Salem 1
3Q/2014 Plant Inspection Findings

Initiating Events

Significance: G Jun 30, 2014
Identified By: Self-Revealing
Item Type: NCV NonCited Violation
Failure to Maintain Shutdown Margin Calculation Procedure to Cover certain Mispositioned Control Rod Events
The inspectors determined there was a Green, self-revealing violation of TS 6.8.1, “Procedures and Programs,” as described in Regulatory Guide 1.33, Revision 2, February 1978, when PSEG did not maintain procedure SC.RE-ST.ZZ-0002, “Shutdown Margin Calculation,” to cover certain mispositioned control rod events. Consequently, PSEG performed unnecessary rapid boration, and a subsequent manual reactor trip, in response to a control rod drop event on January 31, 2014. PSEG entered this in their corrective action program (CAP), implemented compensatory measures for calculating shutdown margin, performed an apparent cause evaluation, and initiated actions to correct the cause of the problem, extent of condition, and extend of cause.

The issue was more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone, and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the finding resulted in unnecessary rapid boration and a manual reactor trip. Using IMC 0609, Attachment 4, “Initial Characterization of Findings,” and IMC 0609, Appendix A, “The SDP for Findings At-Power,” the inspectors determined that this finding was of very low safety significance (Green) because it did not cause the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined that this finding had a cross-cutting aspect in the area of Human Performance, Teamwork, because PSEG work groups did not communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained [H.4]. Specifically, PSEG reactor engineering and operations services did not communicate and coordinate a change to the shutdown margin calculation procedure that was conducted in response to vendor-issued guidance.
Inspection Report# : 2014003 *(pdf)*

Significance: G Apr 08, 2014
Identified By: Self-Revealing
Item Type: FIN Finding
Inadequate Corrective Action to Prevent Recurrence of Silent Steam Generator Feed Pump Coast-Downs
A Green, self-revealing FIN was identified against NC.WM-AP.ZZ-0002, “Performance Improvement Process,” Revision 6, because PSEG did not adequately correct and prevent recurrence of steam generator feedpump (SGFP) silent coast-down events. Consequently, on April 8, 2014, PSEG operators manually tripped the Unit 1 reactor in response to lowering water level in the 13 steam generator that was caused by a coast-down of the 11 SGFP.

Description. On April 8, 2014, at 9:12 p.m., Salem Unit 1 was operating at approximately 100% power when operators received an alarm indicating failure of the
12 Essential Controls Inverter (ECI), followed by several other alarms. At 9:13 p.m., operators observed failed indications associated with 11 SGFP, as well as lowering steam generator water level, and took manual action to trip 11 SGFP in accordance with the alarm response procedure. As expected, this initiated a main turbine automatic

runback to approximately 66 percent turbine loading. At 9:14 p.m., operators manually tripped the reactor due to 13 steam generator water level approaching its setpoint for an automatic reactor trip. PSEG's post-event investigation determined that a ground fault on a limit switch test cable associated with the 11 SGFP turbine main steam stop valve caused a momentary power transfer of 12 ECI, and opened the 12 Miscellaneous AC breaker 8. Once breaker 8 opened to clear the fault, 12 ECI transferred back to the normal power source. The opening of breaker 8 removed power to the 11 SGFP speed probes. As part of the governor control circuit, loss of power to the probes resulted in a governor controller shutdown and SGFP coast-down, thereby constituting a "silent coast-down." The SGFP governor controls were not designed to generate a SGFP trip signal following a governor controller shutdown.

