UNITED STATES
**NUCLEAR REGULATORY COMMISSION**
WASHINGTON, D.C. 20555-0001

August 31, 2000

MEMORANDUM TO: Alan Madison, Acting Chief
Performance Assessment Section
Inspection Program Branch
Division of inspection Program Management
Office of Nuclear Reactor Regulation

FROM: August K. Spector, Communication Task Lead
Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

August Spector

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON August 30, 2000

On August 30, 2000 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss the Reactor Oversight Process initial implementation. An agenda of the meeting, the attendance list, and information exchanged at the meeting are attached.

Attachments:

1. Meeting Agenda
2. Attendance List
3. Fire Protection Attachment 71111.05 (draft)
4 Frequently Asked Questions, Log. 8, 9, 10, 11, 12, 13
5. Performance Indicators Interpretation Feedback Form
6 Frequently Asked Question ERO Drills
7. Frequently Asked Question Revised FAQ 178

Contact: August K. Spector
301-415-2140

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|---|---|---|---|---|---|---|
| NAME: | ASpector | | A. Madison | | | |
| DATE: | 08/ 31 /00 | | 08/31 /00 | | | |

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August 30, 2000 ROP Public Meeting

Agenda TOPICS

1. No-Color Findings
2. PI&R Inspections
3. Fire Protection Inspections
4. Pilot Testing of Proposed Initiating Event PIs
5. Unplanned Transients Strawman
6. Fault Exposure Hours & Definition of Unavailability - Maintenance Rule Approach to Eliminate Fault Exposure Hours
7. EP FAQs
8. RP FAQs
9. Rx Safety FAQs
10. Revising NEI 99-02
11. Feedback Collection Activities
12. Future Meetings

Attachment 1

**NRC Public Meeting**
**Reactor Oversight Process**
**Attendance List**
**August 30, 2000**

K. Borton, PECO Energy
P. Loftus, COMED
W. Dean, NRC
D. Hickman, NRC.
R. L. Sullivan, NRC
A. Madison, NRC
T. Boyce, NRC
A. Spector, NRC
M. Ferdig
S. Floyd, NEI
T. Houghton, NEI
J. Butler, NEI
D. Olson, Dominion Gen
J. Jacobson, NRC
W. H. Warrin, Southern Nuclear
Steve Johnson, INPO
J. Mundy, NRC
D. Raleigh, SERCH/Bechtel
J. Nagle, PSEG
G. Salamon, PSEG
A.K. Krainik, APS
D. Coe, NRC
P. Koltay, NRC

Attachment 2

DRAFT
8/30/00

**ATTACHMENT 71111.05**

INSPECTABLE AREA: Fire Protection

CORNERSTONES: Initiating Events (10%)
Mitigating Systems (90%)

INSPECTION BASES: Fire is generally a significant contributor to reactor plant risk. In many cases, the risk posed by fires is comparable to or exceeds the risk from internal events. The fire protection program shall extend the concept of defense in depth (DID) to fire protection in plant areas important to safety by (1) preventing fires from starting, (2) rapidly detecting, controlling, and extinguishing those fires that do occur, and (3) providing protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by fire suppression activities will not prevent the safe shutdown of the reactor plant. If DID is not maintained by an adequately implemented fire protection program, overall plant risk can increase.

This inspectable area verifies aspects of the Initiating Events and Mitigating Systems cornerstones for which there are no performance indicators to measure licensee performance.

LEVEL OF EFFORT: Routine Inspection: The resident inspector will tour six to twelve plant areas important to reactor safety (on a plant specific basis) each calender quarter to observe conditions related to: (1) licensee control of transient combustibles and ignition sources; (2) the material condition, operational lineup, and operational effectiveness of fire protection systems, equipment and features; and (3) the material condition and operational status of fire barriers used to prevent fire damage or fire propagation.

Annual Inspection: In addition, for approximately two hours each year, the resident inspector will observe a plant fire drill.

Triennial Inspection: Every 3 years, an inspection team consisting of a fire protection specialist, a reactor systems engineer, and an electrical engineer will select approximately three fire areas (fire zones where applicable) and conduct a design-based, plant specific, risk-informed, onsite inspection of the DID elements used to mitigate the consequences of a fire, with emphasis on

the fire protection features provided for maintaining at least one safe shutdown success path free of fire damage.

Identification and Resolution of Problems: Effort will include a review of licensee's problem identification and resolution of fire protection program.

## 71111.05-01 INSPECTION OBJECTIVES

01.01 The resident inspector inspection objective is to determine if the licensee has implemented a fire protection program that adequately controls combustibles and ignition sources within the plant, provides effectively maintained fire detection and suppression capability, maintains passive fire protection features in good material condition, and puts adequate compensatory measures in place for out-of-service, degraded or inoperable fire protection equipment, systems or features. The resident inspector approaches this effort from an operational status and material condition point of view.

01.02 The triennial team inspection objective is to assess whether the licensee has implemented a fire protection program that adequately controls combustibles and ignition sources within the plant, provides adequate fire detection and suppression capability, maintains passive fire protection features in good material condition, puts adequate compensatory measures in place for out-of-service, degraded or inoperable fire protection equipment, systems or features, and ensures that procedures, equipment, fire barriers, and systems exist so that the post-fire capability to safely shut down the plant is ensured. The triennial team approaches this effort from a design point of view, as well as from the operational status and material condition points of view.

