March 9, 2000

Tennessee Valley Authority
ATTN: Mr. J. A. Scalice
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: NRC SPECIAL INSPECTION REPORT NO. 50-328/00-03

Dear Mr. Scalice:

On February 4, 2000, the NRC completed a special inspection at your Sequoyah 2 reactor facility. The enclosed report presents the results of this inspection.

The inspection was performed as a result of implementation of guidance contained in NRC Management Directive 8.3, "NRC Incident Investigation Procedures," Part I, which provides decision-making criteria for NRC management to determine when inspections beyond the routine baseline inspection program are warranted. In this case, the Unit 2 reactor trip with subsequent safety injection followed by the failure of the 2A-A auxiliary feedwater pump and the automatic closure of the main steam line isolation valves, resulted in a risk increase sufficient for this special inspection.

Based on the results of this inspection, we have determined that the cause of the reactor trip and safety injection was well understood and that, in general, operator performance was appropriate. There were several equipment and human factors issues that you identified and placed in your corrective action program.

The NRC identified six issues of low safety significance that have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached special inspection report. Of the six issues, two were determined to involve violations of NRC requirements, but because of their low safety significance the violations are not cited. If you contest these non-cited violations, 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 the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Sequoyah facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

/RA/

Paul E. Fredrickson, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket No. 50-328
License No. DPR-79

Enclosure: NRC Special Inspection Report
w/attached NRC's Revised Reactor
Oversight Process

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U.S. NUCLEAR REGULATORY COMMISSION

Enclosure

REGION II

Docket No:	50-328
License No:	DPR-79
Report No:	50-328/00-03
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Unit 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	January 19 through February 4, 2000
Inspectors:	Russell Gibbs, Team Leader D. Rich, Team Member (Watts Bar Resident Inspector) P. Fillion, Team Member (Region II Engineering Specialist)
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

Sequoyah Nuclear Plant, Unit 2
NRC Special Inspection Report 50-328/00-03

The report covers a six-week period of resident inspection. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the NRC's Significance Determination Process, as discussed in the attached summary of the NRC's Revised Reactor Oversight Process.

Mitigating Systems

- Green. The auxiliary feedwater (AFW) pump 2A-A breaker failed to close during the event which caused motor-driven AFW pump 2A-A to not start as required. The root cause of the breaker failure was not known at the end of the inspection. The inspectors noted, however, that an extensive root cause determination was in progress. The risk significance of this finding was low because both the 2B-B motor-driven and the turbine-driven AFW pumps were available and restored steam generator water levels (Section 4.1).

- Green. A non-cited violation of Technical Specification 6.8.1.a was identified for the licensee's failure to follow the maintenance instruction used to torque main feedwater check valves 2-VLV-3-508 and 2-VLV-3-510. Valve 2-VLV-3-508 developed a body-to-bonnet leakrate of about 60-70 gpm during the transient. This leakage complicated the transient in that feedwater from the AFW system was diverted from steam generator 3. The risk significance of this flow diversion was low because there was sufficient feedwater flow capacity from motor-driven AFW pump 2B-B and the steam-driven AFW pump to restore the steam generators to their normal water levels (Section 4.3).

- Green. Atmospheric relief valve (ARV) 2 failed to close automatically during the Unit 2 reactor trip, but was manually closed by the reactor operator. The valve failed to close due to an excessive recovery time from the valve's controller saturation brought on by a momentary loss of power from inverter 2-IV. The faulty controller was replaced by the licensee prior to unit restart. The risk significance of this valve failure was low because manual operation of ARV 2 and the other ARVs were available throughout the event (Section 4.4).

- Green. A non-cited violation of TS 6.8.1.a was identified for the licensee's failure to follow the emergency operating procedures during the transient. The licensee failed to follow Emergency Procedure E-O when a licensed operator failed to verify at least four emergency raw cooling water (ERCW) pumps running after the reactor trip and safety injection. The failure to verify at least four ERCW pumps running resulted in only three ERCW pumps running after the safety injection. The failure to start the fourth pump was of low safety significance because there was adequate ERCW flow during the event (Section 5.1).