PSEG entered this issue in their CAP (20646085) and performed a root cause analysis (RCA). PSEG determined the root cause "was a result of an accumulation of missed opportunities by Salem Station to use the corrective action system effectively." PSEG also stated that "a known deficiency in the SGFP governor circuit design increased the likelihood of a SGFP shutdown and a reactor trip." The RCA documented several opportunities to address SGFP turbine coast-down events, which were historically unalarmed and referred to as "silent" SGFP coast-downs. Specifically, silent SGFP coast-downs occurred in 1999, 2001, and twice in 2002. Three of these silent coast-down events involved successful main turbine runbacks that were manually initiated prior to, and successfully averted, automatic reactor trips on low steam generator water level. On November 12, 2002, Unit 1 experienced a silent coast-down of the 11 SGFP and manual reactor trip on lowering steam generator water level. PSEG had performed an RCA for that event, and determined the root cause for the "unrecoverable steam generator level" and manual reactor trip was "the unannounced 11 SGFP runback at 180 rpm/min" (i.e., coast-down). The 2002 RCA established a corrective action to "annunciate and eliminate" silent SGFP coast-downs, and designated this as a corrective action to prevent recurrence (CATPR). In response to this action, PSEG created a speed deviation alarm for the SGFPs, and an alarm procedure with a designated action to manually trip the affected SGFP to initiate a main turbine runback. Although not explicitly stated in the RCA, the inspectors determined that the intent of the CATPR was to prevent recurrence of the "unrecoverable steam generator level" as a result of SGFP coast-down events, because the alarm procedure achieves this action through initiation of a main turbine runback. The inspectors determined that the speed deviation alarm installed as a result of the 2002 event did not provide adequate annunciation capability for operators to successfully diagnose a SGFP coast-down prior to the onset of "unrecoverable steam generator level" on April 8, 2014. Finally, the 2002 RCA also established a separate design change action to provide uninterruptible power supplies (UPS) for the SGFP governor controls, but inadvertently omitted the speed probes from the scope during design change development.

After the April 8, 2014 trip, PSEG used simulations to determine that operators would have between 30 and 45 seconds to properly diagnose a SGFP turbine coast-down event and take action to initiate a turbine runback prior to an automatic rector trip on low steam generator water level. PSEG's interim corrective actions following the 2014 event included creating new overhead alarms dedicated to a loss of power to SGFP governor controls, and training licensed operators on a silent SGFP coast-down event. Additionally, PSEG performed a design change on Unit 2 to power the SGFP speed probes from an UPS and incorporated the same design change into the fall 2014 Unit 1 refueling outage scope of work. Long term corrective actions included development of advanced digital feedwater control system design changes that will automate turbine runbacks in the event of SGFP governor control power losses.

NC.WM-AP.ZZ-0002 was the CAP procedure effective at the time of the November 2002 event. Step 5.3.2 required that root cause analyses include "actions to correct the condition and prevent recurrence." NC.CA-TN.ZZ-0003, "Root Cause Manual," Revision 0, defined CATPRs as "Fundamental measures taken to correct the deficiency and prevent recurrence." The inspectors determined that the CATPR designated and completed as a result of the 2002 RCA did not adequately correct and prevent recurrence of silent SGFP coast-downs that result in "unrecoverable steam generator level." Specifically, the speed deviation alarm installed as a result of the 2002 event did not provide adequate annunciation capability for operators to successfully diagnose a SGFP coast-down prior to the onset of "unrecoverable steam generator level" on April 8, 2014.

Analysis. PSEG's inadequate corrective action to prevent recurrence of silent SGFP coast-down events in accordance with NC.WM-AP.ZZ-0002 was a performance deficiency. This issue was more than minor since it was associated with the equipment performance attribute of the Initiating Events cornerstone and adversely impacted its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions. Specifically, the inadequate corrective action did not prevent recurrence of a silent SGFP coast-down that also resulted in a reactor trip. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both 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.

The inspectors determined there was no cross-cutting aspect associated with this finding since it was not representative of current PSEG performance. Specifically, in accordance IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were considered not representative of present performance.

Enforcement. NC.WM-AP.ZZ-0002, “Performance Improvement Process,” Revision 6, step 5.3.2, requires that root cause evaluations include “actions to correct the condition and prevent recurrence.” Contrary to NC.WM-AP.ZZ-0002, PSEG designated and implemented a CATPR in 2002 that did not adequately correct and prevent recurrence of silent SGFP coast-down events. Because this finding does not involve a violation and is of very low safety significance, Green, it is identified as a FIN. (FIN 05000272/2014-004-02, Inadequate Corrective Action to Prevent Recurrence of Silent Steam Generator Feed Pump Coast-Downs)

Inspection Report# : 2014004 *(pdf)*

Significance: G Mar 31, 2014
Identified By: NRC
Item Type: NCV NonCited Violation
Inadequate Online Risk Assessment for an Adverse Change in Grid Conditions
The inspectors identified a Green NCV of Title 10 of the Code of Federal Regulations (10 CFR) 50.65(a)(4) when PSEG inadequately assessed risk during a period of adverse grid conditions. On January 7, 2014, the regional transmission organization declared a Maximum Emergency Generation Action, a condition that PSEG was procedurally required to consider a high risk evolution (HRE) for a loss of offsite power (LOOP). Specifically, PSEG was to elevate online risk to a Yellow condition; however, PSEG did not assess risk as Yellow. PSEG subsequently elevated their risk condition, protected equipment, took other risk management actions (RMAs), and entered the issue in their CAP.

