.4.5, "Concurrent Verification Requirements," B.2., requires CVs for "actions with irreversible consequences" such as industrial safety when an individual could sustain an injury or death. Also, Section 3.4.5, "Example," includes required CVs during the "removal or installation of fuses." Additional descriptions including the regulatory aspects of the teams' Finding associated with CV/IV was provided in Section 5.3.2.2.1.

The operations crew took appropriate actions to mitigate the simulated events and stabilize the reactor safety parameters. The crew followed the abnormal and emergency operating procedures for all of the simulated malfunctions. The simulator fidelity matched the expected equipment and integrated plant response.

In addition to the dynamic scenarios, the team reviewed the simulator discrepancy backlogs and significance of the open issues; no problems were noted. The team also verified that training and personnel qualifications were adequate and appropriate to support safe plant operation.

One exception noted was related to the continued use of SROs for limited in plant equipment manipulations that included the reactor protection system normal and alternate electrical power supplies and feedwater heater water level control systems. The corrective actions planned to address this issue included scheduled qualification training for the ROs and the completion of watch stander qualification cards for the systems currently operated by SROs. The Operations Manager did not have a projected completion date for the planned corrective actions to address this issue. This issue is discussed further in Section 5.3.2.2.2 of this report for the Finding, "Inadequate Corrective Actions to Address Programmatic Procedure Quality Issues."

The use of operations overtime has been reduced over the past 3 years due to completion of initial licensed operator and non-licensed operator training programs. During this inspection, there were additional initial licensed operator training classes in progress, and future classes planned, to replace the operators who have transferred to other departments in an attempt to improve station performance.

BFN has implemented numerous actions to improve the quality and consistency of training for engineering staff. Notwithstanding overall progress in this area, examples of inconsistent engineering program implementation, the partial qualification status for certain program engineers and the composition of BFN engineering staff indicated a need for continued station attention to the area of engineering training and knowledge transfer. The team determined some of the buried cable program and NRC GL-13, "Service Water System Problems Affecting Safety-Related Equipment," heat exchanger inspection program issues discussed in Section 5.1.2.2 were due, in part, to inconsistent subject matter knowledge. The NRC GL 89-13 program and air operated valve program owners were not yet qualified. A qualification plan had not been established for the Aging Management Program. Several additional engineering programs did not have both the primary and backup program owners qualified. The BFN engineering staff was relatively new (40 percent of engineers have been at BFN < 2 years; 60 percent < 5 years). Several experienced senior engineers were eligible for retirement, thereby adding importance to the need for training current staff and knowledge transfer from departing staff to new engineering staff.

5.3.3.3 Assessment Results: BFN has implemented numerous actions to improve the quality and consistency of training for engineering staff. Notwithstanding overall progress in this area, examples of inconsistent engineering program implementation, the partial qualification status for certain program engineers, and the composition of BFN engineering staff indicated a need for continued station attention to the area of engineering training and knowledge transfer. The team determined some of the buried cable program and NRC Generic Letter (GL)-13, "Service Water System Problems Affecting Safety-Related Equipment," heat exchanger inspection program performance deficiencies were due, in part, to inconsistent subject matter knowledge. The NRC GL 89-13 program and air operated valve program owners were not yet qualified. A qualification plan had not been established for the Aging Management program. Several additional engineering programs did not have both the primary and backup program owners qualified. The BFN engineering staff was relatively new (40 percent of engineers have been at BFN < 2 years; 60 percent < 5 years). Several experienced senior engineers are eligible for retirement, thereby adding importance to the need for training current staff and knowledge transfer from departing staff to new engineering staff.

The team concluded that more time was needed for the IIP corrective actions to mature and be able to improve and sustain engineering qualifications. Implementation of the corrective actions in place and completion of the remaining corrective actions is essential to continued sustainability and substantial improvement of the FPA.

5.3.4 Summary and Conclusion

Procedure quality issues at BFN have led to equipment degradation, equipment unavailability, plant transients and reactor scrams. Making standard human performance tools an option rather than a requirement for plant activities and evolutions has exacerbated human performance issues. Previous corrective actions have been ineffective in preventing recurrence of events in which procedure quality was either a contributing or root cause. TVA developed a revision to the IIP to implement a site-wide procedure upgrade project to bring BFN procedure quality in line with established industry standards. An action plan was developed, however, specific actions with due dates had not been determined at the conclusion of this inspection. This procedure upgrade project was entered into the CAP as PER 740212.

BFN has identified personnel qualification issues and implemented corrective actions including training programs. Operator license classes were planned to replace personnel transferring from operations. An aging workforce, with many engineers approaching retirement, underscores engineering qualification issues and BFN's need for an effective knowledge management program. Though the IIP actions are adequate to address the issues discussed, more time was warranted to implement the actions such that substantial and sustained improvement would be achieved.

5.4 Equipment Performance

5.4.1 Inspection Overview

As prescribed by IP 95003, the scope of team's inspection activities included an assessment of Equipment Performance Area. The team inspected the key attributes associated with the following FPA's of Operational Focus and Decision Making (FPA 2), Equipment Performance, Monitoring and Trending (FPA 7), and Strategic Equipment Management (FPA 8). The intent was to ensure that the licensee had identified, established, and implemented corrective actions to address all of the deficiencies identified in these FPA's. The team's objective was to determine whether the licensee's corrective actions, and planned corrective actions, will be effective in achieving sustainable improvements in these FPA's. The team reviewed and observed the licensee's performance in a wide range of plant processes and activities for these FPA's. The team reviewed plant procedures, programs, processes, meetings, technical work products, performed plant walk downs, observed work in the field, and conducted safety culture interviews with BFN personnel during this assessment. The team also assessed the root and contributing causes of risk significant deficiencies associated with each of these FPA's to determine whether they were comprehensive and sustainable.

5.4.2 **Operational Focus and Decision Making (FPA 2 – OFDM)**

5.4.2.1 Inspection Scope: The team reviewed documents and performed inspection activities associated with operational focus and decision making during start up and power operations at BFN Units 1, 2, and 3. The reviews included the Browns Ferry PER 516455, "Operational Focus/Decision Making RCA," and the Browns Ferry "Ops Centric Improvement Gap Analysis," to verify:

- The scope of the root cause and gap analysis (breadth and depth) was appropriate,
- The adequacy of the root cause and extent of condition,
- The adequacy of corrective actions to address the causes identified and that the effectiveness reviews adequately assessed plant progress toward the correction of the deficiencies,
- Priority of corrective actions was commensurate with the safety and risk significance,
- Timeliness of corrective actions was commensurate with the safety and risk significance,
- Implementation of the corrective actions resolved the problems,
- An analysis of the corrective actions to understand adverse trends; and
- Through personnel interviews and observations that corrective actions were implemented satisfactorily.

The team determined whether the turnover environment was adequate to ensure clear communications by:

- Observation of operations crew turnovers and individual operator turnovers in the main control room and work control center and
- The observation of pre-shift morning and evening shift meetings.

The team determined whether the on-coming operators were performing detailed control panel walk downs with current operators, independent electronic plant log reviews, and all required documents by:

- The observation of turnovers in the main control room during the Unit 2 plant startup and all three Units during normal power operation, and
- The review of the turnover process procedure implementation as required by Procedure OPDP-1, "Conduct of Operations," to ensure the required written direction was adequate and actions were performed satisfactorily.

The team determined that plant status information was identified and equipment/operational problems were discussed in sufficient detail for the oncoming shift to comprehend, and that after the shift turnover, the operators had sufficient knowledge of the plant conditions and activities in progress to safely operate each unit as noted by:

- The observation of SRO & RO licensed operator turnovers in the main control room, and
- The observation of non-licensed operator turnovers.

The team assessed TVA's administrative procedures for the shift supervisors conduct and duties, and verified that crew command and control was maintained by:

- The review of the Conduct of Operations administrative procedures specific written direction to ensure the shift command and control function was always maintained for all three Units, and
- The observation of shift turnovers and routine operations activities on day shift, night shift, and weekends to verify whether the procedure requirements were met for the command and control function and proper performance of a majority shift supervision duties.

The team assessed a sample of Emergency Preparedness related equipment and facilities (including communications gear) as required by emergency plan commitments to verify the facilities and equipment were maintained in a readiness condition. The team performed a walkdown of the Operations Support Center (OSC), Technical Support Center (TSC), and self-contained breathing apparatus (SCBA) used by the licensed control room operators during specific emergency events.

Performed an assessment of decision-making regarding longstanding equipment issues;

Performed observations of Assistant Unit Operators during daily building walkdowns across all three units;
Performed dedicated control room observations and assess control room overhead annunciators, and equipment deficiencies.

The team assessed control room workarounds, burdens, and deficiencies to determine if the aggregate impact of the degraded control room equipment and indications impacted the operators' ability to operate the plant safely.

The team performed system walkdowns to verify the adequacy of equipment labeling, and the general material condition of the equipment.

Verified plant configuration was consistent with plant design and related operating procedures.

Verified that testing performed:

- Was completed in accordance with the licensee's procedures, policies, license, and design basis,
- Was technically adequate and in accordance with industry standards as applicable, and
- Was appropriately reviewed and discrepancies appropriately identified and addressed in a technically sound manner and in accordance with the licensee's processes and procedures.

The team observed work activities and meetings to verify:

- Activities or meetings were completed in accordance with the licensee's programs and procedures,
- Adequate communication,
- Adequate and sound decision-making, and
- Discrepancies were identified and addressed in accordance with the licensee's processes and procedures.

The team reviewed and assessed operability determinations to ensure:

- They were completed in accordance with the licensee's procedures, policies, license, and design basis,
- The engineering judgments were technically sound and well supported,

- They were appropriately reviewed and approved, and
- Discrepancies were identified and addressed in accordance with the licensee's processes and procedures.

5.4.2.2 Observations: No Findings of significance were identified. However, Findings related to the FPA of Operational Focus and Decision Making were discussed in the sections regarding Technical Rigor (Section 5.1.4), Procedure Use and Adherence (Section 5.2.2), and Human Performance (Section 5.2.4).

Based on observation and review of the BFN root cause analysis associated with the FPA of Operational Focus/Decision Making, the team confirmed that BFN correctly identified that the root cause specifically, "Decision making at all levels of the station does not consistently demonstrate nuclear safety as a top priority and contributed to significant events, unrecognized equipment inoperability, and deficient operability determinations." BFN developed corrective actions that included:

- Implementation of a leadership strategic performance management process to reinforce and institutionalize conservative decision making principals at BFN,
- Initial and continuing training to reinforce operational focus, nuclear safety culture principles, risk awareness conservative decision making, and systematic rigorous decision making,
- Improved on-line risk management, and
- Improved operability determinations.

The team reviewed station documentation including SRs and PERs, conducted interviews, performed plant and system walkdowns, observed control room activities, observed in plant activities, attended meetings and observed training to determine if BFN management and staff understood and could explain the expected behaviors that demonstrate nuclear safety as a top priority.

The team observed that BFN management and staff understood and could explain the expected behaviors that demonstrate nuclear safety as a top priority, but did not consistently demonstrate these behaviors during planned work activities that included unexpected outcomes. For example:

- A BFN conservative-decision-making expectation was to stop and get resolution if procedures/instructions were unclear before proceeding with an activity. An outside AUO demonstrated an understanding of this expectation while under team observation by stopping when the procedure for flushing a circulating water pump bearing cooler did not have instruction for performing the flush with a temporary modification in place. The operator stopped, called the control room, received resolution, and implemented a temporary procedure change before proceeding with the activity. However, the biocide injection was in process for 3 days and necessitated routine flushing of the bearing coolers. Although correct behavior was demonstrated during team observation, the team recognized that previous unobserved performances of this activity were performed without any procedure change correction request. The team determined that this issue was minor violation of regulatory requirements, in accordance with IMC 0612.

- The team determined that the maintenance Primary Authorized Employee did not verify that all blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW pump planned maintenance. The PAE's decision to only verify two of nine clearance components was a violation of TVA Corporate Procedure NPG-SPP-10.2, Rev. 5, "Clearance Procedure to Safely Control Energy." Refer to Section 5.2.2.2.2 for details including the regulatory aspects of this issue. This issue illustrated the following concerns regarding the FPA of Operational Focus and Decision Making:

    - A maintenance PAE did not ensure that the A2 RHRSW pump was isolated from an unexpected release of energy that could have resulted in personnel injury or pump damage in preparation for a maintenance activity. The PAE did not verify or recognize that the A1 RHRSW pump manual discharge valve was tagged closed instead of the required A2 RHRSW pump discharge valve on May, 6, 2013. Maintenance personnel performed the A2 RHRSW pump impeller maintenance work with the pump discharge valve full open and not danger tagged closed, which did not establish the necessary safe conditions to perform the maintenance activity.

    - In addition, the A1 and A2 RHRSW Incident Prompt Investigation evaluation approved on May 9, 2013, by site management, concluded that the initial clearance and tagging procedure implementation was acceptable, but failed to recognize that the maintenance PAE did not follow the requirements of Procedure NPG-SPP-10.2, Rev. 5, and "Clearance Procedure to Safely Control Energy." The investigation did not highlight the seriousness of protecting the safety of station personnel. For example, Station and Maintenance Department management accepted the maintenance supervisor's initial reason to only perform a partial verification of the A2 RHRSW pump tagout; even though the site procedures required verification of all blocking points.

The team assessed the Operations Department ownership and implementation of proper work control standards to ensure improved station performance. The following deficiencies were noted:

- The team determined that assistant unit operators' failed to comply with Procedure OPDP-1, "Conduct of Operations," Sections 4.2 K. and M., related to the missing A1 RHRSW pump discharge valve label plate that was not corrected prior to applying a red danger tag and an AUOs inadequate walkdown of the A1 RHRSW pump prior to the planned quarterly surveillance test pump start on May 6, 2013. The errors contributed to the unplanned inoperability of the A1 RHRSW pump with the A2 RHRSW pump inoperable for planned maintenance. Refer to Section 5.2.2.2.3 for details including the regulatory aspects of this issue

- 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires, in part, that the licensee shall assess and manage the increase in risk that may result from maintenance activities. However, on May 6, 2013, BFN did not adequately manage the impact of the increase in the emergent risk condition during the self-revealing inoperability of the A1 RHRSW pump quarterly surveillance test. Specifically, for 12 hours, the A1 and A2 RHRSW pumps were both recognized to be inoperable during the A1 RHRSW pump quarterly test. BFN recognized the online maintenance risk condition; however, failed to implement appropriate Risk Mitigation Actions in accordance with Procedure BFN-ODM-4.18, "Protected Equipment." Refer to Section 5.2.2.2.5 for details including the regulatory aspects of this issue

The team observed that BFN had identified quality issues with operability determinations for degraded structures, systems and components. BFN implemented corrective actions including intervention by experienced SROs and coaching and training in all phases of the operability process. The team observed that with these corrective measures in place, operability determinations were technically sound and engineering judgments were well supported. Operability determinations were appropriately reviewed and approved and discrepancies identified and addressed in accordance with licensee processes and procedures.

The team identified that the improvement in operability determination quality was a direct result of intervention and coaching by an outside consultant. The intervention and coaching was used as a temporary measure to improve performance and was not considered a permanent BFN process change. The team concluded that at the time of this inspection, BFN may not have the ability to sustain long term operability determination improvements without the intervention and coaching.

There were several team Findings that represented examples of issues in the Operational Focus and Decision Making FPA that warrant revision to the IIP. The licensee addressed these issues within the CAP. In addition, the safety culture aspects were addressed in the licensee Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724. Furthermore, based on the operations relationship of these Findings and other issues identified by the team, the licensee initiated an Ops Centric Improvement gap analysis as captured by PER 731831. Examples related to operational focus performance included: 1) the May 6, 2013, A1 RHRSW pump start without requiring the outside operator to perform a local verification of the pump, motor, and major flow path alignment in the river water intake structure as stated in Procedure OPDP-1; 2) a maintenance Primary Authorized Employee did not verify that all blocking points were danger tagged to ensure worker personal safety and equipment protection for the A2 RHRSW pump planned maintenance; and 3) BFN did not adequately manage the impact of the increase in the emergent risk condition during the self-revealing inoperability of the A1 RHRSW pump quarterly surveillance test. Specifically, for 12 hours, the A1 and A2 RHRSW pumps were both recognized to be inoperable during the A1 RHRSW pump quarterly test. BFN recognized the online maintenance risk condition; however, failed to implement appropriate Risk Mitigation Actions in accordance with Procedure BFN-ODM-4.18, “Protected Equipment.”

The team reviewed Browns Ferry: Ops Centric Improvement gap analysis, which included three initiatives to address the issues that were identified and or observed by the team:

- Establish Operations Centric Vision,
- Operations Leadership, and
- Operations Reinforcement Process Ownership.

Although the team was not able to determine the effectiveness of the broader actions developed in this gap analysis, the team concluded that the gap analysis conducted by the licensee with the proposed areas of action in the analysis developed to address the issues identified by the Team were actions that were important to implement as part of the revised IIP in order to continue substantial and sustainable improvements in station performance.

5.4.2.3 Assessment Results: The team observed that BFN self-identified a lack of technical rigor in operability determinations for degraded structures, systems, and components. BFN implemented corrective actions that included additional layers of operability review, approval, independent quality of SRO final product, coaching and training for all phases of the operability determination process. The interim changes have resulted in improved technical rigor applied to operability determinations. The team conducted interviews with senior operations management, shift managers, and unit supervisors. The team reviewed immediate and prompt operability determinations, CAP documentation and trend reports. The team observed that BFN has improved operability determination technical rigor due to the implementation of intervention and coaching. The team concluded that although operability determination quality has improved, measures were needed to ensure that technical rigor standards would be sustained and a continuous improvement philosophy would be established as interim intervention and coaching involvement was phased out. SR 766018 addressed the teams concerns of sustainability by requiring periodic Operability Determination Review Board meetings and a self-assessment to measure corrective action effectiveness.

The team reviewed BFNs Operational Focus and Decision Making processes, documentation, and observed on-site station routine and emergent activities to evaluate the extent to which BFN has transitioned toward an Operations led organization. The team determined that the Operations organization does not always take the initiative to embrace the leadership role needed to drive the station to higher standards and improved station performance that exemplifies an Operations led organization. The team's assessment was supported by the high number of operator 'workarounds', 'challenges', and 'burdens', which reflected poorly on the condition of equipment important to safety; frequent delays in supporting scheduled maintenance; limited use of technology enhancements to improve the efficiency and effectiveness of the work control process; acceptance of numerous preventive maintenance deferrals; and a high number of emergent equipment issues. As a result of the team's observation, the licensee developed an action plan to address the issue of the Operations organization embracing a site-wide leadership role in setting the example for site standards and expectations called "Operations Centric Organization."

The team reviewed on-going and completed corrective actions in the area of rigor and decision making that included attributes of technical human performance.

The team interviewed site and TVA Corporate Human Performance Managers and concluded that although there has been some improvement, the success of BFN corrective actions were reliant on the high performance of a few key individuals and to a lesser degree on the establishment of efficient and effective programs and processes. The team concluded that, based on the actions as part of the IIP, there was not a systematic approach at BFN or TVA Corporate to address station-wide issues in decision making and sound technical rigor. Management did not methodically target and correct latent organizational weaknesses involving workforce and supervisors' rigor and decision making. As a result, these issues continue to result in human performance errors, reduced equipment reliability and increased unavailability, and plant events. The team also concluded that without a systematic approach that developed a comprehensive plan to address the continuing human performance errors, BFN could plateau in their performance improvement initiatives with respect to safety culture and workforce behaviors. The safety culture aspects were addressed in the licensee Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724 and provided a site-wide systematic approach to improve decision making and related human performance issues.

Further, for continued sustainability and substantial improvement of the FPA, implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential.

5.4.3 Equipment Performance, Monitoring and Trending (FPA 7 – EPMT)

5.4.3.1 Inspection Scope: The team assessed the licensee's performance in Maintenance, Engineering, Operations, and their CAP related to Equipment Performance, Monitoring and Trending to determine whether the FPA corrective actions were sufficient to prevent further declines in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The team assessed the licensee's performance in Maintenance, Engineering, Operations, and their CAP areas related to Equipment Performance, Monitoring and Trending to determine whether the FPA corrective actions were sufficient to prevent further declines in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The team assessed the effectiveness of corrective actions for deficiencies involving equipment performance, including equipment designated for increase monitoring via implementation of the Maintenance Rule by reviewing the Maintenance Rule program equipment classifications of select components to ensure they are classified properly. The team also reviewed a list of PERs associated with equipment performance issues on selected components and systems, along with a sample of corrective actions based on risk and or recurring issues for those selected systems.

The team assessed selected audits and self-assessments associated with testing. The team also assessed whether the license had effectively implemented programs for control and evaluation of surveillance test, calibration, and post-maintenance testing by reviewing the following Procedures:

- NPG-SPP-06.1, “ASME Code and Augmented Programs,”
- NPG-SPP-06.7, “Instrumentation Setpoint, Scaling, and Calibration,”
- NPG-SPP-06.9,”Testing Programs,”
- NPG-SPP-06.9.1,” ASME Code and Augmented Programs,”
- NPG-SPP-06.9.2, “Surveillance Test Program,” and
- PNPG-SPP-06.9.3,” Post-Modification Testing.”

The team assessed the operational performance of the RHR, CS, RHRSW, and EECW safety systems to verify their capability of performing there intended safety functions. Specifically, the team reviewed system health reports to identify degraded performance or testing issues. Also, the team observed two testing activities and two maintenance/operational activities. The team reviewed preventive maintenance activities for mechanical expansion joints. The team reviewed PMs associated with EDG voltage regulators, inverters, and battery chargers containing electrolytic capacitors to assess age management. The team interviewed system engineers, reviewed work plans & scheduling, and screened subject PERs to assess engineering input to maintenance activities for the selected systems. The team selected major modifications and maintenance to verify that the work was performed consistent with the licensing basis. The team also verified environmental qualification (EQ) of the selected systems for the environment (i.e., temperature, humidity, radiation) assumed under accident conditions. Additionally, the team verified that the maintenance program (including PMs) incorporated appropriate design requirements, vendor manual recommendations, and Operating Experience lessons learned for the selected systems.

The team assessed Emergency Plan (EP) related equipment and facilities against plan commitments and assessed the adequacy of the surveillance program to maintain equipment and facilities, and that deficiencies identified by the surveillance program were corrected. Specifically, the team performed a walkdown of the Operations Support Center (OSC) and Technical Support

Center (TSC). The team verified an adequate number of self-contained breathing apparatuses (SCBA) was available for main control room staff to support emergency operations. The team also verified that the Shift Manager/ Emergency Director made the proper event classifications during observation of simulator training activities. Additionally, the team reviewed corrective action documents associated with Emergency Facilities and of the equipment used within them.

The team assessed the licensee's process for making decisions regarding longstanding equipment issues (i.e. whether conservative decisions were made and decisions supported long term equipment reliability). Specifically, the team observed Assistant Unit Operators during daily building walkdowns throughout all three units. The team observed control room response to overhead annunciators and equipment deficiencies. The team reviewed control room operator workarounds, burdens, and deficiencies. The team also reviewed a sample of NRC GL 89-13 service water program implementation over the last five year period (Procedure NPG-SPP-09.14 and supporting procedures). Additionally, the team reviewed selected system health reports to identify long term equipment issues and associated actions by reviewing the following procedures:

- NPG-SPP-09.18, "Integrated Equipment Reliability Program,"
- NPG-SPP-09.18.1, "System Vulnerability Review Process,"
- NPG-SPP-09.18.3, "Equipment Reliability Strategy Development,"
- NPG-SPP-09.7, "Corrosion Control Program," and
- NPG-SPP-09.15, "Buried Piping Integrity Program."

The team assessed whether inadequate resources were a cause or contributing cause to a delay in resolving any unresolved long-term equipment issues. This was accomplished by reviewing unresolved long-term equipment issues associated with portions of the Emergency Diesel Generator Building Ventilation, the RHR Heat Exchangers, and the Emergency Diesel Generator systems.

The team assessed whether the primary and secondary chemistry control programs adequately controlled the quality of plant process water to ensure long-term integrity of the reactor coolant pressure boundary by observing an RCS sample to verify that operations were completed in accordance with the procedures, and that any discrepancies were entered into the licensee's CAP. The team also observed chemical additions of corrosion inhibitors to the Emergency Equipment Cooling Water system to verify that operations were completed in accordance with procedures and that any discrepancies were entered into the licensee's CAP.

The team performed a review of the licensee's testing program for their vertical pumps used to provide cooling water for Residual Heat Removal Service Water, and their Emergency Equipment Cooling Water systems. Data was collected for 3 years of ASME testing, maintenance records for pump replacement, pump lift adjustments, and river water temperature. The team also performed a review of selected PERs generated for the Residual Heat Removal Service Water and Emergency Equipment Cooling Water system.

In addition, the team evaluated the licensee's apparent cause analysis related to the licensee's Fundamental Problem Area 7, "Equipment Performance, Monitoring And Trending." Specifically the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

5.4.3.2 Observations and Findings: One Finding of very low safety significance was identified.

5.4.3.2.1 Failure to Implement an Adequate Test Program for RHRSW and EECW

Although this Finding was documented under the FPA of Equipment Performance and Monitoring, and trending aspects of this Finding apply to the FPAs of Technical Rigor (Section 5.1.4), Procedure and Instruction Quality (Section 5.3.2), and Corrective Action Program (Section 6.1.4). The regulatory significance of these issues was addressed in the Finding below.

Regarding FPA 12 on Procedure and Instruction Quality (Section 5.3.2), the team reviewed Technical Instruction 0-TI-579 (RHRSW), RHRSW System Pump Baseline Data Evaluation, Rev. 1. The scope stated "This instruction analyzes data to generate new pump reference values. These parameters then become the baseline to which subsequent in-service pump tests are compared for determination of pump operability status and to note any trend towards declining pump performance." A note in the performance section stated, "The lower limit of any RHRSW pump flow rate Alert Range shall NOT be below the minimum pump curve established for RHRSW pumps on drawing 1-47E858-1-ISI. This value was 3000 gallons per minute for any RHRSW pump with the pump differential pressure set at 120 psig. This limit takes precedence over, but is NOT associated with, ASME Operations and Maintenance (OM) Code operability limits." The team determined this Technical Instruction used only system flow requirements, and not an evaluation of pump degradation as the basis for rebaselining pump flow acceptance criteria. The team determined this was an example of a deficient test procedure.

Regarding FPA 9 on Technical Rigor (Section 5.1.4), the team determined that the licensee used 0-TI-383, Evaluation of Test Results for the ASME OM Code In-service Testing Program, to evaluate establishment of new pump reference values (rebaseline). The team reviewed selected recent evaluation forms to determine the additional factors used to evaluate pump condition other than the system required minimums. In no cases had the evaluation discussed the pump's current performance relative to the manufacturer provided performance curves from the initial installation of the new impellers. Pump condition evaluations were based on trends for recent testing and the minimum system requirements. The discussion did not provide a backstop to prevent continuous resetting of the reference values at lower performance values limited only by the system requirements. The team found the lack of an established numerical relationship between flow and temperature for each pump, limited the technical value of the evaluations and their usefulness to identify pump performance degradation.

Regarding the FPA on CAP (Section 6.1.4), the licensee established minimum ASME in-service testing acceptance criteria for the RHRSW/EECW pumps based on system requirements. The ASME code required the function of the pump to be evaluated based on degradation from a reference value, as well as meeting system requirements. The licensee had, through multiple changes in reference values, allowed pump degradation from the original manufacturer's pump head curve in excess of 20 percent of the pumps original flow capacity. In PER 387889, engineers evaluated operating experience (OE) from another utility of reduced reliability and failure of a vertical pump following multiple resets of the pump reference baseline. The resets had been justified based on the minimum system requirements. This showed that use of only system requirements without considering other factors could lead to decreased pump reliability. PER 387889 did not address this deficiency. The team determined engineers did not thoroughly evaluate the applicable OE and incorporate it into the RHRSW/EECW pump test program. This, in turn, limited the licensee's ability to evaluate pump performance and identify pump degradation.

Regarding FPA 5 on CAP (Section 6.1.4), the licensee received correspondence from the RHRSW/EECW pump manufacturer in 1994 that indicated clearances between the pump impeller and bowl would change with river temperature. The manufacturer stated that with the new stainless materials of the new impellers, it was important to avoid the rubbing due to insufficient clearances as had occurred with the previous bronze impellers. Rubbing of the impeller in the pump bowl could cause pump damage. In 2012, the licensee established a semi-annual PM activity to adjust pump lift, and thereby avoid impeller rubbing. The team determined that this action was appropriate to preclude pump impeller rubbing, but was not timely.

5.4.3.2.1.a <u>Introduction</u>: The team identified a non-cited violation of 10CFR50, Appendix B, Criterion XI, Test Control, because the licensee did not establish a test program for RHRSW/EECW pumps such that it adequately demonstrated the pumps would perform satisfactorily in service. Specifically, BFN did not perform RHRSW/EECW pump performance testing such that it adequately accounted for river water temperature impact on the pump lift, which affected pump flow and vibration performance. Without accounting for changes to pump lift caused by river water temperature changes, the test program did not adequately monitor pump and system performance and degradation.

5.4.3.2.1.b <u>Description</u>: The team reviewed pump mechanical design and the associated test program for the pumps used to provide cooling water for the RHRSW and EECW systems. The RHRSW and EECW pumps were vertical pumps with shafts that were approximately 42 feet long. The pump shafts were constructed of stainless steel 410 material and the pump columns were made of carbon steel material. The carbon steel and stainless steel materials exhibited different coefficients of thermal expansions that caused the clearance between the impeller and the bowl to change significantly with river water temperature (also known as pump lift). The longer the pump shaft the more the increased relative growth between the pump shaft and column, which directly increased the pump lift and decreased the pump discharge flow.

The team analyzed periodic ASME pump test data, maintenance records for pump replacements and pump lift adjustments, and river water temperature for the last 3 years. Using additional manufacturer's data, a relationship was estimated between changes in river temperature and pump lift. The team determined that a correlation existed between changes in river temperature, pump lift, and pump discharge flow that adversely impacted the pump performance monitoring testing program.

After the data analysis, the team reviewed PER 387889, “Apparent Cause Evaluation Report. RHRSW/EECW Pump B2, A3, C1, D2 Low Flow Condition,” dated July 13, 2011. The PER included information from multiple sources that recognized temperature changes in the source water for vertical pumps caused variations in flow, but was focused on multiple ASME flow test failures due to the variation in pump flows. As corrective action, beginning in the spring of 2012, the licensee implemented seasonal pump lift changes that were timed independent of the ASME flow testing. The licensee performed quarterly pump testing as required by ASME, and the test data continued to exhibit large pump discharge flow variations with river water temperature.

The team determined discharge flow variations masked timely identification of degraded pump performance based on BFN’s revised test program. Specifically, pump lift was a critical variable that was significantly influenced by river temperature and directly impacted pump flow. However, the licensee did not analyze these related conditions and incorporate their affect into the test program acceptance criteria. The pumps were not tested at the same test conditions as the reference test or controlled all of the critical variables that impacted pump output. The licensee performed the ASME tests on the pump with the lift at different settings, which did not allow adequate pump performance trending, or accurate evaluation of pump performance relative to the reference values. Based on this, the team determined the test program to be inadequate.

In addition, the licensee did not evaluate the additional loss of performance for each pump that would occur after each ASME test during the time of year that the river water temperatures were increasing. The team determined that the river temperature impacted all of the pumps simultaneously. As the river water temperature increased, the pump flows all decreased. This decreased the flow margin available at the same time that the highest water temperatures limit the heat removal capability of the system. The use of the ASME test results was therefore, non-conservative as a way to establish system operability, especially since the licensee had not established the relationship between river water temperature flows and pump performance. In response to the team’s questions, the licensee performed a prompt determination of operability. The PDO documented that the RHRSW and EECW systems remained operable at the river water temperature that existed during the time frame of the inspection.

5.4.3.2.1.c Analysis: The team determined the failure to establish a test program for RHRSW/EECW pumps that adequately demonstrated the pumps would perform satisfactorily in service was a performance deficiency. The PD was more than minor because it affected the Mitigating System Cornerstone and if left uncorrected, could become a more significant safety concern.

The team evaluated the significance of this Finding using IMC 0609, Appendix A, The Significance Determination Process for Findings at Power, dated June 19, 2012. The team determined the Finding was of very low safety significance because it was not a design or qualification deficiency, and it did not result in an actual loss of one or more trains of the RHRSW or EECW systems and/or their function. The Finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Corrective Action Program, because TVA failed to thoroughly evaluate the ongoing changes in RHRSW and EECW pump performance such that the resolution addressed the causes and extent-of-condition. [P.1(c)]

5.4.3.2.1.d Enforcement: Title 10 CFR 50, Appendix B, Criterion XI, Test Control, states, in part, "A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed." Contrary to the above, since approximately 2006, the testing for RHRSW/EECW pump performance testing was not adequate to demonstrate that the pumps will perform satisfactorily under all conditions. Specifically, the test did not adequately account for river water temperature impact on the pump lift and changing pump flow and vibration performance. Without accounting for changes to pump lift, caused by river water temperature changes, the test program did not adequately monitor pump and system performance and degradation (e.g., flow, vibration) to assure the pumps would perform satisfactorily in service. Because this violation was determined to be of very low safety significance and was entered into the licensee's CAP as PERs 730497 and 741036, this violation was treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000259, 260, 296/2013011-14, Failure to Implement an Adequate Test Program for RHRSWS and EECS

5.4.3.2.2 Other Observations: The team evaluated the licensee's causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee's program, that it utilized a thorough and comprehensive method in determining the causes, contributing causes, extent of cause, and extent of condition. The team assessed that the corrective actions implemented and or planned adequately addressed the identified causes.

The increase in engineering staffing over the last several years has led to improved equipment performance, monitoring and trending because engineering personnel have been given more time to focus on improving equipment performance. BFN's commitment to hiring personnel with more engineering experience reduced the emergent engineering work load. Additionally, the establishment of engineering core business hours, which were hours reserved specifically for improving overall system performance, enhanced performance because, it allowed engineering personnel time to focus on these fundamental areas. However, challenges still exist as evidenced by the increasing number of open CAP backlog items at the site. This backlog needs to be managed effectively to ensure that engineering resources are focused and will maintain the gains achieved in the areas of equipment performance, monitoring and trending while addressing the CAP backlog.

The following Findings described elsewhere in the report were related to the equipment performance, monitoring and trending FPA:

<u>Failure to Adequately Implement Procedure 3-SR-3.3.8.2.1(B)</u>
The licensee failed to use approved M&TE to measure the underfrequency relay settings during the performance of the RPS circuit protector calibration surveillance procedure. The maintenance technicians used a digital multimeter to record the underfrequency relay settings, but the multimeter was not considered qualified M&TE for performing this procedure. The licensee entered this issue into their corrective action program as PER 731144. The regulatory significance of this Finding is addressed in Section 5.2.2.2.4 of this report. This observation shows BFN personnel did not adhere to Procedure 3-SR-3.3.8.2.1 while performing a surveillance that monitors and trends RPS circuit protection equipment.

<u>Failure to Translate The Design Into Procedure 3-SR-3.3.8.2.1(B)</u>
The licensee failed to translate seismic uncertainties into acceptance criteria and M&TE accuracy requirements into the RPS circuit protector calibration surveillance procedure. The licensee entered this issue into their CAP as PER 723605. The regulatory significance of this Finding is address in Section 5.3.2.2.4 of this report. This observation is included because it shows a deficiency in the acceptance criteria associated with a procedure

used to ensure the operability of equipment important to safety. That is, equipment performance could have been adversely affected is left uncorrected.

<u>Deficient Acceptance Criteria for Main Battery Bank 1 Inspection</u>
The licensee failed to incorporate appropriate quantitative acceptance criteria into a station battery inspection procedure. Specifically, station battery inspection procedure did not provide the correct acceptance criteria for the battery bank connection resistance results. The licensee entered this issue into their CAP as SR 731341. The regulatory significance of this Finding is addressed in Section 5.3.2.2.3 of this report. This observation illustrated a deficiency in the acceptance criteria associated with a procedure used to ensure the operability of equipment important to safety. That is, equipment performance could have been adversely affected is left uncorrected.

In addition to the Findings described above:

- The team observed the outside rounds operator flush strainers for circulation water bearing coolers. The flush was necessary several times a day while biocide injection was in progress to ensure adequate system flow rates were maintained. The procedure that the operator used did not contain instructions for flushing the strainer with temporary alteration TAF 1-09-001-023 in place. The operator correctly stopped and called the control room when the procedure instructions did not work with the temporary alteration installed.

- The apparent behaviors of working around procedural problems could have a negative effect on equipment performance and reliability. When demonstrating correct and consistent procedural use and adherence operators consistently and reliably operate plant equipment within established and known parameters. Therefore, when operators did not follow procedures as written, the potential existed for equipment to be operated in a manner in which it was not intended and could have adversely affected equipment reliability and operability.

- The team observed a pre-job brief for WOs to perform Surveillance Instructions 1/2/3-SI-4.6.B.1.4, “Reactor Coolant Chemistry.” The WO did not reference Chemistry Instruction CI-13.1, Chemistry Program, even though the data taken during the performance of 1/2/3-SI-4.6.B.1.4, “Reactor Coolant Chemistry,” would be used to complete Chemistry Instruction CI-13.1, Chemistry Program. The Chemistry Technicians stated that they only knew that they should complete Chemistry Instruction CI-13.1, “Chemistry Program,” after they performed 1/2/3-SI-4.6.B.1.4, Reactor Coolant Chemistry. The licensee generated SR 729857 to address this issue. Without procedural guidance the performance of the Chemistry Program, was dependent on chemistry technician knowledge as opposed to clear procedural guidance. This had the potential to affect the trending and monitoring of the chemistry parameters associated with the reactor coolant system.

- The team identified multiple PER’s regarding leakage and through wall leaks in the EECW header, but a trend PER was not initiated. This was a missed opportunity to trend through wall leaks on the EECW header. By not identifying the trend in existing header leaks, BFN was delayed in evaluating the condition. SR 721104 was generated to monitor and trend this leakage.

- The team determined that Procedures NPG-SPP-09.7, “Corrosion Control Program,” and 0-TI-522, ”Program for Implementing GL-89-13” did not provide adequate instruction to assess partial heat exchanger tube blockage. This adversely impacted the accuracy of BFN’s GL 89-13 heat exchanger inspections. This also affected the trending and monitoring of safety-related equipment. Refer to PER 728160 for more information.

5.4.3.4 Assessment Results: BFN performance improved in the FPA of Equipment Performance, Monitoring and Trending. The team observed that the monitoring and trending portion of this FPA has sustainable corrective actions associated with them. Equipment performance will continue to be a challenge for BFN until problems with the work scheduling, work planning, work execution, procedure use and adherence, and procedural quality areas of the work management processes were improved as described in Section 5.5.2. The processes and programs utilized to achieve improvements to the long standing equipment reliability issues being experienced at BFN have been in place for a relatively short amount of time and were expected to continue to improve as the processes and programs become more mature. The licensee’s efforts to encourage the engineering staff to focus on system monitoring and performance trending have been beneficial. However, since the work management processes at BFN have historically not been robust, when emergent/tactical issues upset the schedule, long term Strategic Equipment Management plans have suffered because station priorities have been directed away from the Strategic priorities to the emergent/tactical priority. Work management process corrective actions have been implemented or planned to achieve effectiveness. The team determined that there will be challenges to achieving overall sustained improved equipment reliability. These challenges reinforce the importance of the licensee's continued implementation and completion of the corrective actions associated with this FPA.

5.4.4 **Strategic Equipment Management (FPA 8 – SEM)**

5.4.4.1 Inspection Scope: The team assessed the licensee in multiple areas related to the FPA of Strategic Equipment Management to determine whether the actions taken were sufficient to prevent further declines in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance in this FPA. Strategic Equipment Management is defined for this report as being BFN's long range plans for improving system and equipment/component performance through the integration of various plant procedures, programs, and processes. Emergent work or short term work of the broke fix variety of work will be referred to as tactical work

The team reviewed a number of engineering and maintenance programs and procedures related to Strategic Equipment Management. The team conducted interviews of personnel while assessing the BFN strategic equipment management performance with the Senior Maintenance Manager, Work Control Manager, Work Planning Supervisor, Work Week Manager and System Engineering Manager. Additionally, the team observed Mechanical First Line Supervisor, Electrical First Line Supervisor, and Fix It Now (FIN) First Line Supervisors and their crew during various work activities. The team reviewed selected audits and self-assessments in the area of Strategic Equipment Management. The team also assessed whether the license had effectively implemented maintenance programs to enhance Strategic Equipment Management by reviewing the following Procedures:

- NPG-SPP-02.10, "Equipment Reliability Performance Indicators,"
- NPG-SPP-03.4, "Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10CFR50.65,"
- NPG-SPP-06.2, "Preventive Maintenance,"
- NPG-SPP-06.6, "Inspection Program,"
- NPG-SPP-07.0, "Work Management,"
- NPG-SPP-07.1.1, "Functional Equipment Group (FEG) Development, Implementation, and Maintenance,"
- NPG-SPP-07.3, "Work Activity Risk Management Process,"
- NPG-SPP-07.4, "Management Operating System (MOS),"

- NPG-SPP-07.6, “NPG Work Control Planning Procedure,” and
- NPG-SPP-09.18.12 “Long Term Asset Management Process Integration Procedure.”

The team reviewed Engineering Department staffing levels with respect to Strategic Equipment Management and interviewed the Engineering Manager, System Engineering Manager, System Engineers, and Component Engineers regarding their role in Strategic Equipment Management process. Additionally, the team assessed whether the license had effectively implemented engineering programs to enhance Strategic Equipment Management by reviewing the following Procedures:

- NPG-SPP-09.0, “Engineering,”
- NPG-SPP-09.1, “ASME Code and Augmented Programs,”
- NPG-SPP-09.16, “Plant Health Committee and Plant Health Sub-Committee,”
- NPG-SPP-09.16.1, “System, Component, and Program Health Performance Monitoring Plan (PMP) Development,”
- NPG-SPP-09.18, “Integrated Equipment Reliability Program,”
- NPG-SPP-09.18.2, “Equipment Reliability Classification,”
- NPG-SPP-09.18.3, “Equipment Reliability Program Component Strategy Development and Implementation Process,”
- NPG-SPP-09.18.9, “Long Term Major Maintenance Program,”
- NETP-106, “Pump Testing and Maintenance Program,” and
- NETP-108, “Heat Exchanger Testing and Maintenance.”