- Green. While controlling reactor coolant temperature subsequent to the reactor trip, the reactor operator did not fully understand the indication of small differences in the controller setpoint for ARV 3 and as a result the operator placed the valve in manual override shut. This action rendered the automatic pressure control feature of the ARV inoperable. The inspectors determined through discussions with the licensee that ARV operation when in manual override control was not well understood by some plant operators. The risk significance of this finding was low because decay heat removal capability during the event was maintained (Section 5.2).

Barrier Integrity

- Green. Glycol floor cooling containment isolation valve 2-FCV-61-122 failed to close during the event due to a valve stem lubrication problem. The valve should have automatically closed due to phase A containment isolation signal which occurred as a result of the safety injection signal. Its redundant isolation valve automatically closed as designed. This degraded containment isolation barrier was of low safety significance because it was not a direct release pathway for reactor coolant or containment atmosphere (Section 4.5).

1.0 Special Inspection Team Charter

On January 19, 2000, a Special Inspection team was established by NRC Region II management using the guidance contained in Management Directive 8.3, "NRC Incident Investigation Procedures," Part I. The Special Inspection team charter was to inspect and assess the circumstances associated with a Unit 2 reactor trip and subsequent safety injection (SI) that occurred on January 18, 2000. The team used Inspection Procedure 93812, "Special Inspection." The team focused its inspections on [1] why the Unit 2 reactor tripped, [2] why a SI signal was generated on the A train engineered safety feature (ESF) systems, [3] why the main steam line isolation valves (MSIVs) automatically closed, [4] circumstances associated with the failure of auxiliary feedwater (AFW) pump 2A-A to start, [5] circumstances associated with the failure of atmospheric relief valve (ARV) 2 to automatically close, and [6] circumstances associated with the power interruption to vital 120V AC electrical bus 2-IV.

2.0 Event Description

On January 18, 2000, at 10:52 a.m., while Unit 2 was operating at 100 percent power, a reactor trip occurred due to an actual low-low water level condition in steam generator (SG) 4. About one second later, an inadvertent SI signal was generated on the A train ESF systems. The reactor trip was caused by a replacement modification of power inverter 2-IV for the vital 120V AC system. Activities associated with the modification resulted in a momentary loss of power of about 30 seconds to vital 120V AC electrical bus 2-IV. This power interruption caused main feedwater regulating valve 4 to close resulting in the low water level condition. The inadvertent SI signal (low steam line pressure in loop 4 main steam line) was a result of channel 4 of the 2-out-of-3 control logic losing power from vital bus 2-IV power interruption and a noisy, but operable transmitter (2-PT-1-27B) for channel 2. The 2-out-of-3 trip logic was therefore satisfied for the SI. The B train emergency core cooling water systems did not automatically inject during the event, but were manually initiated by plant operators. The B train did not inject, as was expected, because of the power interruption to vital 120V AC bus 2-IV. During the event the MSIVs closed, as expected due to the same signal which generated the SI signal, separating the main condenser as the primary heat removal system. Decay heat was removed by the AFW system which automatically injected to all SGs.

During the event, motor-driven AFW pump 2A-A failed to start. Motor-driven AFW pump 2B-B and the steam-driven turbine AFW pump responded properly and restored water level to all SGs to their normal levels. Also during the event, a main feedwater check valve, 2-VLV-3-508, developed a body-to-bonnet leak rate of about 60-70 gpm. This leakage caused restoration of normal water level in SG 3 to lag the other three generators. Other issues during the event included the failure of ARV 2 to automatically close, the failure of the reactor operator to start a B train essential raw water cooling water (ERCW) pump, and the failure of a containment isolation valve, 2-FCV-61-122, to close from the containment phase A signal. ARV 2 was manually closed by the operator. Unit 2 was placed in Mode 3 following the event and remained there until the plant was placed back in service on January 20.