## 71111.05-02 INSPECTION REQUIREMENTS

02.01 Routine Inspection. The resident inspector will tour six to twelve plant areas important to safety (not necessarily limited to the top few contributors to overall plant fire risk) to assess the material condition of reactor plant active and passive fire protection systems and features, their operational lineup and operational effectiveness. For the areas selected, as applicable to the area of concern, conduct the following lines of inspection inquiry:

a. Control of Transient Combustibles and Ignition Sources

1. Observe if any transient combustible materials are located in the area. If transient combustible materials are observed, verify that they are being controlled in accordance with the licensee's administrative control procedures.

2. Observe if any welding or cutting (hot work) is being performed in the area. Verify that hot work is being done in accordance with the licensee's administrative control procedures.

b. Fire Detection Systems. Observe the physical condition of the fire detection devices and note any that show physical damage. Determine from licensee administrative controls the known material condition and operational status of the system, and verify that any observed conditions do not affect the operational effectiveness of the system (see compensatory measures section below).

c. Fire Suppression Systems

1. Sprinkler Fire Suppression Systems. Observe that sprinkler heads are not obstructed by major overhead equipment (e.g., ventilation ducts). Verify through visual observation or surveillance record review that the water supply control valves to the system are open and that the fire water supply and pumping capability is operable and capable of supplying the water supply demand of the system. Observe any material conditions that may affect performance of the system, such as mechanical damage, painted sprinkler heads, corrosion, etc.

2. Gaseous Suppression Systems. Observe that the gaseous suppression system (e.g. Halon or CO2) nozzles are not obstructed or blocked by plant equipment such that gas dispersal would be significantly impeded. Observe and verify that the suppression agent charge pressure is within the normal band, extinguishing agent supply valves are open, and that the system is in the automatic mode. Observe and verify that the dampers/doors are unobstructed so that they will be permitted to close automatically upon actuation of the gaseous system. Observe and verify that the room penetration seals are sealed and in good condition. Observe and note any material conditions that may affect performance of the system, such as mechanical damage, corrosion, damage to doors or dampers, open penetrations, or nozzles blocked by plant equipment.

d. Manual Fire fighting Equipment and Capability

1. Fire Extinguishers. Ensure that portable fire extinguishes are provided at their designated locations in or near the area being inspected, and that access to the fire extinguishers is unobstructed by plant equipment or other work related activities. Observe and verify that the general condition of fire extinguishes is satisfactory (e.g., pressure gauge reads in the acceptable range, nozzles are clear and unobstructed, charge test records indicate testing within the normal periodicity).

2. Hose Stations and Standpipes. Observe that fire hoses are installed at their designated locations. Observe and verify that the general condition of hoses and hose stations is satisfactory (e.g., no holes in or chafing of the hose, nozzle not mechanically damaged and not obstructed, valve hand wheels in place). Observe and verify that the water supply control valves to the standpipe system are open and that the fire water supply and pumping capability is operable and capable of supplying the water flow and pressure demand. Ensure that access to the hose stations is unobstructed by plant equipment or work-related activities.

e. Passive Fire Protection Features

1. Electrical Raceway Fire Barrier Systems. Observe the material condition of electrical raceway fire barrier systems (e.g. cable tray fire wraps) and determine if there are any cracks, gouges, or holes in the barrier material, that there are no gaps in the material at joints or seams, and that banding, wire tie, and other fastener pattern and spacing appears appropriate. Where the fire barrier is a wrap or blanket-type material, observe that the material has no tears, rips, or holes in any of the visible layered material, that there are no gaps in the material at joint or seam locations, and that banding spacing is such that the material is held firmly in place. If plant modifications have recently been conducted, establish that fire barriers removed as interference have been restored.

2. Fire Doors. Observe the material condition of the fire door in the area being inspected. Observe that selected fire doors close without gapping (e.g. due to fire door damage from previous obstructions), and that the door latching hardware functions securely.

3. Ventilation System Fire Dampers. To the extent practical and safe, directly observe the condition of the accessible ventilation fire dampers in the areas being inspected (to ensure fusible link fire dampers are not prematurely shut or obstructed). For those dampers which can not be readily observed in the selected plant areas, review the licensee's surveillance efforts directed towards verifying the continuing operability of ventilation fire dampers.

4. Structural Steel Fire Proofing. Observe the material condition of the structural steel fire-proofing (fibrous or concrete encapsulation) within the areas being inspected. Observe that this material is installed and that the structural steel is uniformly covered (no bare areas).

5. Fire Barrier and Fire Area/Room/Zone Electrical Penetration Seals. Tour plant areas being inspected and observe accessible electrical and piping penetrations. Observe whether any seals are missing from locations in which they appear to be needed to complete a fire barrier or area/room/zone wall, and determine that seals appear to be properly installed and in good condition.

6. Reactor Coolant Pump Oil Collection Systems. If applicable, verify that the licensee has installed a reactor coolant pump oil collection system which is designed to and does collect oil leakage and spray from all potential reactor coolant pump oil system leakage points.

f. Compensatory Measures. Verify that adequate compensatory measures are put in place by the licensee for out-of-service, degraded or inoperable fire protection equipment, systems or features (e.g. detection and suppression systems and equipment, passive fire barrier features, or safe shutdown functions or capabilities). Short term compensatory measures should be adequate to compensate for the degraded function or feature until appropriate corrective action

can be taken. Review licensee effectiveness in returning the equipment to service in a reasonable period of time (typically days or weeks).