The issue was more than minor since it was associated with the Protection Against External Factors attribute of the Initiating Events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the extreme cold weather conditions indirectly were affecting grid stability and required risk assessment and management. Additionally, it was similar to IMC 0612, Appendix E, example 7.e, in that an inadequate risk assessment is not minor if the overall plant risk would put the plant into a higher licensee-established risk category. In this case, plant risk was reclassified from Green to Yellow when properly assessed. Specifically, the extreme cold weather conditions indirectly were affecting grid stability. The inspectors evaluated the finding using IMC 0612, Appendix K, “Maintenance Risk Assessment and Risk Management Significance Determination Process.” Since the incremental core damage probability deficit was less than 1 E-6 and the incremental large early release probability deficit was less than 1 E-7, this finding was determined to be of very low safety significance (Green). The finding was determined to have a cross-cutting aspect in the area of Human Performance, Teamwork, in that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. Specifically, PSEG staff in the Electric System Operations Center (ESOC), Salem control room, and Hope Creek control room did not appropriately communicate across organizational boundaries to ensure that risk was appropriately assessed.

Inspection Report# : 2014002 *(pdf)*

Mitigating Systems

Significance: G Jul 24, 2014
Identified By: NRC
Item Type: NCV NonCited Violation
Salem Nuclear Generating Station, Unit Nos. 1 and 2 - NRC Component Design Bases Inspection Report
The team identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” because PSEG did not promptly identify and correct conditions adverse to quality. Specifically, PSEG did not promptly identify and correct degraded conditions associated with the Unit 1 and Unit 2 auxiliary feedwater storage tank (AFWST) and refueling water storage tank (RWST) instrumentation panels. PSEG entered the associated issues into their corrective action program (CAP) as notifications 20654991, 20654996, 20656136, 20657114, 20657115, and 20657117. PSEG’s short-term corrective actions included installing bolts/plugs on the Unit 1 RWST panel 378-1 and unplugging the failed fan in Unit 1 AFWST panel 802-1.

The team determined that the inadequate identification and resolution of the conditions adverse to quality is a performance deficiency that was within PSEG’s ability to foresee and correct. The finding is associated with the Mitigating Systems cornerstone and is more than minor because if left uncorrected it could lead to a more significant safety concern. Specifically, if left uncorrected, the continued exposure to external environmental elements and/or existing internal degraded conditions could potentially result in loss of level indication, non-conservative level indication, and/or loss of low level alarm functions. In accordance with IMC 0609.04, “Initial Characterization of Findings,” and Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” issued June 19, 2012, the team determined that the finding is of very low safety significance (Green), because the finding was a deficiency affecting the design or qualification of a mitigating system, structure, or component (SSC), where the SSC maintained its operability.
Inspection Report# : 2014007 *(pdf)*

Significance: G Mar 31, 2014
Identified By: Self-Revealing
Item Type: NCV NonCited Violation
Failure to Follow Fire Protection Test Procedure Resulted in Fuel Oil Spill
The inspectors determined there was a Green, self-revealing violation of Technical Specification (TS) 6.8.1, “Procedures and Programs,” as described in Regulatory Guide 1.33, Revision 2, February 1978, when PSEG failed to adequately implement procedure steps associated with fire protection hose flow verification testing on March 6, 2014. Consequently, a fuel oil day tank was overfilled, resulting in approximately 3000 gallons of fuel oil on the pump house roof, leaks through the roof onto the fire pumps, and Salem fire water suppression system unavailability for approximately two days. PSEG stopped the leak, entered this issue in their CAP, and completed a Prompt Investigation.