2.1 Independent Reviews

The inspectors performed a detailed review of the applicable logic diagrams to verify the licensee's findings for [1] cause of the Unit 2 reactor trip, [2] cause of the SI, and [3] cause for the automatic closure of the MSIVs. The inspectors also reviewed applicable plant procedures for the interruption of power to vital 120V AC bus 2-IV to determine [1] why the B train SI equipment did not automatically start during the event, [2] why main feedwater regulating valve 4 closed after the power interruption to the vital 120V AC bus, and [3] why ARV 2 failed to close. In addition, the inspectors reviewed the circumstances associated with the noisy low steam line pressure transmitter, 2-PT-1-27B, to understand its impact on, in part, the generation of an SI signal and MSIV isolation. The inspectors concluded that the licensee's trip review team efforts accurately identified the cause of the event and the impacts of the power interruption to vital 120V AC electrical bus 2-IV. There were no findings during these reviews.

2.2 Miscellaneous

The inspectors reviewed the event trip report, plant operating data, operating logs, and self assessments, and conducted interviews with numerous personnel to determine if there were issues associated with [1] quality assurance deficiencies, [2] radiological consequences, and [3] safeguards issues. No findings were identified.

3.0 Risk Significance of the Event

The initial risk significance of the event was estimated by the Region II senior reactor analysts (SRAs). This calculation showed that there was sufficient risk increase to consider the event for more than the baseline inspection program. The results were used as an input to NRC Region II management's decision to conduct a special inspection. The major contributors to risk increase were the closure of the MSIVs and subsequent loss of the normal heat sink removal system (i.e., the main condenser) and the failure of one motor-driven AFW pump to start with no recovery of the pump by the operator.

4.0 Equipment Failures

4.1 AFW Pump 2A-A Breaker Failure

The 6.9 KV circuit breaker for the 2A-A motor-driven AFW pump received an automatic start signal from the event, but it failed to close and energize the pump motor. Shortly thereafter, operators observed that the breaker control switch white disagreement lamp was lit. The lit white disagreement lamp indicated that the breaker received a close signal and traveled to at least 95 percent of the full closed position. Troubleshooting determined that there was no trip signal present. Therefore, the licensee determined that the initial indications were that the failure mode was a failure of the breaker to latch closed.

The failed breaker had been refurbished during December 1997, and preventive maintenance, using Preventive Maintenance Procedure, MI 10.4, which included a checklist for refurbished breakers, was performed in May 1998. Some wiring and adjustment problems were identified by using the checklist, and these were corrected. The breaker was placed in service on June 11, 1998, and records indicated that no work had been performed on the breaker since that time.

During May 1998, the NRC performed a team inspection of medium-voltage and low-voltage power circuit breakers. One conclusion from that inspection was that the licensee's root cause determinations and corrective actions for breaker failures met the requirements of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. During that inspection, the NRC determined that there were five failures of 6.9 KV circuit breakers to close or trip on demand or spurious tripping between the beginning of 1995 and May 1998. Each of the failures was due to a different cause, and the root cause determinations were satisfactory. At the inspectors' request, the licensee performed a search of problem evaluation reports (PERs) involving 6.9 KV circuit breaker failures. These records indicated that one other failure had occurred since May 1998. That failure was pressurizer heater circuit breaker 1A-A (on or about December 7, 1998), and the cause was an open contact on the control device. The pressurizer breaker has a relatively high number of cycles due to the nature of the load. The inspectors' conclusion from the review of the history of 6.9 KV breaker failures was that no adverse trend of failures could be discerned. The licensee initiated PER 00-000501-000 for the AFW breaker failure.

The breaker was removed from its compartment and placed on the test stand. Subsequently, the valve cycled normally about 15 times. A refurbished breaker was placed in service, and functionally tested by energizing the load. These facts led to the licensee's belief that the breaker failed to latch due to a slight mis-alignment in the mechanism resulting in intermittent failure to latch closed. The failed breaker was quarantined for the licensee's root cause analysis.