02.02 Annual Inspection. During the annual observation of a fire brigade drill in a plant area important to safety, evaluate the readiness of the licensee's personnel to prevent and fight fires, including the following aspects:

a. Protective clothing/turnout gear is properly donned.

b. Self-contained breather apparatus (SCBA) equipment is properly worn and used.

c. Fire hose lines are capable of reaching all necessary fire hazard locations, that the lines are laid out without flow constrictions, the hose is simulated being charged with water, and the nozzle is pattern (flow stream) tested prior to entering the fire area of concern.

d. The fire area of concern is entered in a controlled manner (e.g., fire brigade members stay low to the floor and feel the door for heat prior to entry into the fire area of concern).

e. Sufficient fire fighting equipment is brought to the scene by the fire brigade to properly perform their firefighting duties.

f. The fire brigade leader's fire fighting directions are thorough, clear, and effective.

g. Radio communications with the plant operators and between fire brigade members are efficient and effective.

h. Members of the fire brigade check for fire victims and propagation into other plant areas.

i. Effective smoke removal operations were simulated.

j. The fire fighting pre-plan strategies were utilized.

k. The licensee pre-planned the drill scenario was followed, and that the drill objectives acceptance criteria were met.

02.03 Triennial Inspection. Every three years, an inspection team will conduct risk-informed inspection of the licensee's fire protection program with emphasis on post-fire safe shutdown capability and the fire protection features provided for ensuring that at least one post-fire safe shutdown success path is maintained free of fire damage.

a. Inspection Preparation

Select three to five plant areas important to risk for review. Obtain necessary information for determining post-fire safe shutdown capability and the fire protection features for maintaining at least one post-fire safe shut down path free of fire damage.

b. Inspection Conduct. For the plant areas selected for review, conduct the following inspection efforts:

1. Systems Required to Achieve and Maintain Post-fire Safe Shutdown

Consider whether the licensee's shutdown methodology has properly identified the components and systems necessary to achieve and maintain safe shutdown conditions for each fire area, room and/or zone selected for review. Specifically determine the apparent adequacy of the systems selected for reactivity control, reactor coolant makeup, reactor heat removal, process monitoring and support system functions.

If the above high level performance criteria are not met, review the licensee's engineering and/or licensing justifications (e.g., NRC guidance documents, license amendments, technical specifications, SERs, exemptions, deviations).

To the extent that it is confirmed that a postulated fire in an area under consideration can cause the loss of offsite power, verify that hot and cold shutdown from outside the control room can be achieved and maintained with off-site power not available.

2. Fire Protection of Safe Shutdown Capability

Evaluate the separation of systems necessary to achieve safe shutdown, and verify that fire protection features are in place to satisfy the separation and design requirements of Section III.G of Appendix R (or, for reactor plants reviewed under the Standard Review Plan, license specific requirements).

Verify that the fire detectors and automatic fire suppression systems, associated with 1-hour fire barriers and/or 20 foot areas free of intervening combustibles required by Section III.G.2 of Appendix R (or, for reactor plants reviewed under the Standard Review Plan, license specific requirements), have been adequately installed. Review licensee evaluations which confirm, and verify through observation in the reactor plant, that selected installed automatic detection and suppression systems are installed in accordance with the code of record and would adequately control and suppress fires associated with the hazards of each selected area.

For the plant areas selected, when applicable, verify that redundant trains of systems required for hot shutdown located in the same fire area are not subject to damage from fire suppression activities or from the rupture or inadvertent operation of fire suppression systems. Determine each of the following:

(a) How the licensee has addressed whether a fire in a single location may, indirectly, through the production of smoke, heat, or hot gases, cause activation of potentially damaging fire suppression for all redundant trains,

(b) How the licensee has addressed whether a fire in a single location (or inadvertent actuation or rupture of a fire suppression system) may, through local fire suppression activity, indirectly cause damage to all redundant trains (e.g., sprinkler-caused flooding of other than the locally affected train), and

(c) How the licensee has addressed whether a fire in a single location may cause damage to all redundant trains through the utilization of manually controlled fire suppression systems.

For the plant areas selected, review the adequacy of the design (fire rating) of fire area boundaries (i.e., able to contain the fire hazards of the area), raceway fire barriers, equipment fire barriers, and fixed fire detection and suppression systems.

Evaluate licensee operator recovery action capabilities, plans and timing estimates for smoke removal, dewatering of spaces, controlled re-energization, and return to service of equipment in fire-affected areas) for fires in each plant area under consideration.

If a fire brigade drill is observed, consider the lines of inspection inquiry of Section 02.02 above.

3. <u>Post-fire Safe Shutdown Circuit Analysis</u>

Those issues related to analysis of multiple shorts, open circuits and faults (multiple hot shorts, shorts to ground, multiple high impedance faults and three phase faults) are the subject of a voluntary industry initiative that is expected to resolve these issues generically. Accordingly, inspections should not develop findings in these technical areas.

However, this guidance does not preclude any findings associated with deficient licensee performance in these areas. Thus for example, findings are not precluded where they are associated with mathematical errors, and invalid assumptions such as those not reflecting the plant configuration.

Inspect the licensee's electrical systems and electrical circuit analyses with respect to the following:

For the equipment located in the specified fire areas verify that circuit breaker and fuse protection coordination has been analyzed and is acceptable.