The team assessed the Long Term Asset Management Process by reviewing Procedure NPG-SPP-09.18.12, “Long Term Asset Management Process Integration Procedure,” and interviewing Engineering Department management regarding implementation of this program. The team reviewed the licensee’s process for prioritizing resources for long standing equipment issues based on risk, cost, resource availability, and work schedule through a review of various interfacing procedures and programs to assess whether BFN’s corrective actions associated with this FPA will result in sustainable improvements.

The team observed Assistant Unit Operators during daily building walkdowns throughout all three units and observed control room response to overhead annunciators and equipment deficiencies. The team reviewed control room operator workarounds, burdens, and deficiencies with respect to Strategic Equipment Management. The team reviewed a sample of NRC GL 89-13 service water program implementation over the last five year period Procedure NPG-SPP-09.14, “Generic Letter (GL) 89-13 Implementation,” and supporting procedures from a Strategic Equipment Management perspective. The team also reviewed the selected systems health reports. Additionally, the team assessed the licensee's decision-making regarding longstanding equipment issues (i.e. whether conservative decisions were made and decisions supported long term equipment reliability) by reviewing the following Procedures:

- NPG-SPP-09.18.1, "System Vulnerability Review Process,"
- NPG-SPP-09.18.3, "Equipment Reliability Strategy Development,"
- NPG-SPP-09.7, "Corrosion Control Program," and
- NPG-SPP-09.15, "Buried Piping Integrity Program."

In addition, the team evaluated the licensee's apparent cause analysis related to the licensee's fundamental problem area 8, "Strategic Equipment Management". Specifically, the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

5.4.4.2 Observations: No Findings or violations of significance were identified associated with this FPA.

The team evaluated the licensee's causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee's program, that it utilized a through and comprehensive method in determining the causes, contributing causes, extend of cause, and extent of condition. The team concluded that the corrective actions and or planned addressed the identified causes, and were reasonable.

The FPA of Strategic Equipment Management at BFN had several corrective actions in place to improve station performance. For example, the corrective action to establish "Engineering Core Business Hours" has enhanced the Engineering Organization's ability to concentrate engineering resources on Equipment Reliability programs. Feedback provided by the Engineering

Department regarding the action to create “Engineering Core Business Hours”, which are hours reserved specifically for improving overall system performance, has been positive and the team observed that this actions helped focus engineering resources on improving overall equipment performance. The fact that this enhancement has not yet resulted in a significant decrease in the number of SSC’s in Maintenance Rule (a)(1) status at BFN, indicated the importance of continued licensee management involvement and oversight to ensure continued implementation of the corrective actions the IIP.

The licensee established a Long Term Asset Management (LTAM) as part of their efforts associated with this FPA. LTAM created a process that ranks and prioritizes modifications and projects from a BFN site perspective. This process, if followed, focuses site resources on important SSC’s and projects that have the potential to improve equipment reliability over time. The enhancement of the LTAM program along with the enhancement of other engineering programs in addition to the previously established Safe System Recovery Program should support a sustainable Strategic Management Program at BFN.

During the team inspection, the following issues related to this FPA were observed the following.

- Assistant Unit Operators routinely needed to charge multiple Hydraulic Control Units (HCU’s) each shift due to seal wear and leakage. The primary reason for this was because most HCU’s were original equipment. BFN recharged five to ten HCU’s per shift depending on the ambient temperature conditions in the reactor building. The team considered this to indicate an example of an equipment aging issue that has become a resource burden on the AUOs and illustrated the importance for having an effective strategic equipment management program.

- BFN has a process that lists/documents the Top 10 Plant Health Issues. The purpose of this process was to identify and focus resources on significant equipment reliability issues. Once identified, BFN can then develop, prioritize and implement action plans to correct the identified system deficiencies in an effort to re-establish equipment reliability and improve system performance. It was identified that the Top 10 Action Plans have not been reviewed and concurred with regularly at the Plant Health Committee meetings as required by Procedure NPG-SPP-09.16 Step 3.2.2.B.3. The Equipment Reliability Manager stated that this was because they have such a large volume of Red Maintenance Rule systems and that they take priority. Although, compliance with this procedure is not required by NRC regulations, the team considered this to illustrate that BFN still has challenges facing them regarding their Strategic Equipment Management processes. Continued effort to complete the corrective actions associated with this FPA and the licensee's continued effort to reduce the number of long term equipment problems should enable BFN to better manage the equipment within their Top 10 Action Plans.

- Maintenance workers did not correctly torque the coupling bolts on an RHRSW pump. This issue was addressed by the team at the time of occurrence and did not result in any adverse consequences. Additional details regarding this issue including the regulatory aspects were provided in Sections 4.5.2.1 and 6.1.4.2.2. The team considered the behavior illustrated by this example, and others described in the Sections of the report associated with Technical Rigor (Section 5.1.4), Procedure Use and Adherence (Section 5.2.2), Human Performance (Section 5.2.4), Procedure and Instruction Quality (Section 5.3.2), Operational Focus and Decision Making (Section 5.4.2) and Work Management (Section 5.5.2) could undermine the intent of the Strategic Equipment Management program and will cause continued challenges with improvement in equipment performance.

5.5.4.3. Assessment Results: The team concluded that the licensee's efforts to address the Strategic Equipment Management FPA identified the causes and contributing causes, and initiated corrective actions to address the causes. The corrective actions implemented or planned were technically sound. The development of the Long Tern Asset Management (LTAM) strategic equipment management program along with the existing programs were appropriate to control and assess the work activities necessary to improve equipment reliability. In addition, the corrective action to establish "Engineering Core Business Hours", which are hours reserved specifically for improving overall system performance, has enhanced the engineering organization's ability to concentrate engineering resources on Equipment Reliability programs.

The team recognized that improvements have been made in the area of work control, and across the site in the areas of technical rigor, operational focus and decision making, procedure quality, and human performance including procedure adherence. Nonetheless, the team recognized that further improved performance in these areas will be vital to a successful strategic equipment management program. Therefore, completion of the FPA actions in the IIP and continued licensee management involvement and oversight in these areas was warranted.

5.4.5 **Summary and Conclusions**

The team determined that the operations organization had not routinely taken the initiative to embrace a leadership role needed to drive the station to higher standards and improved station performance that exemplifies an Operations led organization. The team concluded that although the quality of operability determinations had improved, measures were needed to ensure that the technical rigor standards achieved sustainability.

The team concluded that, based on the actions defined in the IIP, there was not a systematic approach at BFN or TVA Corporate to address station-wide issues in decision making and sound technical rigor. Management did not methodically target and correct latent organizational weaknesses involving workforce and supervisors' technical rigor and decision making. These issues continue to result in human performance errors, reduced equipment reliability and increased unavailability, and plant events. The team concluded that without a systematic approach that developed a comprehensive plan to address the continuing human performance errors, BFN could plateau in their performance improvement initiatives with respect to safety culture and workforce behaviors. The safety culture aspects were addressed in the licensee Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724 and provides a site-wide systematic approach to improve decision making and related human performance issues. This action plan provided a site-wide systematic approach to improve procedure use and adherence and related human performance issues.

The enhancement of the Long Term Asset Management program along with the establishment of a systematic and integrated work week schedule (T-Week process/schedule) the T-Week, which is a formalized process conducted on a weekly basis starting at 26 weeks prior to a significant maintenance work activity and is used for preparation and planning work activities and Functional Equipment Grouping work week processes should help to provide sustainable improvement to overall equipment reliability. In addition, enhancements of engineering programs should help improve Strategic Management Programs at BFN. However, the team assessed that issues in BFN's work management processes with respect to work scheduling, work planning, work execution, procedure use and adherence, human performance, and procedural quality will continue to present the site with challenges in achieving sustainable improvements in overall long term equipment reliability.

5.5 Configuration Control

5.5.1 Inspection Overview

The team independently assessed the licensee's ability to maintain risk significant systems and the principle fission product barriers in configurations which supported their safety functions. Based on risk insights from the individual plant evaluation configuration reviews focused on fission product barriers and the group of systems that support the containment heat removal function (i.e., residual heat removal, core spray, RHR service water, and emergency equipment cooling water. The assessment included review of configuration control issues addressed through the corrective action program, in-plant walk down of the vertical slice structures, systems, and components (SSCs), fission product barrier assessment, and review of the plant specific probabilistic risk assessment (PRA) model.

5.5.2 Work Management (FPA 4 - WM)

5.5.2.1 Inspection Scope: The team assessed multiple areas related to Work Management to determine whether the corrective actions associated with this FPA were sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote substantial and sustained improved performance.

The team assessed whether the work control process used risk appropriately during planning and scheduling of maintenance and surveillance testing activities and the control of emergent work. Specifically, the team reviewed maintenance procedures to determine whether the work control process used PRA during planning and scheduling of work. The team also observed the work control process in the plant to ensure that PRA was incorporated into the work planning process and verified that SROs were capable of assessing risk when emergent equipment failures occur.

The team discussed the Maintenance Standard Initiative with the Senior Maintenance Manager to assess whether first line supervisor training had been effective at improving the use of human performance tools in the work force. In addition, The team interviewed personnel associated with Work Management including the work planning supervisor, work week manager, work control center SROs, main control room SROs, maintenance first line supervisors, and electrical, mechanical, and I & C technicians, to assess implementation of the work control process. The team also observed work planning meetings to assess whether the licensee's maintenance procedures were being implemented as written and the adequacy of technical decisions.

The team assessed PM deferrals process by reviewing the licensee's procedures for authorizing and performing PM deferrals. The team also reviewed a sample of PM deferrals for adequate technical rigor and reviewed the licensee's PM deferral station performance metrics and corrective actions to reduce the PM backlogs.

The team assessed whether the turnover environment was adequate to ensure clear communications by observing operations crew turnovers and individual operator turnovers in the main control room and work control center. The team also observed the pre-shift morning and evening shift meetings. In addition, the team assessed whether the on-coming operators were performing detailed control panel walk downs with current operators, independent electronic plant log reviews were occurring, and whether all required documents were reviewed. Specifically, the team observed turnovers in the main control room during the Unit 2 plant startup and all three Units during normal power operation. The team also reviewed the turnover process procedure implementation as required by Procedure OPDP-1, "Conduct of Operations," to ensure the required written direction was adequate and actions were performed satisfactorily. In addition, the team assessed whether plant status information was identified and equipment/operational problems were discussed in sufficient detail for the oncoming shift to comprehend, and that after the turnovers, the operators had sufficient knowledge of the plant conditions and activities in progress to safely operate each unit as noted by observing SRO & RO licensed operator turnovers in the main control room and non-licensed operator turnovers.

The team reviewed a sample of written logs and shift statuses to assess whether the licensee provided sufficient detail and described changes in plant or equipment status from one shift to the next.

The team assessed whether control room personnel were appropriately aware of ongoing activities such as maintenance, surveillance and testing, plant equipment taken out of service, and their impact on plant operation; and are implementing the necessary actions. Specifically, the team reviewed a number of scheduled and non-scheduled maintenance activities. The team also questioned the control room operators about ongoing activities that could affect plant operations, and the priorities in resolving plant issues and equipment problems.

The team assessed TVA's administrative procedures for the shift supervisors conduct and duties, and verified that crew command and control was maintained. Specifically, the team reviewed the Conduct of Operations administrative procedures to ensure specific written direction was provided to ensure that the shift command and control function was always maintained for all three Units. The team also observed shift turnovers and routine operations activities on day shift, night shift, and weekends. Additionally, the team verified that the procedure requirements were met for the command and control function and that proper performance of a majority of shift supervision duties.

The team performed tours of the plant to assess whether the licensee used workarounds or conditions that might require workarounds by inspecting for unapproved job aids or markings, or for equipment that is not performing as designed. The team also inspected for the potential for adverse environmental conditions.

The team reviewed Post Maintenance Testing conducted on the 2A RHRSW Pump following a coupling adjustment. The team evaluated whether the testing that was conducted adequately ensured that the 2A RHRSW Pump was returned to an adequate configuration. Also, the team observed pre-evolution/pre-job briefings to assess whether for complex surveillance and tests, that the licensee coordinates with the control room, and that the shift supervision maintained effective control of plant operations, and that the control room was implementing compensatory measures required by the risk/safety evaluations for the evolutions being conducted.

The team reviewed vendor manuals to assess whether the licensee had appropriately incorporated the vendor’s recommendations into maintenance procedures.

The team assessed the maintenance controls by reviewing the nature and extent of the licensee’s backlog of corrective and preventive maintenance, and assessed the licensee’s efforts to integrate preventive and corrective maintenance to minimize equipment unavailability. Specifically, the team reviewed the process for planning work, and reviewed the policies with respect to schedule generation and the use of risk insight. The team reviewed how risk was factored into maintenance scheduling and whether the licensee evaluated possible interactions between components in service and those to be taken out of service or tested. The team verified whether the need for planned contingencies, compensatory actions, and abort criteria were considered prior to performing work activities. The team reviewed safety system tag-outs to determine if the tagouts were adequate for the work to be accomplished by verifying that operators were thorough in tagging and isolation of plant equipment and verifying that tags were properly hung and equipment has been placed in the designated position, and determined if equipment status changes and corresponding entry into or exit from TS action statements were appropriately documented. The team verified whether the licensee had adequate controls to ensure the independent verification of equipment status was also performed. The team verified that maintenance activities were coordinated with control room operations and that appropriate briefings and turnovers were held with control room operators. The team reviewed disabled control room annunciators and instruments, control room deficiencies, operator workarounds and other equipment deficiency tracking systems to assess the significance of these conditions on overall plant operation. The team also reviewed the licensee's process for using rapid response maintenance teams for emergent equipment problems.

In addition, the team verified that work control procedures were established to require special authorization for activities involving welding, open flame, or other ignition sources and take cognizance of nearby flammable material, cable trays, or critical process equipment. Additionally the team verified that work control procedures have been established to require a firewatch with capability for communication with the control room, if an activity identified above was to be performed in the proximity of flammable material, cable trays, or vital process equipment. The team also verified that procedures adequately addressed scaffold controls around safety, critical or operating equipment.

The team reviewed chemistry controls by reviewing records of completed chemical analyses to determine if required analyses have been performed. The team also reviewed trends of recorded water quality data and assessed corrective actions taken when chemical variables exceeded the established levels or limits, including consideration of the timeliness of these actions. Additionally, the team assessed the effectiveness of measures taken to prevent the introduction of chemical contaminants into primary coolant water and to detect the presence of these contaminants.

In addition, the team evaluated the licensee's apparent cause analysis related to the licensee's fundamental problem area 4, "Work Management". Specifically the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

5.5.2.2 Observations: No Findings of significance were identified.

The team observed several occasions where BFN workers did not display the expected human performance behaviors such as a questioning attitude. These issues were assessed with respect to their regulatory aspects and, unless otherwise noted, any associated violations were determined to be minor in accordance with IMC 0612. Nonetheless, these human performance behaviors contradicted expected qualified nuclear plant workers behaviors.

- During observation of WO 11468440 craft workers found that the sheave diameter had changed since the crew had adjusted it the day before. The workers failed to display a questioning attitude as to why this had occurred. When prompted by the team, the craft workers consulted their supervisor who also failed to display the proper questioning attitude as to why the sheave diameter was different than expected.

- The team observed mechanical maintenance workers performing maintenance in the RHRSW pump building. The workers found an unidentified tag for one of the RHRSW Pumps lying on the floor of the room. The workers did not display the correct behavior because they did not enter this condition into the Corrective Action Program until questioned about it the next day. Additional details and the regulatory aspects of this issue is provided in Section 5.2.2.2.3.

- During observation of the pre-job brief for WO 1368440 the job foreman stated that he would not generate an SR for a bad procedure because that would take too long to get it corrected. Instead he would just ask the procedure writer/planner to change it.

- The Maintenance Department did not perform a complete investigation of the Maintenance Supervisor that did an incomplete walk down of the tagout hung to support RHRSW pump impeller adjustment. Maintenance Management made a non-conservative decision that this event did not need to be investigated and thus did not determine that a Department Clock reset should occur until questioned about it by the team. Additional details and the regulatory aspects of this issue were provided in Section 5.2.2.2.2.

The team observed several occasions were BFN had difficulties implementing the T-Week work process:

- The team determined that the work planning department was having problems tracking WO preparations. Work planning was using multiple schedule lists in order to try and account for WOs that were planned and still needed to be planned. The Outage and Scheduling Performance Indication (OSPI) System program that should have been keeping track of these WOs did not contain the correct filters and therefore was not keeping track of all of the WOs that needed to get planned. Refer to SR728688

- The team reviewed the OSPI Daily Work Management Milestone Matrix – Planning Hit List Report printed on May 20, 2013 and it was concluded that work planning was not meeting the T-Week work planning goals associated with have WOs planned in a timely manner as evidence by all the red, orange, and yellow entries extending into week T-2.

The team observed examples of where the low quality work instructions/ procedures were contained within work order packages:

- During the observation of air flow measurements taken on the CS and RHR room coolers, the team noted that the procedure did not give clear guidance on the exact locations to hold the test probe while measuring air flow. The procedure did not contain guidance on how many data points to measure, and there was no location in the procedure to enter all of the air flow readings taken during the execution of the procedure. Based on the team's questions, the licensee addressed the issues prior to completion of the work; therefore, no violations of regulatory requirements occurred. The licensee generated SR 726887 to address these concerns.

- During the observation of WO 11214676 a procedural mistake was made because of a confusing procedural step. The step had the craft worker record the motor starter model number, and if the starter model was a CR 105, he was directed to generate an SR and replace the starter contactor. Because the procedure step was worded poorly the worker did not perform the work correctly and as a result, this was identified by the team. That is, without the team's intervention the motor starter that should have been replaced would have been returned to service following completion of the WO.

The team also discovered problems associated with work execution at BFN:

- During a review of SR 61394 and WO 113969570 workers skipped from Step 7.0.4 to Step 7.0.10 believing the note allowing them to do this was included in the work order instructions they were using. Since the note was not part of the WO instructions the worker actions were not in accordance with the rules of usage for continuous use procedures. This was identified by a QA observer of the work task and does not comply with BFN's procedural use and adherence standards.

- The licensee failed to appropriately coordinate work activities by incorporating actions to address the impact of changes to the work scope or activity on the plant and human performance while implementing modifications to the RHR and CS room coolers under DCNs 69466 and 69467. See Section 6.1.3 for detailed observation and regulatory significance.

5.5.2.3 Assessment Results: The team determined that the corrective actions were comprehensive and adequately addressed the identified root and contributing causes for the FPA of Work Management. However, the team identified examples of issues related to the FPA of Work Management. Specifically, work schedule development, work planning, work instruction quality and work execution. Moreover, an independent oversight organization determining that additional CAs were needed (i.e. Maintenance Standards Initiative) to improve work quality and oversight of work planning and execution. The team determined that BFN employees in operations and maintenance did not consistently display the willingness to follow procedures, stop when unsure, or demonstrate an adequate questioning attitude when faced with marginal technical products such as poor quality procedures and work instructions. The station's low level of performance in Work Management was also evidenced by the current "red" station performance metrics for PMs in the second half of grace, PM Deferrals, and the work planning Outage and Scheduling Performance Indication performance metric, that not all of the corrective actions developed to address the work management process have been effective. The team acknowledged that improvements were made with respect to the work management process; however, this was a new process and additional implementation time was needed to show performance improvement would be sustainable. Therefore, rigorous adherence to the process by the licensee's staff and rigorous oversight of the work management process by the licensee's management will be necessary for sustained improvement.

5.5.3 **Vertical Slice System and Component Review**

5.5.3.1 Inspection Scope: Based on industry operating experience and risk insights from the individual plant evaluation, the team reviewed selected components and vertical slice systems, previously defined in Section 5.1.1 of this report, which supported the containment heat removal function, to ensure that the SSCs associated with each system were in proper configuration and material condition to perform their designed safety functions. The team also assessed the Containment Spray system, which had a direct containment over-pressure protection safety function.

Vertical slice systems that support the containment heat removal function:

- Residual Heat Removal
  - Low pressure coolant injection mode
  - Containment cooling modes (suppression pool spray, suppression pool cooling, drywell spray)
  - Standby coolant injection mode (last resort, injects RHRWS to reactor)
  - RHR cross-tie mode
- Core Spray
- RHR Service Water
- Emergency Equipment Cooling Water

Vertical slice system components selected for in-depth review included:

- Unit 2 ‘C’ Core Spray System Pump – BFN-2-PMP-075-0014 / Motor – BFN-2-MTR-075-0014,Unit 3 ‘B’ RHR Pump – BFN-3-PMP-074-0028 / Motor BFN-3-MTR-074-0028,
- B2 RHRSW Pump – BFN-0-PMP-023-0019 / Motor BFN-0-MTR-023-0019,
- Unit 2 CS Injection Line Check Valve [Testable Check Valve Loop 1] – BFN-2-CKV-075-0026,
- Unit 2 ‘C’ CS Pump Suction Valve – BFN- 2-FCV-75-0011,
- Unit 2 CS System 1 Inboard Discharge Valve – BFN-2-FCV-75-0025,
- Unit 3 ‘B’ RHR Pump Suction MOV for Suppression Pool – BFN-3-FCV-074-0024,
- Unit 3 RHR, Loop 2, LPCI Injection (Testable Check Valve) – BFN-3-CKV-074-0068,
- RHR LPCI Discharge Header Train Cross connect valve from Unit 2, Loop 2, to Unit 3, Loop 1 – BFN-2-FCV-074-0101 (actuator 2-MVOP-074-0101),
- Unit 3 ‘B’ RHR HX Outlet Valve – BFN-3-FCV-023-0046,
- Unit 3 ‘B’ RHR Pump Room Cooler – BFN-3-CLR-064-0069,
- Unit 3 ‘B’ RHR HX – BFN-3-HEX-074-0900B,
- EECW Strainer associated with B EECW supply header– 0-STN-067-0926,

- South EECW Supply header check valve to 3A DG cooler – BFN-3-CKV-067-0695 South EECW Supply header back flow check valve to 3A DG cooler – BFN-3-CKV-067-0696, and
- South EECW Supply header check valves to 3B RHR pump room seal cooler and RHR pump room cooler – BFN-3-CKV-067-0601 and BFN-3-CKV-067-0600.

The in-depth component review consisted of evaluation of various engineering calculations, industry operating experience issues, test results, design criteria, purchase specifications, drawings, vendor manuals, and maintenance history. Documents reviewed are listed in the Attachment. The team also performed in-plant walk-downs of the RHR (Units 1 and 2), RHRSW (common to all three units), CS (Units 1 and 2), EECW (common to all three units), and the intake structure pump house screenwash systems to independently verify material condition and configuration. The system walk-downs included the following inspection elements:

- Reviewed the associated operating procedures, drawings, and UFSAR Sections. Reviewed the licensee's system lineup procedure, system design basis documents, and determined whether the documents were consistent with the as-built configuration.
- Compared system line-up procedures with drawings to ensure they were consistent (e.g., valve positions, installation of blank flanges and caps).
- Reviewed jumper, lifted lead, and other temporary modification logs. Determined whether (1) an adequate technical review was performed before plant modifications were performed to ensure the absence of unreviewed safety questions, and (2) plant drawings were updated to reflect the change. Assessed the role of the plant, system, and design engineering groups in the temporary modification process.
- Determined if accessible valves in the system flow path were in the correct position by either visual observation of the valve; by flow indication; or by stem, local or remote position indication and that they were locked or sealed, if appropriate.
- Verified that valves did not exhibit excessive packing or missing hand-wheels, or bent stems. Ensured that local and remote position indications were functional and indicated the same values. Verified remote manual operating devices should be functional.
- Verified pump seals did not show signs of excessive leakage.
- Verified that cooling water was aligned to bearings and seals and that oil bubblers and bearings did not show signs of excessive leakage.

- Verified that power was available and correctly aligned, functional, and available for components that must activate on receipt of an initiation signal.
- Verified that major and support system components were correctly labeled, lubricated, cooled, and ventilated to ensure fulfillment of their functional requirements.
- Reviewed system mechanical joints (packing, flanges, body to bonnet joint) leakage requirements, verified known leakage was properly addressed, and verified observed leaks were accounted for the licensee.
- Determined whether selected instrumentation, essential to system actuation, isolation, and performance, was correctly installed and functioning, correctly calibrated, and displayed indication were consistent with expected values. Verified instrument elevations were consistent with design documents.
- Identified whether actual or potential adverse environmental condition(s) existed, and the adequacy of any associated compensatory measures.
- Identified whether selected system components were consistent with the UFSAR description. Determined whether a 10 CFR 50.59 safety evaluation was performed for any items that differed from the UFSAR description.
- Identified additional equipment conditions and items that might degrade plant performance by verifying whether:

    - Freeze protection, such as insulation, heaters, heat tracing, temperature monitoring, and other equipment, was installed and operational,
    - Hangers and supports were in their proper positions, aligned correctly, and intact,
    - No unauthorized ignition sources or flammable materials were present in the vicinity of the system being inspected,
    - Cleanliness was being maintained, and
    - Temporary storage of material and equipment was in accordance with the licensee's seismic control procedures and did not interfere with equipment operations or operator actions.

5.5.3.2 Observations: No Findings or violations of significance were identified.

The systems and components reviewed were generally found in good material condition and properly configured in accordance with the UFSAR and station procedures. Plant operators and engineers were generally aware of degraded material conditions when they existed and of planned corrective actions to resolve them. Notwithstanding, the team identified several examples of degraded material condition for which corrective actions were not timely. Examples of the team's observations are listed below:

1. Insulation was not properly installed on two RHRSW pump discharge air relief valves (ARVs)(PER 727908). Fasteners for the majority of the RHRSW and EECW system heat trace control circuit cabinets were not properly secured to keep water out. Inspection of two cabinets identified moisture and corrosion inside the cabinets, but not enough corrosion to cause the heat trace to malfunction (PER 729153). Additionally, RHRSW heat trace wiring conduit was broken in the RHRSW pump rooms and the heat trace wiring was exposed (PERs 729119, 729146, 729180, 729618, and 729623). These could adversely affect operability of the RHRSW and EECW systems during cold weather. See Section 6.1.4.2.1 for a detailed description and regulatory significance.

2. The RHRSW and EECW pumps experienced pump lift changes when river temperature changed throughout the year, thereby affecting pump performance. The pump lift change was an unintended consequence of the pump shafts and columns being made of different materials and experiencing differential thermal expansion. The consequence was that each RHRSW and EECW pump incurred additional undesired unavailability during periodic pump lift adjustments. This was a longstanding degraded material condition. See Section 5.4.3.2.1 for a detailed description and regulatory significance.

3. On May 6, 2013, operators tagged the ‘A1’ RHRSW pump discharge valve closed by mistake, resulting in both the ‘A1’ and ‘A2’ being inoperable during a planned surveillance test. See Sections 5.2.2.2.1, 5.2.2.2.2, 5.2.2.2.3 and 5.2.2.2.5 for a detailed description and safety significance.

4. Several RHRSW and EECW valves in the RHRSW pump rooms were mislabeled or were not labeled (PERs 729154, 729157).

5. The schedule to repair the ‘D’ EECW strainer to eliminate shell bypass, which had previously caused emergency diesel generators to become inoperable, was untimely. The team identified three repair opportunities earlier than the scheduled December 2013 repair. In response to the team’s concern, the licensee rescheduled the repair to an earlier date (September 2013).

6. The ‘1A’ RHR HX inspection performed on 10/31/12, identified a large number of clam shells partially blocking the HX tubesheet. The presence of shells large enough to block the HX tubes indicated station’s NRC GL 89-13 program (e.g., intake bay cleaning and inspection, periodic moluscicide chemical treatment, and pump suction strainers, and HX differential pressure monitoring) was not fully effective at preventing macrofouling of the RHR HXs.

7. Several RHRSW pipe supports were observed to have been removed or disconnected. However, the current pipe stress analysis had been updated to evaluate the removed supports and the analysis was determined to be acceptable. The structural calculations for the Unit 2 ‘C’ CS pump and motor, B2 RHRSW pump & motor, and the Unit 2 ‘B’ RHR pump and motor were adequate.

8. An example of good coordination among engineering disciplines was provided by the calculations performed for the new RHRSW pump impellers, as they had been updated to incorporate the effect on the emergency diesel generator loading calculations.

9. The RHRSW pump pit inspection procedure did not record as-found conditions to support evaluation of inspection periodicity (PER 727624). Additionally, the inspection was performed at 5 year intervals instead of the procedure-specified 2 year interval because there was no permanent diver access to the pit. The licensee was slow to address this longstanding degraded condition (PER 724187). Installation of a pit access for divers was scheduled for July 2013.

10. Both the #1 and #2 screenwash pump discharge rubber expansion joints were found notably degraded (i.e., misaligned, bulged, cracked)(PERs 727685, 727688). Preventive maintenance strategies were not developed for mechanical piping system expansion joints (PER 723062).

11. Red tape was found covering local position indicators for several CS valves (SRs 729085, 729087).

12. A longstanding trend of EECW check valves being found not fully closed during their biennial valve position indication test existed (SR 723619).

13. Scaffolding erected near emergency diesel generator piping and components did not meet procedure requirements. In response to the scaffold clearance issue identified by the team, engineers evaluated the scaffold and determined it did not adversely affect EDG operability.

5.5.3.3 Assessment Results: The team concluded that the Systems Structures or Components (SSCs) associated with containment heat removal were adequately maintained in proper configuration and material condition to perform their designed safety functions. Procedures, testing, maintenance, and drawings were adequately implemented and updated to provide reasonable assurance of SSC operability. Notwithstanding, the team observed that the licensee accepted longstanding degraded conditions without pursuing timely resolution through the CAP (i.e., residual heat removal service water (RHRSW) and emergency component cooling water (EECW) pump differential thermal expansion, infrequent and incomplete GL 89-13 RHRSW pump pit inspections, cold weather protection for RHRSW and EECW pumps and piping, EECW check valve closure, macrofouling of RHR and EECW HXs, equipment labeling). These conditions challenged both equipment configuration and reliability. The team noted recent licensee progress to identify, fund, and schedule actions to correct several of the longstanding degraded equipment conditions (e.g., RHRSW/EECW pump replacement project, RHRSW pump pit access modification, GL 89-13 inspection procedure revisions and training). The team concluded that continued management focus on fundamentals such as equipment labeling, cold weather protection, and equipment tagouts was necessary to support sustainability of continued improvement in the area of equipment configuration control. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement in this FPA.

5.5.4 **Configuration Observations**

5.5.4.1 Inspection Scope: The team assessed the effectiveness of corrective actions for deficiencies involving Configuration Control. Specifically, the team reviewed FPA-14 PER 543132 Design and Configuration Control, configuration control issues identified in QA audit reports SSA 1008 & SSA 1209, and selected configuration related issues addressed in the corrective action program between January 2010 and May 2013. The team reviewed one temporary modification package TACF 0-10-004-067 to ensure proper installation (configuration control adherence) in accordance with the design information for that modification.

The team reviewed and evaluated the programs and controls (tracking systems) in place for maintaining knowledge of the configuration of the fission product barriers including: containment leakage monitoring and tracking, containment isolation device operability (valves, blank flanges), and reactor coolant system (RCS) leak-rate calculation and monitoring. The review included the control room daily documentation of RCS identified and un-identified leak-rate values and calculations for all three Units to ensure the Technical Specification RCS operational leakage requirements were not exceeded. The team also reviewed the RCS Leakage performance indicator three year trend data for all three units.

In addition, the team verified that the RCS containment drywell sump liquid monitoring systems and drywell atmosphere gaseous monitoring systems met the TS operability requirements for the RCS leak detection instrumentation functions. The team reviewed the RCS dose equivalent iodine specific activity performance indicator three year trend data for all three units. The team also evaluated a sample of primary containment isolation valve (PCIV) TS surveillance test isolation closure times and allowable valve leakage rates to ensure the PCIVs met all TS required limits. The sample included a detailed review of main steam isolation valve (MSIV) test data for all three units.

The team reviewed the results of the plant specific PRA risk model relative to the system(s) selected to determine if the PRA risk model has been maintained to reflect actual system conditions regarding system capability and reliability.

5.5.4.2 Observations: No Findings of significance were identified.

Overall, the team observed that vertical slice system components, which were identified in Section 5.1.1 of this report, were properly positioned, operated, and maintained to support their capability to reliably perform their design safety functions. Procedures reviewed and plant activities observed properly returned equipment to its intended position. Some occurrences of deficient configuration control were observed. Examples of the team's observations are discussed below:

The team identified scaffolding erected too close to EDG piping during vertical slice system walkdowns and degraded cold weather protection for RHRSW/EECW air release valves (ARVs). Each condition had potential to adversely affect safety system performance. The details and regulatory aspects of these issues were provided in Sections 5.5.3 and 6.1.4.2.1 respectively.

Equipment tagging and protected equipment controls associated with maintenance and surveillance testing of the 'A1 and 'A2' RHRSW pumps on May 6, 2013 were deficient and adversely affected RHRSW pump availability. The details and regulatory aspects of this issue were provided in Section 5.2.2.2.1.

Commercially procured bearings were not properly dedicated for safety-related use prior to installation on a LPCI motor generator set. Partially implemented design changes to the Unit 2 CS and Unit 2 RHR room coolers were not properly evaluated prior to making further changes to the systems. Each issue had the potential to adversely affect safety-related component reliability or availability.

The details and regulatory aspects of these issues were provided in Sections 5.1.3.2.1 and 5.1.3.2.2 respectively.

Corrective actions (PER 543132) implemented to reduce the backlog of design change notices, vendor manual changes, and drawings were effective. Updated design documents and vendor manuals reduced the likelihood of configuration errors.

A Unit 2 control room ceiling light diffuser in the Unit 2 control room was left unsecured for approximately 6 days following its relocation to support a control room ventilation surveillance test. This posed a missile hazard to control room equipment as discussed in Section 5.2.4.2.1.

Procedure IPDA-025, used several times per day by operators to flush circulation water bearing coolers, did not contain instructions to flush the strainer with temporary alteration TAF 1-09-001-023 in place. The procedure had not been updated when the temporary alteration was installed. Operator use of the procedure without revision was a challenge to configuration control. The regulatory aspects of this issue were determined to be minor in accordance IMC 0612.

Operational RCS leakage (both identified and unidentified) was maintained far below the TS allowable limits established to ensure that the integrity of the reactor coolant pressure boundary was maintained. The low RCS leakage was indicative of good configuration control and maintenance practices.

Reactor coolant activity was maintained well below the TS limit. This indicated that operational parameters (e.g., RCS pressure, temperature, chemistry) were maintained as specified by design to maintain fuel pellet barrier integrity.

Vertical slice systems (RHR, CS, RHRSW, and EECW), trains, and components were properly modeled in the plant-specific PRA in accordance with actual as-built plant configuration. Correct modeling of the vertical slice systems in the PRA supported appropriate risk-informed design making for activities such as the scheduling of planned maintenance and testing.

5.5.4.3 Assessment Results: As previously documented in Section 5.1.3, Design and Configuration Control, the team concluded the licensee's ACE for PER 543132 reasonably evaluated the causes of configuration control challenges and established appropriate corrective actions. Actions to reduce design document backlogs (e.g., controlled drawings, procedures, vendor manuals, design basis documents) were effective. The design document backlogs were reduced from their 2012 high, by 80 percent at the end of this inspection. Actions were in place to completely eliminate the backlog by the end of 2013. Overall, the configuration of vertical slice systems and components was properly maintained to support their design safety functions. The team identified several configuration deficiencies as described above; however, the team determined these examples resulted from deficient licensee staff attention to detail when performing work or area walkdowns, rather than a programmatic breakdown of configuration controls. Configuration errors identified by the team were entered into the CAP for correction.

The configuration of fission product barriers was properly maintained and the operating staff properly implemented procedures to monitor fission product barrier effectiveness. Vertical slice systems and their components were properly modeled in the plant-specific PRA, thereby correctly representing the as-built configuration and supporting accurate assessment of plant risk when components were removed from service to support online maintenance and testing. The team concluded the licensee had made significant progress towards addressing issues pertaining to configuration control and that the performance metrics established to monitor the health of configuration control were adequate for the licensee to maintain a sustainable path towards further improvement in this area. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement of this FPA.

5.5.5 **Summary and Conclusion**

The team independently determined the licensee had appropriately identified the causes of the Work Management FPA and developed a comprehensive set of corrective actions. Although some improvement was observed, performance metrics for PMs in grace, PM deferrals, and work planning indicated that corrective actions developed to address the work management process were not yet effective. Deficient procedure quality, procedure compliance, and inconsistent questioning perspectives when faced with uncertainty were underlying factors which adversely influenced performance. The team concluded continued focus on adherence to implementation of the IIP and the work management process actions was warranted to achieve substantial and sustained performance improvement.

The configuration of fission product barriers was properly maintained and the operating staff properly implemented procedures to monitor fission product barrier effectiveness. In general, material condition and configuration were appropriate for the systems inspected as a part of the vertical slice review to reliably perform their designed safety functions. The team determined continued management focus on fundamentals such as equipment labeling, cold weather protection, and equipment tagouts was necessary to support sustainability of continued improvement in the area of equipment configuration control.

The licensee developed an action plan entitled, Safety Culture Continuous Improvement and Sustainability Plan, PERs 743724 and 757451 included actions to address worker behaviors, procedure quality, work management, and field observations. The team concluded the licensee had made significant progress towards addressing issues pertaining to configuration control and work management. Additionally, actions identified in the IIP as supplemented by the Safety Culture Action Plan, and performance metrics established to monitor the health of configuration control and work management were adequate for the licensee to maintain a sustainable path towards further improvement in this area. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement of this FPA.

6 Licensee Controls for Identifying, Assessing, and Correcting Performance Deficiencies

6.1 Problem Identification and Resolution

6.1.1 Inspection Overview

All nuclear power plants are required by 10 CFR 50, Appendix B, Criterion VXI, Corrective Action, to implement a program for identifying and resolving conditions adverse to quality associated with safety-related equipment, procedures and programs. Through BFN's Integrated Improvement Plan development, BFN reviewed the programs used in identifying and resolving conditions adverse to quality, and identified deficiencies in several processes that support the ability of the station to identify and resolve conditions adverse to quality, including: Leadership and Management Oversight, Resource Management, Corrective Action Program, Governance and Oversight, Continuous Learning Environment, Employee Concerns Program, and Independent Oversight. As a result of these deficiencies, BFN characterized each of these attributes as a fundamental problem area, evaluated each through a cause analysis, and developed corrective actions to correct the identified causes and related issues.

The team reviewed the corrective actions BFN developed to address the causes of the deficiencies, the adequacy of the corrective actions in addressing the cause, the effectiveness of the implemented corrective actions, and the performance indicators developed to measure the level of performance. The team reviewed the above actions to verify BFN developed and implemented corrective actions that arrested the declining performance in their ability to identify, evaluate, and correct conditions adverse to quality. For the actions that the team reviewed above, the team conducted interviews of site personnel and management, observed field activities involving operations, engineering, and maintenance, reviewed program procedures, attended meetings, and evaluated risk significant samples of program documents to assess the breadth and depth of the implementation of the corrective actions and the effects of the corrective actions on daily plant operations.

6.1.2 **Management and Leadership (FPA 1 - MLS)**

6.1.2.1 Inspection Scope: The team assessed the licensee's fundamental problem area, FPA 1, regarding "Leadership and Management Standards," to determine whether it was sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

Specifically, the team evaluated the following:

- The licensee's management and leadership standards as established in their Nuclear Operating Model (NOM),
- The applicable procedures and other documentation containing the licensee's standards and expectations,
- The QA, external and internal audits and assessments of leadership standards,
- The licensee's response and associated actions for related industry operating experience,
- The licensee's succession planning process, and
- The effectiveness measurement tools, such as observation programs.

The team observed several of the licensee's meetings and activities to evaluate completion in accordance with the licensee's procedures and the adequacy of the expectations and standards demonstrated. Specifically the team observed the following:

- Corrective Actions Review Board meetings,
- Departmental CARB meetings,
- Fleet daily plant status and priority teleconference,
- Weekly Fleet Peer Departmental teleconference,
- Station Senior Leadership meeting,

- Various plan of the day meetings, and
- PER Screening Committee meetings.

The team interviewed selected members of the licensee's leadership team from the first level supervisors. These interviews focused on the communications and reinforcement of BFN's expectations and standards; how BFN was verifying their expectations were being met and will continue to be met in the future; how the leadership team was monitoring expectations and standards within the leadership team; and BFN's approach for the willingness to accept and deal with problems. In addition, regarding management and leadership standards, the team compared interview responses with licensee procedures as guidance and performed in-field observations of various levels of the leadership team including first line supervisors to assess implementation and enforcement of standards and expectations. Interviews were completed with the following positions:

- BFN Site Vice President,
- BFN Plant Manager,
- BFN Site Quality Assurance Manager,
- BFN QA assessor,
- BFN Maintenance Department Manager,
- BFN Instrument Maintenance Supervisor,
- BFN Director of Engineering,
- BFN Essential Emergency Cooling Water System Engineer,
- BFN Nuclear Supply System Engineering Manager,
- BFN Corrective Actions Program Manager,
- BFN Chemistry Department Manager,
- BFN Performance Improvement Manager,
- BFN Operations Department PER and Human Performance Coordinator,
- BFN Operations Department Manager,
- BFN Work Control Manager,
- BFN Operations Unit Manager Work Control Center, and
- BFN Human Performance Manger

The team evaluated the licensee's RCA for FPA 1, "Management and Leadership Standards." Specifically, the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's FPA adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's IIP and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

Documents reviewed are listed in the Attachment.

6.1.2.2 Observations: No Findings of significance were identified.

The team reviewed BFN's management and leadership standards as established in the TVA fleet Nuclear Operating Model, and the applicable procedures and other documentation containing the licensee's standards and expectations. The NOM provided specific fleet guidance with respect to standards, leadership commitment and fundamentals, organizational philosophy, code of conduct, alignment, accountability, leadership and employee development, and succession planning.

The team reviewed TVA Corporate procedures that provided specific roles and responsibilities, program implementation, feedback mechanisms, and performance tracking guidance. The team reviewed procedures including:

- BP-289, Rev. 0000, "Leadership Performance Management,"
- NPG-SPP-11.17, Rev. 0001, "Leadership Assessments,"
- NPG-SPP-11.19, Rev. 0001, "New and Transitioning Leaders," and
- NPG-SPP-11.18, Rev. 0000, "Deep Dive Program."

The team also reviewed supporting documentation including the BFN Senior Leadership Playbook, Rev. 3, the ePOP observation program, and station meeting and stand-down presentations. The team determined that in, general, the guidance provided by the NOM and associated procedures and documentation supported an organizational and programmatic structure for management and leadership standards at BFN.