The inspectors discussed the licensee's initial root cause efforts for the AFW pump breaker failure. The licensee stated that two independent offsite experts had investigated the failure. The initial findings from the investigation did not determine the cause of the failure, however, multiple tolerance issues were identified that were outside the vendor's specifications. The tolerance issues were determined to not be the cause of the AFW breaker failure. The inspectors discussed these issues with the licensee who demonstrated that they would not be readily identified using normal industry acceptable preventive maintenance procedures. The significance of the tolerance issues and possible relationship to the refurbishment program was being investigated. The inspectors considered that the licensee's initial root cause determinations were reasonable.

The failure of the AFW pump breaker, including the unavailability of the primary conversion system (main condenser as a heat sink), was of low risk because both the 2B-B motor-driven and the turbine-driven AFW pumps were available and restored SG water level. This finding was screened out of the Significance Determination Process (SDP) in Phase 2 as Green.

4.2 Static Transfer Switch Failure for Inverter 2-IV

On January 18, 2000, just before the unit trip, the licensee was in the process of installing a new inverter for vital 120V AC electrical bus 2-IV. The modification process had reached the point where the new inverter was supplying the vital bus loads. At this point, both the bypass power source and the maintenance power source were de-energized. A technician removed a temporary wire installed for the purpose of synchronizing the inverter to the maintenance source. This temporary wire carried a synchronizing signal which ran from the inverter to the static transfer switch at the output of the inverter. While removing the temporary synchronizing wire, the neutral wire on the same terminal was disturbed at the inverter. The second wire, or neutral wire, caused a sensed undervoltage condition by the static switch control board.

The purpose of the static transfer switch is to provide uninterrupted transfer between the inverter source and the bypass source. Disturbing the wire resulted in the static transfer switch transferring to the bypass source, which, as stated, was de-energized. This transfer was an unexpected event since the design feature of the static transfer switch should have blocked transfer to a deenergized power source. Once the terminal was tightened, the transfer switch switched back to the inverter source after about a 30 - second delay, as designed.

Later, diagnostic and trouble shooting efforts determined that the problem with the static transfer switch was within an electronic control card. This card was replaced, and a test was performed to reproduce the conditions that had caused the static transfer switch to transfer to the deenergized source. The test demonstrated that the static transfer switch properly blocked transfer to a deenergized source. The licensee initiated PER 00-000444-000 for the failed control card and planned to perform a detailed root cause analysis on the card to determine which sub-component on the card was defective.

The inspectors discussed the failure of inverter 2-IV and its impact on risk to plant operation with Region II SRAs. The risk of the failure, using Phase 2 of the SDP is complicated due to the numerous plant loads that inverter 2-IV supplies. Pending license completion of a review of the inverter failure with a better understanding of the failure's risk significance and its cause, and a subsequent NRC review, this item is identified as Unresolved Item (URI) 50-328/0003-01, "Risk Significance of Inverter 2-IV Failure."

4.3 Main Feedwater Check Valve 2-VLV-3-508 Leakage

Shortly after the reactor trip, the loop 3 main feedwater check valve, 2-VLV-3-508, was found leaking by plant operators. At that time the feedwater system was in AFW mode supplying the SGs because the main feedwater system had isolated as expected during the reactor trip. The valve was leaking at the body-to-bonnet seal onto the valve vault floor. The licensee estimated that the leakage was about 60-70 gpm. During the trip recovery maintenance personnel reduced the leak by increasing the body-to-bonnet bolt torque value from about 500 to 900 foot-pounds. During this initial repair effort, the licensee discovered that the torque value for check valve 2-VLV-3-510 was also set at 500 foot-pounds. Although valve 2-VLV-3-510 was not leaking, the torque value was increased to 900 foot-pounds. Prior to unit startup, the body-to-bonnet gap for valve 2-VLV-3-508 was peened and Furmanite compound was injected to stop the leakage.