4. <u>Alternative Shutdown Capability</u>

Determine whether the licensee's alternative shutdown methodology has properly identified the components and systems necessary to achieve and maintain safe shutdown conditions for each fire area, room and/or zone selected for review. Specifically determine the apparent adequacy of the systems selected for reactivity control, reactor coolant makeup, reactor heat removal, process monitoring and support system functions.

If the above high level performance criteria are not met, review the licensee's engineering and/or licensing justifications (e.g., NRC guidance documents, license amendments, technical specifications, SERs, exemptions, deviations).

Verify that hot and cold shutdown from outside the control room can be achieved and maintained with off-site power available or not available.

Verify that the transfer of control from the control room to the alternative location has been demonstrated to not be affected by fire-induced circuit faults (e.g. by the provision of separate fuses and power supplies for alternative shutdown control circuits).

5. <u>Operational Implementation of Alternative Shutdown Capability</u>

Verify that the training program for licensed and non-licensed personnel has been expanded to include alternative or dedicated safe shutdown capability.

Verify that personnel required to achieve and maintain the plant in hot shutdown following a fire using the alternative shutdown system can be provided from normal onsite staff, exclusive of the fire brigade.

Verify that adequate procedures for use of the alternative shutdown system exist. Verify the implementation and human factors adequacy of the alternative shutdown procedures by independently "walking through" the procedural steps. Ensure that adequate communications are available for the personnel performing alternative or dedicated safe shutdown. Verify that the operators can reasonably be expected to perform the procedures within applicable shutdown time requirements.

Establish whether the licensee conducts periodic operational tests of the alternative shutdown transfer capability and instrumentation and control functions. In addition, establish whether these tests are adequate to show that if called upon, the alternative shutdown capability would be functional upon transfer.

6. <u>Communications</u>

Verify through inspection of the contents of designated emergency storage lockers and review of alternative shutdown procedures, that portable radio communications and/or fixed emergency communications systems are available, operable, and adequate for the performance of alternative safe shutdown functions. Assess the capability of the communication systems to support the operators in the conduct and coordination of their required actions (e.g., consider ambient noise levels, clarity of reception, reliability, coverage patterns, and survivability). If specific, risk-significant issues arise relating to alternative shutdown communications adequacy, then, on a not-to-interfere with operational safety basis, observe licensee conducted communications tests in the subject plant area or areas.

7. Emergency Lighting

Review emergency lighting provided, either in fixed or portable form, along access routes and egress routes, at control stations, plant parameter monitoring locations, and at manual operating stations:

(a) If emergency lights are powered from a central battery or batteries, verify that the distribution system contains protective devices so that a fire in the area will not cause loss of emergency lighting in any unaffected area needed for safe shutdown operations.

(b) Review the manufacturer's information to verify that battery power supplies are rated with at least an 8-hour capacity.

(c) Determine if the operability testing and maintenance of the lighting units follow licensee procedures and accepted industry practice.

(d) Verify that sufficient illumination is provided to permit access for the monitoring of safe shutdown indications and/or the proper operation of safe shutdown equipment.

(e) Verify that emergency lighting unit batteries are being properly maintained (observe the unit's lamp or meter charge rate indication, and specific gravity indication).

8. Cold Shutdown Repairs

Verify that the licensee has dedicated repair procedures, equipment, and materials to accomplish repairs of damaged components required for cold shutdown, that these components can be made operable, and that cold shutdown can be achieved within time frames specified by Appendix R to 10 CFR Part 50 (or, for reactor plants reviewed under the Standard Review Plan, license specific requirements). Verify that the repair equipment, components, tools, and materials (e.g., pre-cut cable connectors with prepared attachment lugs) are available on site.

9. Fire Barrier and Fire Area/Zone/Room Penetration Seals |

Selectively verify through review of installation records that material of an appropriate fire resistence rating (equal to the overall rating of the barrier itself) has been used to fill the opening/penetration .

10. Fire Protection Systems, Features and Equipment

In selected plant locations, review the material condition, operational lineup, operational effectiveness and design of fire detection systems, fire suppression systems, manual fire fighting equipment, fire brigade capabilities, and passive fire protection features. Establish that selected fire

detection systems, sprinkler systems, gaseous suppression systems, portable fire extinguishers and hose stations are installed in accordance with their design, and that their design is adequate given the current equipment layout and plant configuration.

11. Compensatory Measures

    Verify that adequate compensatory measures are put in place by the licensee for out-of-service, degraded or inoperable fire protection and post-fire safe shutdown equipment, systems or features (e.g. detection and suppression systems and equipment, passive fire barrier features, or pumps, valves or electrical devices providing safe shutdown functions or capabilities). Short term compensatory measures should be adequate to compensate for the degraded function or feature until appropriate corrective action can be taken. Review licensee effectiveness in returning the equipment to service in a reasonable period of time (typically days or weeks).

02.04 Identification and Resolution of Problems. During routine (quarterly and annual) resident inspection and triennial team inspection, verify that the licensee is identifying issues related to this inspection area at an appropriate threshold and entering them in the corrective action program. For a sample of selected issues documented in the corrective action program, verify that the corrective actions are appropriate. See Inspection Procedure 71152, "Identification and Resolution of Problems," for additional guidance.

## 71111.05-03 INSPECTION GUIDANCE

General Guidance

Routine Inspection. See Attachment 1.