With respect to succession planning and development, the team noted that the TVA Corporate procedures in place provided a formal process for selection, development, and continual assessment of site leadership. The team also noted that personnel performance appraisals included direct comparisons to site fundamentals and the site was utilizing additional tools such as specific succession planning methods to plan and develop personnel for different leadership positions at BFN. The team determined that, in general, the guidance and tools utilized for succession planning supported a management and leadership structure for current and future BFN management teams and enabled BFN to remain integrated into the TVA Corporate model.

The team reviewed several cause analysis and corrective actions associated with management and leadership standards, which were associated with PERs 475878, 516437, 516455, 668535, 668531, and 655461.

The team reviewed BFN's RCA for PER 516437, Rev. 0003, "Management and Leadership Standards." The licensee concluded that there were two root causes associated with leaders at all levels not effectively modeling or reinforcing high standards: 1) BFN leaders were not aligned around a common set of standards and goals (picture of excellence) such that the leadership influence required to change behaviors had not been effective and efforts to improve leadership capability had not achieved desired results; and 2) accountability had been ineffectively implemented at BFN, which had resulted in consequential events and challenges to nuclear safety. The team also reviewed the associated corrective actions to prevent recurrence (CAPRs) and corrective actions (CAs) for the root cause.

The team reviewed the three CAPRs that resulted from the RCA for PER 516437. The first action, CAPR-01, was using the NOM as an organizational management model by which external contracted individuals provided coaching to BFN leaders with an intrusive focus on the strategic plans to ensure management alignment in ownership and accountability. The second, CAPR-02, was for the Site Vice President to implement a policy that focused BFN leaders on the standards and expectations contained in the NOM and industry guidance. This policy was called the BFN Senior Leadership Playbook. The third, CAPR-03, was to implement a leadership assessment to evaluate supervisor and management alignment to the TVA nuclear fleet leadership fundamentals. The associated CAs included development and implementation of a first line supervisor peer team, Compliment and Concerns (CC) alignment meetings, an observation schedule, NOM/GOES seminar training at BFN, revised GOES metrics, and multiple assessments to evaluate effectiveness of NOM and GOES implementation. Additional CAs included procedure quality improvement initiatives and CAP program improvements.

The team determined that the corrective actions focused on executive and senior management alignment and standards improvement and specifically, the three CAPRs focused primarily on aligning and coaching the BFN senior leadership team. For CAPR-01, there were 38 people involved with a consultant supported alignment initiative; only two were first line supervisors (FLSs). The alignment initiative focused on improving behaviors and overall performance by coaching and evaluating leadership qualities at the management level. The BFN approach was specifically designed to be a top-down driven initiative. In addition, this action encompassed multiple sub-actions including a change management plan, multiple communications strategies, meetings between various levels of the SLT, and applicable TVA Corporate procedure revisions.

For the CAPR-02 regarding the development of the BFN Senior Leadership Playbook, although the policy was communicated to the first line supervisors during station meetings, the focus still was at the SLT level where each of them had to sign and commit to the guidance of the new policy. The FLSs had to sign only that they attended the presentation meeting. The third CAPR, CAPR-03, required departments to implement department level weekly alignment meetings in a Compliments and Concerns format. The completion documentations for these meetings noted the departments and personnel who attended the meetings and a summarized the meeting discussions. However, from the documentation, it was not clear that issues were entered into CAP or how and if they were resolved. Moreover, the team noted that the Compliment and Concerns alignment meetings were not administered with the purpose of aligning first line supervisors around a common set of standards and goals (picture of excellence).

The team determined that for RCA 516437, the identified root causes were adequate, and acknowledged that the licensee performed extensive actions to align management and leadership standards as documented in multiple PERs listed above. The team also noted based upon direct observations, interviews, and actions taken by the current senior management team, with respect to management and leadership standards of the SLT, that the actions taken were reasonable and adequate. However, the team identified that the actions did not specifically target the mid/lower level management, supervisors, and workforce alignment around a set of standards and goals (picture of excellence) to change behaviors or the use of accountability at the supervisor or peer-to-peer workforce level. The RCA actions implicitly credited changes that would occur to this layer of the organization through a top-down implemented change process. The team also noted that many of the actions were already being performed as a result of other causal analyses in the areas of GOES and human performance. The team was concerned with the lack of a strategic focus to achieve alignment of first line supervisors and working level individuals around a common set of standards and goals (picture of excellence). The team discussed this with the licensee, after which the licensee generated an action plan to address the issues entitled Safety Culture Continuous Improvement and Sustainability, PERs 743724 and 757451.

The team reviewed the licensee's corrective actions for industry experience associated with "Engaged, Thinking Organizations," issued in 2010, specifically as it related to the licensee's analyses of their first line supervisors and oversight roles in conducting plant activities and their workforce behaviors. The team noted that BFN did perform a supervisor assessment in January 2011, in which the results indicated that BFN supervisors were not always exhibiting the correct oversight and standards in the field even though their evidence indicated that the FLSs knew what appropriate behaviors and standards were. In addition, the team reviewed the leadership development training program description (LD-TPD), including the revision made as a result of a corrective action from RCA 542377 for GOES. The training material for FLSs and above included lesson plan information for this industry experience. The team concluded that overall, the actions taken by the licensee to identify and correct first line supervisor standards and oversight were ineffective or not institutionalized into the grain of the supervisor culture. The team's conclusion was based upon multiple examples identified while observing supervisors not reinforcing standards and not providing adequate oversight while performing routine duties and responsibilities. Notable examples of a lack of supervisor oversight in the field were when supervisors observed inappropriate acts by their staff, they did not recognize and/or justified the incorrect acts or behaviors from their workforce and took no action; and they did not coach and correct poor work practices. These issues were discussed in detail in Sections 4.5, 5.2.2, 5.2.4, and 6.1.5, the team discussed this with the licensee, after which the licensee generated an action plan to address the issues entitled Safety Culture Continuous Improvement and Sustainability, PERs 743724 and 757451.

The team reviewed external and internal audits and assessments of leadership standards to determine the licensee's progress and effectiveness in implementing the NOM and associated guidance procedures. It was noted that two recent audits identified that the lack of overall workforce knowledge with respect to the purpose and use of the NOM. Specifically QA audits BFN-PI-S-13-031, dated March 4 - 8, 2013, and CRP-FA-S-13-002, were performed as a result of corrective action 542377-012. The purpose of these audits was to assess the implementation and sustainability of the NOM and GOES. The audits concluded that the corrective actions had not been fully effective and noted that there had been a lack of reinforcement and understanding of the NOM specifically at levels of FLS to mid-level management. The audit deficiencies were documented in SRs 690808, 691413, and 691414 and were rolled up into PER 693148, "Ineffective Corrective Actions with ACE 542337." The team reviewed ACE 693148 and the associated corrective action. Additional details regarding the audit findings and the team's review was provided in Section 6.1.5, Governance and Oversight, of this report.

The team recognized that the licensee emphasized the value of implementing the NOM/GOES framework. However, based on a review of the causal analyses, corrective actions and audit results, the team identified pertinent items that were not addressed in the IIP regarding Leadership and Management Standards or where the corrective actions were found to be ineffective, specifically in the areas of: 1) Ensuring work attitudes match their behaviors; 2) In-field oversight; and 3) Strategic approach to human performance improvement. These issues were addressed by the licensee in the Safety Culture Continuous Improvement and Sustainability Plan. Moreover, the team recognized that the implementation of the NOM and GOES framework at BFN warrants significant management oversight and involvement to result in long-term sustainability.

Related to the review of the licensee's performance measurement tools, the team observed inconsistencies in the individual department usage of the observation program as a mechanism to improve workers' behaviors and accountability, including the supervisors' skill sets and coaching abilities. After review of the corrective actions and interviews were performed of site and human performance managers, the team concluded that the BFN corrective actions were not comprehensive enough to target and correct the latent issues of workforce and supervisors' work practices and behaviors, which had continued to result in numerous low level regulatory significant human performance errors and events. The team concluded that the corrective actions lacked a systematic approach to address this issue on a broader scale than at individual department levels. The team discussed this issue with the licensee and explained that by not taking a systematic approach, the IIP performance improvement initiatives may plateau with respect to safety culture and workforce behaviors before substantial and sustainable performance improvement is achieved. The licensee responded by development of an action plan entitled, Safety Culture Continuous Improvement and Sustainability Position, PERs 743724 and 757451.

The team observed several performance deficiencies and other issues on the part of the BFN staff and in some instances where the applicable first line supervisors missed the opportunity to identify and or correct the issues. Based on a historical review of BFN performance, the station history in these areas had been below industry standards and expectations. Different types of issues were identified related to standards and expectations not being met, such as the staff failed to follow written instructions, the staff recognized the written instructions were unclear yet continued on in the face of uncertainty, and in some cases failed to enter issues when warranted in the CAP. Other examples were the staff and or supervisors failed to demonstrate a challenging questioning attitude or simply did not recognize the importance of related issues or the consequence of the decisions they made. Based on the insights obtained through the team safety culture assessment, the team recognized the other cultural issues provided additional challenges to the licensee. Specifically, the uniqueness of BFN Station has been internalized by the staff as a basis that the industry standards and expectations did not apply to BFN (Section 4.5). These issues were discussed with the licensee who concurred with the team's observations. The team discussed this with the licensee, after which the licensee generated an action plan to address the issues entitled Safety Culture Continuous Improvement and Sustainability, PERs 743724 and 757451.

6.1.2.3 Assessment Results: The team observed that in general, the guidance provided by the Nuclear Operating Model and associated procedures and documentation supported an organizational and programmatic structure for management and leadership standards at BFN. In addition, the team observed that the guidance and tools utilized for succession planning supported a management and leadership structure for current and future BFN management teams and enabled BFN to remain integrated into the TVA Corporate model.

The team concluded that the IIP had performed extensive actions to align the BFN Senior Management team around a common set of standards and goals (picture of excellence) and implement accountability. However, the team identified the licensee did not utilize this same approach with mid/lower level management and first line supervisors. In addition, the team observed multiple observations during the inspection where supervisors performed inappropriate acts; did not recognize and in some cases justified incorrect acts or behaviors from their workforce; and did not coach and correct poor work practices. The team concluded that the IIP did not have a systematic approach to address this issue and long-standing wide spread low level human performance and culture issues, such that the station would comprehensively target and correct the latent issues of workforce and supervisors' work practices and behaviors.

The team found that the IIP emphasized the value of implementing the Nuclear Operating Model and the Governance, Oversight, Execution and Support framework. However, for the Nuclear Operating Model and the Governance, Oversight, Execution and Support framework to be institutionalized at BFN, this will warrant significant management oversight and involvement. The team determined that the IIP warranted revision to ensure that substantial and sustainable performance improvement would be achieved. The licensee promptly responded with corrective actions to address each of the areas in the IIP that warranted revision, which the team found to be reasonable.

The team concluded that the licensee's actions were sufficient to prevent a decline in safety. The team also concluded that implementation of the corrective actions in place and completion of the remaining corrective actions from the IIP is essential for continued sustainability and substantial improvement of this FPA.

6.1.3 **Resource Management (FPA 3 - RM)**

6.1.3.1 Inspection Scope: The team assessed the licensee in multiple areas related to Resource Management to determine whether it was sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The team assessed whether the process for allocating resources provided for appropriate consideration of safety and compliance, the management of maintenance backlogs, and reduction of work-arounds. Specifically, the team reviewed maintenance procedures to ensure that processes were in place to provide adequate resources to perform corrective, preventative, and elective maintenance. The team reviewed maintenance procedures to ensure that maintenance backlogs and operator work-arounds were being adequately addressed and managed. The team also reviewed corrective action program data for trends related to resource allocation and assessed the results of effectiveness reviews associated with resource allocation related corrective actions. Additionally, the team reviewed resource allocation related performance metrics to verify improving performance or adequacy of the associated IIP and that corrective actions taken in response to past problems were adequately incorporated into the licensee's IIP processes to enable sustainability.

The team reviewed a sample of work packages to assess whether documentation was complete, understandable, and accurate. Additionally, the team reviewed maintenance and surveillance procedures to assess whether they were adequate to accomplish the work with the resources allocated.

The team assessed the licensee's use of overtime in the Operations Department. Specifically, the team observed licensed operator training in the simulator on two occasions for unannounced simulator scenario\event response related to recent plant events. The team also reviewed the simulator(s) fidelity compared to the plant control rooms, reviewed the simulator discrepancy backlogs and significance of the issues. Additionally, the team reviewed training and personnel qualifications for SRO's and RO's to assess whether they were adequate and appropriate to support safe plant operation.

The team reviewed engineering backlogs, engineering staffing levels, associated procedures, and interviewed engineering management personnel to assess whether the licensee was aware of the size of engineering workload backlogs, had prioritized work consistent with risk significance, had tools or methods to track and manage engineering workload, and had established appropriate engineering resources to support safe plant operation. While the review was station-wide, the team focused on engineering backlog items associated with the vertical slice systems. Engineering backlogs and metrics reviewed included the following:

- Environmental qualification (EQ) evaluations,
- Engineering change package (ECP) open,
- Vendor manual (VM) updates,
- Design drawing updates,
- Calculation updates,
- Corrective action program (CAP) backlog.

In addition, the team evaluated the licensee's apparent cause analysis related to the licensee's fundamental problem area 3, "Resource Management". Specifically the team evaluated: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) that the related licensee's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selected corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

6.1.3.2 Observations: No Findings of significance were identified.

The team evaluated the licensee's causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee's program, that it used a thorough and comprehensive method in determining the causes, contributing causes, extent of cause, and extent of condition. The team assessed that the corrective actions that were both implemented and planned were reasonable and addressed the identified causes.

The team identified the following observations related to resource management:

- The use of operations overtime has been reduced over the past 3 years due to completion of initial licensed operator and non-licensed training programs. There were additional initial licensed operator training classes in progress, and future classes planned. These new operators would fill openings caused by the licensee efforts to improve station performance by transferring qualified operators to other departments across the site.

- BFN continued to use SROs for limited plant equipment operation such as the RPS, feedwater heater level control, and reactor recirculation system manipulations. The corrective action planned to address this issue was to schedule qualification training for the ROs to complete qualification cards for the three systems currently operated by SROs. The Operations Manager did not have a projected completion date for this issue.

- BFN Operations personnel have stated that equipment was tagged out of service and then returned to service without any work being performed on the equipment which strained operations resources.

- The age of design backlog items for vertical slice systems was excessive, with several dating back to 1995. BFN estimated the total volume of engineering design backlog items would be approximately 5 years of work if performed by BFN staff. Actions identified in the IIP included hiring contactor resources to work down the engineering design backlog (i.e., the first five categories of backlogs listed above) and revision of fleet modification processes to ensure future ECP closure documentation was included in work scope performed by contract labor rather than assigning this to onsite BFN engineering staff. The team verified these actions were implemented and at the close of this inspection, approximately 80 percent of the design backlog items had been completed.

- The engineering CAP backlog was large (approximately 2300 items) and slowly increasing at the close of this inspection period. The most recent growth was primarily due to BFN staff implementing the IIP actions and as a result more issues were identified and entered into the CAP. The BFN quality assurance staff had written Level 1 and Level 2 escalation letters in 2012 and 2013 respectively, focused primarily on the large engineering backlog. Engineering staffing level had declined to 120 engineers in 2011, which contributed to large backlogs. The team reviewed a sample of the CAP backlog items for significance and noted it contained several safety significant issues (e.g., RHRSW pump replacement, RHRSW inspection pit access, and emergency diesel generator heat exchange fouling). Interim actions had been implemented for each of these issues and actions for permanent resolution were scheduled for completion in a time commensurate with safety significance.

- The majority of engineering CAP items were assigned to BFN engineering staff, rather than contractors, for resolution. In 2011, the station had 120 engineers. The licensee determined this was not sufficient staff to perform the assigned engineering work. From 2011 to May 2013, BFN increased engineering staff to 180 engineers. The team discussed authorized staffing plans for 2013 - 2015, training plans, work load tracking and scheduling tools, and tracking metrics for work backlogs with the Engineering Director. Staffing authorizations included allowances for the training and qualification of new staff, and over-hire authority to compensate for anticipated attrition.

- BFN identified multiple observations regarding the lack of resources and insufficient time to complete CAP obligations. This issue was being addressed by the CA's for PER 475878 which will restructure the CAP roles/responsibilities for BFN's staff.

6.1.3.3 Assessment Results: The team determined that performance in the areas of critical work order backlogs, vendor manual and drawing backlogs, and design change notices (DCNs) backlogs associated with engineering performance have improved. The team also determined that the licensee had demonstrated commitment to maintenance backlog reduction in the areas of On-Line Corrective Maintenance Critical WOs, On-Line Deficient Maintenance, and the Safety System Reliability Plan Work-Off Curve as evidence by the backlog numbers trending in the positive direction. Additionally, the team determined that BFN has made progress to quantify and track engineering work load, to identify the needed quantity and quality of engineering staff, and to hire and maintain appropriate quality and quantity of engineering staff.

While the licensee's corrective actions in the FPA of Resource Management have made advancements toward effectiveness, the team observed areas where challenges still exist. Specifically, the team observed resource strains in the operations department, for performing operability determinations and especially in work week schedule preparation. The team recognized that the current use of contractors in the Engineering Department produced positive results. However, sustaining the gains achieved through the use of a contract workforce were contingent on work that may be transitioned to BFN staff at the current staffing levels. Additionally, the team found that BFN was experiencing an increase in corrective action backlogs. The licensee entered this issue into the CAP as PER 475878 and is monitored by the IIP performance metrics which require corrective actions when thresholds are reached. The team recognized that backlog reduction would likely challenge BFN's resource management. As a result, the team concluded that continued licensee implementation of actions in the FPA of Resource Management is warranted to achieve substantial and sustainable performance improvement.

The team concluded the licensee's actions were sufficient to prevent a decline in safety. The team also concluded that Implementation of the corrective actions in place and completion of the IIP remaining corrective actions is essential for continued sustainability and substantial improvement of this FPA.

6.1.4 **Corrective Action Program (FPA 5 – CAP)**

6.1.4.1 Inspection Scope: All nuclear power plants are required by 10 CFR 50, Appendix B, Criterion VXI, Corrective Action, to implement a program for identifying and resolving conditions adverse to quality associated with safety-related equipment, procedures and programs. Through BFN's Integrated Improvement Plan development, BFN reviewed the programs used in identifying and resolving conditions adverse to quality, and identified deficiencies in several processes that support the ability of the station to identify and resolve conditions adverse to quality, including: Leadership and Management Oversight, Resource Management, Corrective Action Program, Governance and Oversight, Continuous Learning Environment, Employee Concerns Program, and Independent Oversight. As a result of these deficiencies, BFN characterized each of these attributes as a fundamental problem area, evaluated each through a cause analysis, and developed corrective actions to correct the identified causes and related issues.

TVA Nuclear Power Group identified in 2011 that the CAP was not being consistently utilized to document, screen, analyze, and correct conditions adverse to quality. TVA NPG identified the root cause as a failure to align TVA's organization around standards of excellence in the corrective action program. BFN also identified, in 2011, through an additional root cause analysis that there were weaknesses in the CAP cause evaluations where the timely resolution of long standing plant and regulatory issues have been challenged. BFN identified the root cause as inadequate development and dedication of cause analysts capable of producing high-quality and timely products, and management had not consistently supported the cause evaluation process. As a result of these two root cause analyses described above, BFN established the corrective action program as a fundamental problem area, performed a gap analysis between the fundamental problem area problem statement and the two root cause analyses above to verify that all issues associated with the CAP were adequately addressed, and developed corrective actions.

The team evaluated the two root cause analyses and the gap analysis related to BFN's fundamental problem area 5, corrective action program. Specifically, the team evaluated: 1) the completion of the analyses was in accordance with BFN's process; 2) that a thorough and methodical evaluation process was used to complete the analyses; 3) that BFN's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analyses were carried through into BFN's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selective corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

In addition, the team reviewed the different aspects that make up BFN's Corrective Action Program. Specifically, the team evaluated the following:

- The adequacy of the initiation threshold used by personnel at the plant for entering conditions into the corrective action program. The team performed interviews, reviewed the daily population of service requests, and conducted observations of in-plant work to determine whether the threshold for initiating a condition into the corrective action program was low enough to support a program that has sufficient regulatory margin.

- The adequacy of the screening process for conditions adverse to quality that were entered into the corrective action program. The team attended daily problem evaluation report screening committee meetings (PSC) to verify that the PSC was following all CAP program procedures, applying procedural standards in a consistent manner, and was assigning conditions a classification level consistent with their significance.

- The adequacy of BFN's PER trending program. The team reviewed a risk significant sample of PERs related with the safety relief valves, residual heat removal system service water pumps and valves, emergency equipment cooling water system pumps and valves, and RHR system heat exchangers to verify that trending was performed in accordance with BFN's procedures, and that a methodical process was used to complete the evaluation. In addition, the team verified that BFN adequately addressed conditions adverse to quality associated with these systems in the corrective action program.

- The adequacy of the formal cause analysis process. The team reviewed several lower and upper-tier apparent causes that were performed as a result of conditions adverse to quality being identified within the corrective action program to verify that procedures were followed, a formal method was used to develop the cause, the cause identified was adequately supported by the data, and corrective actions were developed to address the cause and were implemented in a timely manner.

- The adequacy of corrective action development and implementation. The team reviewed a sample of corrective actions that were part of the fundamental problem areas, as well as PERs, that involved human performance and risk significant safety-related systems. The team used these samples to verify that the corrective actions adequately addressed the causes and corrected the conditions adverse to quality, and the process used was in accordance with procedures.

As a method of measuring performance in the fundamental problem areas, BFN established performance indicators with quantitative criteria. The team reviewed BFN's performance indicators for the corrective action program to ensure the metrics would effectively measure the appropriate breadth and depth of the program, and assess whether BFN's performance would be sustainable. The team also reviewed the performance indicators basis documentation inputs and analysis to verify accurate metric results and conclusions.

6.1.4.2. <u>Observations and Findings:</u> One Finding of very low safety significance was identified.

6.1.4.2.1 **Deficient Design Control for RHR Service Water Freeze Protection**

Although this Finding was documented under the FPA of CAP, the team also determined this issue revealed an issue related to the FPA of Procedure and Instruction Quality (Section 5.3.2) and Technical Rigor (Section 5.1.4). Procedure 0-GOI-200-1, "Freeze Protection Inspection," Revision 71, was deficient because it did not specifically direct verification that insulation was installed on valves or proper closure of heat trace control circuit cabinets (SR 731375). The initial licensee evaluation of the RHRSW air relief valve (ARV) freeze protection deficiency performed in SR 727908 was not rigorous, because it did not address the potential for ice to block the ARV vent path, the potential of a resulting water hammer transient to damage the RHRSW system, worst case river level and RHRSW check valve leakage conditions, adequacy of RHRSW ARV freeze protection, or the potential misclassification of the ARV as non-safety-related (SR 732519). This Finding was also related to the general aspect of Configuration Control as described in Section 5.5. The regulatory significance of these performance elements was addressed in the Finding below.

6.1.4.2.1.a Introduction: The team identified a Green non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, Design Control, involving the failure to maintain adequate design control measures associated with residual heat remove service water system freeze protection. Specifically, the team identified that freeze protection was not installed on two RHRSW pump air relief valves to maintain operability of the RHRSW system during freezing conditions.

6.1.4.2.1.b Description: On May 16, 2013, the team conducted a focused engineering walkdown of portions of the RHRSW system. The team identified that the RHRSW pump discharge piping ARVs had inconsistent freeze protection configurations. Specifically, the C2 and D3 RHRSW pumps' ARVs, 0-ARV-023-0541B and 0-ARV-023-0596B, had insulation missing such that the designed freeze protection function was not maintained.

The RHRSW system design required that an ARV assembly be provided on the main RHRSW pump discharge lines to prevent water hammer due to water column separation during pump restart following a Loss of Offsite Power event. The RHRSW pumps were deep-draft vertical pumps. The ARV provided a pathway for air to enter the RHRSW discharge piping after the pump was secured. The ARV functioned as a vacuum break, which permitted water to fully drain from the pump suction piping, back to the river without creating a vacuum in the pipe. Similarly, the ARV provided a vent path to release air from the discharge piping upon RHRSW pump start. Fluid transient design analysis determined the ARV function was critical to RHRSW system operability for Browns Ferry Units 1, 2, and 3. The ARV prevented a damaging fluid transient (water hammer) event that could impact the integrity of the RHRSW piping system integrity following a LOOP event. The RHRSW pump rooms, which include discharge piping and the ARVs, had no ceiling and were exposed to outside weather elements. The designed function of the insulation surrounding the ARVs was to maintain operability of the ARV during extended periods of extreme cold weather that could cause water to freeze in the ARV and adversely impact RHRSW safety function.

The team identified that the as-found condition of the insulation on the ARVs for the C2 and D3 RHRSW pumps did not ensure freeze protection and support RHRSW operability under all design basis conditions. The team noted that under the most limiting design basis events, the ARVs could freeze closed and disable their safety function to prevent water hammer in the RHRSW system and impact operability. The licensee entered the degraded condition into their corrective action program as SRs 727908 and 732519 and concluded that an immediate operability concern was not present due to the current warm weather conditions and recent satisfactory pump testing. Additionally, BFN performed a detailed inspection of ARVs on all 12 RHRSW pumps, and identified deficiencies on ARVs for eight pumps and entered each item into the CAP.

The team also reviewed specific opportunities for licensee identification of the freeze protection deficiency. The team reviewed system engineering walkdown records, daily operator rounds, corrective maintenance backlog records, and the most recent focused freeze protection inspection record, Procedure 0-GOI-200-1, “Freeze Protection Inspection,” Revision 71. The team determined the degraded insulation condition was not identified and/or evaluated, despite numerous opportunities. In addition, the RHR service water system freeze protection equipment was not specifically described in the freeze protection inspection procedure. The procedure instruction did not specifically direct verification of insulation on valves or proper closure of heat trace control circuit cabinets. This issue was documented in SR

731375. Based on interviews and record reviews, the team determined the degraded RHRSW pump ARV condition existed since August 31, 2012, or earlier.

The team determined that the degraded freeze protection on the ARVs was a non-conforming condition that could challenge the operability of the RHRSW system. Further, the team determined that BFN had reasonable opportunities to identify the condition through engineering walkdowns, operator rounds, and performance of the freeze protection inspection.

6.1.4.2.1.c Analysis: The team determined that failure to maintain adequate design control measures associated with the RHRSW system freeze protection was a performance deficiency. This Finding was more than minor because it adversely affected the design control attribute of the Mitigating Systems cornerstone and the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Inspection Manual Chapter 0609, Appendix A, The Significance Determination Process for Findings At-Power, the team determined that the Finding was of very low safety significance because it was a deficiency affecting the design or qualification of a mitigating system, structure or component, where the SSC maintained its operability or functionality. The team concluded that the Finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program problem identification, because BFN did not maintain a low threshold for issue identification such that this issue was identified and resolved by BFN staff during numerous previous focused inspections of the RHRSW system configuration. [P.1(a)]

6.1.4.2.1.d Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, Design Control, required in part that measures shall be established to assure that applicable regulatory requirements and the design basis for those structures, systems, and components to which the appendix applied were correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, since August 31, 2012 or earlier, BFN did not establish measures to assure that applicable regulatory requirements and the design basis of the RHR service water system were maintained. Specifically, BFN did not have measures to assure that the RHRSW ARVs freeze protection was adequate to maintain operability of the RHRSW system. Because this Finding was of very low safety significance and was entered into the corrective action program as SRs 727908, 729269, 729792, 729800, 729807, 729812, 729819, 729821, 729822, 731375 and 732519, and PER 732519 this violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy And is identified as NCV 05000259, 260, 296/2013011-15, Deficient Design Control for RHR Service Water Freeze Protection.

6.1.4.2.2 Other Observations:

The team evaluated the licensee’s causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee’s program, that it used a thorough and comprehensive method in determining the causes, contributing causes, extent of cause, and extent of condition. The team assessed that the corrective actions implemented and or planned addressed the identified causes, and were reasonable.

Based on the team's review of corrective action related documents, interviews with plant personnel and observations of plant activities, the team identified four areas related to the corrective action program warranting additional licensee management involvement and oversight. Specifically, these areas were SR initiation threshold, SR quality, PER trending, and lower-tier apparent cause evaluation quality.

<u>SR Initiation Threshold</u>

An effective corrective action program employs a low threshold for identification of conditions adverse to quality, and corrects those conditions in a manner that is consistent with the significance of the condition. The team evaluated implementation of CAP standards, by the plant staff, to determine the threshold for promptly identifying conditions adverse to quality before they become more significant conditions that could affect the ability of the plant to respond to a design basis accident. From interviews conducted with plant management, CAP personnel, plant staff, and contractors performing work in the plant, it was evident that BFN staff were able to communicate the knowledge of a low threshold for initiating SRs in the corrective action program. However, the team observed several examples of individuals not initiating an SR when the Procedure, NPG-SPP-03.1, "Corrective Action Program," required an SR to be initiated based on the definition of a condition adverse to quality. The following observations were identified:

- For surveillance Procedure 3-SR-3.3.8.2.1(B), "RPS Circuit Protector Calibration/FT for 3B1 and 3B2," the team identified three instances in that last 2 years where the "as found" value for 3B2 was outside of the "as left" tolerance and no SR was initiated to document the condition. In accordance with Procedure NPG-SPP-06.7," Instrumentation Setpoint, Scaling, and Calibration Program," Section 3.2.2.C, an instrument that requires a recalibration due to being outside of the "as left" tolerance shall be documented in an SR.

- During a review of WO 11396570, the team observed that technicians began work in accordance with the WO and subsequently lost the WO. The team identified that the technicians did not write an SR to document the lost WO. In accordance with Procedure MMDP-1, "Maintenance

Management System," Section 3.10.2.B, a WO that has had work performed and is subsequently lost is required to be documented in an SR.

- The team identified a unit identification tag for the RHRSW pump not attached to the pump. In accordance with Procedure NPG-SPP-01.3, "Housekeeping," satisfactory labeling of equipment is required. An SR was not initiated until the following day when the team questioned the condition.

- During an October 31, 2012, 1A RHR heat exchanger inspection, BFN identified the heat exchanger divider plate was degraded due to corrosion, which resulted in RHRSW bypass flow, which reduced heat removal performance. The inspection sheet used to document the inspection results was inaccurate in that it did not quantify the bypass flow or assess the effect on RHR heat exchanger operability. When this condition was observed, no SR was initiated to evaluate the bypass flow and tube blockage impact on the heat exchanger operability.

These observations were screened through the Inspection Manual Chapter 0612, and were determined to be minor. The licensee documented these conditions in the CAP (SR 717929, 7221902, 725586, and 731470).

<u>SR Quality</u>

The team reviewed the licensee's service request inputs into the CAP to ensure that issues were identified completely, accurately, and in a timely manner commensurate with their safety significance. BFN Procedure NPG-SPP-01.14, "Service Request Initiation," clearly stated the guidelines for the details to be included in SRs. The team performed a daily review of SRs entered into the corrective action program to ensure station personnel adequately implemented the procedural guidelines for SR quality. The team identified examples of SRs initiated that contained less than adequate documentation of identified issues such that timely and effective immediate operability determinations and adequate corrective actions could be performed. The team identified the following examples:

- SRs 725235, 725329 and 724970 contained insufficient detail to fully evaluate the condition identified. These SRs required additional follow-up from the applicable department performance improvement coordinator and delayed the implementation of corrective actions.

- SR 718260 stated that the high pressure coolant injection pump had a “Small leak on 1/2" tubing line that runs over top of main pump five drops per minute.” The SR provided inadequate information on the condition of the leak such that the BFN operators could make an immediate determination of operability. Therefore, the operators were burdened with pursuing additional information to support an accurate IDO.

- The team identified that mechanical maintenance had not lubricated the coupling bolts per the work order which directly impacted the required torque values for the coupling bolts. SR 727089 was initiated stating the teams’ questions on torqueing values required for the pump coupling however; the SR failed to recognize the nuclear safety or operability implications of the condition. The team identified the issue in the SR and BFN documented the issue in SR 727089.

The team evaluated each example to ensure corrective actions addressed the actual plant condition and that the operability determinations accurately evaluated the condition. The team did not identify any performance deficiencies. The licensee entered the aggregate impact of the examples identified above into SR 723714.

<u>PER Trending</u>

A fundamental element of an effective corrective action program is that the licensee effectively trends and assesses information from the CAP and other assessments in the aggregate to identify programmatic and common cause problems. Furthermore, appropriate corrective actions shall be taken to address the adverse trends in a timely manner, commensurate with their safety significance and complexity. The team identified multiple examples when BFN had performed less than adequate trending of the CAP such that the aggregate impact of deficiencies were not identified and evaluated. In addition, the team identified examples where BFN had not effectively and consistently coded PERs problem for future trend analysis.

The team performed a vertical slice assessment of all PERs written against the safety relief valves, residual heat removal service water and emergency equipment cooling water pumps and valves, and RHR heat exchangers for the last 2 years. The team identified examples where the licensee failed to identify and evaluate the aggregate impact of common cause deficiencies. Specifically, the team identified that six PERs had been written to document through wall leaks in the EECW system piping and a trend PER had not been initiated to understand the aggregate impact. Also, the team identified that nine PERs were written to document failures of RHRSW and EECW check valves and BFN had not previously identified and documented the trend in an SR. The BFN PER trend code analysis process was accomplished on a cognitive basis. This program relied on significant attention from station personnel to identify opportunities to perform PER trend code analyses and allowed for trends to be missed due to human performance inadequacies. In both examples, BFN wrote an SR to document the trends (SR 720914, SR 723619).

The team identified that the station continued to experience issues in the consistent coding of PERs in the CAP and the effective analysis of those trend codes. Specifically, the PER coding process Procedure NPG-SPP-02.7, “PER Trending,” contained a substantial list of codes that were to be applied to PERs entered into the CAP. Also, the process allowed multiple individuals to apply codes to PERs which, when tied to the large number of trend codes, resulted in inconsistent application of trend codes in the CAP. The team identified examples such as PERs 561772 and 599646, both of which documented the same condition; however, the trend codes were not consistent with each other.

The above observations were evaluated through Inspection Manual Chapter 0612 and determined to be minor.

<u>Lower-Tier Apparent Cause Evaluation Quality</u>

One indicator of a strong corrective action program is the effectiveness of the formal cause analysis process to identify the cause and develop adequate corrective actions to correct conditions adverse to quality, and complete the corrective actions commensurate with the significance and complexity of the condition. The team reviewed lower-tier apparent cause evaluations that were performed by the BFN staff, and identified issues with the quality of the evaluations and the grading and acceptance standards that Department Corrective Action Review Board (DCARB) used to approve the cause analyses. The following observations were identified:

- The team reviewed the apparent cause evaluations documented within PERs 704964, “PER not initiated when Action 1 exceeded,” and PER 695320, “As-Left Stem Factor Exceeded Design Value,”, and observed that the identified apparent cause statements were similar to the problem statements that the adequacy of the evaluation was brought into question.

The purpose of an apparent cause evaluation is to evaluate why the problem occurred given readily available data. The identified apparent cause statements failed to address why the condition adverse to quality occurred. These apparent cause evaluations were not performed in accordance with Procedure NPG-SPP-03.1.5, “Apparent Cause Evaluations,” Section 3.2.2.F.1, Cause Determination. Furthermore, these examples showed that there was an inconsistent application of the procedural requirements of NPG-SPP-03.1.5 between CARB and DCARB. For example, CARB rejected several upper-tier apparent cause evaluations that had similar problem statements and apparent causes, while DCARB accepted the above lower-tier apparent cause evaluations with the same issues

- The team reviewed the apparent cause evaluation for PER 672780, Operations Unable to Control the A Diesel Generator During the Performance of 0-SR-3.8.1, “Diesel Generator A Operability Test,” and observed that the corrective actions did not fully support the apparent cause. The apparent cause was identified as a programmatic deficiency dealing with insufficient or confusing details, while the corrective actions supported a single issue. The corrective actions developed were not in accordance with Procedure NPG-SPP-03.1.5, “Apparent Cause Evaluations,” Section 3.2.2.H, Corrective Action Development.

These observations were screened through IMC 0612, and were determined to be minor. The licensee entered the aggregate impact of the examples identified above into SR 729324.

6.1.4.3 Assessment Results:

SR Initiation Threshold

BFN had identified in the IIP that the Corrective Action Program relied on station personnel utilizing a low threshold in initiating conditions adverse to quality into the corrective action program (PER 475878). This issue was identified under the Fundamental Problem Area 5, Corrective Action Program, and corrective actions were developed and implemented to address the issue. Specifically, BFN revised the Corrective Action Program procedures, implemented site-wide communications and implemented training on the importance of using the corrective action program, defined the roles and responsibilities of station personnel in identifying conditions adverse to quality, and issued several alignment messages from the Chief Nuclear Officer to station management and personnel.

The team recognized that with the implementation of a revised corrective action program and the alignment of the organization with the revised corrective action program that challenges would exist in ensuring that all station personnel were adequately trained and could effectively implement a low threshold for initiating conditions adverse to quality. The team assessed that BFN has improved in lowering the threshold for initiating conditions adverse to quality into the corrective action program. However, the implementation of the new lower threshold has yet to be completely ingrained in the work force as evidenced by the team's observations described above. Therefore, continued management involvement and oversight was warranted in the continued implementation of the corrective actions in the IIP to provide reasonable assurance that performance improvement related to low initiation threshold will be sustainable.

SR Quality

BFN had identified that an aspect of an effective CAP was the quality of SRs initiated. This key element was initially addressed under the Corrective Action Program fundamental problem area (PER 475878) and corrective actions were implemented to address improvements in the CAP, including SR quality. Specifically, BFN performed substantial revisions to the CAP basis and implementing procedures, implemented site-wide communications defining expectations of quality CAP products, and focused continual training on the importance of and appropriate use of CAP with the goal of improving quality of CAP products. The team had identified that the focused CAP training addressed procedural guidelines for the appropriate inclusion of information in SRs.

The team recognized that with the increased quantity of SRs generated and the improved station participation in CAP that challenges would be exhibited in ensuring all site staff were adequately trained on appropriate SR quality, and that there would be sufficient resources and time to support the completion of the increased station workload. The licensee acknowledged that additional training opportunities may be warranted based on external benchmarking and reinforced the need through the team's assessment. However, the team assessed that the station made progress in the quality of SR documentation and that the additional planned corrective actions in the IIP, if implemented as documented along with continued licensee management involvement and oversight, will provide reasonable assurance that the stations performance improvement related to SR quality will be sustainable.

Lower-Tier Apparent Cause Evaluation Quality

BFN had identified in the IIP that the Corrective Action Program's ability to successfully determine the cause and develop corrective actions to address a condition adverse to quality relied on a formal cause analysis program that was supported by management (PER 435440). This issue was identified under the FPA 5, Corrective Action Program, and corrective actions were developed and implemented to address the area. Specifically, TVA NPG established dedicated positions for causal analysis subject matter experts at BFN, updated the training program based on identified weaknesses, revised the causal analysis procedures, and had CARB members observe DCARB meetings to gain consistency in the use of the corrective action program procedures. Despite the team having identified issues with lower tier ACE quality, the team assessed that the corrective actions BFN instituted had resulted in higher quality cause analyses, and that the corrective actions in place provided reasonable assurance that performance improvement related to lower-tier apparent cause evaluations and alignment of standards between CARB and DCARB would be sustainable. Continued management involvement and oversight was warranted for the continued implementation of the corrective actions in the IIP to give reasonable assurance that performance improvement would be achieved.

<u>PER Trending</u>

Although the team identified examples of continued issues in the PER trending process, BFN had previously identified these deficiencies in the Integrated Improvement Plan. Specific to issues in PER trend code application, the station restricted the population of individuals applying trend codes and heightened awareness of PSC members on ensuring consistent application of trend codes. Additionally, the PSC and CARB maintain active lists of common issues observed or identified in the CAP as an additional method to identify common issues and evaluate their aggregate impact (PER 471366, 475878, 549159). The team assessed that the corrective actions had resulted in more consistent application of PER trend codes and more effective and timely identification of common cause issues. In addition, the team evaluated the corrective actions planned to address the outstanding issues with the PER trending process through the implementation of an equipment maintenance integrated tracking and trending process with Electric Power Research Institute (EPRI) standardized parameters for site equipment (PER 547430). The team assessed that the corrective actions were comprehensive and would provide BFN an industry standardized approach to equipment trending and, when implemented, would continue to improve station PER trending performance. The team concluded that the completed IIP corrective actions had improved PER trending performance at BFN and the planned IIP corrective actions would promote sustainable performance improvement Continued management involvement and oversight was warranted for the ongoing implementation of the corrective actions in the IIP to give reasonable assurance that performance improvement would be achieved.

Overall Assessment

The team performed a comprehensive program review and onsite observations of the risk-significant aspects of the corrective action program to conduct an assessment of the condition of the program and its effectiveness. The team assessed that BFN had performed an intrusive and thorough cause analysis that accurately captured the causes and extent of condition of the CAPs prior issues in adequately identifying and correcting conditions adverse to quality. BFN adequately implemented comprehensive corrective actions to address the CAP deficiencies and established measures to continually focus on the adequate implementation of the corrective actions. In general, the team identified improved performance in the implementation and effectiveness of the CAP to identify and correct conditions adverse to quality.

As CAP performance improves overall, BFN must remain cognizant of the aspects of CAP that do not yield the same level of performance improvement progress. Specifically, SR quality, PER trending, lower tier ACE quality, and SR initiation threshold were CAP aspects that the team identified as requiring continued attention due to the lower level of performance improvement progress. The team identified examples that warrant managements continued focus and commitment to effective implementation of planned and completed corrective actions for those CAP aspects.

A limited number of corrective actions associated with the issues identified under the CAP FPA have not had sufficient run time or had not been completed such that the Team could provide a full assessment of the effectiveness of correctives actions. However, the corrective actions taken to date have provided the team reasonable assurance that performance improvement had occurred and continued improvement would occur as the station continued to attentively implement the planned and completed corrective actions in the IIP.

6.1.5 Governance and Oversight (FPA 10 – G&O)

6.1.5.1 Inspection Scope: The team assessed the licensee’s governance and oversight framework to determine whether it was sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

Specifically, the team evaluated the following:

- The licensee's governance and oversight framework as established in their Nuclear Operating Model (NOM),
- The governance and oversight implementing procedures for both the TVA fleet and the Browns Ferry Station,
- The licensee's corporate and site organization structure,
- The effectiveness of the corporate/site relationship, and
- The effectiveness of measurement tools, such as performance metrics and observation program results.