The inspectors determined that the performance deficiency was more than minor because it was associated with the Protection Against External Factors attribute of the Mitigating System cornerstone and adversely its cornerstone

objective to ensure the availability, reliability, and capability of systems that respond to initiating events (fire) to prevent undesirable consequences. The inspectors determined that the finding was of very low safety significance (Green) because it did not impact the ability of Salem Units 1 or 2 to achieve and maintain safe shutdown. The inspectors determined that this finding had a cross-cutting aspect in the area of Human Performance, Avoid Complacency, because PSEG fire protection operators did not recognize and plan for the possibly of mistakes, latent issues, and inherent risk, even while expecting successful outcomes of procedure steps to refill the fuel oil day tank. Further, they did not implement appropriate error reduction tools.
Inspection Report# : 2014002 *(pdf)*

Significance: G Mar 31, 2014
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to establish appropriate MR performance goals
Green. The inspectors identified a Green NCV of Title 10 of the Code of Federal Regulations (10 CFR) 50.65(a)(4) when PSEG inadequately assessed risk during a period of adverse grid conditions. On January 7, 2014, the regional transmission organization declared a Maximum Emergency Generation Action, a condition that PSEG was procedurally required to consider a high risk evolution (HRE) for a loss of offsite power (LOOP). Specifically, PSEG was to elevate online risk to a Yellow condition; however, PSEG did not assess risk as Yellow. PSEG subsequently elevated their risk condition, protected equipment, took other risk management actions (RMAs), and entered the issue in their CAP.

The issue was more than minor since it was associated with the Protection Against External Factors attribute of the Initiating Events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the extreme cold weather conditions indirectly were affecting grid stability and required risk assessment and management. Additionally, it was similar to IMC 0612, Appendix E, example 7.e, in that an inadequate risk assessment is not minor if the overall plant risk would put the plant into a higher licensee-established risk category. In this case, plant risk was reclassified from Green to Yellow when properly assessed. Specifically, the extreme cold weather conditions indirectly were affecting grid stability. The inspectors evaluated the finding using IMC 0612, Appendix K, “Maintenance Risk Assessment and Risk Management Significance Determination Process.” Since the incremental core damage probability deficit was less than 1 E-6 and the incremental large early release probability deficit was less than 1 E-7, this finding was determined to be of very low safety significance (Green). The finding was determined to have a cross-cutting aspect in the area of Human Performance, Teamwork, in that individuals and work groups communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained. Specifically, PSEG staff in the Electric System Operations Center (ESOC), Salem control room, and Hope Creek control room did not appropriately communicate across organizational boundaries to ensure that risk was appropriately assessed.
Inspection Report# : 2014002 *(pdf)*

Significance: G Mar 31, 2014
Identified By: NRC
Item Type: FIN Finding
Failure to take adequate corrective actions following a PDP failure to couple-on-demand event.
The inspectors identified a Green FIN associated with Unit 1 for PSEG’s failure to take adequate corrective actions in accordance with procedure LS-AA-125, “Corrective Action Program,” Attachment 1 guidance following a PDP failure to couple-on-demand event, and to preclude subsequent failures during other couple-on-demand events and additional unplanned PDP unavailability. PSEG entered this issue into their CAP, implemented a compensatory measure, and initiated actions to correct the condition causing the failure to couple events.

The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affected its objective to ensure the availability and reliability of systems (safe shutdown charging cross-connect) that respond to initiating events (fire) to prevent undesirable consequences (i.e., core damage). The inspectors determined that the finding was very low safety significance as the Unit 2 reactor would have been able to reach and maintain safe shutdown. This finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Resolution, in that PSEG did not take effective corrective actions to address issues in a timely manner commensurate with their safety significance. Specifically, PSEG did not take adequate corrective actions in response to a PDP failure-on-demand event in February 2013 to preclude several additional unexpected PDP failure-on-demand events which resulted in additional unplanned unavailability.
Inspection Report# : 2014002 *(pdf)*

Significance: G Dec 31, 2013
Identified By: NRC
Item Type: NCV NonCited Violation
Inadequate HELB Barrier Controls
The inspectors identified a Green NCV of TS 6.8.1, "Procedures and Programs", as described in Regulatory Guide (RG) 1.33, Revision 2, when PSEG did not properly implement high energy line break (HELB) barrier controls in accordance with CC-AA-201, Plant Barrier Control, during maintenance activities that affected the performance of safety-related equipment on October 1, 2 and 17, 2013. PSEG entered the issue into the CAP under notifications 20623371 and 20633614.