The main focus of the resident inspector's activities is on the material condition and operational status of fire detection and suppression systems and equipment, and fire barriers used to prevent fire damage or fire propagation. The six to twelve plant areas to be inspected should be selected on the basis of site-specific risk worksheets.

Triennial Inspection

Objective. The triennial inspection is primarily a risk-informed look at the mitigation elements of fire protection defense in depth (DID) (i.e., detection, suppression, and confinement of fires through passive barriers, and the fire protection features and procedures which establish the licensee's ability to achieve and maintain post-fire safe shutdown conditions during and after a fire). The triennial inspection is that portion of the baseline inspection program that focuses on the design of reactor plant fire protection and post-fire safe shutdown systems, features, and procedures. The inspection team leader will manage and coordinate the conduct of an inspection emphasizing post-fire safe shutdown. The team will use plant-specific risk, event, and technical information (including the results of licensee self-assessments) to confirm that at least one train of safe shutdown

equipment (capable of providing reactivity control, reactor coolant makeup, reactor heat removal, and process monitoring and support functions) is free of fire damage.

Inspection Team and Responsibilities. The team assigned to conduct the multi-disciplinary triennial fire protection inspection would include a fire protection inspector, an electrical inspector, and a reactor systems/mechanical systems inspector.

1. Reactor Systems/Mechanical Systems Inspector (RSI). The reactor systems/mechanical systems inspector (RSI) will assess the capability of reactor and balance-of-plant systems, equipment, operating personnel, and procedures to achieve and maintain post-fire safe shutdown and minimize the release of radioactivity to the environment in the event of fire. Therefore, the inspection team leader will ensure that he is knowledgeable regarding integrated plant operations, maintenance, testing, surveillance and quality assurance, reactor normal and off-normal operating procedures, and BWR and/or PWR nuclear and balance-of-plant systems design.

2. Electrical Inspector (EI). The EI will identify electrical separation requirements for redundant train power, control, and instrumentation cables. He will review alternative shutdown panel electrical isolation design to establish the panels' electrical independence from postulated fire areas. Therefore, the inspection team leader will ensure that he is knowledgeable regarding reactor plant electrical and instrumentation and control (I&C) design and is familiar with industry ampacity derating standards

3. Fire Protection Inspector (FPI). The FPI will work with other team members in determining the effectiveness of the fire barriers and systems that establish the reactor plant's post-fire safe shutdown configuration and maintain it free of fire damage. He will determine whether suitable fire protection features (suppression, separation distance, fire barriers, etc.) are provided for the separation of equipment and cables required to ensure plant safety. Therefore, the inspection team leader will ensure he is knowledgeable regarding reactor plant fire protection systems, features and procedures.

Regulatory Requirements and Licensing Bases. The regulatory requirements and licensing bases against which post-fire safe shutdown capability is assessed are as follows:

1. Plants licensed before January 1, 1979. Effective February 17, 1981, the NRC amended its regulations by adding Section 50.48 and Appendix R to 10 CFR Part 50 to require certain provisions for fire protection in nuclear power plants licensed to operate before January 1, 1979. This action was taken to resolve certain contested generic issues in fire protection safety evaluation reports (SERs), and (1) to require all applicable licensees to upgrade their plants to a level of fire protection equivalent to the technical requirements in Sections III.G, J, L, and O of 10 CFR Part 50, Appendix R, and (2) to require all applicable licensees to meet all other requirements of Appendix R to the extent that comparable items had not been closed out in pre-Appendix R SERs (under Appendix A of the Branch Technical Position). Licensees were required to meet the separation requirements of Section III.G.2, the alternative or dedicated shutdown capability requirements of Sections III.G.3 and III.L, or to request an exemption in accordance with 10 CFR

50.48. Alternative or dedicated safe shutdown capabilities were required to be submitted to the Office of Nuclear Reactor Regulation (NRR) for review. NRR approvals are documented in SERs.

2. Plants licensed after January 1, 1979: These plants are subject to requirements similar to those in 10 CFR part 50, Appendix R, as specified in the conditions of their facility operating license, commitments made to the NRC, or deviations granted by the NRC. These reactor plants licensed after January 1, 1979, are subject to 10 CFR 50.48 (a) and (e) only.

   The fire hazards analysis (FHA) ("Fire Protection Review, Fire Protection Evaluation") document of the reactor plants licensed after January 1, 1979, may have been reviewed under Appendix A to Branch Technical Position APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear power Plants Docketed Prior to July 1, 1976," of August 23, 1976 (in which case, the licensee conducted an Appendix R comparison and justified final safety analysis report (FSAR) or FHA differences from the specific provisions of Appendix R). It is possible also that licensee submittals for plants licensed after January 1, 1979, were reviewed under the Standard Review Plant, NUREG-0800, and Branch Technical Position (BTP) CMEB 9.5-1 (formerly BTP ASB 9.5-1), "Guidelines for Fire Protection for Nuclear Power Plants," Rev. 2 (July 1981) (in which case, licensee submittals were reviewed according to requirements that closely paralleled the provisions of Appendix R).

   The actual fire protection requirements applicable to a given reactor plant licensed after January 1, 1979, arise from the specific license conditions in the facility operating license. These license conditions possibly refer to SERs and their supplements. Section 9.5 of such an SER delineates which licensee submittals were reviewed (e.g., a fire hazards analysis would be such a submittal).

3. All changes to fire protection license conditions which have been placed in the reactor plant's FSAR/USAR may be conducted under 10 CFR 50.59.