The team observed several of the licensee's meetings and activities in accordance with the licensee's procedures and the adequacy of the oversight demonstrated. Specifically the team observed the following:

- Corrective Actions Review Board meetings,
- Departmental CARB meetings,
- Fleet daily plant status and priority teleconference,
- Weekly Fleet Peer Departmental teleconference,
- Station Senior Leadership meeting,
- Various plan of the day meetings, and
- PER Screening Committee meetings.

The team interviewed selected members of the licensee's leadership team, from both the TVA Corporate level and the station. These interviews focused on the individuals' knowledge of the licensee's governance and oversight framework in accordance with procedures, guidance documents, and implementation of the framework associated metrics, and actions taken to address challenges. In addition, regarding governance and oversight, the team assessed the communications and coordination within and across the licensee's departments. Interviews were completed with the following:

- BFN Site Vice President
- BFN Plant Manager
- BFN Site QA Manager
- BFN QA assessor
- BFN Maintenance Department Manager
- BFN Instrument Maintenance Supervisor
- BFN Director of Engineering
- BFN Essential Emergency Cooling Water System Engineer

- BFN Nuclear Supply System Engineering Manager
- BFN Corrective Actions Program Manager
- BFN Chemistry Department Manager
- BFN Performance Improvement Manager
- BFN Operations Department PER and Human Performance Coordinator
- BFN Operations Department Manager
- BFN Work Control Manager
- BFN Operations Unit Manager Work Control Center
- BFN Human Performance Manger
- Fleet Vice President Functional Area and Outage Governance
- Fleet Vice President of Oversight
- Fleet General Manager QA
- Fleet Program Manager, Organization Effectiveness
- Fleet Senior Program Manager, Corporate Duty Officer
- Operations Corporate Functional Area Manager (CFAM)
- Engineering CFAM
- Maintenance CFAM
- Work Control CFAM
- Performance Improvement CFAM
- Corrective Action Program CFAM
- Licensing Corporate Functional Manager

In addition, the team evaluated the licensee's apparent cause analysis related to the licensee's FPA 10, "Governance and Oversight." Specifically, the team evaluated that: 1) that completion of the analysis was in accordance with the licensee's process; 2) that a thorough and methodical process was used to complete the analysis; 3) the related licensee's FPA adequately covered the related issues; 4) the appropriate aspects of the analysis were carried through into the licensee's IIP and the associated action plans; 5) the corrective actions adequately addressed the causes; 6) the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) selected corrective actions were adequately implemented; 8) the extent of condition and cause were adequately addressed; and 9) the completed or planned effectiveness reviews were adequate.
Documents reviewed are listed in the Attachment.

6.1.5.2 Observations: No Findings of significance were identified.

The team reviewed the IIP governance and oversight framework as established in the TVA fleet NOM, Governance, Oversight, Execution, and Support), and the applicable procedure, performance metrics, and other documentation. The NOM provided specific fleet guidance with respect to policy and process structure, organizational structure and staffing levels of the TVA Nuclear Power Group, along with the specific organizational structure and core responsibilities of the main functional areas, like Operations, Maintenance, etc. The NOM also defined GOES and its associated roles and responsibilities, and TVA Corporate oversight and support, including CFAM/Corporate Functional Managers (CFMs), TVA Corporate duty officers, and peer teams. In turn, TVA Corporate procedures provided additional guidance for individual and program responsibilities, which included Procedure NPG-SPP-01.4, Rev. 0002,“Governance, Oversight, Execution, and Support Program,” Procedure NPG-SPP-01.5, Rev. 0000, “Administration of Standard Programs and Processes (SPPs); Standard Department Procedures (SDPs); and Business Practices (BPs),” and Procedure BP-134, Rev. 0000, “Corporate Risk Management/Decision Making Process.” The team also reviewed the QA escalation process and change management plans for multiple initiatives, including GOES. The team determined that, in general, the guidance provided by the NOM, GOES, and associated procedures supported an organizational and programmatic structure for governance and oversight at BFN, both internally at BFN and externally through TVA Corporate office.

The team reviewed the ACEs, PERs, and associated corrective actions, including those documented in the IIP for the licensee’s and TVA Corporate’s analyses and initiatives associated with governance and oversight. The team reviewed ACE 542377, Rev. 0003, dated April 26, 2012, “NOM and GOES Implementation.” The licensee’s causal analysis team consisted of CFAMs and CFMs from multiple disciplines and evaluated fleet performance issues, even though the PER itself had been initiated from BFN. The ACE concluded that “the NOM had not been effectively implemented and that governance, performance metrics, and TVA Corporate oversight had been less effective at improving human and equipment performance and regulatory margin.”

The causal analysis report documented that the apparent cause of these issues was that the BFN leadership team had not fully engrained into their culture and in some cases had not recognized that all fleet policies, procedures, and standards established in the NOM must be implemented and reinforced during the conduct of day-to-day operations to achieve and sustain excellence. The causal analysis identified two contributing causes which were: 1) some CFAMs/CFMs had not effectively executed their specific responsibilities for governance and oversight. Specifically for BFN, weaknesses in TVA Corporate governance and oversight had resulted in missed opportunities to assist BFN in effectively implementing NPG programs and processes; and 2) the NPG strategy to reinforce the importance of the NOM had been ineffective in ensuring all sites and TVA Corporate leaders understood the expected application of the NOM and GOES model.

Based on the causes identified in the ACE, multiple corrective actions were created, which included training at the three sites and corporate office; increased accountability through TVA Corporate management review meetings (MRMs) and Strategic Council meetings; revised GOES metrics; and multiple assessments were created to evaluate effectiveness NOM and GOES implementation. The team determined that ACE 542377 had identified adequate causes and developed corrective actions to address the issues identified. Through interviews, observations, and reviewed documentation, the team identified examples where both site and TVA Corporate organizations were adhering to the NOM and GOES requirements, and additionally examples of where a lack of adherence and oversight resulted in long term issues not being resolved. These examples are discussed later in this section of the report.

The team reviewed Quality Assurance, external and internal audits, and assessments to determine the licensee's progress in implementing the NOM, GOES, and associated guidance procedures. It was noted that two recent audits identified the lack of overall workforce knowledge with respect to the NOM, GOES, and the CFAM function. Specifically, QA audits BFN-PI-S-13-031, dated March 4 to 8, 2013, and CRP-FA-S-13-002, dated January 16 to April 12, 2013, were performed as a result of corrective action 542377-012, to perform an assessment of the implementation and sustainability of the NOM and GOES implementation. The audits concluded that the corrective actions taken by BFN associated with the NOM and GOES had not been fully effective. The BFN-PI-S-13-031 audit identified that 70 percent of the interviewed FLS and above personnel at BFN did not know of the NOM or where it could be found; and 60 percent of the people interviewed did not know the relationship of the NOM to GOES or what support a CFAM/CFM provided to the site. The audit deficiencies were documented in SRs 690808, 691413, and 691414 and were rolled up into PER 693148, "Ineffective Corrective Actions with ACE 542337." Audit CRP-FA-S-13-002 also identified CFAM oversight needed improvement and that the lack of strategies and standards to track site performance had contributed to some long standing unresolved issues at the sites.
As a result of the deficiencies identified in audit BFN-PI-S-13-031, BFN performed an ACE under PER 691348, dated March 8, 2013. The ACE identified the cause of the ineffective NOM/GOES implementation was the lack of management reinforcement and expectations towards the need for knowledge retention of the NOM and GOES. The ACE specifically determined that the training itself was adequate for the purpose of information sharing and the

actions resulting from PER 542377; however, the only corrective action associated with the ACE was to conduct additional training seminars. In addition, the ACE concluded no additional action for an effectiveness review was required.

The team found that although there had been multiple corrective actions taken at BFN and TVA Corporate to implement the NOM/GOES process; some actions were still in progress, while others were deemed ineffective by the licensee's audits and assessments. In addition, from interviews performed and review of the applicable GOES metrics including human performance metrics, the team determined that some of the metrics were administratively based or at such a high monitoring threshold that they did not provide specific BFN status, needs, or were leading indications of performance issues (See Section 3.4.2). The team recognized that the licensee was emphasizing the value of implementing the NOM/GOES framework. Nonetheless, the team identified pertinent items not addressed in the IIP regarding Governance and Oversight, as well as specific difficulties the licensee had in implementing the NOM/GOES framework, specifically in the areas of: 1) Ensuring work attitudes match their behaviors; 2) In-field oversight; and 3) Strategic approach to Human Performance improvement. The team found that the IIP emphasized the value of implementing the NOM/GOES framework. However, for the NOM and GOES framework to be institutionalized at BFN, this will warrant significant management oversight and involvement. The team determined that the IIP warranted revision to ensure that substantial and sustainable performance improvement would be achieved. The licensee promptly responded with corrective actions to address each of the areas in the IIP that warranted revision, which the team found to be reasonable action plans. The safety culture aspects were addressed in the licensee's Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724.

The team performed multiple interviews with TVA Corporate and BFN site personnel to determine the status of BFN's implementation of the NOM/GOES structure and their interactions with TVA Corporate for governance and oversight. The team also observed various licensee meetings to assess the completion of the meeting in accordance with the structure established by the NOM and the oversight provided during these meeting. These meetings were found to be completed as specified by the various controlling documents, and in general the oversight was adequate.

Based upon the interviews and observations, the team found that, in general, the licensee's programmatic development and implementation of the governance framework as specified by the NOM, associated procedures, and organizations structure were, in general, sound. Moreover, the licensee's efforts in establishing a fleet-wide management process had been overall effective in creating a mutually beneficial working relationship between the CFAMs/CFMs and the associate BFN department managers and supporting staff. This was evidenced by interviews with both TVA Corporate and station personnel, as well as reviewing several examples indicating effective implementation of the process. For example, the licensee used the framework to reconcile disconnects between the Maintenance Rule, Equipment Reliability, and Corrective Action Programs. Another example identified was the use of a recent escalation of the process to complete a preventative maintenance optimization reassessment project and to address differences between the licensee's preventative maintenance program and fleet and industry standards.

The team assessed the licensee's efforts to address the oversight aspect of the FPA. In general, the team recognized that the efforts were focused on the oversight of the NOM and GOES, placing the responsibility of the individual departments to ensure that implementation and reinforcement of the standards and expectations during the conduct of day-to-day operations were achieved and sustained excellence. In addition, Procedure NPG-SPP-18.2.1, "Oversight of the Human Performance Program," contained specific guidance describing various tools and requirements for observations, but did not direct a comprehensive approach to monitor the conduct of day-to-day operations. Based on the discussions with various BFN department managements and supervisors, the efforts for oversight at specifically the first line supervisor level and the working level varied greatly and most departments did not have a methodical process to perform this oversight.

The team identified from discussions with the BFN Site HU Manager that several initiatives were being considered to improve the station's oversight for the first line supervisor and the workforce. For example, the use of the observation tracking tool, ePOP, which provided immediate feedback between the observer and the individual being observed, had been effective; however, the team identified that a station-wide strategic approach to address oversight issues had not yet been formalized and made programmatic. In addition, the station had taken some initiatives to train first line supervisors to reinforce management expectations and to better equip the first line supervisors to challenge the staff and enforce the station standards. Furthermore, the team recognized that some departments had initiatives to increase the amount of oversight and improve the quality of the oversight. For example, the "Maintenance Standards Initiative," as driven by PER 723046, and the root cause analysis associated with PER 695846 recognized that oversight was not effectively addressed during the licensee's initial assessment of the governance and oversight fundamental problem area. The root cause recognized that without improvement in the station culture that

BFNs staff's reluctance to change and accept coaching and oversight of the work process problems would continue.

With respect to BFN's long standing, human performance related issues of low level regulatory significance, the team interviewed the CFAM for human performance to determine what level of corporate governance and oversight was provided to BFN in order to resolve these issues and to ensure actions and improvements made were sustainable. The team reviewed the TVA Corporate HU business plan, "HU Performance (Site Clock Resets) Gap Analysis," for 2013-2017.

The team identified the following four issues in the licensee efforts to address the long standing human performance issues:

- Corporate HU business plan only contained high-level strategic HU actions. Tactical actions for implementation strategies and status tracking had not been developed, and, as a result, were not included in the plan. In addition, the lack of tactical actions flowed down to the sites. Specifically, the site had the strategic actions listed, but had no tactical actions or milestone due dates to implement at the sites. This issue was discussed with TVA Corporate staff and individuals who subsequently generated PER 750175 and SRs 740236, and 740025 for TVA Corporate to provide oversight of BFN HU improvement plan and tactical actions.

- Corporate HU Business Plan actions were not entered and tracked in the corrective action program. Although TVA was tracking these actions outside the CAP, the team observed that TVA Corporate did not incorporate the business plan actions into the CAP for both TVA Corporate and site actions that have resulted from conditions adverse to quality. This issue was discussed with TVA Corporate who subsequently generated PERs 750166 and 750328. The team did note that BFN Site HU Manager had entered the site specific actions into CAP.

- Corporate HU business plan did not include a formal action/mechanism to evaluate effectiveness of fleet HU actions or new program/procedure implementations. The CFM utilized an informal annual lessons learned process to discuss actions, for example, through the HU fleet peer group meetings. However, due to the large HU programmatic initiatives being developed and implemented across the TVA fleet, along with the long standing performance issues at BFN, the use of an informal methodology was not in line with formal TVA processes, such as the Change Management effectiveness process or the Corrective Action Program for effectiveness reviews. This issue was discussed with TVA Corporate who determined that an SR was not required.

- BFN did not utilize department human performance improvement plans as specified by their procedures. Specifically, Procedure NPG-SPP-18.2.1, Section 3.3, stated that HU work practices and supervisory oversight shall be addressed in the department level improvement plans in accordance with Procedure NPG-SPP-02.8, "Integrated Trend Review." This issue was discussed with the licensee and was documented in SR 740668 to address this concern. In addition, with respect to governance and oversight, TVA Corporate generated PERs 750168 and 750181 to develop an oversight plan for the HU fleet procedure requirements.

The team reviewed the regulatory aspects of the above described issues, and concluded that the failure to not utilize department human performance improvement plans as specified by their procedures was not a violation of regulatory requirements. Specifically, the procedure in question was not covered by the regulations, and the failures to incorporate the business plan actions that have resulted from conditions adverse to quality into CAP were considered minor. Additional examples of failing to enter issues into the CAP were described in Section 6.1.4 of this report. The aspects not covered by the IIP as described above were addressed by the licensee in PERs 757451 and 743724, Safety Culture Continuous Improvement and Sustainability Plan, which warranted a revision to be incorporated into the IIP. The team reviewed this Plan to verify that the necessary aspects were adequately captured and that the corrective actions were reasonable.

6.1.5.3 Assessment Results: The team observed that the licensee had improved in the overall station organizational structure as a result of actions taken in the areas of governance and oversight and that the licensee's efforts to establish a governance framework as specified in the Nuclear Operating Model (NOM) were, in general, sound. The team noted the licensee's efforts in establishing a fleet-wide management process had been overall effective in creating a mutually beneficial working relationship between the TVA Corporate Function Area Managers and TVA Corporate Functional Managers (CFAMs/CFMs) and the associate BFN department managers and supporting staff. In addition, BFN and TVA Corporate had extensive corrective actions in place, both completed and in-progress. The team found that the licensee emphasized the value of implementing the NOM/Governance, Oversight, Execution and Support (GOES) framework. Nonetheless, the team identified pertinent items not addressed in the IIP regarding Governance and Oversight, as well as specific difficulties the licensee had in implementing the NOM/GOES framework, specifically in the areas of: 1) Ensuring work attitudes match their behaviors; 2) In-field oversight; and 3) Strategic approach to Human Performance Improvement. The items missing from the IIP were addressed by the licensee in the Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724. Implementation difficulties were addressed in the licensee's corrective action program. Moreover, the team recognized that the implementation of the NOM and GOES framework at BFN warrants significant management oversight and involvement to result in long-term sustainability.

The team assessed the licensee's efforts to address the oversight aspect of the FPA. Over the last several years BFN demonstrated chronic low level performance as evidenced by several widespread low safety significant issues, indicated the need for a more effective oversight on the part of the onsite staff and TVA Corporate. The TVA assessment and approach to oversight failed to provide a systematic effort to correct long-standing widespread low-level human performance and culture issues at BFN. These aspects of oversight and human performance were acknowledged by the licensee and documented in Safety Culture Continuous Improvement and Sustainability Plan captured by PERs 757451 and 743724. The team concluded that this plan provided a systematic approach that developed a comprehensive plan to address the issues. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement in this FPA. The team concluded that the licensee's actions were sufficient to prevent a decline in safety and would promote sustained performance improvement.

6.1.6 **Continuous Learning Environment (FPA 15 – CLE)**

6.1.6.1 Inspection Scope: Through BFN's Integrated Improvement Plan development, BFN performed a series of reviews of its programs and processes and identified in 2012 that the station failed to utilize self-assessments, benchmarking, and operating experience to help the station improve performance. Therefore, BFN established the areas associated with these processes as a fundamental problem area under continuous learning environment, performed an apparent cause evaluation, and developed corrective actions. BFN identified the apparent cause as the failure of BFN leadership to recognize the importance of self-assessments, benchmarking, and operating experience reviews and ensure adequate incorporation into station processes

The team evaluated the apparent cause analyses and corrective actions related to BFN's Fundamental Problem Area 15, Continuous Learning Environment.

Specifically, the team evaluated: 1) the completion of the analysis was in accordance with BFN's process; 2) that a thorough and methodical evaluation process was used to complete the analysis; 3) that BFN's fundamental problem area adequately covered the related issues; 4) that the appropriate aspects of the analysis were carried through into BFN's Integrated Improvement Plan and the associated action plans; 5) that the corrective actions adequately addressed the causes; 6) that the timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) that selective corrective actions were adequately implemented; 8) that the extent of condition and cause were adequately addressed; and 9) that the completed or planned effectiveness reviews were adequate.

The team reviewed a risk significant sample of self-assessments, benchmarking, and operating experience items to verify adequate implementation of the processes, prioritized and entry into the CAP. The team evaluated a risk significant sample of the corrective actions addressing the deficiencies identified by the self-assessments to validate that the timeliness of corrective actions were commensurate with the safety significance. The team also conducted focused interviews with individuals from several organizations responsible for performing self-assessments and benchmarking as well as with individuals responsible for implementing the operating experience program.

The team performed in-field focused observations of operating experience. Specifically, the team focused on how the station incorporated operating experience into the daily processes of the plant by attending pre-job briefs, shift turnovers and CAP meetings to ensure the process was adequately implemented and utilized by station staff.

As a method of measuring performance in the fundamental problem areas, BFN established performance indicators with quantitative criteria. The team reviewed BFN's performance indicators for the continuous learning environment to ensure the metrics would effectively measure the appropriate breadth and depth of the program, and assess whether BFN's performance would be sustainable going forward. The team also reviewed the performance indicators bases documentation and analyses, as well as inputs to verify accurate metric results and conclusions.

6.1.6.2 Observations and Findings: One Finding of very low safety significance was identified.

6.1.6.2.1 Failure to Establish Qualified Ultrasonic Examination Procedures

Although not explicitly described in this report, aspects of the Finding also apply to FPA of Procedure and Instruction Quality (Section 5.3.2) for the licensee's failure to establish qualified ultrasonic examination procedures in accordance with ASME Code, Section XI, Appendix VIII requirements (PER 730250).

6.1.6.2.1.a Introduction: The team identified a Green non-cited violation of 10 CFR 50 Appendix B, Criterion IX, Control of Special Processes, for the licensee's failure to establish qualified ultrasonic examination procedures in accordance with applicable American Society of Mechanical Engineers Code Section XI, Appendix VIII requirements

6.1.6.2.1.b Description: The team reviewed a sample of the licensee's ultrasonic examination reports. The team identified an issue of concern while reviewing the licensee's implementing UT examination procedures that involved the absence of procedure qualification in accordance with applicable American Society of Mechanical Engineers Section XI, Appendix VIII requirements. Specifically, Procedures N-UT-76, N-UT-64, N-UT-65, N-UT-78, N-UT-82, and N-UT-84 did not contain the required essential variables described in ASME Code Section XI, Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems." The above UT examination implementing procedures referenced the applicable generic Performance Demonstration Initiative (PDI) procedures and these applicable PDI procedures contain all the required Appendix VIII essential variables. However, none of the above UT examination implementing procedures required the use of these generic PDI procedures when performing the UT examination. Therefore, the licensee's implementing UT examination procedures listed above were unqualified in accordance with ASME Code Section XI, Appendix VIII. The absence of explicit requirement in the implementing procedures to use the applicable generic PDI procedures along with the absence of Appendix VIII required essential variables in these implementing procedures introduced the possibility of performing unqualified UT examinations when using these implementing procedures.

6.1.6.2.1.c Analysis: The team determined that the licensee's failure to establish qualified UT examination procedures was a performance deficiency. The PD was determined to be more than minor, and a Finding because, if left uncorrected, it could become a more significant safety concern. Absent the team's identification of this PD, the licensee could continue to perform UT examinations on safety-related components using unqualified procedures. The performance of UT examination using unqualified procedures could lead to safety-related components with potentially unacceptable service-induced flaws being missed during UT examinations and being returned to service. The licensee entered this issue into their corrective action program as PER 730250 with the recommended action to qualify all the identified licensee UT examination procedures to ASME Code Section XI, Appendix VIII requirements. In addition, the team interviewed the licensee's NDE staff and determined that there was reasonable assurance that the licensee's process and expectations while performing past UT examinations would have identified the use of applicable PDI procedures as necessary when performing examinations. Therefore, the team answered "No" to all of the worksheet questions identified in IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone and answered "No" to IMC 0609 Appendix A, Exhibit 1 screening questions. Therefore, this Finding screened as having very low safety significance (Green).

This Finding has a cross cutting aspect in the area of Problem Identification and Resolution, Operating Experience because the licensee failed to adequately implement and institutionalize OE pertaining to UT examination procedure issues through changes to station processes, procedures, and training programs to support plant safety. The team reached this conclusion based on evaluation of the preliminary results of the licensee's investigation and interviews with licensee staff. [P.2 (b)]

6.1.6.2.1.d Enforcement: Title 10 CFR 50, Appendix B, Criterion XI, "Control of Special Processes," requires, in part, that measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

ASME Code Section XI, Appendix VIII, Section 2100, "Procedure Requirements", requires, in part, that the examination procedure contain all the essential variables listed under Section 2100 (d).
Contrary to the above, the team identified that the licensee failed to establish qualified UT procedures which controlled UT examinations on safety-related components. Specifically, during review of several licensee UT examination implementing procedures, the team identified that six procedures were not qualified in accordance with applicable ASME Code Section XI, Appendix VIII because the procedures did not contain any of the essential variables listed under Appendix VIII, Section 2100 (d) nor did they

require the use of the applicable PDI procedures which contained all the essential variables required under Appendix VIII, Section 2100 (d).

The licensee subsequently initiated prompt corrective actions that included actions to revise all UT implementing procedures to qualify in accordance with ASME Code Section XI, Appendix VIII requirements. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as PER 730250, it is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000259, 260, 296/2013011-016, Failure to Establish Qualified Ultrasonic Examination Procedures.

6.1.6.2.2 Other Observations: The team evaluated the licensee's causal analyses associated with this FPA, and determined that it was completed in accordance with the licensee's program, that it utilized a through and comprehensive method in determining the causes, contributing causes, extent of cause, and extent of condition. The team assessed that the corrective actions implemented and or planned addressed the identified causes, and, in general, were reasonable.

6.1.6.3 Assessment Results: The team performed program reviews and onsite observations of the aspects contained in BFN's continuous learning environment fundamental problem area to assess the condition of the area and its effectiveness in increasing performance of the station. The team determined that BFN had performed a thorough cause analysis that adequately captured the causes of the continuous learning environment's prior issues in adequately incorporating self-assessments, benchmarking, and operating experience into station processes. BFN developed corrective actions that adequately addressed the causes, implemented the corrective actions to address the issues, and established indicators to continually measure the implementation of the corrective actions. In general, the team identified improved performance in the effectiveness of the continuous learning environment in incorporating self-assessments, benchmarking, and operating experience into station processes.

The team recognized an improved performance in the continuous learning environment area; however, based on team observations and identified issues such as the NCV identified above, Failure to Establish Qualified Ultrasonic Examination Procedures, were examples of past problems and latent issues that were insufficient. The team observation and findings were examples that reiterate the need for management's continued focus and commitment in implementing the corrective actions in the IIP in order to continue to improve station performance.

6.1.7 **Independent Oversight (FPA 21 – IO)**

6.1.7.1 Inspection Scope: BFN identified in December 2012, that the independent oversight organizations on multiple occasions had missed opportunities to help the station avert the decline in station performance. BFN established independent oversight as a fundamental problem area and performed a root cause analysis and subsequent corrective actions to prevent repetition. The predominant cause identified that the BFN organization had not valued and prioritized the corrective actions tied to independent oversight organizations feedback. The team reviewed the root cause analysis, supporting documentation and resultant corrective actions to preclude repetition.

The team reviewed a risk significant sample of Quality Assurance, line, and independent organizations audits and self-assessments. The review focused on the programs and procedures that govern the execution of audits and self-assessments and the assessment of the thoroughness and self-criticism to verify that problems identified through those activities were appropriately prioritized and entered into the CAP for resolution. The team evaluated a risk significant sample of the corrective actions addressing the deficiencies identified by the audits and self-assessments to validate that the timeliness of corrective actions were commensurate with the safety significance. A focused inspection of the licensee's response to QA escalation letters was performed to assess BFN's disposition and prioritization of corrective actions. Also, the team evaluated BFN's evaluation and response to emergency preparedness related deficiencies identified as a result of actual events, exercises and drills. The team independently reviewed 2 years of emergency preparedness related deficiencies as well as performance data, audits, extent of condition evaluations and corrective actions. The team conducted focused interviews with organizations responsible for audits, self-assessments, independent oversight and the emergency preparedness program.
The team assessed the licensee's effectiveness and responsiveness to insights from external oversight entities, such as the BFN Nuclear Safety Review Board (NRSB) and other industry organizations that assessed the performance at BFN. Specifically, the team reviewed the NRSB meeting minutes since July 2011 and assessed the licensee's actions to address a sample of significant NSRB comments.

The team performed in-field focused observations of independent organization performance. Specifically, the team focused on QA oversight of CAP risk significant meetings and reviewed their observations to ensure the depth and quality was adequately documented. Additionally, the team validated that the identified deficiencies were adequately captured in the CAP.

BFN established oversight effectiveness performance indicators in specific performance areas with quantitative criteria. The team reviewed BFN's station performance indicators for Oversight Effectiveness from 2011 through April 2013. BFN's goal was to use the indicator to measure oversights ability to influence improvement at the station. The team reviewed the performance metrics to verify they accurately measured the effectiveness of key oversight functions, and that the metrics had the appropriate depth and breath. The team reviewed the performance indicators bases documentation as well as the data inputs to validate accurate metric quantitative results and conclusions. The team evaluated the stations response to performance indicator decline and reviewed associated corrective actions.

6.1.7.2 Observations: No Findings of significance were identified.

The team identified one issue in quality assurance's (QA) implementation of Procedure QADM-0.12, "Quality Assurance Observations." The procedure stated that "Observation activities should be performed to fit the intent of the scope and documented with enough details so that the information obtained may be used later as objective evidence for a higher level evaluation (e.g., assessment and/or audit The team identified examples of documented QA observations that did not provide sufficient detail to fully characterize the issue so the information could be used for future audits/assessments. QA initiated SR 728355 and performed immediate corrective actions to address the deficiency as well as perform an extent of condition review. The team did not identify any conditions adverse to quality that were not adequately dispositioned through the CAP or a performance deficiency greater than minor.

The team assessed the licensee's effectiveness and responsiveness to insights from external oversight entities, such as their Nuclear Safety Review Board (NRSB) and other industry organizations that assessed the performance at BFN. Specifically, the team reviewed the NRSB meeting minutes since July 2011 and assessed the licensee's actions to address a sample of significant NSRB comments. The team selected approximately twenty significant NSRB comments and or recommendations and assessed how the licensee tracked and addressed them in their corrective action program. In general, the team found that more than half the issued assessed were poorly addressed by the licensee, although most items were entered into the CAP, some of the CAP items did not accurately represent the concerns identified by the NSRB, several were closed to earlier CAP items, without addressing the potential ineffectiveness of those earlier CAP items, and other issues were simply not covered by the CAP. Moreover, the team observed that BFN demonstrated the same lack of responsiveness to other external industry oversight assessments as the demonstrated to the NSRB.

As part of the licensee's IIP, they identified a FPA associated with independent oversight and completed a root cause analysis (PER 655461). This root cause identified several additional supporting examples illustrating the lack of the licensee's responsiveness to external oversight organizations. For example:

- NSRB cited weaknesses in the corrective action program in seven separate reports spanning March 2008 to February 2012. In addition, other industry oversight organizations identified the need for improvement in the corrective action program during that same time period.

- From beginning of 2010 through the end of 2012, only 18 of 233 SRs written on NSRB issues had any corrective actions. In addition, repeated negative trends identified by NSRB were brought to BFN and TVA senior management's attention; however, neither the NSRB process nor the CAP required corrective actions to ensure the trends were appropriately addressed.

- Since February 2010, in the executive summary of five out of eight meetings for NSRB reports there were expressed concerns with human performance at BFN. Furthermore, other independent oversight organizations identified these same concerns as a long-standing gap that has not been effectively resolved.

An overall cause to this problem as described by the root cause analysis was the licensee, both TVA Corporate and Station Management have not consistently demonstrated that they value independent oversight. The corrective actions were related to the concept identified during the NRC Safety Culture focus group interviews, specifically that many of the BFN staff believe that since BFN is the only government ran, three unit BWR in the country the insights from these external organizations do not apply to the uniqueness of BFN. The corrective actions included strengthen various licensee procedures to ensure comments and recommendations from the NSRB will be addressed in the CAP. Specifically, that comments and recommendations will be discussed at NSRB at meetings to ensure issues were appropriately captured in the CAP and that actions tracking were address the issues and added emphasis provided if negative trends develop or continue. Additional actions were established to development routine meetings between the NSRB chairman and TVA senior management to discuss licensee performance to ensure that the NSRB concerns will be understood by TVA senior management. Although, the licensee has developed and implemented corrective actions to address their lack of effectiveness and responsiveness to the insights from external oversight organizations, continued licensee management oversight is warranted to ensure the effectiveness of these corrective actions.

6.1.7.3 Assessment Results: The team's review and evaluation of the Independent Oversight fundamental problem area determined that the licensee adequately identified the root and contributing causes and developed comprehensive corrective actions to prevent recurrence. A root cause to this problem, as described by the root cause analysis, was that the licensee, both TVA Corporate and Station Management, had not consistently demonstrated the value independent oversight. Specifically, many of the BFN staff believed that since BFN is the only government ran, three unit BWR in the country the insights from these external organizations do not apply to the uniqueness of BFN.

The corrective actions included strengthening various licensee procedures to ensure comments and recommendations from the Nuclear Safety Review Board and Quality Assurance organization will be addressed in the CAP, and that there will be added emphasis on negative trends that develop or are on-going. Additional actions were established to develop routine meetings between the NSRB chairman and TVA senior management to discuss licensee performance to ensure that the NSRB concerns would be understood by TVA senior management. The team also observed increased quantity, quality, and management awareness of QA observations.

The site performance indicators for independent oversight had generally improved and the team's assessment validated performance improvement in the fundamental problem area. However, management oversight is warranted to ensure sustainable performance improvement. The continued performance improvement will depend on the timely and adequate implementation of planned corrective actions and continued successful implementation of process and program revisions.

6.1.8 **Summary and Conclusions**

CAP performance has improved overall; however, there were areas that were identified that indicated that BFN must remain cognizant of specific aspects of CAP that were not yielding the same level of performance improvement as the rest of the program. Specifically, SR quality, PER trending, lower tier ACE quality, and SR initiation threshold were aspects of CAP where the team identified issues that indicated continued attention to performance improvement progress was warranted. A limited number of corrective actions associated with these issues identified under the CAP problem area had not had sufficient implementation time or had not been completed such that the team could provide a full assessment of the effectiveness of correctives actions. However, the corrective actions taken to date have provided reasonable assurance that performance improvement would continue with implementation of planned and completed corrective actions in the IIP.

The team observed that the licensee had improved in the overall station organizational structure as a result of actions taken in the areas of governance and oversight and that the licensee's efforts to establish a governance framework as specified in the Nuclear Operating Model was sound. The team noted the licensee's efforts in establishing a fleet-wide management process had been overall effective in creating a mutually beneficial working relationship. The team recognized that the implementation of the Nuclear Operating Model and Governance, Oversight, Execution and Support framework at BFN warranted significant management oversight and involvement to result in long-term substantial and sustained performance improvement, specifically in the areas of oversight and human performance as addressed by the licensee's Safety Culture Continuous Improvement and Sustainability Plan.

The team also recognized that the licensee performed extensive actions to align the organization around a common set of standards and goals (picture of excellence) and implement accountability. However, the IIP did not utilize this same approach with mid/lower level management and first line supervisors. The team observed multiple observations during the inspection where supervisors made inappropriate decisions, did not recognize or justified incorrect acts or behaviors from their workforce, or did not have the skill set to coach and correct poor work practices. The licensee lacked a systematic approach to address this issue, such that the station would comprehensively target and correct the latent issues of workforce and supervisors' work practices and behaviors.

6.2 Performance Deficiency Cause Analysis

6.2.1 **Inspection Overview**

The licensee's diagnostic investigation for the IIP concluded that the Equipment Performance, Monitoring and Trending programs were not being implemented in a manner to prevent equipment failures. The IIP also stated that Equipment Reliability programs and processes needed to drive and sustain high levels of equipment reliability were not being implemented in a manner that resulted in the timely resolution of long standing equipment problems and the prevention of new problems. The team found that these conclusions were evident starting from the Unit 1 restart in 2007. Plant performance issues were noted in the plant power history curves and the NRC Performance Indicators.

Unit 1 was placed in column 4 of the NRC Action Matrix in 2010 as the result of an RHR injection valve failure identified on October 23, 2010. The valve stem and disc had separated, resulting in a loss of one train of low pressure coolant injection and shutdown cooling safety function for a prolonged period (approximately 2 years). The NRC determined this issue was a Finding of high safety significance (Red), which was documented in NRC Inspection Report 05000259/2011008 (ML 111290482). The significance of the Finding was strongly influenced by the licensee's self-induced station blackout (SISBO) approach to fire event response. The NRC concluded that the reduced reliability of safety-related equipment, as noted above, was caused by systemic problems in several licensee programmatic areas.

NRC Inspection Procedure 95003 Supplemental Inspection (Part 1) was performed in September 2011 to assess the licensee's root cause analysis of the Red Finding, including the extent-of-condition, extent-of-cause, and corrective actions. The 95003 Part 1 inspection determined the RCA was too narrow in scope and corresponding corrective actions. Specifically, the RCA did not address related programmatic deficiencies in the licensee's maintenance and testing programs and in the CAP. In response to the NRC assessment and internal reviews, the licensee revised their RCA, established and implemented additional corrective actions, and monitored corrective action effectiveness through performance metrics established as part of the IIP. During this NRC 95003 Supplemental Inspection (Part 3), the team assessed the revised licensee RCA for the red Finding, ROP substantive cross-cutting issues P.1(c) and P.1(d) (see Section 6.1.7.3, Findings with cross-cutting aspects identified during this inspection, and insights from safety culture observations (see Section 4.1.5) to independently determine the primary cause(s) of the licensee decline in equipment performance and evaluate whether the licensee corrective actions identified in the IIP appropriately addressed the cause(s).

6.2.2 **LPCI Valve Failure (FPA 16 – PD)**

6.2.2.1 Inspection Scope: The team assessed BFN's evaluation of the red Finding to determine whether causal assessment, extent of condition reviews, and associated station-wide corrective actions were sufficient to prevent a decline in safety that could result in unsafe operations and that actions in place or planned would promote sustained improved performance.

The licensee diagnostic and Recovery Review identified the Undetected Failure of Low Pressure Coolant Injection Valve 1-FCV-74-66 (Red Finding) as a fundamental problem area (FPA 16). BFN performed RCA PER 369800 to determine the cause(s), extent-of-condition, and corrective actions to address this fundamental problem. The RCA was revised four times, as the licensee identified additional corrective actions to address programmatic issues or improved methods of implementing corrective actions and verifying their effectiveness. The team evaluated the licensee's RCA (PER 369800) and a sample of ten associated corrective actions.

Specifically the team evaluated whether: 1) completion of the analysis was in accordance with the licensee's process; 2) a thorough and methodical process was used to complete the analysis; 3) the related licensee's fundamental problem area adequately covered the related issues; 4) appropriate aspects of the analysis were carried through into the licensee's Integrated Improvement Plan and the associated action plans; 5) corrective actions adequately addressed the causes; 6) timeliness of completed and planned corrective actions was commensurate with the related safety significance; 7) selected corrective actions were adequately implemented; 8) extent-of-condition and cause were adequately addressed; and 9) completed or planned effectiveness reviews were adequate.

Documents reviewed are listed in the Attachment.

The team interviewed BFN staff, attended meetings, and reviewed various documents and records as listed below to assess the completeness of the RCA and effectiveness of corrective actions. Specific inspection items reviewed included:

- Selected engineering program procedures (listed in Section 5.1.2.1),
- Selected system and engineering program health reports (listed in Section 5.1.2.1),
- Selected engineering program audits and self-assessments (listed in Section 5.1.2.1),
- Equipment Aging Management program self-assessment and actions to manage aging of mechanical expansion joints and components containing electrolytic capacitors,
- Interviewed selected system engineers, engineering program owners, engineering managers, procurement staff, chemistry technicians, and plant operators,

- Revision of selected operating procedures to improve operating margin by stroking certain valves only when differential pressure was verified to be less than 350 pounds per square inch,
- Actions to test and inspect eight Unit 1 safety-related flow control valves similar to 1-FCV-74-66 to verify they did not have stem-skirt/disc separation,
- Action to review the list of valves previously removed from the NRC GL 89-10 test program to determine whether any should be moved back into the GL 89-10 test program,
- Action to develop an IST Program Bases document,
- Action to establish a requirement for periodic self-assessments of the IST and Motor Operated Valve programs,
- Action to add 1-FCV-074-52 and 1-FCV-074-66, LPCI outboard injection valves to the NRC GL 89-10 and NRC GL 96-05 test programs, and
- Actions to verify completeness of the BFN MOV program design bases document.

6.2.2.2 Observations

No Findings of significance were identified.
The team observed that the breadth and depth of the RCA was far-reaching, across various station departments and processes. Actions to address the causal factors were revised several times and rolled into the IIP as the licensee performed several reviews of the RCA and corrective action implementation. The majority of corrective actions reviewed by the team were complete. However, a significant number of the RCA corrective actions remained in-progress, some being long-term actions with completion scheduled as far out as 2017. Examples of the team's observations are discussed below:

1. The RCA and elements of the IIP associated with FPA 16 identified approximately 400 corrective actions to address the primary and contributing causes of the LPCI injection valve failure. The actions were comprehensive and addressed a broad range of areas including resources, training, procedures, capital improvements, industry operating experience, vendor support, technical rigor, human performance, engineering programs, CAP, and maintenance.

2. Revisions to six fleet level procedures for test programs provided clear program guidance and structure to support onsite test program development and implementation.

3. Corrective actions included performance of 23 engineering program self-assessments. Assessment of this large number of engineering programs was a significant and resource intensive set of actions. The team reviewed 11 of the program self-assessments, including selected corrective actions from each. The team determined the self-assessments were generally critical, identified numerous deficiencies or learning opportunities, and added significant value to the quality of engineering programs and their implementation. See Section 5.1.2.1 for further discussion of engineering program implementation (FPA 13).

4. The MOV self-assessment resulted in an in-depth review of the complete Browns Ferry MOV program by TVA. In addition, an outside consulting firm independently reviewed the BFN MOV program scope and benchmarked it to MOV programs at several other boiling water reactor facilities. These efforts resulted in the addition of 36 MOVs (12 per unit) to the BFN GL 89-10 MOV program and a clearly defined program scope. An additional 64 MOVs remained under evaluation via the CAP for potential addition to the GL 89-10 MOV program scope. The Pump and Electrical Breaker program self-assessments were similarly detailed and generated several PERs to further improve equipment reliability and plant safety.

5. Test equipment used to evaluate motor performance was not calibrated, and test results were not consistently analyzed. This impacted the licensee's ability to monitor long term reliability of safety-related motors.

6. The licensee identified the cause of several emergent equipment reliability issues to be a lack of preventive maintenance. A Preventive Maintenance Optimization Recovery project was established to verify appropriate preventive maintenance was identified, planned, and implemented for station equipment. At the close of this inspection 230 of 360 program actions were complete, with the rest scheduled for completion by the end of September 2013.

7. The NRC 95003 Inspection (Part 2) previously identified that electrolytic capacitors in safety-related components were not being properly tested or periodically replaced prior to reaching their end of service life (see NCV 05000259(269)(296)/2011-012-001). The team verified the licensee had evaluated the issue (PER 469567) and reviewed a sample of the corrective actions to assess timeliness. At the close of this inspection, the associated PM procedures had been revised and electrolytic capacitors had been replaced on all but one of the safety-related station battery chargers. Replacement of electrolytic capacitors on the #1 station battery charger was

scheduled to be complete by June 30, 2013. The team determined the corrective actions were timely.

8. Corrective action to implement Limitorque Maintenance Update 07-02 to address a potential MOV actuator failure mechanism was not scheduled at the first opportunity. Actions were established to inspect each unit's High Pressure Coolant Injection pump min flow valve actuator clutch gear for pin and lug alignment. The inspections were scheduled for next system availability (July 2014, December 2013, February 2014, and respectively). However, the inspectors identified the licensee missed earlier opportunities to perform this inspection during planned maintenance on both the Unit 1 (valve outage in November 2012) and Unit 2 (valve outage during March 2013 refueling outage) valves (SR 729832).

9. The licensee's RCA (PER 369800) identified that the root causes were: 1) mechanical failure due to undersized stem thread barrel; 2) deficient work instructions to verify stem thread dimensions during stem and disc reassembly in 1983; and 3) misapplication of active/passive function classification criteria which resulted in removing 1-FCV-74-66 from the NRC Generic Letter (GL) 89-10 valve test program. Eight additional contributing causes were identified including: 1) inadequate knowledge and program bases for the In-service Testing program; 2) inadequate assessment and implementation of engineering programs for an extended period; 3) inadequate use of CAP including extent-of condition review, operating experience review, and untimely corrective actions; 4) inadequate TVA fleet governance and oversight of Inservice Testing (IST) and Motor Operated Valve (MOV) programs; 5) inadequate emphasis on regulatory compliance; and 6) non-conservative decision making by the Plant Operations Review Committee and senior station management.