This finding was more than minor because it was associated with the configuration control attribute of the Mitigating System cornerstone, and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, improper barrier controls could potentially affect the operating equipment in the case of a HELB. This performance deficiency required a detailed risk evaluation (DRE) in accordance with IMC 0609, Appendix A, screening questions in Exhibits 2, "Mitigating Systems," because of an assumed loss of the AFW system decay heat removal safety function. The inspectors and a Region I Senior Reactor Analyst (SRA) conducted a bounding DRE and determined this finding to be of very low safety significance (Green). This finding had a cross-cutting aspect in the area of Human Performance, Work Control, in that licensees plan and coordinate work activities by incorporating the need for planned contingencies, compensatory actions, and abort criteria. Specifically, PSEG did not properly plan and coordinate compensatory actions via station procedures for HELB barrier impairments. [H.3(a)] (Section 1R18)
Inspection Report# : 2013005 *(pdf)*

Barrier Integrity

Significance: G Sep 30, 2014
Identified By: Self-Revealing
Item Type: NCV NonCited Violation
Improper Risk Assessment and Risk Management Actions for a Reheater Drain Valve
A self-revealing, Green NCV of 10 CFR 50.65(a)(4) was identified when PSEG did not properly assess and manage risk on Salem Unit 1 during an evolution with the potential to cause a reactivity change and overpower event. Specifically, while working on a moisture separator reheater (MSR) drain valve, it failed closed, reduced MSR reheat efficiency, led to the turbine control valves opening further, and resulted in an overpower event. Consequently, this resulted in violating the thermal power limit in license condition 2.C.(1).

Description. On June 17, a PSEG equipment operator observed 11RD60, the 11 West MSR shell drain and level control valve, cycling every three to five seconds. Moisture separation and reheating of the high-pressure turbine exhaust steam is performed by six combined MSRs. The MSRs and associated drains are not safety-related but are considered Maintenance Rule components. The MSR drain valves position to control condensate level in the MSRs and, therefore, control efficiency of the reheated steam that is supplied to the low pressure main turbines. PSEG entered the cycling valve issue in their CAP (notification 20653895) and recommended an instrument loop tuning. On June 19, at 1:25 a.m., operators received an MSR high level alarm. Equipment operators dispatched to the area identified that the 11RD60 was cycling from 50 to 70 percent. PSEG placed the valve in manual, jacked the valve full open, and entered this in their CAP (20654174). On June 26, at 9:30 a.m., maintenance technicians commenced corrective maintenance on 11RD60, an evolution that had already been completed seven times on similar valves. When the valve was taken from manual to automatic, it resumed cycling while the controller was tuned. The technicians monitored performance over the next several hours. Approximately 75 minutes later, the valve failed closed and operators received an MSR high level alarm. An equipment operator returned 11RD60 to manual and jacked the valve open. Following another control room brief, the technicians returned to the valve to conduct additional tuning. When placed in automatic, the valve did not respond as expected. Specifically, the technicians expected the valve to initially move in the closed direction given MSR level was below the controller setpoint, but also expected the valve to then move in the open direction after the controller received level feedback from the rising level. After four to five minutes, the technicians moved to the controller located on the turbine building roof and discovered the valve had failed closed again. At the same time, the operators received another MSR high level alarm. Due to the reheat steam efficiency loss, steam demand and, consequently reactor power increased. Reactor thermal power exceeded the licensed limit of 3459 MWth for approximately eight minutes and reached a maximum of 3489.9, or 0.89% above the limit. PSEG took actions in accordance with procedures to lower power and restore it within the license limit. Additionally, they classified this as a level-four reactivity event, entered this in the CAP (20655041), and performed an Apparent Cause Evaluation (ACE).

The inspectors reviewed the ACE, interviewed PSEG staff, walked down equipment, and reviewed station procedures and recorded parameters. PSEG determined that the apparent cause was that “operators failed to precisely control the MSR valve tuning evolution due to a knowledge deficiency related to MSR level control valve failure and its resulting impact on steam demand and reactor power level. Risk of the 11RD60 valve failing closed was not recognized by the crew and mitigating actions were not performed to prevent the overpower event.” PSEG’s investigation also identified that technicians had not been stationed at the controller during the second attempt to tune the valve and that had there been, immediate information would have been provided to the team. Further, the valve had not been adjusted in manual to ensure a “bumpless transfer” when returned to automatic. Finally, monitoring of plant parameters associated with MSR efficiency would have allowed operators additional means to detect MSR level changes.