Inspection Process

1. Licensee Notification Letter. The licensee should be notified of the triennial inspection in writing at least three months in advance of the onsite week. The information gathering visit shall be conducted no fewer than three weeks in advance of the onsite inspection week. The letter should discuss the scope of the inspection, request an information-gathering visit to the licensee reactor site/engineering offices, discuss documentation and licensee personnel availability needs during the onsite inspection week, and request a pre-inspection conference call to discuss administrative matters and finalize inspection activity plans and schedules. A template for an NRC to licensee triennial fire protection baseline inspection notification letter is provided as Attachment 2.

2. Information-gathering Site Visit. The inspection team leader **should conduct** a two to three day information gathering site. The purposes of the information gathering site visit are to (1) gather site-specific information important to inspection planning, and (2) conduct initial discussions with licensee representatives

regarding administrative items and inspection activity plans and schedules. In advance of the information-gathering site visit, the team leader should provide the licensee with a list of information and documents that may be needed for the team to prepare for and conduct the triennial inspection, as well as a list of any planned requests for licensee conducted evolutions (e.g., emergency lighting tests, communication tests, fire drills, shutdown walkthroughs, etc.).

2. Information Required/Preparation The team members should gather sufficient information to become familiar with the following during preparation period:

(a) The reactor plant's design, layout, and equipment configuration.

(b) The reactor plant's current post-fire safe shutdown licensing basis through review of 10 CFR 50.48, 10 CFR Part 50 Appendix R (if applicable), NRC safety evaluation reports (SERs) on fire protection, the plant's operating license, updated final safety analysis report (UFSAR), and approved exemptions or deviations.

(c) The licensee's strategy and methodology, and derivative procedures, for accomplishing post-fire safe shutdown conditions. Among the sources of information are the updated final safety analysis report (UFSAR), the latest version of the fire hazards analysis (FHA), the latest version of the post-fire safe shutdown analysis (SSA), fire protection/post-fire safe-shutdown related 10 CFR 50.59 and Generic Letter 86-10 review documentation and modification packages, plant drawings, emergency/abnormal operating procedures, and the results of licensee internal audits (e.g., self assessments and quality assurance (QA) audits in the fire protection and post-fire safe shutdown areas).

(d) The historical record of plant-specific fire protection issues through review of plant-specific documents such as previous NRC inspection results, internal audits performed by the reactor licensee (e.g., self-assessments and quality assurance audits), corrective action system records, event notifications submitted in accordance with 10 CFR 50.72, and licensee event reports (LERs) submitted in accordance with 10 CFR 50.73.

(e) The safe shutdown systems and support systems credited by the licensee's analysis for each fire area, room, or zone for accomplishing of the required shutdown functions (e.g., reactivity control, reactor coolant makeup, reactor heat removal, and process monitoring and support functions) as necessary to comply with the safe shutdown requirements of 10 CFR 50.48(a) and plant-specific licensing requirements. The shutdown logic for each area, room, or zone to be inspected must be thoroughly understood by the team members.

(f) The licensee's analytical approach for electrical circuits separation analyses, and the licensee's methodology for identification and resolution of associated circuits of concern. The team's electrical review should include addressing the assumptions and boundary conditions used in the performance of the licensee's analyses.

Specific Guidance

03.01 Inspection Requirement 02.01. The resident inspector should not attempt to address all plant areas each inspection. The routine plant tour should focus on six to twelve plant areas important to risk. The resident inspector should note transient combustibles and ignition sources (and compare these with the limits provided in licensee administrative procedures). The resident inspector should also note the material condition and operational status (rather than the design) of fire detection and suppression systems, and fire barriers used to prevent fire damage or fire propagation.

03.02 No specific guidance provided

03.03 Inspection Requirement 02.03 a.

1. Prior to the inspection information gathering trip, the team leader should contact the regional senior reactor analyst (SRA) to obtain summary of plant specific fire risk insights (e.g., fire risk ranking of the rooms/plant fire areas, conditional core damage probabilities (CCDPs) for those rooms and areas, and transient sequences for these rooms). After considering the focus of past fire protection and post-fire safe shutdown inspections, the team leader should select three to five areas important to risk for inspection

2. The fire protection and post-fire safe shutdown information gathered should focus on the samples selected.

3. After the information gathering site visit, the team leader should use the SRA developed fire risk insights, as well as technical input from the other team members, to develop an inspection plan addressing (for the selected three to five plant areas, rooms or zones) post-fire safe shutdown capability and the fire protection features for maintaining one success path of this capability free of fire damage.

Inspection Requirement 02.03b2: Short term compensatory measures should be adequate to compensate for the degraded function or feature until appropriate corrective action can be taken.

03.04 Identification and Resolution of Problems.

No specific guidance is provided.

71111.05-04 RESOURCE ESTIMATE

The resource to perform this inspection procedure is estimated to be, on average, 33 hours per year for routine inspection including approximately 2 hours for annual observation of a fire drill and 200 hours every 3 years for the triennial inspection regardless of the number of reactor units at the site.

## 71111.05-05 REFERENCES

The SDP Guideline "Appendix 4 - Determining Potential Risk Significance of Fire Protection and Post-fire Safe Shutdown Inspection Findings."

Appendix H of the Fire Protection Supplemental Inspection Procedure (FPSI) "Guidance for Making a Qualitative Assessment of Fire Protection Inspection Findings, Fire Protection Risk Significance Screening Methodology" [FPRSSM])

Inspection Procedure 71152, "Identification and Resolution of Problems."