6.2.2.3 Assessment Results: The team's independent assessment of the RCA and supporting documents determined the licensee had appropriately identified the apparent causes that led to the site challenges described under FPA 16. The RCA was thorough and comprehensive.

Overall, implementation of corrective actions for FPA 16 was timely. The few actions scheduled to complete after December 31, 2013, were associated with corrective action effectiveness reviews, NFPA-805 fire code transition, or required further interaction with the ASME code committee. Based on interviews, equipment walk downs, review of staffing and equipment performance, and review of eleven engineering programs the team determined the licensee had made significant progress toward addressing the root causes and contributing causes of the issues pertaining to the Red Finding. Continued sustainability and substantial improvement of the FPA, implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential.

6.2.3 **Fire Risk Reduction (FPA 17 - FRR)**

6.2.3.1 Inspection Scope: The licensee's SISBO approach to fire event response was a significant contributor to the risk significance of the LPCI injection valve failure discussed in Section 6.2.2. Additionally, PER 214592 was created to address a previous Yellow NRC violation for failure to protect cables from potential fire damage that were used to fulfill 10 CFR 50, Appendix R, Fire Protection Program requirements for safe shutdown (NRC Inspection Report 05000259/2009009, 05000260/2009009, 05000296/2009009; ML 100201056). In response to the violation, and insights from the Red Finding, the licensee established corrective actions to implement the National Fire Protection Association 805 code, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." The licensee diagnostic and Recovery Review identified Fire Risk Reduction as a fundamental problem area (FPA 17). BFN performed apparent cause evaluation PER 214592 to determine the cause(s), extent-of-condition, and corrective actions to address this fundamental problem. The team interviewed BFN staff, reviewed various documents and records, and performed selected cable walkdowns to assess whether appropriate interim measures were implemented to address fire protection of safe shutdown equipment prior to the licensee's transition to NFPA 805.

In preparation for the transition to NFPA 805 and to address the concerns in PER 214592, the licensee conducted cable walkdowns to verify the location and impact from fire for the cables. The LPCI injection valve, which resulted in a Finding of substantial safety significance (Red Finding), was important because it was used in a credited recovery path for certain fire events. The major risk insight from the Red Finding was that damage or unavailability to equipment in the protected fire train selected to provide safe shutdown of the plant during specific fire scenarios could have a large risk impact, because of the number of risk significant areas that use selected equipment for safe shutdown.

As part of the vertical slice to evaluate the plant's ability to remove heat from the primary containment, a fire protection sample was chosen. The team performed walkdowns of selected cables and raceways to insure that selected vertical slice system equipment, which was used as mitigating equipment in the fire Safe Shutdown Instruction procedures, would remain free from fire damage. The team evaluated, based on the walkdowns, whether the selected components used in the fire Safe Shutdown Instructions had cable routing such that the function would not be lost due to fire in the credited area that would impact the cabling. The components were selected to include a sample that would be used for the areas that had the highest risk.

The team traced selected electrical conductors for equipment used in the SSIs through use of elementary diagrams (Schematic Diagrams), and the station's electrical termination drawings (wiring diagrams) to allow identification of the cables the wiring was located in, and their routing. The routing was used to check the output from the Integrated Cable and Raceway Design System for the equipment. Selected functions of control power, power, starting, stopping, opening, and closing functions were traced. A subset of the cables supporting these functions was walked down to identify the fire areas the cables passed through. The team then evaluated whether the cables supplying selected control and power functions for those components would have stayed free from fire damage for the fire areas that credited the use of those components during fire recovery and safe shutdown of the unit. The components selected were: 1-PCV-0011-0179; 1-PCV-001-0004; RHRSW Pump A1; RHR Pump 1A; 1-FCV-074-0053; Normal DC power for the 4kV Shutdown Board 3EA; and RHR Service Water Pump 3A.

6.2.3.2 <u>Observations</u>: No Findings of significance were identified.

Fire strategies at the facility were modified, including safe shutdown procedure revisions, to allow equipment that may be available outside the dedicated fire shutdown train to be used if the dedicated train failed. Several fire areas were redefined, and additional barriers were created to reduce fire risk.

In those cases that identified where the cable passed through a credited fire area, the licensee provided information showing the condition had been previously identified, and the reason the exception was allowed (e.g., a fire wrap was provided for the cable, or an isolation circuit with separate fusing was provided for recovery of the circuit in case of damage).

The team requested that the licensee provide documentation associated with cables, identified during the NFPA 805 effort, which did not meet the routing requirements for Appendix R. Based on risk insights, the team selected a specific cable for detailed evaluation. Identified issues were entered into the plant's corrective action system, evaluations were performed to show the cable would not result in a red risk condition, and compensatory measures were put in place to compensate for the deficiency. The issue was properly reported to the NRC in accordance with 10 CFR 50.73, Licensee Event Report System. Contributing cause CC-04 under FPA 17 was "Ineffective use of the Corrective Action Program to identify Appendix R issues and drive them to resolution." For the cable examined, the CAP was used to document the deficiency, evaluate the significance to be below the threshold for a plant committed to NFPA 805, and to insure compensatory actions were in place. The team determined the CAP was properly used to evaluate and resolve this cable deficiency.

The personnel that the team interfaced with were knowledgeable of the fire requirements, plant documentation, and plant layout necessary to perform and implement the requirements of NFPA 805.

6.2.3.3 Assessment Results: Fire strategies at the facility were modified, fire areas were redefined, and additional barriers were created, all to reduce fire risk. The team determined that for the equipment and cable fire samples that were evaluated, the automated database reflected the plant configuration. The team concluded that, for the equipment selected, the cable routing was adequate to support the applicable Safe Shutdown Instructions (SSIs) and reasonable interim measures were implemented to address fire protection of safe shutdown equipment prior to the licensee's transition to National Fire Protection Association (NFPA) 805. The NRC's baseline inspection program includes regular fire protection program inspections that will further inspect BFN's transition to NFPA 805. Implementation of the corrective actions in place and completion of the remaining corrective actions in the IIP is essential for continued sustainability and substantial improvement of this FPA.

6.3 Summary and Conclusions

The team independently determined the licensee had appropriately identified the causes that led to the LPCI injection valve failure (Red Finding) described under FPA 16. The RCA was thorough and comprehensive and implementation of corrective actions for FPA 16 to date was timely. The licensee had made significant progress toward addressing the root causes and contributing causes of the issues pertaining to the Red Finding.

Following the Red Finding fire strategies at the facility were modified, fire areas were redefined, and additional barriers were created to reduce fire risk. The team determined that for the equipment and cable fire sample evaluated, the automated database reflected the plant configuration and cable routing was adequate to support the applicable Safe Shutdown Instruction procedures. The sample of interim measures implemented to address fire protection of safe shutdown equipment prior to the licensee's transition to NFPA 805, reviewed by the team, were reasonable to assure safety.

The team concluded that the licensee's corrective actions identified in the IIP appropriately addressed the causes of the RED Finding, ROP substantive cross-cutting issues P.1(c) and P.1(d) (see Section 7.3), and previously documented safety culture concerns (see Section 4.5) were adequate to prevent declines in safety that could result in unsafe operations. Additionally, implemented and proposed actions identified in the IIP were appropriate to promote sustained improved performance.

7 Other

7.1 Follow-up on White Mitigating Systems Performance Index for the High Pressure Injection System

The NRC previously performed a supplemental inspection in accordance with Inspection Procedure 95001, "Inspection for One or Two White Inputs in a Strategic Performance Area," to assess the licensee's evaluations associated with the Mitigating Systems Performance Index (MSPI) for the High Pressure Injection System, which crossed a threshold from GREEN to WHITE safety significance in the second quarter of 2012 as documented in inspection report 05000259/2012015050 (ADAMS Accession No. ML12335A380). The inspection reviewed the casual analyses conducted for the individual contributors that caused Unit 1 HPCI to incur the multiple equipment failures and excessive unavailability that drove the MSPI reporting indicator to White. The performance indicator returned to GREEN in the third quarter 2012.

The BFN MSPI basis documents and probabilistic risk assessment (PRA) parameters were revised based on Calculation NDN 000 999 2010 003, Revision 007 to reflect BFN PRA Model Revision 5 approved on November 6, 2012. This change became effective first quarter 2013. The BFN Unit 1 High Pressure Injection MSPI Indicator subsequently changed from GREEN to WHITE in the first quarter of 2013. The update to the PRA parameters resulted in an unavailability index of 6.75E-07 change in core damage frequency (ΔCDF) and an unreliability index of 9.35E-07 ΔCDF, for a total indicator value of 1.60E-06 ΔCDF, which exceeded the GREEN - WHITE threshold value of 1.0 E-6 ΔCDF. The NRC inspectors verified that no additional failures had occurred since April 2012, and the IP 95001 supplemental inspection reviewed all the previous contributors to the current High Pressure Injection MSPI indicator.

7.2 (Closed) Unresolved Item 05000259/2011011-05, Verification of Valve Obturator as Required by ASME OM Code

7.2.1 Inspection Scope: This URI was opened regarding BFN's implementation of the ASME OM code Section ISTC 4.1 for verification of valve obturator movement. Specifically, the NRC had previously identified that BFN had not implemented the

ASME OM Code guidance for the verification of remote valve position indication and obturator movement in accordance with the NRC interpretation and issued a Red Finding (IR 05000259/2011008). This URI was documented to evaluate BFN's corrective actions to address the differences in their IST program and the ASME OM Code requirements. The NRC continues efforts with the industry to develop clarification of the ASME OM code requirements. The inspectors reviewed BFN's corrective actions resulting from the Red Finding performance deficiency for its failure to implement an IST program in accordance with the ASME OM code.

7.2.2 Observations: No Findings or Violations of NRC Requirements were identified.

In an August 16, 2011 letter to BFN, the NRC acknowledged a diversity of views among NRC staff and industry experts on the ASME OM code interpretation, and has pursued generic resolution of the OM code testing issues. NRC headquarters staff has been pursuing clarification and guidance on the requirements with the ASME code subcommittee with no prescribed completion date.

The team reviewed BFN's latest revision to their IST program as well as the corrective actions developed/implemented to address the ASME OM code implementation deficiencies previously identified as a result of the Red Finding. Specifically, the team reviewed BFN's IST Program Basis document and IST program readiness review, with emphasis on safety significant SSCs, to evaluate appropriate scope and programmatic issues were captured in the corrective action program.

The team recognized that BFN had taken interim compensatory actions to enhance IST testing while the ASME OM code clarification and guidance was being developed. Although BFN did not commit to use supplemental parameters to confirm local observation of valve travel, BFN established corrective action 369800-153 to coordinate and work with ASME and the industry to develop an improved methodology for meeting the requirements of the ASME OM code concerning the verification of valve obturator position. The ASME OM code clarification had an expected date of January, 2014. The licensee Action, 3690800-292, was established to implement the approved methodology by July, 2014. These actions were included and tracked in the BFN 95003 Integrated Improvement Plan. The team assessed that BFN had taken reasonable interim actions to address IST program deficiencies and that the documented long term actions developed, when implemented, would provide reasonable assurance that BFN would meet the ASME OM code requirements. This URI is closed.

7.3 Review of Two Substantive Cross Cutting Issues

7.3.1 Inspection Scope: The NRC identifies a substantive cross cutting issue (SCCI) to communicate a concern with the licensee's performance in a cross-cutting area and to encourage the licensee to take appropriate action before more significant performance issues emerge. In the March 3, 2010 BFN annual assessment letter (ML100620960), the NRC identified an SCCI in the area of Problem Identification and Resolution, in the "thorough evaluation of identified problems" component (P.1(c)). Also, in the March 4, 2011 BFN annual assessment letter (ML11063042), the NRC identified an SCCI in the area of Problem Identification and Resolution in the "appropriate and timely corrective actions" component (P.1(d)). The NRC had maintained the SCCIs open due to ineffective implementation of corrective actions during prior assessment periods.

The team evaluated the licensee's root cause analyses, related to the P.1(c) [PER 668535] and P.1(d) [PER 668531] SCCIs, to assess the scope, content and effectiveness of BFN's actions to address the SCCIs. The team evaluated the adequacy and effectiveness of the following planned or completed corrective actions:

- Revised corrective action program basis and implementation procedures,
- CNO vision of excellence in CAP,
- Roles and responsibilities of performance coordinators in effectively managing the CAP,
- Requirements and mechanisms to ensure appropriate safety and regulatory risk screen for conditions adverse to quality in CAP,
- BFN CAP organizational staffing levels and progress in filling vacancies,
- Revised strategic approach to managing site resources and organizational capacity,
- Equipment maintenance integrated tracking and trending process, and
- Revised CAP computerized tracking program user interface and standardization of database for integrated tracking and trending process.

The team evaluated that completion of the root cause analyses were in accordance with the licensee's process, a thorough and methodical process was used to complete the analyses, the cause analyses appropriately covered the scope of the SCCIs, the corrective actions adequately addressed the causes, the timeliness of completed and planned corrective actions were commensurate with the related safety significance, selected corrective actions were adequately implemented, the extent of condition and cause were adequately addressed, and the completed or planned effectiveness reviews were adequate. In addition, the team evaluated that a fewer number of Findings with the same cross cutting components had been identified in the past 12 months and whether an increased level of confidence in BFN's ability to deal effectively with operational and equipment issues related to the SCCIs.

7.3.2 Observations: No Findings of significance were identified.

The team performed an assessment of the root cause analyses and subsequent corrective actions to prevent repetition. BFN identified that parallel root causes existed between the SCCI's and the resource management and corrective action program fundamental problem areas (FPA). The corrective actions for the SCCI's credited the planned and completed corrective actions in those FPAs. Furthermore, BFN established corrective actions to address the contributing causes for the SCCIs. The team assessed that the corrective actions credited from the aforementioned fundamental problem areas, along with the additional corrective actions to address the contributing causes, were, in general, reasonable to address the causes of the SCCIs.

The team evaluated that a fewer number of Findings had been documented, in the past 12 months, in the P.1(c) and P.1(d) cross cutting aspects. Additionally, the corrective actions planned and completed were reasonable to address the deficiencies identified for the SCCIs such that the team had an increased level of confidence in BFN's ability to deal effectively with operation and equipment issues related the P.1(c) and P.1(d) cross-cutting themes.

7.4 Closure of Inspection Report 05000259/2012009

For administrative purposes, IR 05000259/2012009, which captured efforts associated with the 95003 inspection is closed coincident with this report.

8 Summary and Conclusions

The overall result and conclusion of the inspection was that the plant was being operated safely and that Tennessee Valley Authority (TVA) had made some progress in improving Browns Ferry station performance. However, TVA needs to aggressively continue the implementation of the licensee's performance improvement initiative, the Integrated Improvement Plan (IIP), to achieve substantial and sustainable performance improvement. The team identified four issues that warranted revision to the licensee's Integrated Improvement Plan (IIP) to ensure that substantial and sustained performance improvement would be achieved. The areas warranting improvement were associated with Safety Culture, Procedure Quality, Human Performance Verification Program, and an Operations Led Organization.

The root cause analysis (RCA) for the RED finding identified the root causes to be 1) mechanical failure due to undersized stem thread barrel, 2) deficient work instructions to verify stem thread dimensions during stem and disc reassembly in 1983, and 3) misapplication of active/passive function classification criteria which resulted in removing 1-FCV-74-66 from the NRC GL 89-10 valve test program. Eight additional contributing causes were identified including 1) inadequate knowledge and program bases for the In-service Testing (IST) program, 2) inadequate assessment and implementation of engineering programs for an extended period, 3) inadequate use of CAP including extent-of condition review, operating experience review, and untimely corrective actions, 4) inadequate TVA fleet governance and oversight of IST and MOV programs, 5) inadequate emphasis on regulatory compliance, and 6) non-conservative decision making by the Plant Operations Review Committee and senior station management. The team's independent assessment of the RCA and supporting documents determined the licensee had appropriately identified the apparent causes that led to the site challenges and the RCA was thorough and comprehensive.

Following the RED finding, fire strategies at the facility were modified, fire areas were redefined, and additional barriers were created to reduce fire risk. The team determined that interim measures implemented to address fire protection of safe shutdown equipment prior to the licensee's transition to National Fire Protection Association (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," that were reviewed by the team were reasonable to assure safety.

The licensee's IIP was a diagnostic review of the issues identified during the RCA of the RED Finding that BFN deemed needing additional review. As a result BFN found a total of 21 fundamental problems areas (which include the actual finding and the related area of fire protection) warranting attention by TVA in the BFN recovery plan. The team reviewed the licensee's recovery plan, including a review of the causal analysis, action plans, effectiveness review plans, and associated performance metrics. In addition, the team completed an independent graded safety culture assessment. The team determined that the licensee's framework and controlling procedures for recovery, as well as, the licensee's process for monitoring ongoing conditions and events for potential revisions to the IIP were comprehensive and sound. The team concluded that TVA needed to reinforce the continued oversight and involvement in effectively implementing the IIP to ensure substantial and sustained performance improvement.

Regarding safety culture, most of the departments demonstrated improvement in the 2013 safety culture survey results as compared to the results in the 2011 assessment. Based on the improvement in the results of the 2013 Independent Nuclear Safety Culture Assessment (INSCA) and verification by the 95003 Inspection team's (referred as the team) independent graded safety culture assessment , many of the corrective actions taken to address the safety culture issues from the 2011 INSCA were generally effective. The team independently identified concerns that were consistent with the ongoing issues identified by the INSCA 2013 assessment; in particular, the following concerns were identified in the 2013 INSCA, staffing and resources, writing quality Problem Evaluation Reports in the corrective action program, deficiencies in procedures, and concerns about management getting staff input before making changes at the station.

The team's independent graded safety culture assessment was able to confirm that the results obtained from the 2011 and the 2013 INSCA were a reasonable characterization of the culture that existed at the site during that time period. The team found that employees perceived notable improvements in safety culture across the site. Employees had recognized a notable change in the overall focus of the site, from a production-focus and an emphasis on doing the minimum required to keep the plant running, to a safety-focus and emphasis on making conservative decisions. Employees also indicated that they had greater trust in upper management and perceived an increased level of support for raising safety concerns and increased emphasis on raising standards for safe performance. Despite the overall improved safety culture, translating the safety culture improvements into repeatable, sustainable safety culture behaviors still remained a challenge at BFN. Some station personnel including operators, technicians, and their immediate supervisors were challenged to routinely exhibit site standards and expectations when performing normal duties and responsibilities involving work practices, decision making, and implementation of the problem identification and resolution programs. In addition, procedures specifically used to operate the plant did not meet industry quality standards.

The team determined that seven specific areas of concern, related to safety culture sustainability were needed to drive continue performance improvement progress, but were not adequately covered by the licensee's IIP. As a result the licensee developed a Safety Culture Improvement and Sustainability Plan. The following concerns warranted revisions to the IIP to ensure that substantial and sustainable performance improvement would be achieved:

1) Although employees exhibited attitudes that supported a positive safety culture, those behaviors were not consistently demonstrated, particularly by employees who were closest to the operation of the plant (individual contributors and supervisors).

2) The work management process was not effectively implemented to facilitate coordination between departments. The lack of coordination may have contributed to quality issues with work packages, and affected the timeliness of performing work.

3) Current resources may not be adequate to effectively manage the additional workload required to reduce backlogs and improve reliability at the station. In

addition, the need for appropriate training and qualifications may create a gap between having enough staff and having enough qualified staff to meet work demands.

4) There was a recognized issue with the quality of procedures at the station; however, there lacked a systematic process for improving procedure quality in an efficient manner.

5) Management and supervisors were not consistently reinforcing desired behaviors and work practices through the use of direct observations and coaching. In addition, the station lacked a systematic process to improve behaviors and work practices through supervisor oversight.

6) Administration and oversight roles of the Nuclear Safety Cultured Monitoring Panel required additional structure and involvement to monitor and drive continued and sustainable safety culture improvement across the station.

7) Administration and oversight of the BFN human performance (HU) plan, specifically the lack of strategic action plans and TVA Corporate oversight to address the station's long-standing HU issues.

In the area of Safety Conscious Work Environment and the Employee Concerns Program, the team assessed that at the time of the inspection, there were no indications of a SCWE issue and improvements had been made to the Employee Concerns Program and BFN's actions to address these areas to be adequate.

The implemented and planned corrective actions for Design and Configuration Control, Strategic Equipment Performance, Equipment Programs and System Management, Work Management and Resource Management were sufficient to prevent a decline in safety that could result in unsafe operations. The implemented and proposed actions in the IIP were appropriate to promote sustained improved performance.

Equipment associated with containment heat removal were, in general, adequately maintained in proper configuration and material condition to perform their designed safety functions. However, the team observed several examples in which the licensee accepted longstanding degraded conditions without pursuing timely resolution through the CAP (i.e., RHRSW and EECW pump differential thermal expansion, infrequent and incomplete GL 89-13 RHRSW pump pit inspections, cold weather protection for RHRSW and EECW pumps and piping, EECW check valve closure, macrofouling of RHR and EECW HXs, equipment labeling). These conditions historically challenged both equipment configuration and reliability. The team noted recent licensee progress to identify, fund, and schedule actions to correct several of the longstanding degraded equipment conditions.

Strategic Equipment Performance implemented by the Long Term Asset Management (LTAM) program created a process that ranks and prioritizes modifications and projects from a BFN site perspective. This program was implemented at the end of 2009. An essential enhancement to the LTAM program along with the recent establishment of a systematic and integrated work week schedule and the Functional Equipment Grouping (FEG) work week processes should help to provide sustainable improvement to overall equipment reliability. The LTAM program focused site resources on important equipment and projects that have the potential to improve Equipment Reliability over time. The implementation of the LTAM program along with the enhancement of other engineering programs such as the Safety System Recovery Program should help to improve the overall Strategic Management Program at BFN.

The team concluded that BFN performance has improved in Equipment Performance, Monitoring and Trending. The team concluded that the monitoring and trending portion of this problem area had sustainable corrective actions.

The team determined that the IIP corrective actions were comprehensive in nature and adequately addressed the identified root and contributing causes for Work Management. The team acknowledged that improvements have been made at the station with respect to the work management process; however, this is a new process for the station and additional implementation time is needed to show performance improvement is sustainable in this area. However, the team identified several examples where the work management process was not implemented in accordance with the program; specifically in the areas of work scheduling, work planning, work execution, procedure use and adherence, and procedural quality. In addition, the Work Management processes at BFN have not historically been robust, when emergent/tactical issues upset the schedule, long term Strategic Equipment Management plans have suffered because station priorities have been directed away from the Strategic priorities to the emergent/tactical priority. These difficulties in implementing the work management process can also adversely affect the equipment performance monitoring and trending process. Even though the work management process corrective actions have been implemented to achieve full effectiveness, a challenge remains to achieve overall improved equipment reliability at the station. Therefore, rigorous adherence to the process by the licensee’s staff and oversight of the work management process by the licensee’s management will be necessary for sustained improvement.

The licensee implemented reasonable actions, to date, to reduce and manage the design engineering backlog at levels appropriate to support safe plant operation. As of September 2012, BFN estimated the total volume of engineering design backlog items to be 5 years of work if performed by BFN staff. Actions identified in the IIP included hiring contactor resources to work down the engineering change package backlog and revision of fleet modification processes to ensure future engineering design change package closure documentation was included in work scope performed by contract labor rather than assigning this to onsite BFN engineering staff. The team verified these actions were implemented, and at the close of this inspection approximately 80 percent of the design backlog items had been completed. While progress was notable, the team determined that several related IIP actions were not fully implemented or had not had sufficient run-time to support NRC assessment of sustainability. Continued implementation was warranted in this area to ensure that substantial and sustainable performance improvement is achieved.

The team concluded that the licensee had improved in overall station performance as a result of actions taken in the areas of procedure use and adherence, human performance, technical rigor and ownership and accountability, procedure quality, and operation focus and decision making. The team also noted that BFN had extensive corrective actions in place, both completed and in-progress. In some areas, BFN's actions were too new to determine long-term performance improvement sustainability. However, the also team identified several examples related to these areas where BFN staff failed to meet the standards established at the station.

The team identified multiple Findings and observations that demonstrated failures to meet BFN procedure use and adherence standards. This included Findings in the limited use of fundamental human performance tools by all organizations, lack of manager and supervisor oversight to enforce procedure use and adherence standards, inconsistent procedure use and adherence standards in corporate and site procedures, BFN acceptance of sub-standard procedures, and frequent examples of station personnel errors related procedure use and adherence. The team concluded that station management did not methodically address and correct latent organizational human performance weaknesses, including procedure use and adherence and the limited use of human error prevention verification tools and practices.

A programmatic review of the human performance program concluded that there was not a systematic approach at BFN or TVA Corporate to address the human performance issues. Although a fleet Business Plan existed for Corporate and BFN's human performance improvement initiatives, these plans focused on high level strategic actions only and tactical implementation actions did not exist. In addition, the station did not methodically target and correct the latent organizational weaknesses with human performance, including procedure use and adherence and verification practices. Based upon a review of the IIP and associated actions, the team concluded that the station's focus warranted a systematic approach to improving work practices, decision making (rigor), and supervisory oversight to ensure long-term corrective actions were effective for performance improvement sustainability.

Regarding Technical Rigor and ownership and accountability, the team concluded that the licensee had adequately addressed the multitude of challenges at the site which formed the bases of the design related fundamental problem areas experienced at the site. The licensee's Safety Culture Continuous Improvement and Sustainability Plan included additional actions to address issues related to technical rigor and human performance.

Procedure quality issues at BFN have led to equipment degradation, equipment unavailability, plant transients and reactor scrams. Making standard human performance tools an option rather than a requirement for critical evolutions had exacerbated human performance issues. Previous corrective actions have been ineffective in preventing recurrence of events in which procedure quality was either a contributing or a root cause. As a result of these conclusions, TVA developed a revision to the IIP to implement a site-wide procedure upgrade project to bring BFN procedure quality in line with established industry standards.

Following review of BFNs Operational Focus and Decision Making processes, the team determined by direct observation, that the Operation Organization had not taken the initiative to embrace the leadership role needed to drive the station to higher standards and improved station performance that exemplifies an Operation led organization. As a result of these conclusions, the licensee developed an action plan entitled "Operations Centric Organization," to address the issues in the Operation Organization embracing the site-wide leadership role.

CAP performance has improved overall; however, there were areas that were identified that indicated that BFN must remain cognizant of specific aspects of CAP that were not yielding the same level of performance improvement as the rest of the program. Specifically, SR quality, PER trending, lower tier ACE quality, and SR initiation threshold were aspects of CAP where the team identified issues that indicated continued attention to performance improvement progress was warranted. A limited number of corrective actions associated with these issues identified under the CAP problem area had not had sufficient implementation time or had not been completed such that the team could provide a full assessment of the effectiveness of correctives actions. However, the corrective actions taken to date have provided reasonable assurance that performance improvement would continue with implementation of planned and completed corrective actions in the IIP.

The team observed that the licensee had improved in the overall station organizational structure as a result of actions taken in the areas of governance and oversight and that the licensee's efforts to establish a governance framework as specified in the Nuclear

Operating Model was sound. The team noted the licensee's efforts in establishing a fleet-wide management process had been overall effective in creating a mutually beneficial working relationship at TVA. The team recognized that the implementation of the Nuclear Operating Model and Governance, Oversight, Execution and Support framework at BFN warranted significant management oversight and involvement to result in long-term substantial and sustained performance improvement, specifically in the areas of oversight and human performance as addressed by the licensee's Safety Culture Continuous Improvement and Sustainability Plan.

The team also recognized that BFN performed extensive actions to align the organization around a common set of standards and goals (picture of excellence) and implement accountability. However, the IIP did not utilize this same approach with mid/lower level management and first line supervisors. The team observed multiple observations during the inspection where supervisors made inappropriate decisions, did not recognize or justified incorrect acts or behaviors from their workforce, or did not have the skill set to coach and correct poor work practices. BFN lacked a systematic approach to address this issue, such that the station would comprehensively target and correct the latent issues of workforce and supervisors' work practices and behaviors.
The team concluded that the licensee's corrective actions identified in the IIP appropriately addressed the causes of the RED finding, ROP substantive cross-cutting issues P.1(c) and P.1(d), and previously documented safety culture concerns were adequate to prevent declines in safety that could result in unsafe operations. Additionally, implemented and proposed actions identified in the IIP were appropriate to promote sustained improved performance.

8.1 Aggregate Risk Assessment

The senior reactor analyst (SRA) performed an assessment of the individual risk associated with the team's findings. In addition, the SRA performed a collective risk assessment by summing or qualitatively assessing the risk impacts of multiple separate or independent findings that overlapped in time to gain an understanding of the aggregated or collective risk profile. The collective risk assessment considered the time history (appropriate identification of start and end dates) of each overlapping inspection finding. Each of the individual inspection Findings were evaluated for significance in accordance with the Significance Determination Process and the results were documented with each Finding.

Many of the Findings in this report involved human performance issues. Human performance issues have the potential to negatively impact equipment reliability and availability, cause an increase in initiating event frequency, and increase the likelihood that human actions will not be effective in responding to events. Modeling of specific human events is possible given enough information; however, broad impacts are not well defined. Generally accepted techniques for quantification of the magnitude of degradation can be assessed systemically based on the details of the Findings. NRC risk models do not specifically model pre-initiators, or equipment left inoperable due to human errors prior to the initiating event. Based on these factors, this aggregation evaluation of risk did not warrant a numerical assessment of the human performance related factors.

The models have the ability to evaluate the impact of specific equipment being unavailable for periods of time, and the impact of initiating events. Because the Findings did not involve equipment issues that resulted in a loss of function and none of the issues existed for extended durations, there wasn't a large change to the risk evaluation. The qualitative assessment, supported by the team, determined that the aggregated risk characterization due to equipment issues was not greater than GREEN.

9 Management Meetings

On July 11, 2013, a public meeting was held to present the results of the inspection to Mr. Preston D. Swafford, Executive Vice President and Chief Nuclear Officer, and other members of the licensee's staff. The licensee acknowledged the inspection results. Propriety information was reviewed during this inspection. The proprietary information was returned to the licensee and was not included in this inspection report.

Attachments
1. List of Documents Reviewed/Acronyms
2. Inspection Procedure 95003 Information Request, February 21, 2013
3. Inspection Procedure 95003 Second Request for Information, March 29, 2013

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

W. Baker, Superintendent, Operations Support
S. Bono, General Manager, Operation
P. Branton Program Manager, Functional Area & Outage Governance
J. Browder, Program Manager Corrective Action
S. Brown, Senior Maintenance Manager
B. Bruce, Systems Engineering Manager
P. Chase, 95003 Recovery
P. Carthen, Human Resources Manager
E. Cobey, Director, 95001/Licensing
P. Donahue, Assistant Director of Engineering
S. Douglas, Vice President Nuclear Oversight
M. Durr, Management Development, Function Area & Outage Oversight
G. Doyle, Director, 95003 Recovery
B. Dungan, Senior Program Manager
W. Eckes, Site Quality Assurance Manager
J. Emens, Nuclear Site Licensing Manager
J. Ferguson, RP Manager
M. Gaston, Chemistry Manager
R. Fowler, Day and Zimmerman ECP
M. Giacini, Work Control
G. Hall, Human Performance Manager
S. Harvey, General Manager Equipment Reliability & Components
D. Horgen, Senior Manager, Corrective Action Program
D. Hughes, Senior Manager, Operations
S. Hunnewell, Director of Engineering
G. McAndrew, Nuclear Licensing
B. McCreary, Senior Program Manager, ECP
M. McKelvey, Supervisor, NSSS
M. Oliver, Site Licensing Manager
K. Polson, Site Vice President
M. Rasmussen, Senor Manager, Work Control
M. Richerson, Employee Concerns Specialist
J. Rodriguez, Assistant Maintenance Manager
T. Scott, Performance Improvement Manager
J. Shea, Vice President Nuclear Licensing
P. Summers, Director of Safety and Licensing
L. Thibault, General Manager, Performance Improvement

M. Williams, Corporate Functional Area Manager
P. Wagner, Senior Program Manager Organizational Effectiveness
A. Yarbrough, Assistant Director of Engineering

ITEMS OPENED AND CLOSED

Opened & Closed

05000296/2013011-01	NCV	Failure to Perform Evaluation of Non-conforming Material during Commercial Grade Dedication of Safety-Related Bearings (Section 5.1.3.2.1)
05000260, 296/2013011-02	NCV	Failure to Follow Procedure during Implementation of Plant Modifications to the Residual Heat Removal and Core Spray Systems (Section 5.1.3.2.2)
05000260/2013011-03	SL IV	Failure to Perform 10 CFR 50.59 Evaluation Intergranular Stress Corrosion Cracking Examination on ASME Code Class 1 Piping Weld (Section 5.1.4.2.1)
05000259, 260, 296/2013011-04	NCV	Two BFN Assistant Unit Operators Closed and Danger Tagged the A1 RHRSW Pump Manual Discharge Valve Instead of the Required A2 RHRSW Pump Discharge Valve (Section 5.2.2.2.1)
05000259, 260, 296/2013011-05	NCV	Maintenance Personnel Not Following Clearance Procedure Violation (Section 5.2.2.2.2)
05000259, 260, 296/2013011-06	NCV	Conduct of Operations Procedure Violation (Section 5.2.2.2.3)
05000259, 260, 296/2013011-07	NCV	Failure to Adequately Implement Procedure 3-SR-3.3.8.2.1(B). (Section 5.2.2.2.4)
05000259, 260, 296/2013011-08	NCV	Failure to Manage Emergent Risk Condition during A1 and A2 RHRSW Inoperability (Section 5.2.2.2.5)
05000259, 260, 296/2013011-09	NCV	Failure to control a modification to the seismically mounted control room ceiling light diffusers. (Section 5.2.4.2.1)
05000259, 260, 296/2013011-10	NCV	Requirements for Concurrent Verification, Independent Verification, and Peer Checks (Section 5.3.2.2.1)

05000259, 260, 296/2013011-11	NCV	Inadequate Corrective Actions to Address Programmatic Procedure Quality Issue (Section 5.3.2.2.2)
05000259/2013011-12	NCV	Deficient Acceptance Criteria for Main Battery Bank 1 (Section 5.3.2.2.3)
05000259, 260, 296/2013011-13	NCV	Failure To Translate The Design Into Procedure 3-SR-3.3.8.2.1(B) (Section 5.3.2.2.4)
05000259, 260, 296/2013011-14	NCV	Failure to Implement an Adequate Test Program for RHRSWS and EECS (Section 5.4.3.2.1)
05000259, 260, 296/2013011-15	NCV	Deficient Design Control for RHR Service Water Freeze Protection (Section 6.1.4.2.1)
05000259, 260, 296/2013011-16	NCV	Failure to Establish Qualified Ultrasonic Examination Procedures (Section 6.1.6.2.1)

Closed

05000259/2011011-05	URI	Verification of Valve Obturator as Required by ASME OM Code (Section 7.2)

LISTS OF DOCUMENTS REVIEWED

AUDITS AND ASSESSMENTS

Number	Document Title	Rev./ Date
	Significant Event and Condition Review Report (A Level	04/1/13-05/31/13
	DZ Safety Conscious Work Environment Pulsing Survey Browns Ferry	8/11-3/12
	BFN Nuclear Safety Review Board Meeting Minutes	1/2012
	BFN Nuclear Safety Review Board Meeting Minutes	6/2012
	BFN Nuclear Safety Review Board Meeting Minutes 95003 READINESS REPORT	12/2012
	BFN Nuclear Safety Review Board Meeting Minutes	7/2011
	BFN Nuclear Safety Review Board Meeting Minutes	10/2012
	Critical Component Failure Trend Evaluation for 3/1/08 to 9/30/09 (PER 84025)	10/27/09
	Significant Events and Issue Review (A Level PERs) July 1, 2011 – October 31, 2012 Against the Fundamental Problem Areas	01

	Significant Events and Issue Review (A Level PERs) November 1 – December 31, 2012 Against the Fundamental Problem Areas	00
	Significant Events and Issue Review (A Level PERs) January 1 – March 31, 2013 Against the Fundamental Problem Areas	00
	Review of Emergent Significant Occurrence Level “B” PERs Initiated July1, 2011 – October 31, 2012	
	Critical Component Failure Trend Evaluation for 10/27/09 to 12/31/11	
	BFN-OPS-S-10-010 BFN Operational Snapshot Self - Assessment	5/28/2010
	New Issue Review of PER 655461, Independent Oversight Effectiveness	00
	Finalization and Approval of BFN Integrated Improvement Plan Actions	8/7/12
	BFN 95003 Inspection Readiness Assessment Executive Summary	
	95003 Readiness Assessment Performance Report, CAP Combined Report	
	95003 Readiness Assessment Performance Report, Maintenance Combined Report	
	95003 Readiness Assessment Performance Report, Operations/Decision Making Combined Summary	
	95003 Readiness Assessment Performance Report, SC/SCWE Combined Report	
	95003 Readiness Assessment Performance Report, Engineering Combined Report	
	95003 Readiness Assessment Performance Report, G&O Combined Report	
	Corrective Maintenance WO Failure Trend Report	10/27/09-12/31/11
	Critical Component Failure Trend Evaluation Period: 3/1/08-9/30/09	10/27/09
	Design Engineering Program Fleet Comparative Audit	09/27/10
	QA Oversight Report	10/26/12
	QA Oversight Report	04/30/12
	QA Oversight Report	07/27/12
	QA Engineering Program –audit – fleet comparative report	12/14/12
	QA Materials & Procurement Audit	07/08/12
	QA Materials & Procurement Program Fleet Comparative Audit	08/11/10
	QA Design Engineering-Site Audit Report	08/10/10
	QA Design Engineering-Audit Report	09/24/12

	QA Design Engineering-Audit-Fleet Comparative Report	10/10/12
369800-217	Focuses Self-Assessment of the Aging Management Program	01/13
95003-003-005	IA&CPD ECP Assessment, Performance Area Report	01
95003-006	Third Party Independent Nuclear Safety Culture Assessment	09/07/12
Audit SSA 1108	QA NPG—Licensing & ECP Site Audit Report	5/11/11
Audit SSA1108	QA NPG—Licensing & ECP Audit Fleet Comparative Report	6/7/11
BF NSCMP	CY12 Reporting QTR Meeting Minutes	1/18/13
BFN IIP CAP	Self-Assessment of the BF Heat Exchanger Program	1/31/13
BFN-ENG-F-12-013	Commercial Grade item Acceptance and Dedication Process Self-Assessment Report	01
BFN-ENG-S-12-001	Surveillance Test Program Snapshot Self-Assessment	1/15-2/17/12
BFN-LIC-S-12-002	Resolution of Issues identified in PER Action 214592-060 for PER Action 368733-001	1/9-10/13
BFN-OPS-S-10-010	SOER 94-01, Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections, and Water Solid Conditions	
BFN-OPS-S-12-005	Group Snapshot Self-Assessment Report	07/12
BFN-PI-S-10-010	95002 Mock Assessment Follow-up	09/10
BFN-PI-S-13-031	The Leadership's Team's awareness and understanding of the Nuclear Operating Model and the relationship between it, the CFAM's and the GOES model.	3/4-8,13
CRD-PI-F-12-002	Operating Experience Program- Use and Applicability of OE	
CRP-ECP-S-10-001	ECP Snap Shot Assessment Corporate	9/15/10
CRP-ECP-S-12-003	ECP Snap Shot Assessment Browns Ferry Plant	8/12/12
CRP-ENG-F-11-002	Focused Self-Assessment Report	12/13/10-01/28/11
CRP-ENG-F-12-014	Report, Motors	04
CRP-ENG-F-12-021	Report, Breakers	2/9/13
CRP-ENG-S-11-005	Effectiveness Review of BF IST Self-Assessment	1/10-12/11
CRP-FA-S013-002	Nuclear Operating Model and GOES Model Execution	1/16-4/12/13

CRP-PA-I-10-002	Corporate Effectiveness Review of the CNO Strategy Assessment	6/18/10
CRP-PA-I-11-012	NPG SOER 10-2 Recommendation 1b Fleet Assessment	2/25/11
CRP-PA-S-12-001	Effectiveness review of AFI's from CRP-PA-I-11-012 on SOER 10-2 recommendation 1.b as required by PER 328901	2/21-3/23/12
CRP-PA-S-12-007	BFN SOER 10-2 Recommendation 1 Self-Assessment	8/13-17/12
CRP-PI-S-13-009	Review of BFN SOER 10-2 Recommendation 2 and 3	2/4-28/13
DRF0000-0107-0149	TVA BFN Performance and Reliability Assessment – RHR System	10/09
ENG-S-12-020 RI	EECW System Vulnerabilities	01
FN PI-S-10-010	95002 Mock Assessment Follow-up	9/7-10/10
QA-BF-12-009	Fleet Assessment of Licensing and Employee Concerns Program	3/28/12
QADM-0.11	Quality Assurance Effectiveness Review	07
RHRSW/EECW	System Vulnerability Review	2/22-2/25/10
SSA 1105	Site Audit Report Operations Functional Area	07/11
SSA1008	Design Engineering Program Fleet Comparative	09/10
SSA-1207	Materials and Procurement Audit Report	06/12
SSA1209	Design Engineering NPG Audit Report	09/12
SSA1213	QA NPG Engineering Programs – audit report	12/14/12
SSA1303	TVA Quality Assurance, Nuclear Power Group, BFN, Licensing/Employee Concerns Program Audit Report	4/12/13
BFN-ENG-F-11-004	10CFR50.59 Plant Modification Process	11/10-12/10

CALCULATIONS

Number	Title	Rev./Date
	Service Transformer (USST)-3A and USST-3A differential relay 387SA	
0018-2F-10 3B	Residual Heat Removal (RHR) Pump Inservice Test (IST) Trend Data	
10.3.390	Title: Seismic Analysis 12x16x12 Class 300 Motor Operated Valves for TVA Browns Ferry Nuclear Plant	02
10.3.415	Seismic and Operational Addendum to 10.3.390 12x16x12 Class 300 Motor Operated Valves for TVA Browns Ferry Nuclear Plant	02