PSEG procedure WC-AA-105, “Work Activity Risk Management,” Revision 2, classifies work activity risk as Low, Medium, High, Production, and Reactivity. During the ACE review, the inspectors identified differences in PSEG staffs’ risk assessment of the evolution. Specifically, the Control Room Supervisor and the maintenance supervisor told inspectors that the work activity risk had been determined to be Low-Production and Medium-Production risk, respectively, while the ACE described the risk assessment as Medium-Reactivity. The inspectors determined that the initial evolution had been Medium-Production-Reactivity risk since WC-AA-105, Exhibit 5, lists MSRs as a production risk system and step 4.9.6 states, in part, that “any production risk activity is automatically considered to also be a reactivity risk activity, because it could result in a power change of >20 MWE.” WC-AA-105 directs risk management actions based on the assessed risk level. For Medium and High risk activities, form 2 requires identification
of the most likely undesirable outcome and designation of contingency and/or compensatory measures and human error prevention techniques to prevent that outcome. The inspectors determined that PSEG’s risk assessment and risk management actions associated with the maintenance evolution were inadequate as evidenced by PSEG’s post-event evaluation of staff actions in preparation for and during the evolution and overpower event. The issue was determined to be within PSEG’s ability to foresee and correct based on both risk procedure guidance, the valve’s cycling, and initial response to the closed position before the final failure.

Regulatory Issue Summary 2007-21, “Adherence to Licensed Power Limits,” Revision 1, endorsed the NEI Position Statement for Guidance to Licensees on Complying with the Licensed Power Limit. That guidance describes performance deficiencies that include “failure to take prudent action prior to a pre-planned evolution that could cause a power increase to exceed the licensed power limit.” The inspectors determined that the system response during the initial work activity demonstrated the potential to cause a transient increase in reactor power and, therefore, further evaluation of and prudent action based on this performance should have been taken.

Analysis. Improperly assessing and managing risk in accordance with WC-AA-105 was a performance deficiency that was evaluated in accordance with IMC 0612, Appendix B. The issue was determined to be more than minor since it was associated with the configuration control attribute of the barrier integrity cornerstone and adversely affected its objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Specifically, the system alignment was impacted during maintenance, resulting in an overpower event. It was also similar to IMC 0612, Appendix E, Example 8.a. Specifically, PSEG did not comply with procedural requirements associated with risk that contributed to violating a thermal power limit,
a condition prohibited by the operating license. The finding was then evaluated using IMC 0609, Attachment 4 and Appendix A, Exhibit 3, where it screened to Green since
it was only associated with the fuel cladding barrier.

The finding was determined to have a cross-cutting aspect in Human Performance, Avoid Complacency, in that individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Individuals are expected to consider potential undesired consequences and implement appropriate error reduction tools. Specifically, PSEG staff relied on past successes and assumed conditions working on this and similar drain valves and did not perform adequate, successive activity reviews when the valve exhibited unexpected responses. [H.12]

Enforcement. 10 CFR 50.65(a)(4) states, in part, that “before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.” Contrary to this, on June 26, 2014, PSEG did not properly assess and manage the risk associated with 11RD60 valve corrective maintenance as implemented by WC-AA-105. Consequently, this resulted in an overpower event that exceeded and, therefore, violated the thermal power limit license condition 2.C.(1). PSEG reduced power below the licensed limit and placed the valve in manual. Because this finding was of very low safety significance, was entered in PSEG’s CAP (20655041), and was not repetitive or willful, this finding is being treated as an NCV in accordance with section 2.3.2 of the NRC’s Enforcement Policy. (NCV 05000272/2014-004-01, Improper Risk Assessment and Risk Management Actions for a Reheater Drain Valve)

Inspection Report# : 2014004 *(pdf)*

Emergency Preparedness

Occupational Radiation Safety

Public Radiation Safety

Security

Although the Security Cornerstone is included in the Reactor Oversight Process assessment program, the Commission has decided that specific information related to findings and performance indicators pertaining to the Security Cornerstone will not be publicly available to ensure that security information is not provided to a possible adversary. Other than the fact that a finding or performance indicator is Green or Greater-Than-Green, security related information will not be displayed on the public web page. Therefore, the cover letters to security inspection reports may be viewed.

Miscellaneous

Last modified : November 26, 2014