Generic Letter 91-18 "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Non-conforming Conditions and on Operability."

Information Notice 97-48 "Inadequate or Inappropriate Interim Fire Protection Compensatory Measures," July 9, 1997

NRC Internal Memorandum dated August 17, 1998, from John N. Hannon to Arthur T. Howell titled "Response to Region IV Task Interface Agreement (TIA) (96TIA008) - Evaluation of Definition of Continuous Fire Watch (TAC No. M96550).

Individual Plant Examination of Externally Initiated Events(IPEEE)

END

ATTACHMENT 1
ROUTINE INSPECTION GUIDANCE TABLE

| CORNERSTONE | RISK PRIORITY | EXAMPLES |
|---|---|---|
| INITIATING EVENTS | Equipment or actions that could cause or contribute to initiation of fires in plant areas important to safety or near equipment required for safe shutdown. | Transient combustibles (rags, wood, ion exchange resin, lubricating oil, or Anti-Cs) are not in areas where transient combustibles are prohibited. Transient combustible amounts in other areas do not exceed administrative controls.<br><br>Ignition sources (welding, grinding, brazing, flame cutting) have a fire watch. Planning includes precautions and additional fire prevention measures where these activities are near combustibles. |

| | | |
|---|---|---|
| MITIGATING SYSTEMS | Functionality of fire barriers in plant areas important to safety.<br><br>Functionality of detection systems in plant area important to safety.<br><br>Functionality of automatic suppression systems in plant areas important to safety.<br><br>Fire brigade manual suppression effectiveness.<br><br>Compensatory measures for degraded fire detection systems, fire suppression features, and barriers to fire propagation. | Doors and dampers that prevent the spread of fires to/or between plant areas important to safety remain in place and are functional.<br><br>Electrical raceway fire barriers and penetration seals that protect the post-fire safe-shutdown train are not damaged.<br><br>Fire detection and alarm system is functional for plant areas important to safety.<br><br>Automatic suppression system sprinklers are functional and their sprinkler head patterns are not blocked by plant equipment.<br><br>Fire brigade performance indicates a prompt response with proper fire fighting techniques for the type of fire encountered.<br><br>Manual fire suppression equipment is of the proper type and has been tested.<br><br>Degraded fire detection equipment, suppression features and fire propagation barriers are adequately compensated for on reasonably short-term bases. |

Mr. , President
Licensee Nuclear Department
Licensee Corporation or Company
Address

SUBJECT: SELECTED NUCLEAR POWER STATION, UNITS 1 AND 2 - NOTIFICATION OF CONDUCT OF A TRIENNIAL FIRE PROTECTION BASELINE INSPECTION

Dear Mr. :

The purpose of this letter is to notify you that the U.S. Nuclear Regulatory Commission (NRC) Region # staff will conduct a triennial fire protection baseline inspection at Selected Nuclear Power Station, Units 1 and 2 in Month, 20##. The inspection team will be lead by First Last, a fire protection specialist from the NRC Region # Office. The team will be composed of personnel from NRC Region #, and Contracted National Laboratory. The inspection will be conducted in accordance with IP 71111.05, the NRC's baseline fire protection inspection procedure.

The schedule for the inspection is as follows:

- Information gathering visit - Month ##-##, 20## [Note - this date is pre-coordinated with the licensee]
- Week of onsite inspection - Month ##, 20##.

The purposes of the information gathering visit are to obtain information and documentation needed to support the inspection, to become familiar with the Selected Nuclear Power Station, Units 1 and 2 fire protection programs, fire protection features, and post-fire safe shutdown capabilities and plant layout, and, as necessary, obtain plant specific site access training and badging for unescorted site access. A list of the types of documents the team may be interested in reviewing, and possibly obtaining, are listed in Enclosure 1.

During the information gathering visit, the team will also discuss the following inspection support administrative details: office space size and location; specific documents requested to be made available to the team in their office spaces; arrangements for reactor site access (including radiation protection training, security, safety and fitness for duty requirements); and the availability of knowledgeable plant engineering and licensing organization personnel to serve as points of contact during the inspection.

We request that during the onsite inspection week you ensure that copies of analyses, evaluations or documentation regarding the implementation and maintenance of the Selected Nuclear Generating Station, Units 1 and 2 fire protection program, including post-fire safe shutdown capability, be readily accessible to the team for their review. Of

specific interest are those documents which establish that your fire protection program satisfies NRC regulatory requirements and conforms to applicable NRC and industry fire protection guidance. Also, personnel should be available at the site during the inspection who are knowledgeable regarding those plant systems required to achieve and maintain safe shutdown conditions from inside and outside the control room (including the electrical aspects of the relevant post-fire safe shutdown analyses), reactor plant fire protection systems and features, and the Selected Nuclear Power Station fire protection program and its implementation.

Your cooperation and support during this inspection will be appreciated. If you have questions concerning this inspection, or the inspection team's information or logistical needs, please contact First Last, the team leader, in the Region # Office at ###-###-####.

Sincerely,

Docket Nos.: 50-###
and 50-###

Enclosure: As stated (1)

**Reactor Fire Protection Program Supporting Documentation**

[Note: This is a broad list of the documents the NRC inspection team may be interested in reviewing, and possibly obtaining, during the information gathering site visit.]