The inspectors discussed the as-found torque values with the licensee. Through these discussions and through the inspectors' review of Maintenance Instruction (MI) 0-MI-MVV-000-029.0, "Maintenance of MFW and AFW Walworth Check Valves, " Revisions 0 and 1, the inspectors determined that the required torque setting for the check valves was 900 foot-pounds. Attachment 3 to MI 0-MI-MVV-000-029.0 identified the correct torque values. Step 6.5[1] of the MI required the torque values to be determined using Attachment 3.

The inspectors discussed the leakage of AFW through valve 2-VLV-3-508 with Region II SRAs to determine the risk significance of this flow diversion from SG 3. Although the leakage resulted in the operators taking manual action to increase flow to SG 3 by opening the main level control valve, the amount of leakage (60-70 gpm) was of low risk because the steam-driven AFW pump supplied adequate flow for SG level recovery. The finding was screened out of the SDP in Phase 1 as Green.

Technical Specification (TS) 6.8.1.a. requires, in part, that procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, "Quality Assurance Program Requirements (Operations)." Contrary to the above, the licensee failed to follow MI 0-MI-MVV-000-029.0 for required torque values for valves 2-VLV-3-508 and 2-VLV-3-510. Failure to torque valve 2-VLV-3-508 to 900 foot-pounds resulted in a body-to-bonnet leakage of about 60-70 gpm during the trip recovery and the need for operator action to open the normal level control valve which further complicated the unit trip response. The NRC is treating this violation as an NCV, consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as PER 00-000524-000. This violation is identified as NCV 50-328/0003-02, Failure to Properly Torque Main Feedwater Check Valves.

4.4 ARV 2 Failure to Close

Plant operators observed that after the trip, the ARVs actuated to remove decay heat by discharging main steam from the SGs to the environment. During this time the MSIVs had closed as expected. ARV 2 failed to close when required and the operator overrode the valve shut and left it shut in manual throughout the remainder of the recovery. The licensee subsequently removed the controller and performed a calibration check, which it passed. The ARV 2 controller was powered from inverter 2-IV and had experienced a momentary loss of power during the event. The licensee bench tested the controller to determine its recovery time from a loss of power and found that the controller remained saturated and in a full open demand condition for about 17 minutes after power was restored. The other controllers tested required 2-3 minutes to recover from a loss of power. The licensee was not able to determine the cause of this excessive time required for recovery and therefore replaced the controller prior to restarting the unit.

The inspectors determined that since manual operation of ARV 2 was available throughout the event, the safety function of the ARV was maintained and thus, the risk significance of the valve failure was low. This finding was screened out of the SDP in Phase 1 as Green.

4.5 Containment Isolation Valve 2-FCV-61-122 Failure to Close

As an expected function of the SI actuation, a phase A containment isolation occurred during the event. Valve 2-FCV-61-122, a glycol floor cooling containment isolation valve, failed to fully close and was noted by operators to have dual indication. TS Limiting Condition for Operation 3.6.3 was entered due to the failure and, as required, the licensee verified closed and deactivated valve 2-FCV-61-110, the backup valve to 2-FCV-61-122. The licensee lubricated the valve stem and the valve subsequently cycled within the allowable administrative time limits of 1.4 to 3.7 seconds. The inspectors reviewed the recorded stroke times for valve 2-FCV-61-122 for the last two and one-half years and found all times to be within the administrative limits. The licensee stated there had been no previous failures of the valve to fully stroke shut but did not determine a root cause of the failure. Although containment isolation valve 2-FCV-61-122 failed to fully shut, the inspectors determined that since valve 2-FCV-61-110 shut normally, the containment isolation function was maintained. Also, the degraded isolation barrier was less significant because it was not a direct release pathway for reactor coolant or containment atmosphere. The risk significance of the valve failure was low due to the successful operation of the redundant valve. The finding was screened out of the SDP in Phase 1 as Green.