10.4.200	Title: SPX Valves and Controls Copes-Vulcan Report No. 10.4.200 16 Inch Class 300 Motor Operated Globe Valve Thrust and Limiting Component Calculation for TVA Browns Ferry Nuclear Plant	03
10.4.306	Calculation Title: Weak Link Addendum to 10.4.200 12x16x12 Class 300 Motor Operated Valves for TVA Browns Ferry Nuclear Plant	05
36439-02-03	Thrust Capacity of Stem and Stem Nut	01
3-AOI-100-1	Reactor Scram	61
50147-C-003	Browns Ferry A46/IPEEE Outlier and HCLPF Evaluations for The RHR Pump Anchorage	00
50147-C-004	BFNP A46/IPEEE Outlier Evaluation – RHR Heat Exchangers	00
50147-C-005	Anchorage Outlier Resolution and HCLPF Evaluation for RHR Service Water Pumps	10
B30880711609	Revision 7 Total RHR System Head vs. Flow Rate for Priority I Mode Support (SRC Modes 74-01-M-S, 74-02-M-MS, 74-04-M-L	07
B30880711809	Total RHR System Head vs. Flow Rate For Priority I Mode Support (SRC Modes 74-01-M-S, 74-01~M-S. 74-04-M-L)	21
B30880822201	Total RHR System Head vs. Flow Rate for Priority I Mode Support (SRC Mode 74•03-M-S)	07
CD-Q0023-871459	Pipe Stress Analysis of Stress Problem No. N1-023-1R	09
CD-Q0023-880426	Pipe Stress Analysis of Stress Problem No. N1-023-3R	07
CD-Q0023-880518	Pipe Stress Analysis of Stress Problem No. N1-023-2R	07
CD-Q0023-880520	Pipe Stress Analysis of Stress Problem No. N1-023-4R	07
CD-Q0999-892719	Fluid System Component Nozzle Load and Valve Acceleration	02
CDQ0999894801	BFN LITIP Equipment Evaluation, Pump Nozzle Loads, Valve Accelerations & Operator Support Loads	20
CD-Q2074-893812	Pipe Stress Analysis of Stress Problem No. N 1-274-14R	10
CD-Q2074-900852	Seismic Qualification of Valve Accelerations	00
CD-Q2075-881234	Title: Browns Ferry Nuclear Plant, Summary of Piping Analysis N1-275-1 RA, Core Spray System	12
CD-Q2075-886548	Pipe Stress Analysis of Stress Problem No. N 1-275-4RA	15
CDQ3023910369	Pipe Stress Analysis of Stress Problem No. N1-323-5R	10

CD-Q3069-922490	: BFN Unit 3 Stress Report for Recirculation Piping Loop "A" - Stress Problem No. N 1-368-1 R	03
CDQ3073920014	Browns Ferry Nuclear Plant, Summary of Piping Analysis, N1-373-5R	08
DCN 61731	New Main Bank Transformers, Unit Station	
DCN 70132	Change setpoint of air temperature sensor for DW bulkhead	A
DCN 70664	Revise wiring so that the 43 switch prevents spurious start of EECW	A
ECP 176376	Replacement of U3 GSU Transformers and USST 3A and Installation of a new U3 Spare GSU Transformer	
MDQ0009992013000171	: Calculation of EECW/RHRSW Flow Distribution in the Absence of RHRSW Pump D1 Crosstie to EECW valve, BFN-0-FCV-067-0048 During Appendix R Fire Scenarios	01
MDQ002320100019	RHRSW System Hydraulic Analysis for Units 1, 2, & 3 RHR Heat Exchangers	01
MDQ0023980143	RHR Heat Exchanger Tube Plugging Analysis for Power Uprate	03
MDQ0030 880215	480V Auxiliary Board Room Ventilation Requirements	07
MDQ0064980007	Title: Primary Containment Analysis	07
MD-Q0067-890063	Sizing of Orifices for EECW Air Release Valves	02/84
MDQ0067930043	RHR and Core Spray Room Cooler Analysis	06
MDQ0111110034	NRC Generic Letter 89-10 Motor Operated Valve Evaluation	17
NPG-SPP-07.2.3	Plant Startup Review/Checklists	3
OPDP-8	Operability Determination Process and Limiting Condition for Operation Tracking	14
OTC-242	OTC-242 for 16” Fig 5202	01
R14980819102	RHR Heat Exchanger Tube Plugging Analysis for power Uprates	8/15/12
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MISCELLANEOUS DOCUMENTS

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BFN-ECP-S-12-001	Snap Shot Assessment-Establishment & Maintenance of a SCWE	1/12/12
BFN-PI-S-12-024	BFN Assessment of NOER Responses	
	Fleet Focus	11/17/11 and 12/11/12
	Maintenance Program Manual	
	Keeping Current	12/12 & 3/13
	NPG News	5/5,5/11/12, 5/12-13/12, and 1/22/13
	Safety Culture & Safety Conscious Work Environment PowerPoint Slides	
	Performance Review & Development (PR&D) forms for senior level managers, mid-level, and excluded schedule employees	~ FY 2013
	Site Leadership Team Semi-Annual Meeting minutes	10/01/12, 03/06/12
	TVA Nuclear Power Employee Advisory Group Charter	
	Organizational Health Index Survey 2012 Employee Review Team Charter	
	FY12 OHI Supplemental Safety and Values Questions Report	09/25/12
	OE Search and Application training slides	
	Maintenance Program Manual training slides	
	BFN Operation's Daily Instructions April 15, 2012	
	Site Leadership Team Semi-Annual Meeting minutes	10/1/12
EPRI	Capacitor Application and Maintenance Guide	12/6/06
NQA-1	ASME 1994 Edition	
NUREG/CR 5507	Results from the Nuclear Plant Aging Research Program: Their Use in Inspection Activities	
EPRI	Technical Report on Control Relay Aging Management	2011

EPRI	Guidelines for Establishing, Maintaining, and Extending Shelf Life Capability of Limited Life Items	2011
EPRI	HX Inspections	2012
89-13	Program health Report	4/23/13
GL 8913	Focused Self-Assessment Report	11/10
EPRI	Expansion Joint Maintenance Guide	01
	Program Health Report, GL 89-13	7/1/10-12/31/10
	Program Health Report, GL 89-13	7/1/11-12/31/11
	Equipment Reliability	01
ASME Code	Operation and Maintenance of Nuclear Power Plants	2004
	Eng. Strategic Improvement Plan QA Escalation	8/21/12
Plant Health Comm.	5/13, 1/28, 3/12, 5/14	
	Corporate Oversight – Level 1 Escalation Letter, Preventive Maintenance Optimization	09/17/12
BFN PMO	Recovery Project Plan	01
BFN-VTD-B083-0030	Installation and Maintenance Data for Barry Blower Bearing Lubrication	01
BFN-VTD-B083-0020	Installation & Maintenance Data for Barry Blower Centrifugal Fans	01
ISA	Setpoints for Nuclear SR Instrumentation used in Nuclear power Plants	1982
Reg. Guide 1.105	Setpoints for Safety-Related Instrumentation	1999
BFN CAP Action	Establish Plan to Overhaul all 4 EECW Strainers	
VTD-D012-0020	Vendor: Daniel Flow Products Chexter Check Valves	01
17982	Clearance Coversheet 2-CKV-0558 Back Flow Check	4/16/10
EPRI Seminar	Temperature Effects of Service Water Pump Hydraulic Performance and Reliability	6/25/96
System health Report	RHR Service Water/EECW	10/1/012 03/15/13
Component Health Report	Heat Exchangers	4/26/13 6/30/12 12/31/11
G5910-1-025-DLB	Capacitors, fixed, all types & manufacturers	00
TPD-ESP	Training Program IST, Attachment F	01
	RCW-EECW Treatment Schedule	05/12
Part 50 App. B	QA Criteria for Nuclear power Plants and Fuel Processing Plants	06/13

IEEE STD. 450	Recommended Practice for Maintenance, Testing, and Replacement of Vented lead-Acid Batteries for Stationary Applications	2/25/11
Stone & Webster	Review of Fluid Transients for BFN U1/2/3	06/88
369800-224	CAP Action Closure Report- Category 1 Closure	1/31/13
Program Health Report	IST 7-1-12-12/31/12, 7-1-11-12/31/11	
	RHR 3B Relay Setting Sheet 8945R1, 4kV Shut Down Board 3EC Panel 2	
DatAWare History	, RHR Pump 1C data Unit 1, System 74, May 21, 2013 System data page 3 of 18	10/10
	RHR Pump 1C data Unit 1, System 74, May 21, 2013 System data page 3 of 18	
76097	Baker Test System Calibration by TVA Central Laboratories	4/25/13
RHR 3B	GE Report of Motor Test, No. HSJ1142	8/25/69
PIP2012-0723	by Sargent and Lundy, Unit Trip due to Transformer Differential	
PR#61731-04 R00	Procurement Request, Transformer Differential Relay	
	BF NPP Engineering Leadership Expectations	04
10CFR Part 50	QA Criteria for Nuclear Power Plants, App. B	05/13
2RF17	Outage ISI Scan Plan	00
2RF17	Examination Schedule	00
ASME Codes	Boiler and Pressure Vessel Code, Section VA Subsection 4	2004
EPRI BWRVIP-94NP	BWR Vessel and Internals Project	2011
EPRI TR-105696-R15	BWR Vessel and Internals Project	15
PKG. AYD945B	Procurement Data Sheet Ball Bearing	17
PKG. CTK660.J	Procurement Data Sheet Banana Jack	03/13
PKG. CTK659P-X0	Test Report QA2, Banana Jack Tracking 765057 BFN	03/13
PKG. ALC105WK0	Document the Critical Thinking for the review and disposition of Central Lab Test Reports	03/13
PKG. CHM023A-R0	Address Part Number for Telltale Pneumatic Power Pack	04/13
EPRI TR-110392	Tube Plugging Criteria for Service Water Heat Exchangers	02/99
ASME IWA-2200	Examination Methods	09/09
GL 88-01	NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping	01/88
RHR-2A	Eddy Current Examination Report	10/04,

		04/05
A Level PERs	Significant Event and Issue Review	00
A Level PERs	Significant Event and Issue Review	01
B Level PERs	Emergent Significant Occurrence	00
BFN Daily	Plan of the Day	5/22/13
WW1319	Maintenance Only Daily Schedule	
Quarter 1	Training Program Health Report OPS SAP Matrix not maintained current	2013
		2013
Quarter 1	Training Program Health Report, Mechanical Maintenance	2013
	BFN Maintenance Monthly Report	09/11
	BFN Maintenance Monthly Report	09/10
	BFN Maintenance Monthly Report	09/09
082-B	Function 082-B DG (a)(1) Plan,	02
BFN NSRB	Maintenance Subcommittee Report	01/12
BFN NSRB	Maintenance and Work Management Subcommittee Report	06/12
BFN NSRB	Maintenance Subcommittee Report	07/11
BFN NSRB	Maintenance Subcommittee Report	09/12
95003-002	Collective Evaluation and Action Plan Development	03/13
QADM-0.11	Quality Assurance Effectiveness Review	07
	Strategic Council Meeting	03/6/13
410394-014	IIP CAP Action Closure Report	
2-044-02	Equipment Programs and System Monitoring	4/23/13
PMO	PMO Recovery Project Plan	01
PMO	PMO Project Phase II, Electrical Subcomponents Pilot	00
469567-009	CAP Action Closure Report, Procedures to Collect Voltage Ripple Data	04/13
NRC IN	2012-11 Age-Related Capacitor Degradation	07/12
USNRC IN	94-24 Inadequate Maintenance of Uninterruptible Power Supplies and Inverters	03/94
410394-014	Action Closure Report Revise all Limitorque Procedures to incorporate All Limitorque Tech. and Maintenance Updates based on the Results Outlined	02/13
	System Health Report RHR U1	01/13
	System Health Report RHR U2	01/13
	System Health Report RHR U3	01/13
	System Health Report RHR U3	9/12
369800-343	CAP Action Closure Report to Verify the Procedure Revisions Required to Implement the 4^{th} Interval IST Program Basis	04/13
USNRC	Safety Evaluation Report Regarding Two Relief Requests for the Third 10-year IST Program at BFN 1/2/3	11/14/02

USNRC	SER for a Relief Request to Use a Paragraph from a Later Edition of the ASME Code, Section XI, and the ASME OM CODE	02/02/09
369800-219	CAP Action Closure Report, Perform a Focused Self-Assessment for the Buried Cable program	01/13
	Program Health Report	6/13
BFN E/I&C	Moisture Impervious Medium Voltage Cable	01/06
NSRB	Operations Subcommittee Meeting Minutes	07/12/11 10/18/11
BFN-VTD-L200-0260	Limitorque-SMB Series/SB Series Installation and Maintenance Manual	06
BFN-VTD-P305-0050	Instruction Manual for Powell Pressure Seal Valves	02
BFN-VTD-W030-0110	Walworth Technical Manual for Motor Operated Valves	06
BFN-VTD-W030-0030	Walworth Motor Operated Valves	19
Walworth Motor Operated Valves	Instruction Manual for Atwood-Morril 24” Testable Check valve	02
BFN-RAH-306	Plant Rigorous Analysis Handbook “Valve Qualification”	03
	Functional Evaluation 43556 for PER 174820	
	Functional Evaluation for PER 203766 and PER 203769	
	Apparent Cause Evaluation PER 203769	10/27
BFN-50-7023	General Design Criteria Document	19
BTN-VTD-B260-0040	Operation and Maintenance for Bingham-Willamette 18”x24”x28” Single Stage CVIC Pumps Class	03
21A5790	RHR Service Water Pump Purchase	00
BFN-50-7074	Residual Heat Removal System	21
BFN-50-7074	General Design Criteria Document	21
BFN-50-7075	Detailed Design Criteria Document	12
	Installation, Operation and Maintenance Instructions for Residual Heat Removal (RHR) Pumps General Electric Company (A.P.E.D.) P.O. No. 205-H-672 Bingham Type 18 x 24 x 28 CVIC Pumps Bingham Serial Nos. 270671/690	03
LER 20120996	Unplanned Automatic Reactor Scram due to Loss of Power to the RPS	12/12/12
	Maximo CAP Overview	03/13
CRP-EP-S-12-014	Exercise Report BF Training Drill	08/22/12
R92-110103-001	2010 Blue Team Drill Report	01/03/11
	Integrated Drill Exercise Report	11/08/11

CRP-EP-S-12-016	Snap Shot Self-Assessment	9/12/12
CRP-EP-S-13-006	Snap Shot Self-Assessment	02/06/13
	Unit 2 Shift Turnover Meeting	05/14/13
	Unit 3 Shift Turnover Meeting	05/20/13
	Observation Report CARB	01-05/13
	Observation Report PSC	01-05/13
DG-M4.2.2	Metallurgical Engineering, Assessment of General Condition of Raw Water Piping Systems	02
95003-002	Collective Evaluation & Action Plan Development	02
95003-003-FA-008	IA & CPD-BFN Inservice Testing Program Focused Assessment	02
95003-003-FA-016	IA & CPD-BFN Surveillance Test Program Assessment	01
BFN	Maintenance Team KPI Reports, September 2012, March 2013	
506529	PM Deferral Clean RFPT Turbine Oil Tank C.	12/01/12
691582	PM Deferral Inspection and PM on 480V RMOV Board 2B	06/01/13
691959	PM Deferral Perform Electrical Preventative Maintenance and Inspection on 2-MVOP-023-0046	06/01/13
505422	PM Deferral Perform EPI-0-000-MOV-001 On 1-MVOP-3.5	12/01/12
692923	PM Deferral Replace the Agastat Relays at the Shut Down Board	06/01/13

PERS AND CAUSE ANALYSES

Number	Document Title	Rev. #
	PER Summaries of Corrective Action on Safety Culture	
54313-	95003 Fundamental Problem: Resource Management	4/25/13
21322	Vault Summary Report for PER: 213224	
68092	680792, Procedures and Work Instruction (resources) omit necessary technical details/steps to support work	2/12/2013
143157	Summary Report for 2A RHR HEX Floating Head Seal Weld	
174820	Summary Report for Unit 2 Loop I Core Spray System Leakage	
213088	PER Functional Evaluation Low EECW Flow to 3A Diesel Generator	
214592-061	EFR-Implementation Issues	
217728	SI 3.2.4 Test Configuration	
243132	EECW DG Functional Failure	
243684	INPO 2010 Assessment-AFI-IER 2.1	
43697	INPO 2010 Assessment – AFI or 1-2	10/19/11
274840	1C RHR Motor Failure	1/21/11

298861	During the BFN Emergency Preparedness training drill conducted on 12/9/10, the state update was not performed	12/17/10
315818	PER Bypass Flow in 2C RHR Heat Exchanger Lower Tier Apparent Cause	
345374	ICS point 23-42 for RHRSW C Flow Setpoint	
369800-365	Verify that an NPG Controlled Design Basis Exists of the MOV Program	
369800-232	IIP CAP Action Closure Report Perform a focused self-assessment of the Browns Ferry Pump Program IIP	
369800-227	Report Perform a focused self-assessment for the Motor Operated Valve Program IIP CAP PER/Action Number	
369800	Undetected Failure of the 1-FCV-74-66, Root Cause Report (RCA)	
381569	Monitor and trend EECW flows to all eight DG HEXs	
381569	3D Diesel Generator Inoperable due to low EECW flow	
383204	A3 EECW STN Inspection	
387889	ACE Report RHRSW/EECW Pump B2, A3, C1, D2 Low Flow Condition	
423213	BFN Cooling Tower project did not meet schedule and budget	
423553	BFN July 2011 NSRB Chairman Recommendation	9/28/11
430206	500 kV Switchyards Exceeding the Prescribed Voltage Scheduled	
431148	95003 Inspection Readiness Review – IST	
435440	Formal Cause Analysis	2/20/12
436575	Continued Leakage Issue was Identified by the BFN Mid-Cycle Integrated PA	
437973	95003 Discrepancy in acceptance criteria section and action steps in 2-SI-4.5.C.1(3)	
440224	Since 11/30/10 TVA fleet wide Has Had Five Events Involving Loss of Control of SGI	
440359	U3 Scrammed on 9/28/11	
464028	Possible Inadvertent Exchange of Drill Information with a Participant,	11/18/11
468954	NSRB Operations Subcommittee recommendation, October 2011	1/10/12
468956	NSRB Operations Subcommittee recommendation, October 2011	1/12/12
469528	NSRB Operations Subcommittee recommendation, October 2011	12/22/11
469567	ACE Untimely Replacement of Battery Charger Capacitors	
469634	NSRB Chairman Recommendation from October, 2011 BFN NSRB	4/27/12
469642	NSRB Chairman Recommendation from October, 2011 BFN NSRB	3/20/12
469695	NSRB Chairman Recommendation from October, 2011 BFN NSRB	9/27/12
470068	NSRB Chairman Recommendation from October, 2011 BFN NSRB	3/1/12
475878-015	CAP Action Closure Report, Implement a Maximo CAP Users Working Group	03/13

475878	Ineffective Corrective Action Program across the TVA Nuclear Power Group	10/24/12
501815	PI&R Readiness review, System Health reports	
509696	95003-003-FA-16 Surveillance Test Program Resources	
509699	Surveillance Test Program Outage Tests	
509735	IER L2-11-2 recommendation 9 GAP identified	
509774-002	Brief CARP on SC & SCWE Details from 2012 PI&R Inspection	
513715	Surveillance Test Program Reports	
515388	Equipment Reliability Program GAP Plan	
516455	Operational Focus/Decision-Making issues	01/10/13
516458	Work Management Root Cause Analysis (RCA)	03/05/12
520972	Areas for Improvement Related to Principles for a Strong Nuclear Safety Culture	
523769	Legacy Issue found during Surveillance Test Self-Assessment	
524787	Surveillance Test Program SA	
529712	PER Vault Summary Report for PER: 529712	
530439	PER Vault Summary Report for PER: 530439	
531079	Fouling Conditions of the 3D Diesel Heat Exchangers	
532356	Interim CA for Operational Focus Decision Making RC	4/13/12
539534	Interim CA for Operational Focus Decision Making RC: PER 516455	9/10/12
ACE 542377	Ineffective Corrective Actions (NOM/GOES Implementation) PER 693148	3/8/13
542377	95003 Fundamental Problem: Governance, Oversight, and Monitoring	4/25/13
543130	Resource Management	00
543131	ACE Technical Rigor	02
543132	ACE Design Configuration Control	02
543134	Apparent Cause Evaluation – Inappropriate Reliance on Processes	01
543135	GAP Analysis of Procedure Use & Adherence Root Cause Analysis, 01/13	
547424	Strategic Equipment Managerment ACE	02
547427	FPA: Equipment Programs and System Management ACE	
547431	Apparent Cause Evaluation – Continuous Learning Environment	01
549159	GAP Analysis of CAP Root Cause Analysis Reports	5/9/12
552135	Preliminary GAP Analysis of Procedure/Instruction Quality	06/12
552170	CRP-ENG-F 12-016 LO – duct back moisture trending	
555391	Learning Opportunity 3 from CRP-ENG-F-12-019	
555573	Unit 3 SCRAM of 5/22/2013 - CT Polarity Issue	
558183	Unit 3 SCRAM of 5/29/2013 – Differential relay failure	

562780	License Renewal Focused Self-Assessment CRP-ENG-F-12—026 Learning Opportunity	
571345	ECP, ACE PER Report	02
575801	NSRB Chairman Recommendations-Minutes dated July 5, 2012 from BFN June 2012 NSRB meeting	10/25/12
576848	NSRB Chairman Recommendations – Minutes dated July 5, 2012 from BFN June 2012 NSRB meeting	11/5/12
576857	NSRB Chairman Recommendations – Minutes dated July 5, 2012 from NSRB meeting	10/9/12
579250	Unqualified Tasks performed by personnel in Maintenance and Technical Training Program	03
591105	Increasing Trend in NRC Allegations, ACE Report	02
595244	BFN Review of WBN 8/10/13 NOUE Declaration	08/14/12
596266	COC Engineering Review/Evaluate NRC in 2012-11	
600151	QA Identified – SSA1209 – WBNEQ 11011 not Incorporated in EQ Binder in Time Requirements	08/24/12
604427	Revise root cause evaluation for PER 243132	
617305	Timeliness Implementation of CAs to address EECW System Health	
619929	Site Leadership Team Second Semi-Annual Nuclear Safety Culture Monitoring Meeting	
629212	RCA PER Report	02
630742	Discrepancy in NPG procedures	
633836	Operability Determination Review Board (ODRB)	
634860	Room Cooler Coils for Unit 1	
645289	Engineering Program Owners have not completed qualification requirements	
646538	Significant Issue GAP Analysis	01/13
655461	Root Cause Analysis: Independent Oversight Effectiveness	
665294	Change Deferral WO 113110504	05/28/12
666508	The following key issue was noted in the Chairman's portion of the NSRB 95003 Review Minutes	1/11/13
666520-001	1BFN-ECP-S-13-001, (in response to PER 571345-008 Column 4 Recovery 95003) Identified; NSRB Identified	3/4/13
668744	RCA Commercial Grade Dedications Implemented Inconsistent with 10CFR21 95-11	
668841	95003 Review Team identified- Identified GAP Analysis of Procedure use and Adherence	1/17/13
669542	Maintenance Standards Initiative	1/18/13
675937	Radiograph of 2-CKV-67-639 Showed Valve to be Partially Open	
677491	B3 EECW Pump High Vibration JH 2/5/13	

680792	Procedures and Work Instruction (resources) omit necessary technical details/steps to support work	
680792	Procedures and Work Instruction (resources) omit necessary technical details/steps to support work - Root Cause Analysis 02/13	
691892	PER 542377- Ineffective Corrective Actions	3/13/13
692074	Per 542377-Ineffective Corrective Actions	3/13/13
695846	WANO Identified Area for Improvement (MA. 1-3) RCA	3/14/13
687265	Additional PM Deferral Required	02/25/13
700273	Mechanical First Line Supervisor failed to meet expectations for oversight of maintenance	4/10/13
700624	95003 PT 3: PER 567742 supporting NCV found corrupt in Maximo	05/10/13
700864	Protected Equipment Program Implementation GAPs (ACE)	
702151	MSI-FIN First line supervisor failed to meet expectations for oversight of maintenance	3/27/13
702639	NSI-BFN Electrical First Line Supervisor failed to meet expectations for oversight of Maintenance	3/27/13
703943	Requirements of TSR 3.8.1 on EDGs	
706191	Preliminary Independent Nuclear Safety Culture Assessment Results Review	05/23/13
707519	MSI-BFN I&C failed to meet expectations for oversight of maintenance	4/7/13
707531	Adverse Trend in Concurrent Verification Practices 4/5/13 ACE	00
720487	ePOP gap in observation of contractor oversight	
713321	I&C Removed Speed Sensor Without Steps in the Work Package	4/17/13
723508	WO 114369751 Failed inspect 2-CKV-067-0639	5/10/13
723646	Use of PM Deferral for Schedule Changes while still in Grace	05/08/13
739929	95003 PT 3 DCN 69466 and 69467 Do Not Meet NPG-SPP-09.3 Section 3.2.17	6/13/13
748039	95003 Pt. 3 BFN Nuclear Safety Culture Monitoring Panel	

PROCEDURES

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	Various Calibration Reports	
0-AOI-100.3	Flood Above Elevation 558’	35
0-GOI0300-3	General Valve Operation	138
0-GOI-200-1	Freeze Protection Inspection	71
0-GOI-200-1	Freeze Protection Inspection	73

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0-OI-23	Operating Instruction Residual Heat Removal Service Water System	94
0-OI-23/ATT/1C	Valve Lineup Checklist Unit 3	87
0-OI-23/ATT-1	Valve Lineup Checklist Unit 0	87
0-OI-23/ATT-1A	Valve Lineup Checklist Unit 1	87
0-OI-23/ATT-1B	Valve Lineup Checklist Unit 2	89
0-OI-23/ATT-2A	Panel Lineup Checklist Unit 1	88
0-OI-23/ATT-2B	Panel Lineup Checklist Unit 2	87
0-OI-23/ATT-2C	Panel Lineup Checklist Unit 3	87
0-OI-67/ATT-1A	Valve Lineup Checklist Unit 1	85
0-OI-67/ATT-2A	Panel Lineup Checklist Unit 1	84
0-OI-67/ATT-2C	Panel Lineup Checklist Unit 3	84
0-SI-3.1.11	Pump Baseline Data Acquisition and Evaluation	23
0-SI-4.5.C.1(D2)	RHRSW Pump D2 IST Group A Quarterly Pump Test	01
0-SI-4.5.C.1(D3)	RHRSW Pump D3 IST Group A Quarterly Pump Test	06
0-SR-3.7.3.2(B)	Control Room Emergency Ventilation System Iodine Removal Efficiency	08
0-TI-230	Predictive Maintenance Program	25
0-TI-362	RHRSW IST	37
0-TI-362 (BASES)	Applicable Flow Diagrams, ISI Drawings, and Design Criteria	02
0-TI-63	RHRSW Flow Blockage Monitoring Revision 0026	26
1-AOI-1-1	Abnormal Operating Instruction Relief Valve Stuck Open	03
1-AOI-99-1	Loss of power to One RPS Bus	20
1-SI-4.2.B-55	CSCS RHR Loop II Discharge Pressure Calibration	12
1-SIMI-74A	Residual Heat Removal System Index	
2-AOI-99-1	Loss of Power to One RPS Bus	27
2-ARP-9-3E	Panel 9.3 2-XA-55-3E	25
2-OI-75	Operating Instruction Core Spray System	106

2T-056-0002-00-03	Setpoint and Scaling Document	03
3-ARP-9-23D	Diesel Generator 3D Ground Fault	18
3-OI-74	Residual Heat Removal System Revision	109
3-SR-3.5.1.6	RHR Loop II Comprehensive Pump Test Revision	10
3-SR-3.84.2	DG 3D) Diesel Generator 3D Battery Service Test	20
95003-003	Identification, Assessment, & Correction of Performance Deficiencies	00
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BFN 95003-004	Assessment of Performance in the Reactor Safety Strategic Performance Area (IP 95003 Section 02.03)	
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DCN 69907	Install New Motor Operators on Valves 3-FCV-074-007	06/11
DCN 701761	Remove vent and drain lines from RHR Pump Room Coolers 2A and 2D	04/13
DCN 70946	Issue Design Output that Documents the Most Limiting Flow to Each EECW Heat Exchanger and Cooler	A
DG-M4.2.2	Metallurgical Engineering Design Guide	02
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EPI-0-000-MCC001	Maintenance And Inspection Of 480V AC and 250V DC Motor Control Centers	75
EPI-0-000-MOV006	Maintenance and Adjustments for Types L120-10 and LY2001 Limitorque AC Motor Operators	01
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G-38	Installation, Modification, and Maintenance of Insulated Cables Rated Up to 15,000 Volts	21
G-40	Installation, Modification and Maintenance Of Electrical Conduit Cable Trays, Boxes, Containment Electrical penetrations, Electric Conductor Seal Assemblies, Lighting and Misc. Systems	17
MCI-0-000-CKV006	Generic Maintenance Instructions for Wafer Check Valves	02
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NPG-SPP-01.2	Administration of Site Technical Procedures	07
NPG-SPP-01.5	Peer Teams	01

NPG-SPP-01.6	Nuclear Power Group Corporate Duty Officer	00
NPG-SPP-01.7	Nuclear Safety Culture	02
NPG-SPP-01.7	Nuclear Safety Culture	00
NPG-SPP-01.7.2	Nuclear Safety Culture Monitoring	00
NPG-SPP-02.3	Operating Experience Program	05
NPG-SPP-02.8	Integrated Trend Review	03
NPG-SPP-02.9	CAP Health Monitor	07
NPG-SPP-03.1	Corrective Action Program	05
NPG-SPP-03.1.10	PER Effectiveness Review	04
NPG-SPP-03.1.12	NPG Benchmarking Program	00
NPG-SPP-03.1.4	Corrective Action Program Screening and Oversight	11
NPG-SPP-03.1.5	Apparent Cause Evaluations	07
NPG-SPP-03.1.6	Root Cause Analysis	06
NPG-SPP-03.1.7	PER Analysis, Actions, Closures, and Approvals	11
NPG-SPP-03.2	Nuclear Safety Oversight	01
NPG-SPP-04.2	Material Receipt and Inspection	02
NPG-SPP-04.3	Material Storage and Handling	01
NPG-SPP-06.2	Preventive Maintenance	07
NPG-SPP-06.2.1	Condition Based Maintenance Implementation	00
NPG-SPP-06.3	Pre-/Post-Maintenance Testing	01

NPG-SPP-06.4	Measuring and Test Equipment	01
NPG-SPP-06.5	Foreign Material Control	01
NPG-SPP-06.7	Instrumentation Setpoint, Scaling and Calibration Program	01
NPG-SPP-06.9	Testing Programs	00
NPG-SPP-06.9.1	Conduct of Testing	05
NPG-SPP-06.9.3	Post-Modification Testing	04
NPG-SPP-06.10	NPG Fix It Now (FIN) Team Process	00
NPG-SPP-07.1	On Line Work Management	09
NPG-SPP-07.1.2	On-Line Ready-Ready	03
NPG-SPP-07.1.4	Work Control Prioritization – On Line	03
NPG-SPP-07.3	Work Activity Risk Management Process	11
NPG-SPP-07.6	NPG Work Control Planning Procedure	02
NPG-SPP-09.1	ASME Code and Augmented Programs	02
NPG-SPP-09.12	Margin Management	03
NPG-SPP-09.14	Generic Letter 89-13 Implementation	02
NPG-SPP-09.16	Plant health Committee	04
NPG-SPP-09.16.1	System, Component and Program Health	02
NPG-SPP-09.18	Integrated Equipment Reliability Program	04
NPG-SPP-09.18.1	Material Condition Improvement Plan-System Vulnerability Reviews	05
NPG-SPP-09.18.2	Equipment Reliability Classification	01

NPG-SPP-09.18.3	Equipment Reliability Program Component Strategy Development and Implementation Process	02
NPG-SPP-09.18.5	Development of Life Cycle Management Plan	00
NPG-SPP-09.18.7	Single Point Vulnerability Review Process	02
NPG-SPP-09.21	Cable Aging Management Program	01
NPG-SPP-09.3	Plant Modifications and Engineering Change Control	13
NPG-SPP-09.3.1	Guidelines for preparation of Design Inputs and Change impact Screen	02
NPG-SPP-09.3.2	Risk Ranking, Compensating Actions and Augmented Reviews	01
NPG-SPP-09.4	10CFR 50.59 Evaluation of Changes, Tests and Experiments	05
NPG-SPP-09.4	10CFR 50.59 Evaluation of Changes, Tests and Experiments	05
NPG-SPP-09.5	Temporary Alterations	02
NPG-SPP-09.5	Temporary Modifications	05
NPG-SPP-09.9	10CFR 72.48 Evaluations of Changes, Tests, and Experiments for Independent Spent Fuel Storage Installation	01
NPG-SPP-10.2	Clearance Procedure to Safely Control Energy	05
NPG-SPP-10.3	Verification Program	01
NPG-SPP-18.2	Human Performance Program	00
NPG-SPP-18.2.1	Oversight of the Human Performance Program	03
NPG-SPP-18.2.2	Human Performance Tools	06
NPG-SPP-18.2.3-1	Incident Prompt Investigation (Prompt) Form	05/13
NPG-SPP-18.4.8	Control of Ignition Sources (Hot Work)	00
NPG-SPP-31.1	Document Control	02
NPG-SPP-7	Work Management	00

NPG-SSP-01.4	Governance, Oversight, Execution and Support Program	02
NPT-SPP-06.2.1	Condition Based Maintenance Implementation	00
NQA-PLN89-A	Nuclear Quality Assurance Plan	0
N-UT-64	Ultrasonic Examination of Austenitic Pipe Welds	12
N-UT-65	Ultrasonic Through Wall Sizing in Pipe Welds	06
N-UT-76	Ultrasonic Examination of Ferritic Pipe Welds	08
N-UT-78	Manual ultrasonic Examination of Reactor Pressure Vessel Welds PDI-UT-6	06
N-UT-82	Ultrasonic Examination of Dissimilar Metal Welds	05
N-UT-84	Phased Array UT Examination of Austenitic and Ferritic Pipe Welds	01
N-UT-84	IGSCC Exam	11
ODM-4.18	Protected Equipment	11
OPDP-1	Conduct of Operations	27
OPDP-1	Operations Log	5/5-5/6/13
OPDP-11	Operational Decision Making Evaluation Process	02
OPDP-8	Operability Determination Process and Limiting Conditions for operation Tracking	14
PDI-FG	Performance Demonstration Initiative Focus	03
PDI-UT-1	Ferritic Pipe Welds	E
PDI-UT-2	Austenitic Pipe Welds	E
PDI-UT-3	Through-Wall Sizing in Pipe Welds	E
PIDP-20	Corrective Action Program Lower Level Metrics	03
PM 500103184	Evaluation, Perform Check of Plant Sump Pumps	05/13
PM 500103528	RHR SW motor offline testing	03/10
PM 500136376	Perform Charger/Inverter Overhaul and Replace Electrolytic Capacitors	05/13
PM 500139924	RHR SW motor offline testing	03/10
PMTI-61731-004	Differential Relays	9/21/12
QADM-0.11	Quality Assurance Effectiveness Review	4/01/13
QADM-0.12	Quality Assurance Observations	05
SP-11.17	Leadership Assessments	01
SPP-01.7.1	ECP Program	01
SPP-02.4	TVA Incentive	00
SPP-1.7	Nuclear Safety Culture	00

SPP-1.7.2	Nuclear Safety Culture Monitoring	00
SPP-10.3	Verification Program	00
SPP-11.10	Adverse Employment Action	02
SPP-11.16	Individual Development Plans	00
SPP-11.18	Deep Dive Program	01
SPP-11.19	New and Transitioning Leaders	01
SPP11.3.16	Employee Discipline	01
SPP-11.302	Integrated Performance Management for Managers Specs, & Excluded Schedule Employees	02
SPP-11.302	Succession Planning	02
SPP-11.8.4	Expressing Concerns & Differing Views	07
SPP-18.005	Plan jobs Safety	10
SPP-19.5	Conflict Resolution	00
SR-3.5.1.6	Core Spray Loop I Comprehensive Pump Test	
SS-E12.6.02	5-15kV Cable, Moisture Impervious, Ethylene-Propylene Rubber Insulated	01
TACF 0-10-004-067/R0	Emergency Equipment Cooling Water System	07/10
TACF 2-10-004-074/R0	Remove the RHR Loop II LPCI piping insulation between the 2-FCV-74-66 and 2-FCV-74-67.	03/10
T-DCN T40220C	Impeller Replacement RHRSW Pump	10/99
TE 9300026106M003	Fixed Electrolytic Capacitors	11/22/11
TRN-12	Simulator Regulatory Requirements	11
TS 3.4-12	Reactor Coolant System	A234
TS 3.6	Containment Systems	
TS 3.9	Refueling Operations	
TS 5.1	Administrative Controls	
TVA 40897	NPG Pre-Job Briefing Checklist	1/11/12
TVA-SPP-11.301	Succession Planning	02
TVA-SPP-11.302	Integrated Performance Management for Managers, Specialists, and Excluded Schedule Employees	02
U1 TS 3.6.1.4	Containment Systems Drywell Air Temperature	234
U1 TS 3.6.2.1	Containment Systems Suppression Pool Temp	234
U1 TS 3.6.2.4	Containment Systems RHR Suppression Pool Spray	234
VTD-B083-0040	Barry Blower Versacon “R” Centrifugal Fans Backward inclined & airfoil wheels	01

729163, 733390	95003 PT 3 raw water training, see details
729167	Maintenance Clock reset missed opportunity
729168	Maintenance Department Turnover of plant events
729176	Unit 2 Fuel Pool Cooling Pumps not protected
729178	System Eng. not cognizant of A(1) Plan Actions
729179	NRC identified. “95003 PT 3” Remove sump pumps and hoses Intake Cable Tray
729180	95003 PT 3 Heat Trace flex has pulled out of the insulation.
729180 114699318	Heat Trace flex has pulled out of the insulation
729188	NPG-SPP-06.5 Foreign Material Control -- latest revision (Rev 2) is not in BSL
729211	95003 PT3 Walkdown
729211 114699339	Walkdown
729557	Repair insulation
729557 114703202	Repair insulation
729603	95003 PT 3 - Cigarette pack found in RHRSW Pump Room ‘C’
729603 114703644	Cigarette pack found in RHRSW Pump Room ‘C’
729618	95003 PT 3, Exposed electrical wiring between two heat trace components.
729618 114703802	Exposed electrical wiring between two heat trace components
729623	95003 PT 3, Disconnected conduit on underside of temperature switch box.
729623 114703836	Disconnected conduit on underside of junction box
729625	NRC identified housekeeping issues
729646	Commercial Grade Dedication of Bearing AYD945B -- NRC 95003 Item ID no. 0349-02
729654	Interview results indicate uncertainty exists in revising procedures
729674	NRC Question for QA
729682	95003 Walkdown
729682 114704781	95003 Walkdown
729705	Missed learning Opportunity Per 703268 A1 RHRSW HURB

729724	95003 PT 3 Cable and lock were staged @ U-2 FPC cage door (lock not in use) for when it was necessary
729726	NRC feedback
729727	95003 PT 3 RP received notification that NRC identified electrical routing issues for AMS-4 and air
729732	95003 PRT 3, Evaluate air monitor power supply
729733	95003 PT 3 Inspection due to SR 728141. There is no C-zone in area nor is water flowing out of a c-z
729735	95003 PRT 3, Local amp indication does not match Main Control Room indication
729738	95003 PT 3 Effectiveness Review of IST Corrective Actions
729753	95003 Part 3 - Housekeeping issue at U3 Precoat Tank
729755	95003 Part 3 - Fuel Pool Cooling cage swing gate not secure
729757	95003 Part 3 - Housekeeping issue at back of Panel 3-LPNL-925-0009
729758	95003 Part 3 - Housekeeping issue at Calgon Building
729764	95003 PT 3
729786	Defense in depth tag in U1 northwest quad
729787	95003 Part 3 - CI-13.1 not referenced in the WOs for 1/2/3-SI-4.6.B.1-4
729789	95003 Part 3 - Dose rate meter not listed Special Tools Equipment Recommended in 1/2/3-SI-4.6.B.1-4
729790	95003 Part 3 - Housekeeping issue at U1 Precoat Tank
729791	95003 Part 3 - Housekeeping issue at U2 Precoat Tank
729792	95003 PT 3 Burnt out bulb at local hand switch
729792, 729793	Housekeeping Issue: Red tape on hand switch indicating lights.
729793	95003 PT 3 Housekeeping Issue: Red tape on handswitch indicating lights.
729810	Report of CAL and Tool room issue ticket conflicts
730249	NRC Identified housekeeping issues
730250	N-UT-64 and N-UT-84 Procedure Revisions
730276	95003 PT 3
730305	95003 PRT 3, Local amp indication does not match Main Control Room indication
30305, 114709113	95003 PRT 3, Local amp indication does not match Main Control Room indication
730315	95003 PRT 3, Local amp indication does not match Main Control Room indication

730315, 114709150	95003 PRT 3, Local amp indication does not match Main Control Room indication
730321	Unit 1 Core Spray housekeeping
730323	95003 pt 3 Duct tape found at ceiling on fire header pipe penetration
730323, 114709204	Duct tape found at ceiling on fire header pipe penetration
730327	95003 PT 3 1-HS-75-23B has bulb burnt out and tape over it.
730327, 114709240	95003 PT 3 1-HS-75-23B has bulb burnt out and tape over it.
730331	95003 pt 3 1-PI-75-41 reading high
730331, 114709265	95003 PT 3 1-PI-74-41 reading high
730334	95003 pt 3 Hanging drop and Body to bonnet connection with slight degradation at surface.
730334, 114709293	95003 PT 3 Hanging drop and Body to bonnet connection with slight degradation at surface.
730346	95003 pt 3 1-BKR-75-0014 breaker green bulb not illuminated
730346, 114709325	95003 PT 3 1-BKR-75-0014 breaker green bulb not illuminated
730353	95003 PT 3 0-TI-362 Typical UNIDs for skid mounted valves
730355	95003 Part 3 - Housekeeping issue at Panel 3-AN-043-2075
730358	95003 PT 3 - RHRSW Pump air release valve Inspection
730358, 114709430	95003 PT 3 - RHRSW Pump air release valve Inspection
730376	Potential trend in Service Request initiation
730384	Potential trend in lower tier ACE quality
730423	95003 PT 3 - RHRSW Pump air release valve Inspection
730423, 114710140	95003 PT 3 - RHRSW Pump air release valve Inspection
730424	95003 PT 3 - RHRSW Pump air release valve Inspection
730424, 114710148	95003 PT 3 - RHRSW Pump air release valve Inspection
730427	95003 PT 3 - RHRSW Pump air release valve Inspection
730427, 114710170	95003 PT 3 - RHRSW Pump air release valve Inspection
730429	95003 PT 3 - RHRSW Pump air release valve Inspection
730429, 114710185	95003 PT 3 - RHRSW Pump air release valve Inspection
730432	95003 PT 3 - RHRSW Pump air release valve Inspection
730432, 114710199	95003 PT 3 - RHRSW Pump air release valve Inspection