5.0 Operator Performance and Procedure Deficiencies

5.1 Operator Failure to Start B Train ERCW Pump

In response to the reactor trip and SI, the operators executed Emergency Procedure E-0, Reactor Trip or Safety Injection, Revision 21. Step 6 required verification that at least four ERCW pumps were operating. Normally, the SI actuation would have ensured at least four ERCW pumps running, but since B train did not actuate due to the loss of power to vital instrument power board 2-IV, only 3 ERCW pumps were running. The operators failed to perform step 6 and did not start an additional ERCW pump (pump L-B). Since both train A and train B of the ERCW system had at least one operating pump and continued to perform their safety function, the risk significance of this issue was low. The finding was screened out of the SDP in Phase 1 as Green.

TS 6.8.1.a. requires, in part, that procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, "Quality Assurance Program Requirements (Operations)." Contrary to the above, the licensee failed to follow Emergency Procedure E-O when the licensed operators failed to verify at least four ERCW pumps running after the reactor trip and SI. The failure to verify at least four ERCW pumps running resulted in only three ERCW pumps running after the SI. The NRC is treating this violation as an NCV, consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as PER 00-000523-000, and is identified as NCV 50-328/0003-03, Failure to Follow Emergency Procedure And Verify Four ERCW Pumps Running.

5.2 ARV 3 Operation

After the reactor trip, the licensed operator controlled RCS temperature by allowing the SG ARVs to relieve steam in the automatic control mode. Approximately 4 hours after the trip, the licensed operator became concerned when the ARV 3 controller deviation read differently than the other ARV controllers. The operator believed the controller might be malfunctioning and, even though ARV 3 was shut, he placed the manual override switch to shut to prevent the valve from opening. The licensee performed a calibration check on the controller and found it to be in calibration. Inspection of data from the plant computer plots of SG pressures revealed that the ARV 3 controller had been controlling SG 3 pressure about 30 psig lower than the other SGs which indicated the controller's setpoint was slightly different from the other controllers. The controller setpoint is selected using a manual dial on the controller face. The operator did not fully understand the indication of small differences in controller setpoints.

The inspectors discussed the operation of the ARVs with the licensee regarding the impact of placing the valve in manual override to the shut position. The inspectors were concerned that operators did not fully understand the impact of placing the ARVs in override shut and the ARVs' ability to open automatically on high pressure. The licensee subsequently interviewed operators on this issue and determined that operator knowledge in this area needed improvement. The inspectors concluded that this deficiency was important because some operators believed that the valves would continue to operate automatically even with the valves in override shut. This would be a potential problem if the operators believed the ARVs would operate automatically to control decay heat levels in the override shut position. The licensee initiated PER 00-0001046-000 to address the issue for corrective action. This operator knowledge issue was of low risk significance because the function of decay heat removal through the ARVs was maintained during the event. This finding was screened out as Green using Phase 1 of the SDP.

6.0 Management Meetings

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 15, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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H. Butterworth, Operations Manager
E. Freeman, Maintenance and Modifications Manager
J. Gates, Site Support Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Plant Manager
M. Lorek, Site Engineering Manager
B. O'Brien, Maintenance Manager
P. Salas, Manager of Licensing and Industry Affairs
J. Valente, Engineering & Support Services Manager

NRC

R. Bernhard, Region II Senior Reactor Analyst
W. Rogers, Region II Senior Reactor Analyst

ITEMS OPENED AND CLOSED

Opened

50-328/0003-01	URI	Risk Significance of Inverter 2-IV Failure (Section 4.2).

Opened and Closed

50-328/00003-02	NCV	Failure to Properly Torque Main Feedwater Check Valves (Section 4.3).
50-328/0003-03	NCV	Failure to Follow Emergency Procedure And Verify Four ERCW Pumps Running (Section 5.1).

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.