730434	95003 PT 3 - RHRSW Pump air release valve Inspection
730434, 114710202	95003 PT 3 - RHRSW Pump air release valve Inspection
730435	95003 PT 3 - RHRSW Pump air release valve Inspection
730435, 114710204	95003 PT 3 - RHRSW Pump air release valve Inspection
730440	INTR 651000-013 (Maintenance procedure validation) is ineffective
730443	95003 - Part 3 - NRC Identified - Main Control Room Ceiling Panels
730444	95003 PT 3 Vibration Analyzer Calibration
730445	95-003 NRC identified, SR's not written in a timely manner
730447	improper questioning attitude
730447	improper questioning attitude
730449	95003 PT3 conduits improperly sealed
730449, 114710231	95003 PT3 conduits improperly sealed
730453	95003 PT 3 NRC Identified; Cable Program Health Report Is Inadequate
730467	95003 PT 3 Electrical routing to AMS-4 and air sampler in the 1C Mech. Equip Room
730495	95003 PT 3 1,2,3-SR-3.3.8.2.1(A), (B), (C) fails to prescribe M&TE accuracy requirements
730893	WO 111118040 not processed timely - Original condition identified during NRC 95003 inspection.
730893, 114713060	WO 111118040 not processed timely - Original condition identified during NRC 95003 inspection.
730931	NPG-SPP-09.5 Editorial Change
730995	95003 PT 3 - Diesel Aux Board Exhaust Fan
730999	95003 PT 3 HH26 has water in it.
730999, 114713677	95003 PT 3 HH26 has water in it.
731087	95003 PT 3 M&TE issue for 114265032 0-SI-4.5.C.1(A1)
731092	Missed Opportunity
731144	95003 PT 3 During the 4/2013 performance of 3-SR-3.3.8.2.1(B), M&TE step N/A'd
731146	95003 PT 3 NEDP-20 System Walkdowns
731149	95003 PT 3 NRC Inspector identified PM typographical error
731429	95003 Pt 3 Initiate Part 21 Evaluation for MSRV valve piston found cracked at Wyle
731524	95003 PT 3 NRC Identified - Surveillance 0-SR-3.3.7.1.4
731551	Missed Opportunity
731570	95003 PT 3 - A1/A2 RHRSW PUMP - Decision Making

731574	PM #500103184 is deficient. (BFN 95003 Audit)
731580	Error Identified on NDE UT Report Provided to NRC
731637	95003 PT 3 Potential Part 21
731645	95003 PT 3 WO packages
731654	95003 PT 3 More Cables added to MR List
731661	95003 PT 3 WOs documented as DC incorrectly, see details.
731892	NPG-SPP-09.14 Generic Letter (GL) 89-13 Implementation Procedure Problems
732107	95003 PT 3 GL 89-13 Inspection
732158	95003 PT 3 DG Flush steps, see details.
732158, 113859592, 114216053	DG Flush steps, see details
732298	CRP-ENG-F-12-019
732358	95003 PT 3 CRP-ENG-F-12-019
732359	95003 PT 3 Inadequate design output for RPS circuit protector calculations
732407	95003 PRT 3 - Oil soak pads and mop heads found in DG Fan Rooms
732409	95003 PRT 3 - Oil soak pads and mop heads found in 'D' DG Fan Room
732439	TVA procedure or formal training for evaluating material shelf life requirements does not exist
732519	95003 PT 3 PER to drive resolution on NRC questions about RHRSW ARV performance
732521	95003 PM deferrals on the RHRSW pump pit have inaccurate late date.
732524	95003 PT 3
732529	95003 PT 3 - 0-GOI-200-1, Freeze Protection Inspection Retention Requirement
732531	95003 PT 3 Historical issue with disconnect between SSD and 3-SI-4.1.B-16(B)
732537	95003 PT 3 3-RFV-23-555 port 75% blockage in 2007, see details
732564	95003 PT 3 GL 89-13 Heat Exchanger Visual Inspections
732571	INITIATE SELF ASSESSMENT OF SHELF LIFE PROGRAM AT BFN - 95003
733390	95003 PT 3 raw water training, see details.
733495	NRC not notified of discrepancy identified by PER 443133
733517	WO 06-722059-000 not processed timely - Original condition

	identified during NRC 95003 inspection.
734054	95003 PT 3 ESP075.531 will need revision, see details
734318	95003 PT 3 raw water visual inspections, see details
n/a	Spent Fuel Pool Time to Boil Information

SRs and PERs Generated as a Result of 95003 Inspection

SR Number	Related PERs / WOs	Summary Description
695499	696472	Critical Component Corrective Maintenance Work Order evaluations in OPEN status in SRM.
696598	174461, 201402, 696681	GE RICSIL 090 & GE SIL 662 have applicability to Unit 1.
698221	699028	Need to revise Diesel Generator 2 Year Inspection surveillances
698729	699655	95003 PIs for Independent Oversight inaccurate for NRC Orientation presentation
699622	701486	NRC 95003 OPDP-1 review
700225	700624	PER 567742 supporting NCV found corrupt in Maximo
701158	702039	Critical Thinking documentation for PER action 215281-001
702407	704843	NRC identified – 95003 Review Access Training Material
702794	703799	Need to clarify FSAR and Design criteria with respect to RHR pump
703009	703769	NRC 95003 identified – improper scaffold tie off
703314	703892	Modifications in INSTV status for an excessive duration
708835	710181	95003 PT 3 – B2 RHRSW Vendor Manual
709001	710192	Concerns with the 50.59 done for U1 CRD high temperatures
709663	710444	95003 PT 3 NRC Orientation Material on Equipment Performance,
710147	711011	NRC walkdown of outside areas
710250	711457, 114597450	NRC Identified broken conduit on BFN-2-FCV-068-0035, JET PUMPS SUPPLY HDR ISOL VLV
710271	711902	NRC Identified loose conduit on back of BFN-2-PNLA-025-0404, TRANSIENT SHIELD
710444710308	710998	NRC identified rusty RBCCW on the outside of both A and B Blower Banks inside the Drywell
710310	711232	NRC walkdown of RHRSW pump rooms resulted in

		NRC identified deficiencies
713473	714505	PER Corrective Action Revision
713925	715476	Training procedure TRN-18
713944	714777	Planning Department CRC
713949	714580	Inadequate PER action completion
713952	714583	TPN-PLN training requirement
714213	714273	IPS-RHRSW PMP RM deficiencies transient combustible material trend
714328	714820	QA noted shortfalls in BFN Work Management Process
715941	718239	Operability Determinations Review Boards - Lack of sustainability
715947	718243	Ops Aggregate Indicator performance
716068	716821	Engineering Inspection Vulnerabilities (Technical Rigor/Equip Performance Monitoring and Trending)
716264	717504	NRC Observation regarding NPG-SPP-03.1
716864	718026	Inspector observation for deferred PMs
716904	717533	NPG SPP 6.10 sections 3.2.A.1 and 3.1.B1-4 needs clarification *[note: this should close to SR 716904]*
717229	718135	Difficulty in obtaining timely data to support an inspection request
717267	717278	Issue associated with NPG-SPP-06.10 ambiguities
717644	718347	IST Filing In Accordance With ISTA-3200 (a)
717883	720802	95003 PT 3 Inspector Observation for NPG-SPP-06.9.2
717929	718374	95003 PT 3 - Replacement undervoltage relay not available for scheduled replacement
718029	718390	95003 - part 3 - Request MMDP-3 be evaluated for opportunities to improve
718093	718397	95003 PT 3 - Critical thinking for TVA Board minutes vs. NOC Charter not documented
718298	718276	Elevated drift of 3B2 RPS
718935	719755	Top 10 Action Plans for PHC
719185	719949	NRC Identified-95003 Part 3 Inspection. PER 509701 dispositioned with no action taken to resolve.
719755	114644254	PER 509701
719846	721446	UT Procedures N-UT-84 and N-UT-64
720177	721043	Missed communication regarding 3B2 circuit protector calibration
720312	720429	95003 PT 3 - missed initial in 3B2 circuit protector surveillance
720315	721733	95003 PT 3 Engineering Evaluation not performed WO

		step NA'd by Maintenance, see details.
720375	721029	95003 PT 3 System Health Team Walkdowns
720418	722401	NETP-108 does not include general plugging criteria - 95003 PT 3
720488	721052	95003 PT 3 - Visual Inspection and Evaluation form not put in Original WO package, see details.
720717	721753	95003 PT 3 - Electrician and SRO documented acceptance criteria met for out of spec condition
720895	721757	95003 PT 3 - Potential FSAR Appendix O Reference Error
720914	721623, 339927, 364471, 370714, 390832, 611633, 695119	95003 PT 3 - Trend in EECW through wall leaks, see details.
720924	721611	Use of Concurrent Verification
721104	721583	System health team walkdown
721318	723605	Calculation B22 890929 153 has an incorrect as-found allowable value (AV)
721370	721786	Appropriate method to disposition BWRVIP 75A weld coverage
721387	721790	95003 PT 3: Leak Sealing/Temporary Alteration Procedure Interface Issue
722115	723015	Verification requirements for "As Left" settings
722190	723038	reconstituted lost work order package
722237	723049	95003 PT 3 – PER List provided to 95003 Inspection Team incomplete.
722356	723087	Problems not previously documented associated with the execution of WO 113969570
722453	723062	95003 PT 3 - Expansion Joint PM issue
722559	722859	Tagout error resulting in unplanned LCO entry
722931	723646	Inappropriate and inadequate use of NPG-SPP-06.2 Appendix A

723405	723087, 724197	Work order 113969570 revision issue from PER 723087
723500	724186	Developing inspection themes - Operability evaluations
723504	724187	Long standing equipment Issues
723619	724211	Review check valve failures for a potential trend issue
723710	724194	Developing inspection themes - Standards and Expectations - Operations and Maintenance
723712	724201	Developing inspection themes - Procedure Revision Process and Quality
723713	724204	Developing inspection themes - Need to Write Service Requests (SRs)
723714	724209	Developing inspection themes - Quality of Service Requests (SRs)
723715	724214	Developing inspection themes - Maintenance Deferrals
723716	724217	Developing inspection themes - Inservice Inspection (ISI) Program
723717	724222	Developing inspection themes - Engineering Qualifications (Knowledge and Skill)
723895	724725	Developing inspection theme - Anonymous PER generation
723905	728717	Inaccuracies in reporting PM Deferrals
723914	724740	Developing inspection theme - Validation of information
723976	724755	Inaccurate Pm Deferral Performance Indicators
724069	725292	CAP Chatter is not being published in a timely manner
724188	724713	Referenced document contained a transposed number for a PER
724244	724724	Plant readiness for 95003 inspection does not meet standards.
724458	725557	Vendor Revision Requests not attached to Vendor Manual as a Child Document
724531	725568	95003 PT 3 0-TI-522 Program for Implementing NRC Generic Letter 89-13
724675	725411 613017	Evaluation of Manufacturing Defect is Described in PER 61307
725516	726109 114688535	Amber light above 2-HS-099-002B/B is out
725569	726032	Walkdown
725577	726613	Walkdown
725581	726045	Walkdown
725584	726049	Walkdown

725586	726051	Walkdown
725589	726052	Walkdown
725590	725625	Walkdown
725593	726053	Walkdown
725597	725625 726618	Walkdown
725624	726573 114690042	Loose Nuts for Tie Rods on Battery Racks
725632	726606 114690202	Missing Spacer Material Between Batteries
725635	728721	Incorrect PER Reference in Self-Assessment CRP-ENG-F-12-012
725822	726878	Walkdown
725828	727260	Walkdown
725896	726632	Walkdown
725898	726639	Walkdown
725961	726687	HOUSEKEEPING IN THE SOUTH EAST QUAD
726021	726678	Housekeeping during AUO rounds of U2 RB.
726064	728722	PSC Coaching on SR Problem Statement Quality Gaps is not systematically captured and trended
726096	727299	Walkdown
726101	727313	Walkdown
726103	727316	Walkdown
726105	726731	Walkdown
726108	726738	Walkdown
726109	726739	Walkdown
726115	726742	Walkdown
726117	726743	Walkdown
726146	727369 114692162	Cover Plate for breaker has an approximately 1/2” gap
726149	726761	TORQUE VALUE FOR COUPLING
726188	727389	Augmented ISI Weld Coverage DRHR-2-12
726189	726763	Scaffolding material inappropriately stored
726220	726777	Walkdown Test Cart not properly secured
726232	726722 114690470	Fuse alarm light is illuminated
726528	727675	Maximo PMCR Improvements Needed
726531	727679	Walkdown
726625	704964 727670	ACE PER 704964 To Be Revised

726676	728846	Walkdown
726679	728026	Walkdown
726697	728846 728848	Walkdown
726701	727648	Walkdown
726716	728029	Walkdown
726721	728031	Walkdown
726729	725364 727649	Feedback provided by CARB on problem description for PER 725364
726740	728866	Walkdown
726743	727653	Walkdown
726748	729211 114699339	Walkdown
726753	727656	Walkdown
726755	727405	95003 Part 3 identified gaps in implementation of verification practices (Peer Check, CV, IV)
726777	728035	3-SR-3.8.4.2(DG 3D)
726809	728038	NRC Observation on Scheduled Molluscicide Activity
726836	728040	Poor housekeeping found at 2B/2D and 2A/2C RHR cooler catwalks
726867	727680	NRC Identified, IST Program Health Observation 7-1-12 to 12-31-12
726869	727682	NRC Identified - Improperly Stored Ladder
726870	727683	PER 546734-001 Action Taken Long Description Error
726871	727685 114692427	Expansion Joint on Suction Line for BFN-2-PMP-027-0907, SCREEN
726874	727687	PM change for new MHs was not initiated by DCN
726877	727688 114692433	Expansion Joint in Suction Line for BFN-1-PMP-027-0907, SCREEN WASH PUMP 1A
726882	727693	Candy wrapper found in U1 RHR II quad
726887	727695	Inadequate Procedure guidance in -TI-134 CS and RHR Room Coolers Air Flow
727081	728074	Oil/water mixture found on HPCI turbine skid in the lip around the turbine
727089	728075	documentation of issues associated with re-coupling the D2 RHRSW Pump
727133	728091	Developing inspection themes - Work Management
727308	728912	Preliminary Action Omission in some Inservice Testing Pump Procedures
727315	728923	Review of historical WO

727457	728138	Improper verification practices observed during biocide project
727470	728965 114698921	Walkdown
727484	728979	Walkdown
727510	728150	Walkdown
727517	728889	Walkdown
727541	114186756	Work instruction revision was not capture for WO114186756
727545	728916	95003 / PT-3 IV statement in the work instruction.
727546	114186756	Inadequate walk down by MEG and Planning
727569 727755	114186756	95003 - PT-3
727601	728936	NRC Identified. Steps not performed in order for continuous use procedure
727604	728941 114698862	DCN replaced valve and left associated work incomplete
727624	728160	NRC Identified: 0-TI-562 Deficiencies
727627	728946	NRC identified, CI-0-023-PMP004 changed prior to vendor manual.
727793	729038	Motor Nameplate discrepancy on Online Baker Test Reports
727803	729049	Failure to initiate SR
727869	729137	PER 462782 was closed without adequately addressing the problem
727908	729557 114703202	Repair insulation
727910	729146 114699295	Repair conduit
728085	729603 114703644	Cigarette pack found in RHRSW Pump Room ‘C’
728088	729116	NRC 95003 Part 3 Question to QA on CARB Observations
728097	729119	NRC Identified Conduit to 0-ZS-026-0072K has a hole in it.
728100	729121	MCI-0-023-PMP004 revision question
728103	729122	Operations Identified Trash in Intake Cable Tunnel at Turbine Hatch
728105	729124	Detached label not documented in CAP
728108	729127	CI-13.1 rolls and responsibilities

728110	729128 112124676	Procedure Issue
728112	729129	Is shift manager signature required on App B, CI-13.1?
728116	729130	Why does CI-13.1 allow 96 hours before initiating PER
728118	729132	CI-13.1, page 15. Section 3.3.2 references "Nuclear Power Sites.”
728120	729133	CI-13.1 page 51 states to notify CNO if Zn >0.4
728128	729134 112124676	Procedure enhancement
728141	729138 114699292	NRC Identified Water Build Up Intake/ Turbine Cable Tunnel
728163	729149	Portable heater found inside instrument cabinet
728166	729153	Heat tracing power compartments in RHRSW Pump Rooms are rusted.
728168	729154	Several loose or missing labels in RHRSW Pump Rooms.
728169	729155 114699302	‘C’ EECW Strainer motor is hot to the touch.
728170	729156 114699305	Insulation surrounding 0-67-213A is not in place.
728174	729157	RHRSW/EECW Pump Discharge Check Valves are inconsistently
728175	729618 114703802	Exposed electrical wiring between two heat trace components
728176	729623 114703836	Disconnected conduit on underside of junction box
728197	729176	Unit 2 Fuel Pool Cooling Pumps not protected
728199	729178	System Eng. not cognizant of A(1) Plan Actions
728200	729180 114699318	Heat Trace flex has pulled out of the insulation
728202	729625	NRC identified housekeeping issues
728203	728211 114695608	Floor drain clogged causing water intrusion into D DG room
728205	728216	NRC identified housekeeping issues
728206	730249	NRC Identified housekeeping issues
728355	729674	NRC Question for QA
728434	729163	Raw Water Fouling and corrosion control Program training needs revision, see details.
728447	730250	N-UT-64 and N-UT-84 Procedure Revisions
728456	729167	Maintenance Clock reset missed opportunity

728459	729168	Maintenance Department Turnover of plant events
728506	729179	NRC identified. “95003 PT 3” Remove sump pumps and hoses Intake Cable Tray
728546	729188	NPG-SPP-06.5 Foreign Material Control -- latest revision (Rev 2) is not in BSL
728697	n/a	Spent Fuel Pool Time to Boil Information
728754	729654	Interview results indicate uncertainty exists in revising procedures
728780	729705	Missed learning Opportunity Per 703268 A1 RHRSW HURB
728856	730931	NPG-SPP-09.5 Editorial Change
728901	729682 114704781	95003 Walkdown
728970	729646	Commercial Grade Dedication of Bearing AYD945B -- NRC 95003 Item ID no. 0349-02
729001	730276	95003 PT 3
729039	729724	95003 PT 3 Cable and lock were staged @ U-2 FPC cage door (lock not in use) for when it was necessary
729043	729726	NRC feedback
729045	729727	95003 PT 3 RP received notification that NRC identified electrical routing issues for AMS-4 and air
729050	729732	95003 PRT 3, Evaluate air monitor power supply
729055	729733	95003 PT 3 Inspection due to SR 728141. There is no C-zone in area nor is water flowing out of a c-z
729057	729735	95003 PRT 3, Local amp indication does not match Main Control Room indication
729067	729738	95003 PT 3 Effectiveness Review of IST Corrective Actions
729075	730305, 114709113	95003 PRT 3, Local amp indication does not match Main Control Room indication
729076	730315, 114709150	95003 PRT 3, Local amp indication does not match Main Control Room indication
729079	729786	Defense in depth tag in U1 northwest quad
729080	730321	Unit 1 Core Spray housekeeping
729084	730323, 114709204	Duct tape found at ceiling on fire header pipe penetration
729085	729792	95003 PT 3 Burnt out bulb at local hand switch
729087	730327, 114709240	95003 PT 3 1-HS-75-23B has bulb burnt out and tape over it.
729091	729792, 729793	Housekeeping Issue: Red tape on hand switch indicating lights.

729092	730331, 114709265	95003 PT 3 1-PI-74-41 reading high
729093	730334, 114709293	95003 PT 3 Hanging drop and Body to bonnet connection with slight degradation at surface.
729095	730346, 114709325	95003 PT 3 1-BKR-75-0014 breaker green bulb not illuminated
729104	731892	NPG-SPP-09.14 Generic Letter (GL) 89-13 Implementation Procedure Problems
729110	730353	95003 PT 3 0-TI-362 Typical UNIDs for skid mounted valves
729232	729787	95003 Part 3 - CI-13.1 not referenced in the WOs for 1/2/3-SI-4.6.B.1-4
729233	729789	95003 Part 3 - Dose rate meter not listed Special Tools Equipment Recommended in 1/2/3-SI-4.6.B.1-4
729234	729790	95003 Part 3 - Housekeeping issue at U1 Precoat Tank
729235	729791	95003 Part 3 - Housekeeping issue at U2 Precoat Tank
729236	729753	95003 Part 3 - Housekeeping issue at U3 Precoat Tank
729237	730355	95003 Part 3 - Housekeeping issue at Panel 3-AN-043-2075
729239	729755	95003 Part 3 - Fuel Pool Cooling cage swing gate not secure
729240	729757	95003 Part 3 - Housekeeping issue at back of Panel 3-LPNL-925-0009
729241	729758	95003 Part 3 - Housekeeping issue at Calgon Building
729269	730358, 114709430	95003 PT 3 - RHRSW Pump air release valve Inspection
729323	730376	Potential trend in Service Request initiation
729324	730384	Potential trend in lower tier ACE quality
729458	730893, 114713060	WO 111118040 not processed timely - Original condition identified during NRC 95003 inspection.
729498	730467	95003 PT 3 Electrical routing to AMS-4 and air sampler in the 1C Mech. Equip Room
729765	729764	95003 PT 3
729792	730423, 114710140	95003 PT 3 - RHRSW Pump air release valve Inspection
729800	730424, 114710148	95003 PT 3 - RHRSW Pump air release valve Inspection
729807	730427, 114710170	95003 PT 3 - RHRSW Pump air release valve Inspection
729812	730429, 114710185	95003 PT 3 - RHRSW Pump air release valve Inspection

729819	730432, 114710199	95003 PT 3 - RHRSW Pump air release valve Inspection
729821	730434, 114710202	95003 PT 3 - RHRSW Pump air release valve Inspection
729822	730435, 114710204	95003 PT 3 - RHRSW Pump air release valve Inspection
729831	505709, 651000, 680792, 730440	INTR 651000-013 (Maintenance procedure validation) is ineffective
729841	730443	95003 - Part 3 - NRC Identified - Main Control Room Ceiling Panels
729845	730444	95003 PT 3 Vibration Analyzer Calibration
729848	729810	Report of CAL and Tool room issue ticket conflicts
729850	730445	95-003 NRC identified, SR's not written in a timely manner
729857	730447	improper questioning attitude
729858	730449, 114710231	95003 PT3 conduits improperly sealed
729861	730999, 114713677	95003 PT 3 HH26 has water in it.
729864	730453	95003 PT 3 NRC Identified; Cable Program Health Report Is Inadequate
730048	731524	95003 PT 3 NRC Identified - Surveillance 0-SR-3.3.7.1.4
730107	613017, 725411, 731429	95003 PT 3 Initiate Part 21 Evaluation for MSRV valve piston found cracked at Wyle
730356	731570	95003 PT 3 - A1/A2 RHRSW PUMP - Decision Making
730362	731087	95003 PT 3 M&TE issue for 114265032 0-SI-4.5.C.1(A1)
730512	730495	95003 PT 3 1,2,3-SR-3.3.8.2.1(A), (B), (C) fails to prescribe M&TE accuracy requirements
730513	731144	95003 PT 3 During the 4/2013 performance of 3-SR-3.3.8.2.1(B), M&TE step N/A'd
730514	730995	95003 PT 3 - Diesel Aux Board Exhaust Fan
730520	732107	95003 PT 3 GL 89-13 Inspection
730536	731146	95003 PT 3 NEDP-20 System Walkdowns
730552	731149	95003 PT 3 NRC Inspector identified PM typographical error
730119	731551	Missed Opportunity

730125	731092	Missed Opportunity
730592	733495	NRC not notified of discrepancy identified by PER 443133
730599	731580	Error Identified on NDE UT Report Provided to NRC
730608	732158, 113859592, 114216053	DG Flush steps, see details
730766	731574	PM #500103184 is deficient. (BFN 95003 Audit)
730798	732298	CRP-ENG-F-12-019
730828		PER 571765 Actions Inadequate (NRC 95003 PT 3)
730857	732358	95003 PT 3 CRP-ENG-F-12-019
730866	732359	95003 PT 3 Inadequate design output for RPS circuit protector calculations
730928	734318	95003 PT 3 raw water visual inspections, see details
730942	729163, 733390	95003 PT 3 raw water training, see details
730955	734054	95003 PT 3 ESP075.531 will need revision, see details
730979	605866, 31661, 112592982, 112593009	95003 PT 3 WOs documented as DC incorrectly, see details
731162	731645	95003 PT 3 WO packages
731181	731654	95003 PT 3 More Cables added to MR List
731213	732439	TVA procedure or formal training for evaluating material shelf life requirements does not exist
731130	731637	95003 PT 3 Potential Part 21
731154	732407	95003 PRT 3 - Oil soak pads and mop heads found in DG Fan Rooms
731158	732409	95003 PRT 3 - Oil soak pads and mop heads found in 'D' DG Fan Room
731365	732519	95003 PT 3 PER to drive resolution on NRC questions about RHRSW ARV performance
731367	732521	95003 PM deferrals on the RHRSW pump pit have inaccurate late date.
731375	732524	95003 PT 3
731386	732529	95003 PT 3 - 0-GOI-200-1, Freeze Protection Inspection Retention Requirement
731398	732531	95003 PT 3 Historical issue with disconnect between SSD and 3-SI-4.1.B-16(B)
731421	732537	95003 PT 3 3-RFV-23-555 port 75% blockage in 2007, see details

731470	732564	95003 PT 3 GL 89-13 Heat Exchanger Visual Inspections
731523	732571	INITIATE SELF ASSESSMENT OF SHELF LIFE PROGRAM AT BFN - 95003
732535	728894, 733517, 114698646	WO 06-722059-000 not processed timely - Original condition identified during NRC 95003 inspection.
734975		95003 PT 3 IDO for PER 731144 had factual inaccuracy
735711		95003 PT 3 NRC Observation During Re-Debrief on potential 50.9

OTHER SRS

SR Number	Summary Description
666312	95003 Review Team Identified GAP Analysis of Procedure Use and Adherence 01/13
722544	Security Procedure 16.1
722984	Work Performed without the Correct Tagout/Clearance in Place
725953	During RHR Room Cooler T0134
726024	WO 114162145 TI-134 on 1D RHR Room Cooler
726114	Wrong Tolerances in WO Description
726408	Anenometer Air Flow Readings in 1-TI-134
728061	Change Out All Charcoal Trays Installed in CREV B, 03/1
730449	95003 PT3 Conduits improperly Sealed

WORK ORDERS

Number	Document Title	Rev./Date
EDQ3057920035	Diesel Load Study for Unit 3	47
EDQ2000870548	Protective Relaying for RHR and Core Spray Motors	34
MDQ002394001 2	RHRSW Pump Impeller Replacement	05
3-L6139	Modern Welding Co., Inc.	
0-J8073C1	Diesel Fuel Storage Tank	02
08-7166590999	Main Bank Battery 1: End of Qualified Life	12/09
09-726312-000	Performa breaker test on BFN-1-BKR-253-0003/310	5/3/10
08-725464-000	PM Activity is to Replace Capacitors in 250V Main Bank Battery Charger 2A	06/09
09-723118-001	250 V Main Battery 1	10/09
09-722187-000	RHR Pump 3B Motor, On Line Motor Performance Testing	4/11/12

09-721841-000	Heat Exchanger Visual Inspection and Evaluation Form	08/4/10
07-720007-000	RHR Heat Exchanger 3C, Visual Inspection and Evaluation Form	1/22/08
08-717490-000	2-HEX-74-900A, Visual Inspection and Evaluation Form	04/14/09
09-714730-000	3-HX-74-900A, Visual Inspection and Evaluation Form	03/03/10
06-714487-000	Pre-outage PM to Clean, Inspect, and Eddy Current Test	11/30/06
07-712340-017	BFN-3-CKV -067-0696	
07-712340-016	BFN-3-CKV -067-0695	
05-711558	Deferral There is no safe way for the divers to perform the task	10/27/05
05-711558	2nd Deferral Reschedule 1/31/06, 5/11/07, 8/27,07	
DCN-70833	Separate 250 VDC and 120 VAC power control cables to SCRAM valves	A
DCN-70651	Separation of Drywell Nitrogen to Support SRV	A
DCN T-38580A	Repair 3A & C RHR Heat Exc. Flange leaks using Furmanite Sealing Compound	09/95
1/2/3-47E858-1	RHR Service Water System	64
0-47W310-5	Mechanical Tanks	00
0-47W585-1	Mechanical Drains & Embedded Piping	02
3-47W587-2	Mechanical Drains & Embedded Piping	02
3-47W587-1	Mechanical Drains & Embedded Piping	03
3-CLR-64-69	“Flow Trending Data for 3-TI-134 3B RHR Room Cooler	
47W585-2	Mechanical Drains & Embedded Piping	04
47W310-1	Mechanical Tanks	03
EDC 693111	Allow Repair of 3B and 3D RHR Heat Exchanger Flange Leaks as Necessary	03/08
10527047	Procedure 2-SI-4.5.C.1(3-COMP) Title: 2-SI-4.5.C.1 (3-COMP) - RHRSW Comprehensive Pump & Header Operability Test	
10671206	2B RHR HEX, Visual Inspection and Evaluation Form	09/07/11
11828675	2-SI-3.2.27(1)- 2-FCV-75-26 Operability Test	
110711454	Verification of Remote position indicators for RH system/valves	5/3/12
111383247	Perform Inspection and PM on 250V DC Main Battery Bank 1	1/3/11
113969570	Re-Zero Gap Voltages for Feedpump Turbine 2A	1/17/13
111584012	RHR Motor 1C	10/30/10
111589218	RHR Motor 1C Post Mod Testing	10/30/10
111640846	Miscellaneous Equipment Record Unit 0 System 050 – Perform check of Plant Sump Pumps	11/11
112124676	Perform An Inspection And Preventative Maintenance On 480V Radwaste Board 1 Compartment 5D	05/17/13
112254075	Heat Exchanger Visual Inspection and Evaluation Form	10/31/12
112254075	1A RHR HEX, Visual Inspection and Evaluation Form	10/31/12
112353554	Disassemble and Inspect Check Valve 3-ckv-67-600	2/13/12

112353556	Disassemble and Inspect Check Valve 3-ckv-67-601	2/13/12
112353559	Radiograph for inspection south EECW header check valve 3-CKV-67-695	3/26/12
112353571	Radiograph for inspection south EECW header check valve 3-CKV-67-696	
112390843	250V Battery Charger 1	06/13
112451685	3-SI-3.2.74(RHRII) - Pressure Isolation Valve Leakage Test RHR Loop II Shutdown Cooling Return	
112565723	Procedure 3-SR-3.5.1.6(RHR 11-COMP) Title: 3-SR-3.5.1.6(RHR 11-COMP) - RHR Loop II Comprehensive Pump Test dated 05/07/2012	05/07/12
112834112	Verification of Remote position indicators for RHR system II valves	5/6/12
112834903	3-SI-3.2.21(II) - Cold Shutdown Testing of 3-FCV-74-682	
112988609	Perform Check of plant Sump Pumps for Listed Manholes, Handholes, Valve Pits and Tunnels	06/12
113018273	Polarity and phasing	06/2/12
113118445	Inspect Valve per 2-SI-3.2.3 using Radiography	1/28/13
113118446	Inspect Valve per 2-SI-3.2.3 using Radiography	1/28/13
113218814	WO Deferral	11/24/13
113218912	Perform Inspection and PM on the U1, DIV/ECCS inverter PER EPI-0-256-INV003	12/12
113218918	Maintenance on U1DIV II ECCS Inverter Per EPI-0-256-INV003	12/12
113218921	Perform Inspection and PM on the U-1, DIV II ECCS Inverter Per EPI-0-256-INV003	12/12
113265453	Procedure 3-SI-3.2.3 Title: 3-SI-3.2.3 - 3-SI-3.2.3- Testing ASME Section XI Check Valves (Internal Inspection)	02/12
113265624	Procedure 3-SI-3.2.3 Title: 3-SI-3.2.3 - 3-SI-3.2.3- Testing ASME Section XI Check Valves (Internal Inspection)	
113316160	PM Performance of 0-TI-63 for 3-HEX-74-900B and 3-HEX-74-900D	
113347438	1-HEX-074-0900B, Visual Inspection and Evaluation Form	08/7/12
113523038	DCN Stage 4, Unit STA Serv. Xfrmr 3A, 387 relay	05/23/12
113630934	Perform Annual inspection and PM on 250V DC Main Battery Bank	12/31/12
113761434	2-SI-3.2.75(CS I)- Pressure Isolation Valve Leakage Test Core Spray Loop I Injection	
113779087	Procedure 3-SI-3.2.4 (DG A) Title: 3-SI-3.2.4 (DG A) – EECW Check Valve Test on Diesel Generator A	
113859589	Perform Trial Flush of 3A DG HX’s	1/28/13

113864212	Procedure 3-8R-3.5.1.6(RHR II) Title: 3-8R-3.5.1.6(RHR II)- Quarterly RHR System Rated Flow Test- Loop II dated 02/23/2013	3/23/13
113948278	2-SR-3.5.1.2(CS I) - Core Spray Sys Injection Path Monthly Valve Position Verification	
114057462	CSCS RHR Loop 2 Discharge Pressure Calibration	5/14/13
114060141	2-SI-4.6.B.1-4 – Reactor Coolant Chemistry	
114061028	3-SI-4.6.B.1-4 – Reactor Coolant Chemistry	
114072536	EECW Annual Flow Rate Test-D3 pump only	5/14/13
114143022	Calibrate Voltmeters, Amp Meters and Alarms on U3 DG 3D 125VDC Bat. Charger B	05/13
114186756	Perform Breaker Inspection and testing on breaker 310	5/13/13
114194486	Diesel Generator 3D Battery Annual Test	5/14/13
114307946	RHRSW Pump B3 IST Group A Quarterly Pump Test	02/13
114348222	Testing ASME section XI Check Valves	5/7/13
114348258	Testing ASME section XI Check Valves	1/30/13
114369751	Radiograph of 2-CKV-67-639 Showed to be partially open	5/27/13
114385805	Diesel Generator 3D Battery Service Test	5/15/13
114486926	RPS CKT Protector 3B2 Undervoltage Relay	12/20/13
114585312	Miscellaneous Equipment	04/13
114597429	Commitment-Flood Protection Seals in the MS Vault do not match design drawings	4/26/13
114614330	RPS Circuit Protector Calibration/FT for 3B1 and 3B2	4/23/13
114162145	Perform Flow Rate Testing per 1-TI-134 on 1D RHR Room	05/13
114656500	1-SI-4.6.B.1-4 – Reactor Coolant Chemistry	
114684400	Turbine room supply fan 2B has a broken belt	
113800578	3 SE 3.3.8.2.1(B) RPS Circuit protector Calibration	3/13/13

LIST OF ACRONYMS

AC	Alternating Current
ACE	Apparent Cause Evaluation
ACRB	Action Closure Review Board
ANS	American National Standards
ANSI	American Nuclear Standards Institute
AOI	Abnormal Operating Instructions
ARV	Air relief valves
ASME	American Society of Mechanical Engineers
AUO	Assistant Unit operators
BFN	Browns Ferry Nuclear Station
BP	Business Practices
BWR	Boiling Water Reactor
BWRSCC	Boiling Water Reactor Stress Corrosion Cracking
CA	Corrective Action
CAL	Confirmative Action Letter
CAP	Corrective action program
CAPR	Corrective Action to Prevent Recurrence
CARB	Corrective Action Review Board
CFAM	Corporate Functional Area Manager
CFM	Corporate Functional Manager
CFR	Code of Federal Regulation
CGD	Commercial grade dedication
CLE	Continuous Learning Environment
CS	Core Spray
CV	Concurrent Verification
DCARB	Department Corrective Action Review Board
DCC	Design/Configuration Control
DCN	Design Change Notice
ΔCDF	Change in Core Damage Frequency
DM	Decision Making
ECCS	Emergency Core Cooling System
ECP	Employee Concerns Program
ECRB	Effectiveness Review Challenge Board
EDG	Emergency diesel generator
EECW	Emergency Equipment Cooling Water
ELP	Excelerated Leadership Partners
EOI	Emergency Operating Instructions
EPMT	Equipment Performance Monitoring and Trending
ePOP	Electronic Performance Observation Program
EPRI	Electric Power Research Institute
EPSM	Equipment Programs and System Management

EQ	Environmental Qualification
FEG	Functional Equipment Group
FIN	Fix It Now
FLS	First Line Supervisor
FPA	Fundamental Problem Areas
FRR	Fire Risk Reduction
FY	Fiscal year
G&O	Governance & Oversight
GCWE	General Culture and Work Environment
GL	Generic Letter
GOES	Governance, Oversight, Execution and Support
HCU	Hydraulic Control Unit
HDR	Historical Data Review
HIRD	Harassment, Intimidation, Retaliation, or Discrimination
HIT	High Impact Team
HPCI	High Pressure Coolant Injection
HR	Human Resources
HU	Human Performance
HX	Heat Exchanger
I&C	Instrumentation and Control
IACPD	Identification, Assessment and Correction of Performance Deficiency
IAW	In Accordance With
IDO	Immediate determinations of operability
IEEE	Institute of Electrical and Electronic Engineers
IGSCC	Inter granular stress corrosion crack
IIP	Integrated Improvement Plan
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
INSCA	Independent Nuclear Safety Culture Assessment
IO	Independent Oversight
IP	Inspection Procedure
IPE	Individual Plant Evaluation
IR	Inspection Report
IRP	Inappropriate Reliance on Procedures
ISI	In-Service Inspection
IST	In-Service Testing
ITR	Integrated Trend Review
IV	Independent Verification
KAR	Key Attributes Review
LCO	Limited Condition of Operations
LD-TPD	Leadership Development Training Program Description
LOCA	Loss of Coolant Accident

LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LTAM	Long Term Asset Management
M&TE	Measuring and test equipment
MG	Motor generator
MLS	Management and Leadership Standards
MODs	Modifications
MOS	Management Operating System
MOV	Motor Operated Valve
MRM	Management Review Meeting
MSIV	Main Steam Isolation Valve
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEDP	Nuclear Engineering Department Procedure
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NOM	Nuclear Operating Model
NOV	Notice of Violation
NPG	Nuclear Power Group
NRC	Nuclear Regulatory Commission
NSC	Nuclear Safety Culture
NSCMP	Nuclear Safety Culture Monitoring Panel
NSRB	Nuclear Safety Review Board
OE	Operating Experience
OF	Operations Focus
OFDM	Operational Focus/Decision Making
OM	Operations and Maintenance
OSC	Operations Support Center
OSPI	Outage and Scheduling Performance Indicator
PAE	Primary Authorized Employee
PARS	Publicly Available Records
PCIV	Primary Containment Isolation Valve
PCR	Procedure change request
PD	Performance deficiency
PDI	Performance Demonstrated Initiative
PDO	Prompt Determination of Operability
PER	Problem Evaluation Report
PHC	Plant Health Committee
PI	Performance Indicator
PIQ	Procedure/Instruction Quality
PI&R	Problem Identification and Resolution

PM	Preventive Maintenance
PMP	Performance Monitoring Plan
PRA	Probabilistic Risk Assessment
PSC	PER Screening Committee
psig	Pounds Per Square Inch
PU&A	Procedure Use and Adherence
PU&A	Procedure Use and Adherence and Work Practices
QA	Quality Assurance
QADM	Quality Assurance Department Manual
QRT	Quality Review Team
RB	Reactor Building
RCA	Root Cause Analysis
RCIC	Reactor Core Isolation Coolant
RCS	Reactor Coolant System
Rev	Revision
RFP	Reactor Feedwater Pump
RG	Regulatory Guide
RHR	Residual Heal Removal
RHRSW	Residual Heat Removal Service Water
RM	Resource Management
RMA	Risk Management Actions
RO	Reactor operator
ROP	Reactor Oversight Process
RP	Radiation Protection
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SBGT	Stand-by gas treatment
SCAQ	Significant condition adverse to quality
SCBA	Self Contained Breathing Apparatus
SCCI	Substantive Cross Cutting Issue
SCWE	Safety conscious work environment
SDP	Significant Determination Process
SEM	Strategic Equipment Management
SISBO	Self-Induced Station Blackout
SLC	Standby Liquid Control
SLT	Site Leadership Team
SME	Subject Matter Expert
SPP	Standard Programs and Processes
SR	Service Request
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSC	System, Structure or Component

SSI	Safe Shutdown Instructions
SVP	Site Vice President
TR	Technical Rigor
TRN	Training
TS	Technical Specification
TSC	Technical Support Center
TVA	Tennessee Valley Authority
T-week	Systematic and Integrated Work Week Schedule
UAI	Unavailability Index
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USST	Unit Station Service Transformer
UT	Ultrasonic
VP	Vice President
WM	Work Management
WO	Work Order

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

February 21, 2013

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3D-C
Chattanooga, TN 37402-2801

SUBJECT: INSPECTION PROCEDURE 95003 INFORMATION REQUEST

Dear Mr. Shea:

The purpose of this letter is to request information to support the upcoming 95003 inspection. The inspection will be conducted in accordance with Inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input."

The current schedule for the inspection is as follows:

- March 18 - 22 – Site Orientation at Browns Ferry
- May 13 -24 – On-site Inspection at Browns Ferry

Per previous discussions with your staff, you are requested to post the requested documentation on the IMS website and provide each team member a user identification and unique password. As team members are identified, we will provide you with the necessary information in order for you to setup account access. This documentation will be available for each team member to review and download if necessary. Please make the electronic version of this information available as soon as practical, but no later than March 18, 2013. In addition, we will be providing you a second request for information around March 29, 2013. This request will ask for additional focused items for inspection. This information should be available to the team by April 19, 2013, in the same manner as the initial request. Your cooperation and support during this inspection will be appreciated. If you have questions concerning this inspection please contact me at (404) 997-4662.

Sincerely,

/RA/

Eugene F. Guthrie, Chief
Special Project, Browns Ferry
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296
License Nos.: DPR-33, DPR-52, DPR-68

ML13052A371

Attachment 2

Inspection 95003 Documentation Request

For each of the following, provide an electronic copy on the IMS website. Requests for corrective action program documents should include data from the traditional sources (as well as systems outside the corrective action program (training deficiency lists, etc.))

95003 Preparation Materials

1. Procedures, Assessments, RCA, PERs, and reports used for generation of the Integrated Improvement Plan.
2. Integrated Improvement Plan, and implementing procedures.
3. Performance Metrics and basis, and implementing procedures.
4. Safety Culture Assessment process procedures, basis documents, and policy statement.
5. Follow-up actions to issues identified during the Part I, Part II, and PI&R inspection.

Audit and Assessment Reports (include copies of documents associated with audit findings and assessments)

6. Since January 2010, a copy of all external audits and assessments.
7. Since January 2010, a summary listing of all internal audits and assessments (Area assessed, date performed, responsible organization, conclusions, and recommendations).
8. Since January 2010, a copy of all Quality Assurance Department audit reports.
9. Since January 2010, a summary of all Quality Assurance Department assessment reports (Area assessed, date performed, responsible organization, conclusions, and recommendations).
10. Since January 2010, a summary of bench marking activities (date, subject, lessons learned, and CAP document number).
11. Since 2000, audits and assessments of suppliers' QA programs.
12. Corrective Action Program (CAP) Crosscutting Area.
13. Since January 2008, a summary listing of all root analyses (date opened, problem description, root and contributing causes, date evaluation was completed, date final corrective action was performed, and the effectiveness review).
14. Since 2000, copies of Offsite Nuclear Oversight Committee meeting minutes.
15. Since 2010, a cross reference of LER's to corrective action program (LER number, CAP document number, event date, and summary description).
16. Since 2010, a summary listing of all processes and performance metrics used to track backlogs at the station.
17. List of root cause analysis qualified personnel by department.
18. Since January 2010, summary of site wide and departmental performance measures and metrics.
19. Since January 2010, summary of all CAP documents documenting a potential or actual adverse trend.
20. Since 2003, summary of generic communications received and processed (NRC communications, vendor recommendations, etc.).
21. Since September 1, 2009, Key Performance Indicator Reports, Equipment Reliability Index Reports and any associated Equipment Reliability Bubble Charts.

22. Since January 1, 2009, Critical Component Failure Trend Evaluation Reports.
23. Since January 1, 2010, Safety Cultural Assessment Reports, and any associated Improvement Plans and related PERs.

<u>Procedures – include a consolidated index of procedures for reference</u>

24. Complete and up-to-date copy of reference materials provided for NRC initial licensing operating test preparations and review (Items included in this package that are duplicated below only need to be submitted once).
25. Corrective Action Program procedures, instructions, and charters (CAP processes, root cause analysis, apparent cause analysis, oversight functions, trending, etc.).
26. Procedure change process procedure.
27. Summary listing of all open procedure change requests, including maintenance instructions, sorted by organization and date of request.
28. UFSAR
29. Technical Specifications, (hard copy to be available in team room).
30. Technical Requirements Manual, (hard copy to be available in team room).
31. Policies and procedures on nuclear safety (including corporate).
32. Industry operating experience program procedures.
33. Instructions for developing and implementing performance measures and metrics.
34. Change management procedures.
35. Communication procedures.
36. Decision making process procedures.
37. Procedures for raising concerns.
38. Departmental conduct of operations, maintenance, engineering, security, etc. procedures.
39. Safety impact/risk assessment review procedures.
40. Policies and procedures on harassment and intimidation.
41. Employee discipline procedures.
42. Assessment and audit procedures.
43. Design control procedures.
44. Design modification procedures.
45. Control of design basis procedures.
46. Control of overtime procedures.
47. Procedures for simulator fidelity.
48. Work control procedures (planning, scheduling, outage, and implementing).
49. Pre-job brief and shift brief procedures.
50. Procedures and policies involving procedural compliance.
51. Policies and procedures for supervisory and management oversight of work.
52. Equipment Qualification and Commercial Parts Dedication procedures.
53. Governing procedures for local leak rate testing, containment leak rate testing, code welding, and motor operated valve, air operated valve, and check valve testing, include the IST and MOV program basis documents.
54. Employee Concerns Program Procedures.
55. Policies and procedures associated with assessing equipment reliability and maintenance quality and/or effectiveness (rework).
56. Procedures related to operability determinations.

Engineering Documents

57. Since Jan 2010, summary listing (including a short description) of all temporary modifications, permanent, minor, and maintenance modifications. This should include modifications that were cancelled, completed, or remain open.
58. Since Jan 2010, summary listing (including a short description) of all temporary modifications, permanent, minor, and maintenance modifications. This should include modifications that were cancelled, completed, or remain open.

Documents in support of critical safety element review (Vertical Slice Review)

59. For all systems required to support the function of containment heat removal, including;
    a. Ultimate Heat Sink and the raw water closed cooling water systems that support the Emergency Diesel Generators;
    b. EDGs and their other support systems;
    c. Residual Heat Removal System
        i. Suppression Pool heat removal;
        ii. Containment Spray;
    d. Core Spray;
    e. Condensate Storage Tank and systems needed for its swapover mode to the Suppression Pool and emergency refill;

    For each of the above provide the following:

    - System health reports since January 1, 2010.
    - System recovery plan actions and associated PERs.
    - Electrical and mechanical system drawings.

Other Documents

60. List of Operability determinations completed since January 1, 2012.
61. List of PERs initiated since December 1, 2012.
62. Current station organizational chart, including special groups in place for the 95003 inspection.
63. Current site rooster or telephone listing.
64. Any Safety Conscience Work Environment/Safety Culture Training material used since January 2012.
65. Minutes from Employee Review Boards or any other disciplinary screening boards.
66. List of routine meetings including their times and locations for the month of May 2013.
67. List of issues reviewed against Browns Ferry 95003 Inspection Preparation Criterion 1, with a summary of the review results.

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

March 29, 2013

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3D-C
Chattanooga, TN 37402-2801

SUBJECT: INSPECTION PROCEDURE 95003 SECOND REQUEST FOR INFORMATION

Dear Mr. Shea:

The purpose of this letter is to request additional information to support the upcoming 95003 inspection. The inspection will be conducted in accordance with Inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input."

The current schedule is for the onsite inspection to be completed May 13 to 24, 2013, at Browns Ferry.

Per previous discussions with your staff, you are requested to post the requested documentation on the IMS website in the same manner as the initial request. This documentation will be available for each team member to review and download if necessary. We would appreciate it if the electronic version of this information was made available as soon as practical, but no later than April 19, 2013. We recognize that there may be some items in this request that you may have provided in the original request, if that is the case please refer to its location in the initial request. Your cooperation and support during this inspection will be appreciated. If you have questions concerning this inspection please contact me at (630) 780-8781.

Sincerely,

/RA/

Richard A. Skokowski, Assistant Team Leader
Special Project, Browns Ferry
Division of Reactor Projects

Enclosure: As stated

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

Attachment 3

March 29, 2013

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3D-C
Chattanooga, TN 37402-2801

SUBJECT: INSPECTION PROCEDURE 95003 SECOND INFORMATION REQUEST

Dear Mr. Shea:

The purpose of this letter is to request additional information to support the upcoming 95003 inspection. The inspection will be conducted in accordance with Inspection Procedure 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input."

The current schedule is for the onsite inspection to be completed May 13 to 24, 2013, at Browns Ferry.

Per previous discussions with your staff, you are requested to post the requested documentation on the IMS website in the same manner as the initial request. This documentation will be available for each team member to review and download if necessary. We would appreciate it if the electronic version of this information was made available as soon as practical, but no later than April 19, 2013. We recognize that there may be some items in this request that you may have provided in the original request, if that is the case please refer to its location in the initial request. Your cooperation and support during this inspection will be appreciated. If you have questions concerning this inspection please contact me at (630) 780-8781.

Sincerely,

/RA/

Richard A. Skokowski, Assistant Team Leader
Special Project, Browns Ferry
Division of Reactor Projects

Enclosure: As stated

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

X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE XNON-SENSITIVE
ADAMS: X Yes ACCESSION NUMBER:_______________________ ☐ SUNSI REVIEW COMPLETE ☐ FORM 665 ATTACHED

OFFICE	RII:DRP	RII:DRP					
SIGNATURE		Via email					
NAME	RSkokowski	EGuthrie					
DATE	3/ /2013	3/29/2013	3/ /2013	3/ /2013	3/ /2013	3/ /2013	3/ /2013
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\BF RFI2 LETTER.DOCX

Attachment 3

Inspection 95003 Second Documentation Request

For each of the following, provide an electronic copy on the IMS website. Requests for corrective action program documents should include data from the traditional sources (as well as systems outside the corrective action program (training deficiency lists, etc.))

Item Number	Requested Information	Requesting Inspector
1	NPG-SPP-11.16, Individual Development Plans	Allen
2	NPG-SPP-11.17 Leadership Assessments	Allen
3	NPG-SPP-11.18 Deep Dive Program	Allen
4	NPG-SPP-11.19 New and Transitional Leadership Change Procedure	Allen
5	NPG-SPP-19.5 Conflict Resolution Process	Allen
6	2006 and 2009, 2011 SYNERGY survey results and the 2013 Synergy results when they become available	Keefe
7	Nuclear Safety Culture monitoring panel procedure and meeting minutes From the beginning (Every plant started implementing in 2011)	Keefe
8	Minutes for the small group meetings the Site VP had with the employees from 2010-present	Keefe
9	Any "pulsing" surveys 2010-present	Keefe
10	PERs associated with not following procedures 2012-2013	Keefe
11	Procedure usage procedure	Keefe
12	Any PERs associated with surveys, assessments, etc 2010-present	Keefe
13	Any common cause analyses 2010-present	Keefe
14	Procedures on awards/incentive programs	Keefe
15	Restart committee meeting minutes 2011-present	Keefe
16	Causal analysis of NRC allegations from summer 2012	Keefe
17	TVA organizational health survey from July 2012	Keefe
18	Documentation of analyses performed by the BFN safety culture team to follow up on the priority organizations from the 2011 INSCA	Keefe
19	All corrective actions associated with each of the 9 problem areas identified by the 2011 INSCA	Keefe
20	List of PERs classified as SCWE by PER screening committee in the past 6 months	Keefe
21	ECP self-assessments 2010-present	Keefe
22	ECP gap analysis	Keefe
23	ECP metrics	Keefe
24	PER 514964	Keefe
25	QA audits of ECP 2010-present	Keefe
26	GOES Assessment	Keefe
27	Adverse Action Procedure NPG-Spp-11.10	Keefe
28	Procedures BFN 95003-003, and 006	Keefe
29	SCWE communications/training materials	Keefe
30	INPO organizational effectiveness survey results from 2010 and 2012 (do not place on CETREC, please make available for on-site review)	Keefe
31	Training Assessment (as mentioned in the Safety Culture Presentation 3/21/13)	Keefe
32	Manager/supervisor self-assessment (as mentioned in the Safety Culture Presentation 3/21/13)	Keefe
33	Charters, procedures , and meeting minutes for all meetings for the following: 1. ACRB 2. ERCB 3. SCMP	Keefe
34	List of all meetings scheduled for May 13 to May 24, including meeting name time, location and purpose	Skokowski
35	List of all scheduled maintenance and testing activities for May 13 to May 24, for all units	Skokowski

36	A list of all CAPRs initiated since October 2010	Skokowski
37	List of system number to system name	Skokowski
38	Maximo user guide	Skokowski
39	List of longstanding nonconforming conditions	Skokowski
40	Margin management program procedure	Skokowski
41	Safety culture monitoring panel procedure and reports since October 2010	Skokowski
42	List of PAR failure codes	Skokowski
43	A list the QA classifications of your procedures or a means to determine procedure QA classification(safety –related or nonsafety-related)	Skokowski
44	The completed Actions Plans to date	Skokowski
45	Top ten margin list (tied to system health)	Skokowski
46	List of Maintenance rule A1 systems and red system health systems	Skokowski
47	Copies of any SERs/PERs written as a result of our questions since the start of the NRC's preparation for the 95003 Part 3 Inspection	Skokowski
48	Copy of the R-E-A-D-E decision making tool, and any assessment of the effectiveness of this tool	Skokowski
49	Rework definition, and the CAP program documenting requirements for generating SERs/PERs for rework, and, if applicable the CAP program rework trending code	Skokowski
50	Update 1RFI-0067 for any issues reviewed since the first RFI response	Skokowski
51	Copies of all PERs associated with repetitive and/or rework maintenance over the last three years	Even
52	All SRs initiated over the last three years for the SRVs, RHR SW and EECW pumps and valves, and RHR HXs	Even
53	List of the corrective action backlog	Even
54	Copies of all operating experience (from NRC generic communications, fleet, vendors, industry groups, etc.) items entered into the CAP over the last three years	Even
55	Root Causes and all associated PERs having to do with your review of the Corrective Action Program generated in preparation for this inspection	Even
56	List of all issues entered into the ECP over last two years (all titles and corresponding PERs, if PERs exists)	Even
57	Copies of ECP self-assessments from 2010 to 2013	Even
58	Copies of CAP self-assessments from 2010 to 2013	Even
59	Copies of all operating experience items that screened out of your process in the last three years	Even
60	Provide information necessary to validate functionality of equipment required for the mitigation strategy in the SSIs for the primary water path that includes an RHR pump, the valves required to get water to the suction of the pump, and to the vessel, and the MSRVs. The validation should include the instrumentation, controls, and power to the components, and proof that they are routed in a manner that they, or their support equipment are not impacted by fire, or from hot shorts.	Bernhard
61	Self-assessments - BFN-ENG-S-11-012	Bernhard
62	Copies of Corporate Maintenance Procedures	Moore
63	All Performance Indicators Related to Maintenance for the last 5 years	Moore
63	All Performance Indicators Related to Equipment Reliability for the last 5 years	Moore
64	All Maintenance Program Documents, including: 1. Post Maintenance Testing (PMT) Procedures 2. Preventative Maintenance (PM) Procedures 3. Corrective Maintenance Procedures 4. Predictive Maintenance Procedures	Moore

65	Copies of the following Maintenance Schedules: 1. 26 week 2. 12 week 3. Current week 4. May 13th week 5. May 20th week	Moore
66	List of Maintenance Meetings and Scheduled Meeting Times	Moore
67	Station Work Control Procedures	Moore
68	Corporate Work Control Procedures	Moore
69	List of Work Control Meetings and Scheduled Meeting Times	Moore
70	List of Open / Pending Post Maintenance Tests	Moore
71	All System P&ID's	Moore
72	General Area Drawing	Moore
73	Procedures Governing Vendor Manual Updates / Revisions	Moore
74	List of Vendor Manual Updates / Revisions Pending	Moore
75	Maintenance Worker Qualification Procedures / Training Requirements	Moore
76	Strategic Equipment Performance Indicators	Moore
77	All PM Deferral Program Procedures	Moore
78	Maintenance Rule Scoping Documents	Moore
79	Provide the following maintenance related information for the Unit 2 'C' Core Spray Pump: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
80	Provide the following maintenance related information for the Unit 2 'C' Core Spray Motor: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years	Moore

	11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
81	Provide the following maintenance related information for the Unit 2 'C' Core Spray Motor Breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
82	Provide the following maintenance related information for the Unit 3 'B' Residual Heat Removal Pump: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
83	Provide the following maintenance related information for the Unit 3 'B' Residual Heat Removal Motor: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's	Moore

	7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
84	Provide the following maintenance related information for the Unit 3 'B' Residual Heat Removal Motor Breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
85	Provide the following maintenance related information for the '2B' Residual Heat Removal Service Water Pump: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
86	Provide the following maintenance related information for the '2B' Residual Heat Removal Service Water Motor: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks	Moore

	5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
87	Provide the following maintenance related information for the '2B' Residual Heat Removal Service Water Motor Breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
88	Provide the following maintenance related information for the CSS Injection Line Check Valve [Testable Check Valve Loop 1] – BFN-2-CKV-075-0026: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
89	Provide the following maintenance related information for the CSS Injection Line Check Valve [Testable Check Valve Loop 1] actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years	Moore

	3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
90	Provide the following maintenance related information for the CSS Injection Line Check Valve [Testable Check Valve Loop 1] actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
91	Provide the following maintenance related information for the 'C' CSS Pump Suction Valve [CS Pump 2C Suc Vlv] – BFN- 2-FCV-75-0011: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore

92	Provide the following maintenance related information for the 'C' CSS Pump Suction Valve [CS Pump 2C Suc Vlv] actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
93	Provide the following maintenance related information for the 'C' CSS Pump Suction Valve [CS Pump 2C Suc Vlv] actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
94	Provide the following maintenance related information for the CSS Injection Line Inboard CIV [CS Sys 1 Inb Disch Vlv] – BFN-2-FCV-75-0025: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years	Moore

	13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
95	Provide the following maintenance related information for the CSS Injection Line Inboard CIV [CS Sys 1 Inb Disch Vlv] actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
96	Provide the following maintenance related information for the CSS Injection Line Inboard CIV [CS Sys 1 Inb Disch Vlv] actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
97	Provide the following maintenance related information for the 'B' RHR Pump Suction MOV for Suppression Pool – BFN-3-FCV-074-0024: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years	Moore

	11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
98	Provide the following maintenance related information for the 'B' RHR Pump Suction MOV for Suppression Pool valve actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
99	Provide the following maintenance related information for the 'B' RHR Pump Suction MOV for Suppression Pool valve actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
100	Provide the following maintenance related information for the RHR, Loop 2, LPCI Injection Testable Check Valve – BFN-3-CKV-074-006: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages	Moore

	9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
101	Provide the following maintenance related information for the RHR, Loop 2, LPCI Injection Testable Check Valve actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
102	Provide the following maintenance related information for the RHR, Loop 2, LPCI Injection Testable Check Valve actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
103	Provide the following maintenance related information for the RHR LPCI Discharge Header Train Cross connect valve from Unit 2,Loop 2, to Unit 3, Loop 1 – 2-FCV-074-0101: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO)	Moore

	6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
104	Provide the following maintenance related information for the RHR LPCI Discharge Header Train Cross connect valve from Unit 2,Loop 2, to Unit 3, Loop 1 actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
105	Provide the following maintenance related information for the RHR LPCI Discharge Header Train Cross connect valve from Unit 2,Loop 2, to Unit 3, Loop 1 actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
106	Provide the following maintenance related information for 'B' RHR HX Outlet FCV-3-FCV-023-0046: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual	Moore

	4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
107	Provide the following maintenance related information for 'B' RHR HX Outlet FCV actuator: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
108	Provide the following maintenance related information for 'B' RHR HX Outlet FCV actuator circuit breaker: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
109	Maintenance Schedules for the Four Red System Health Systems	Moore

110	Provide the following maintenance related information Unit 3 ‘B’ RHR Pump Room Cooler – BFN- 3-CLR-064-0069: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO’s for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO’s 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT’s for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
111	Provide the following maintenance related information for 0-STN-067-0926 – EECW Strainer associated with B EECW supply header: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO’s for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO’s 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT’s for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
112	Provide the following maintenance related information for 3-CKV-067-0695 – South EECW Supply header check valve to 3A DG cooler : 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO’s for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO’s 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT’s for the last 5 years	Moore

	13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
113	Provide the following maintenance related information for 3-CKV-067-0696 – South EECW Supply header back flow check valve to 3A DG cooler: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
114	Provide the following maintenance related information for 3-CKV-067-0601 and 3-CKV-067-0600 – South EECW Supply header check valves to 3B RHR pump room seal cooler and RHR pump room cooler: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
115	Copies of Station Maintenance Procedures	Moore
116	Provide the following maintenance related information for EDG 'A': 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years	Moore

	11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
117	Provide the following maintenance related information for Battery '2' 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
118	Pr Provide the following maintenance related information for Battery Charger '2': 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
119	Provide the following maintenance related information for a safety-related Uninterruptable Power Supply: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years	Moore

	11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) Lube Oil Testing and Analysis for the last 5 years (if applicable)	
120	Provide the following maintenance related information for control emergency ventilation: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
121	Provide the following maintenance related information for Unit 2 RCIC pump: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years 10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	Moore
122	Provide the following maintenance related information for Unit 2 HPIC turbine: 1. Completed PM Work Orders (WO) for the last 5 years 2. Completed Corrective Maintenance WO's for the last 5 years 3. Vender Manual 4. Preventative Maintenance (PM) Tasks 5. Completed PM Work Orders (WO) 6. Open / Pending PM WO's 7. All Completed PM Deferrals 8. All Modification Packages 9. System Health Reports for the last 5 years	Moore

	10. Maintenance Rule System Status for the last 5 years 11. A List of Open and closed Corrective Action Requests (PER/SER) with a Short Description for the last 5 years 12. All completed PMT's for the last 5 years 13. Vibration Testing and Analysis for the last 5 years (if applicable) 14. Lube Oil Testing and Analysis for the last 5 years (if applicable)	
123	For EECW strainer 0-STN-067—926, provide the following: 1. Vendor manual 2. Drawings (electrical and mechanical) 3. List of PMs, including periodicity and dates of the last three times the PM was performed 4. Work packages for the last calibration and the last test of the instrumentation associated with the strainer auto-start feature	Mazzoni
124	Please provide the following PERs 1. 143225 Diesel Generator outboard bearing vibration issues, identified 11/27/ 2007, due 12/31/2013 (Unit 1) 2. 379134 U3 HPCI elevated turbine casing temperature, identified 06/11/2011, due U3R16 (Unit 3) 3. 556063 3B recirc pump #2 seal, identified 05/25/2012, due U3R16 Unit 3 4. the PER on the recent IRM Scram 698289 Unclear direction on SSI reactor cool down rate	Norton
125	Copies of the following items from the degraded equipment list: 1. 165288/503024 | BFN compliance with exemptions for operator manual actions in III.G.2 Fire Areas/Zones (SRM BFN-009305/BFN-021144) NC 2. 384210 | Debris and water present in A Train of SBGT (SRM BFN-017641) D	Norton
126	Normal RHRSW alignment procedure	Ferrarini
127	The following information associated with Unit 3 'B' Residual Heat Removal System **Pump BFN-3-PMP-074-0028**: 1. Pump performance requirements/assumptions used to support Chapter 14 accident analysis (i.e., DBA LOCA) 2. Purchase specifications including pump performance curves 3. Most recent pump baseline performance curves 4. Vendor manual 5. Drawings 6. Maintenance history 7. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 8. List of periodic surveillance test procedures 9. Most recent quarterly and cyclic IST program pump surveillance tests (entire WO package) 10. IST pump performance trend data since 1/1/08 11. Evaluation of any observed pump degradation observed during the last 5 years (if any) 12. Seismic analysis/qualification 13. Structural connections 14. Latest system flow balance results 15. The procedure for adjusting lift on vertical pumps Environmental qualification documentation	Ferrarini

128	The following information associated with Unit 2 ‘C’ Core Spray System **Pump BFN-2-PMP-075-0014**: 1. Pump performance requirements/assumptions used to support Chapter 14 accident analysis (i.e., DBA LOCA) 2. Purchase specifications including pump performance curves 3. Most recent pump baseline performance curves 4. Vendor manual 5. Drawings 6. Maintenance history 7. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 8. List of periodic surveillance test procedures 9. Most recent quarterly and cyclic IST program pump surveillance tests (entire WO package) 10. IST pump performance trend data since 1/1/08 11. Evaluation of any observed pump degradation observed during the last 5 years (if any) 12. Seismic analysis/qualification 13. Structural connections 14. Latest system flow balance results 15. The procedure for adjusting lift on vertical pumps Environmental qualification documentation	Ferrarini
129	The following information associated with the 2B Residual Heat Removal Service Water System **Pump BFN-0-PMP-023-0019**: 1. Pump performance requirements/assumptions used to support Chapter 14 accident analysis (i.e., DBA LOCA) 2. Purchase specifications including pump performance curves 3. Most recent pump baseline performance curves 4. Vendor manual 5. Drawings 6. Maintenance history 7. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 8. List of periodic surveillance test procedures 9. Most recent quarterly and cyclic IST program pump surveillance tests (entire WO package) 10. IST pump performance trend data since 1/1/08 11. Evaluation of any observed pump degradation observed during the last 5 years (if any) 12. Seismic analysis/qualification 13. Structural connections 14. Latest system flow balance results 15. The procedure for adjusting lift on vertical pumps 16. Environmental qualification documentation	Ferrarini
130	The following information associated with the Unit 2 Core Spray Loop 1 testable check **valve and associated actuator BFN-2-CKV-075-0026**: 1. Purchase specifications 2. Weak link analysis	Ferrarini

	3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	
131	The following information associated with the Unit 2 Core Spray Pump 'C' suction **valve and associated actuator BFN-2-FCV-075-0011**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	Ferrarini

132	The following information associated with the Unit 2 Core Spray System 1 inboard discharge **valve and associated actuator BFN-2-FCV-075-0025**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	Ferrarini
133	The following information associated with the Unit 3 Residual Heat Removal Pump 'B' suction **valve and associated actuator BFN-2-FCV-074-0024**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	Ferrarini

134	The following information associated with the Unit 3 Residual Heat Removal Loop 2 testable check **valve and associated actuator BFN-3-CKV-075-0068**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	Ferrarini
135	The following information associated with the Residual Heat Removal System discharge header train cross-connect **valve and associated actuator** from Unit 2 Loop 2 to Unit 3 Loop 1 **BFN-2-FCV-074-0101**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	Ferrarini
136	The following information associated with the Unit 3 Residual Heat Removal Heat Exchanger outlet **valve and associated actuator BFN-3-FCV-023-0046**: 1. Purchase specifications 2. Weak link analysis 3. Vendor manual 4. Drawings	Ferrarini

	5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures 8. Most recent completed surveillance test including LLRT, valve timing, position verification, and actuator thrust/torque performance (entire WO package) 9. Valve performance trend data since 1/1/08 10. Evaluation of any observed valve degradation observed during the last 5 years (if any) 11. Seismic analysis/qualification 12. Environmental qualification documentation 13. MOV schematic control diagrams	
137	The following information associated with the South EECW supply header **check valve** to the Unit 3 'A' Diesel Generator Cooler **BFN-3-CKV-067-0695**: 1. Vendor manual 2. Drawings 3. Maintenance history 4. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 5. List of periodic surveillance test procedures 6. Most recent completed surveillance test including LLRT and position verification (entire WO package) 7. Valve performance trend data since 1/1/08 8. Evaluation of any observed valve degradation observed during the last 5 years (if any)	Ferrarini
138	The following information associated with the South EECW supply header backflow **check valve** to the Unit 3 'A' Diesel Generator Cooler **BFN-3-CKV-067-0696**: 1. Vendor manual 2. Drawings 3. Maintenance history 4. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 5. List of periodic surveillance test procedures 6. Most recent completed surveillance test including LLRT and position verification (entire WO package) 7. Valve performance trend data since 1/1/08 8. Evaluation of any observed valve degradation observed during the last 5 years (if any)	Ferrarini
139	The following information associated with the South EECW supply header **check valve** to the Unit 3 'B' Residual Heat Removal pump seal cooler and room cooler **BFN-3-CKV-067-0601**: 1. Vendor manual 2. Drawings 3. Maintenance history	Ferrarini

	4. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 5. List of periodic surveillance test procedures 6. Most recent completed surveillance test including LLRT and position verification (entire WO package) 7. Valve performance trend data since 1/1/08 8. Evaluation of any observed valve degradation observed during the last 5 years (if any)	
140	The following information associated with the South EECW supply header back flow **check valve** to the Unit 3 'B' Residual Heat Removal pump seal cooler and room cooler **BFN-3-CKV-067-0600**: 1. Vendor manual 2. Drawings 3. Maintenance history 4. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 5. List of periodic surveillance test procedures 6. Most recent completed surveillance test including LLRT and position verification (entire WO package) 7. Valve performance trend data since 1/1/08 8. Evaluation of any observed valve degradation observed during the last 5 years (if any)	Ferrarini
141	The following information associated with the Residual Heat Removal Unit 3 'B' **Heat Exchanger BFN-3-HEX-074-0900B**: 1. Performance requirements/assumptions used to support Chapter 14 accident analysis (i.e., DBA LOCA). Include range of RHRSW temperature evaluated. 2. Purchase specifications 3. Drawings 4. Vendor manual 5. Calculations (heat transfer performance) 6. Maintenance history 7. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 8. List of periodic performance monitoring procedures 9. Most recent completed performance monitoring work order. 10. Heat exchanger performance trend monitoring data since 1/1/08 11. Seismic analysis/qualification 12. Evaluation of any observed valve degradation observed during the last 5 years (if any) 13. List of related industry operating experience issues and how BFN evaluated/addressed each.	Ferrarini

142	The following information associated with the Unit 3 'B' Residual Heat Removal Pump room **cooler BFN-3-CLR-064-0069**: 1. Performance requirements/assumptions used to support Chapter 14 accident analysis (i.e., DBA LOCA). Include range of RHRSW temperature evaluated. 2. Purchase specifications 3. Drawings 4. Vendor manual 5. Calculations (heat transfer performance) 6. Maintenance history 7. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 8. List of periodic performance monitoring procedures 9. Most recent completed performance monitoring work order. 10. Heat exchanger performance trend monitoring data since 1/1/08 11. Seismic analysis/qualification 12. Evaluation of any observed valve degradation observed during the last 5 years (if any) 13. List of related industry operating experience issues and how BFN evaluated/addressed each.	Ferrarini
143	Copies of the following corporate led self-assessments 1. CRP-ENG-F-12-001 2. CRP-ENG-F-12-002 3. CRP-ENG-F-12-009 4. CRP-ENG-F-12-011 5. CRP-ENG-F-12-014 6. CRP-ENG-F-12-015 7. CRP-ENG-F-12-017 8. CRP-ENG-F-12-019 9. CRP-ENG-F-12-020 10. CRP-ENG-F-12-021 11. CRP-ENG-F-12-025 12. CRP-ENG-F-12-026 13. CRP-ENG-F-11-002 14. CRP-ENG-F-11-004 15. CRP-ENG-S-11-005 16. CRP-REF-F-11-001 17. CRP-ENG-F-10-004 18. CRP-ENG-F-10-007 19. CRP-ENG-S-10-001 20. CRP-ENG-S-10-011 21. CRP-ENG-S-10-013	Kern
144	All UFSAR section 10.9 drawings	Kern
145	P&ID (flow drawings) for all 3 Units for the following systems: 1. CSS 2. RHR 3. RHRSW 4. EECW	Kern

146	Design Basis Document for the following systems: 5. CSS 6. RHR 7. RHRSW 8. EECW	Kern
147	BFN response to NRC GL 89-13 and NRC response	Kern
148	Procedures and/or program documents that implement BFN's NRC GL 89-13 program	Kern
149	Completed work package for last replacement of the Unit 1 vital battery (the TS batter with 120 cells).	Kern
150	GL 89-10 MOV program document, including listing of MOVs in program scope.	Kern
151	The latest 10 CFR 50.65(a)(3) Maintenance Rule periodic evaluation for each unit.	Kern
152	Snap Shot Assessment of the system health reports (stated as FP-13, PER 547427, effectiveness review action item due in Feb 2013)	Kern
153	PERs associated with RHR System Health Reports 1. 142923, 2. 210437, 3. 214957, 4. 232449, 5. 235900, 6. 271338, 7. 274840, 8. 315818, 9. 362340, 10. 369800, 11. 392781, 12. 410394, 13. 485119, 14. 539886, 15. 539889, 16. 567719, 17. 643071, 18. 812236	Kern
154	Current 10 year cycle IST Plan (pumps & valve testing) for each of the 3 units. Also provide copy of applicable IST code(s) in effect for each respective unit's IST Plan.	Kern
155	PER 417006	Kern
156	Evaluation or documentation associated with each commercial grade dedication performed for BF since 1/1/07. Identify which evaluations pertain to safety-related parts that have been installed at BF unit 1, 2, or 3.	Kern
157	PER associated with 2013 NRC CDBI issue regarding deficient HPCI test requirements. Also SR 687904	Kern
158	Provide IST trend data and motor trend data for each of the 12 CS pumps/motors, the 12 RHRSW pumps/motors, and the 12 RHR pumps/motors for the period 1/1/08 to current. Prefer a data listing and graph for each.	Kern
159	BF evaluation for applicability of NRC N 2010-11.	Kern

160	PERS associated with EECW System Health Report 1. 150500, 2. 160106, 3. 223543, 4. 211737, 5. 381569,	Kern
161	The status of replacing 2A RHR motor.	Kern
162	Operator log or other monitoring data for Unit 2 and Unit 2 pressure suppression chamber (PSC) keep fill system pressure and head tank level. If available as a computer trended point, provide data for period 1/1/12 to 3/31/13. If not on computer trend, provide data for the first day of each month (Jan 2012 – Mar 2013) and daily for 3/1 – 3/31/13.	Kern
163	All Fire Protection related PERS open and closed over the last 5 years	Kern
164	Self Assessments 1. BFN-95003-S-12-001 2. BFN-ENG-F-12-013 3. BFN-ENG-S-12-001 4. BFN-ENG-S-12-007 5. BFN-ENG-S-12-014 6. BFN-ENG-S-12-020 7. BFN-ENG-S-12-022 8. BFN-PI-S-12-004 9. BFN-PI-S-12-007 10. BFN-PI-S-12-019 11. BFN-PI-S-12-029 12. BFN-PI-S-12-033 13. BFN-PI-S-12-034 14. BFN-ENG-F-11-003 15. BFN-ENG-F-11-004 16. BFN-TRN-F-11-003	Kern
165	Procedures for programs listed below. (Please verify correct procedure number for the program identified.) 1. NPG-SPP-02.3 Operating Experience 2. NPG-SPP-03.4 Maintenance Rule Trending 3. NPG-SPP-06.7 Instrumentation Setpoint and Calibration 4. NPG-SPP-06.9 Testing Programs 5. NPG-SPP-06.9.1 Conduct of Testing 6. NPG-SPP-09.0 Engineering 7. NPG-SPP-09.1 ASME Code and Augmented Programs 8. NPG-SPP-OP.1.2 ASME Section XI Pressure Test Program 9. NPG-SPP-09.12 Margin Management 10. NPG-SPP-09.14 NRC GL 89-13 Implementation 11. NPG-SPP-09.16 (rev. 4) Plant Health Committee 12. NPG-SPP-09.16 (rev. 2) SSC and Program Health 13. NPG-SPP-09.16 (Rev. 0) Performance Monitoring Program 14. NPG-SPP-09.18 Material Condition Improvement Plan 15. NPG-SPP-09.4M 10 CFR 50.59 16. NPG-SPP-09.4U 10 CFR 50.59 17. NPG-SPP-09.7 Corrosion Control	Kern

166	PERS (including follow-up actions) associated with the following IP 95003 Part 1 inspection findings. 1. 05000259(260)(296)/ 2011011-01 2. 05000259(260)(296)/ 2011011-02 3. 05000259(260)(296)/ 2011011-03 4. 05000259(260)(296)/ 2011011-04 5. 05000259(260)(296)/ 2011011-05	Kern
167	PERS (including follow-up actions) associated with the following IP 95003 Part 2 inspection finding 05000259(260)(296)/2011012-01	Kern
168	Root Cause Evaluation procedure	Kern
169	Documents associated with CS system health as follows: 1. Non-conforming HGA relay PERs 415242 and 454956 2. last 3 leak tests for each of the Unit 1 and 2 and 3 Core Spray testable check valves (6); for example BFN-2-CKV-075-0026 is 1 of these 6 valves. 3. last 3 leak tests for each of the Unit 1 and 2 and 3 Core Spray discharge header inboard containment isolation valves (6); for example BFN-FCV-75-25 is 1 of these 6 valve. 4. all PERs (since 1/1/09) associated with CS testable check valve and/or CS discharge header inboard containment isolation valve leakage	Kern
170	The following information associated with Unit 3 'B' Residual Heat Removal System Pump **Motor BFN-3-MTR-074-0028**: 1. Purchase specifications including manufacturer motor test data 2. Most recent motor performance data (i.e., motor start and motor running current and voltage data) 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures and copy of most recent motor performance data 8. Environmental qualification documentation 9. Motor breaker schematic control diagrams	Mazzoni
171	The following information associated with the 2B Residual Heat Removal Service Water System Pump **Motor BFN-0-MTR-023-0019**: 1. Purchase specifications including manufacturer motor test data 2. Most recent motor performance data (i.e., motor start and motor running current and voltage data) 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation	Mazzoni

	7. List of periodic surveillance test procedures and copy of most recent motor performance data 8. Environmental qualification documentation 9. Motor breaker schematic control diagrams	
172	The following information associated with Unit 2 'C' Core Spray System Pump **Motor BFN-2-MTR-075-0014**: 1. Purchase specifications including manufacturer motor test data 2. Most recent motor performance data (i.e., motor start and motor running current and voltage data) 3. Vendor manual 4. Drawings 5. Maintenance history 6. List of modifications (i.e., material or design changes) and associated modification package and 50.59 screens/evaluations since original installation 7. List of periodic surveillance test procedures and copy of most recent motor performance data 8. Environmental qualification documentation 9. Motor breaker schematic control diagrams	Mazzoni
173	Abnormal operating procedure for LOOP	Mazzoni
174	Abnormal operation procedure for SBO	Mazzoni
175	Alarm response procedures for EDG	Mazzoni
176	Browns Ferry SER	Mazzoni
177	EDG system self assessment reports (by TVA) since from the last 10 years	Mazzoni
178	EDG system health reports from the last 5 years	Mazzoni
179	EDG main breaker Schematic Control Diagrams	Mazzoni
180	Class 1 E Medium Voltage Bus main breaker Schematic Control Diagrams	Mazzoni
181	**RHRSW B1** motor breaker Schematic Control Diagrams	Mazzoni
182	**RHRWS B2** motor breaker Schematic Control Diagrams	Mazzoni
183	Reports of the last two incidents of loss of offsite power (LOOP), providing detail graphing for automatic actions (switchyard SER graphs, plant computer graphs/event time records)	Mazzoni
184	Plant Electrical Systems Design Bases Documents, for Class 1E AC, DC, and EDG	Mazzoni
185	Basis document for the plant response to station blackout (SBO)	Mazzoni
186	The following electrical drawings: 1. Switchyard main one line diagram 2. EDG main one line diagram, including 4.16kV shut down boards and Class 1E boards. 3. 460 V Class 1E boards 4. 250 VDC Class 1E batteries	Mazzoni
187	Criteria for Protective Relay Settings and Coordination	Mazzoni
188	Criteria for MOV thermal Over Load Protection	Mazzoni
189	Battery sizing calculations for the Class 1E dc system	Mazzoni
190	Charger sizing calculations for the Class 1E dc system	Mazzoni
191	Bus and Cable Protection system sizing and coordination for the Class 1E dc system	Mazzoni
192	Cable sizing calculation for the Service Water pump, Core Spray pump and RHR pump motors	Mazzoni

193	EDG loading calculations all EDGS?	Mazzoni
194	Short Circuit Calculations for the Class 1 E AC Medium Voltage and Low Voltage Buses	Mazzoni
195	Loading Calculations and for the Class 1 E AC Medium Voltage and Low Voltage Buses	Mazzoni
196	Degraded Voltage Relay Settings calculation/evaluation and schematic control diagrams	Mazzoni
197	Protective Relay Settings calculations/evaluation and schematic control diagrams for the following: 1. Core Spray motor BFN-2-MTR-075-0014 2. Residual Heat Removal motor BFN-3-MTR-074-0028 3. Residual Heat Removal Service Water BFN-0-MTR-023-0019 4. All EDGs	Mazzoni
198	Schematic control diagrams for the Class 1 E AC Medium Voltage and Low Voltage Buses	Mazzoni
199	The following EDG completed surveillance tests for all EDGs: 1. 3 most recent monthly 2. 2 most refueling outage, including the most recent load sequence test and 24 hour run test for each EDG	Mazzoni
200	The most recent completed surveillance tests for the following: 1. RHRSW B1 motor 2. RHRSW B3 motor	Mazzoni
201	The most recent completed battery discharge tests for each of the Class 1E batteries	Mazzoni
202	The Class 1E 4.6 kV motor test requirements, and the two most recent completed test reports on Core Spray, RHR, and RHRSW motors listed: 1. BFN-2-MTR-075-0014 2. BFN-3-MTR-074-0028 3. BFN-0-MTR-023-0019	Mazzoni
203	Voltage regulation calculations/Evaluations and schematic control diagram under: 1. EDG power 2. Preferred Power Supply (PPS) power	Mazzoni
204	Most recently completed surveillance tests for and 3 units Containment HVAC fan and compressor motors	Mazzoni
205	The 5 most recent operability determination evaluations	Shaikh
206	The 5 most recent Ultrasonic examination reports and Examiner certification records for each NDE examination	Shaikh
207	The 5 most recent Magnetic particle examination reports and Examiner certification records for each NDE examination	Shaikh
208	The 5 most recent Penetrant examination reports and Examiner certification records for each NDE examination	Shaikh
209	The 5 most recent Visual examination reports	Shaikh
210	The 5 most recent 50.59 evaluations and 5 most recent 50.59 screenings	Shaikh
211	The 5 most recent engineering design change packages that have been installed	Shaikh

212	List of all PERs (since 1/1/11) identifying discrepancies between design drawings and as-found condition of SSCs and associated Engineering Evaluations (if applicable) to address these discrepancies	Shaikh
213	Name(s) and contact information of POCs for BWR Vessels Internals Program (BWRVIP), Buried Piping program, FAC program, and ISI program	Shaikh
214	Current EDG fuel oil calculations that demonstrate fuel oil tank capacity is sufficient to meet EDG mission time for each Rx unit. (i.e., 4 EDGs draw off tank(s) to meet Unit 1 and 2 EDG mission times and 4 EDGs draw off tank(s) to meet Unit 3 mission time. Provide the separate calculations for each.)	Shaikh
215	The 5 most recent ASME Section XI repair/replacement plans	Shaikh
216	Documents that show whether the pipe that failed and required the 3/19/13 Unit 1 shut down is in a monitoring program such as the Flow Accelerated Corrosion (FAC) program. If it was in a monitoring program. Provide data since 1/1/09 for this monitored pipe.	Shaikh
217	Copies of the following Self Assessments: 1. CRP-ENG-F-12-007 2. CRP-ENG-F-12-010 3. BFN-TRN-S-12-009 4. BFN-TRN-S-12-017 5. BFN-TRN-S-12-022 6. BFN-TRN-S-12-025 7. BFN-TRN-S-12-034 8. BFN-TRN-S-12-048 9. BFN-ENG-F-11-004 10. BFN-ENG-S-11-013 11. FN-TRN-F-11-003	Shaikh