1. The current version of the Fire Protection Program and Fire Hazards Analysis.

2. Current versions of the fire protection program implementing procedures (e.g., administrative controls, surveillance testing, fire brigade).

3. Fire brigade training program and pre-fire plans.

4. Post-fire safe shutdown systems and separation analysis.

5. Post-fire alternative shutdown analysis.

6. Piping and instrumentation (flow) diagrams showing the components used to achieve and maintain hot standby and cold shutdown for fires outside the control room and those components used for those areas requiring alternative shutdown capability.

7. Plant layout and equipment drawings which identify the physical plant locations of hot standby and cold shutdown equipment.

8. Plant layout drawings which identify plant fire area delineation, areas protected by automatic fire suppression and detection, and the locations of fire protection equipment.

9. Plant layout drawings which identify the general location of the post-fire emergency lighting units.

| 10

11. Plant operating procedures which would be used and describe shutdown from inside the control room with a postulated fire occurring in any plant area outside the control room, procedures which would be used to implement alternative shutdown capability in the event of a fire in either the control or cable spreading room.

12. Maintenance and surveillance testing procedures for alternative shutdown capability and fire barriers, detectors, pumps and suppression systems.

13. Maintenance procedures which routinely verify fuse breaker coordination in accordance with the post-fire safe shutdown coordination analysis.

14. A sample of significant fire protection and post-fire safe shutdown related design change packages (including their associated 10 CFR 50.59 evaluations) and Generic Letter 86-10 evaluations.

15. The reactor plant's IPEEE, results of any post-IPEEE reviews, and listings of actions taken/plant modifications conducted in response to IPEEE information.

16. Temporary modification procedures.

17. Organization charts of site personnel down to the level of fire protection staff personnel.

18. If applicable, layout/arrangement drawings of potential reactor coolant/recirculation pump lube oil system leakage points and associated lube oil collection systems.

19. A listing of the SERs and actual copies of the 50.59 reviews which form the licensing basis for the reactor plant's post-fire safe shutdown configuration.

20. Procedures/instructions that control the configuration of the reactor plant's fire protection program, features, and post-fire safe shutdown methodology and system design.

21. A list of applicable codes and standards related to the design of plant fire protection features and evaluations of code deviations.

22. Procedures/instructions that govern the implementation of plant modifications, maintenance, and special operations, and their impact on fire protection.

23. The three most recent fire protection QA audits and/or fire protection self-assessments.

24. Recent QA surveillances of fire protection activities.

25. A listing of open and closed fire protection condition reports (problem reports/NCRs/EARs/problem identification and resolution reports).

26. Listing of plant fire protection licensing basis documents.

27. A listing of the NFPA code versions committed to (NFPA codes of record).

28. A listing of plant deviations from code commitments.

29. Actual copies of Generic Letter 86-10 evaluations.

END

| FAQ Log 8 | | | | |
|---|---|---|---|---|
| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 15. | MS02 | **Question:**<br>Our HPSI system is similar to that depicted in Figure 5.2 of NEI 99-02, consisting of two independent trains, as defined NEI 99-02 for monitoring purposes. Each train consists of one HPSI pump and the associated train related valves and piping. Each pump is able to take a suction from the Refueling Water Tank (RWT) or Containment Sump (CS), and inject into the RCS through four cold leg injection flow paths and one hot leg flow path. Each cold leg flow path includes one motor operated isolation valve and an isolation check valve. These flow paths, four each for the two independent trains, then converge into four common headers that flow to the RCS. Flow may be split between the train related cold legs and the associated hot leg later into an event when necessary to preclude boron precipitation in the core.<br><br>We are performing an analysis to demonstrate that injection flow, sufficient to satisfy the requirements of the safety analysis, can be achieved by either train with one of its four cold leg injection paths out of service. Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis.<br><br>**Alternate Question:**<br>Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis?<br><br>**Response:**<br>Fault exposure unavailable hours are not counted for a failure to meet design or technical specifications, if engineering analysis determines the train was capable of performing its safety function during an operational event. The engineering analysis must take into account other equipment deficiencies that existed at any time during the failure to meet design or technical specification requirements, and must assume the worst case accident for the plant conditions. However, it is not necessary to assume an independent single failure and the analysis can assume nominal (expected) performance of other plant equipment. System unavailability is not subject to the same analysis requirements as the corresponding 10CFR50 Appendix K safety analysis.<br><br>**Alternate Response:**<br>Guidance on operability determinations and the resolution of degraded and nonconforming conditions is provided in Generic Letter 91-18. However, for the purposes of the safety system unavailability indicator, each train of a system must be capable of meetings all of its design basis requirements. To demonstrate that a train is available, then, requires that all design basis assumptions used in the FSAR safety analyses be employed. | Discussed 6/14/00<br>Revised 6/14/00<br>Action: NEI discuss revised response with APS<br>7/11/00 – awaiting response from APS<br>7/12/00 – Discussed, on hold<br>8/2 – Alternate question and response provided by NRC | APS |

Attachment 4

FAQ Log 8

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 21. | MS04 | **Question:**<br>**Appendix D Indian Point 2, Indian Point 3**<br>The ECCS designs for Indian Point 2 and Indian Point 3 include two recirculation pumps, recirculation containment sump, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR), two RHR heat exchangers and associated valves. These two subsystems are identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically started on an SI, takes suction from the RWST as does the high head SI pumps (3), and provides water in the injection phase of an accident. The recirculation pumps are in standby in the injection phase and are actuated by operator action during switchover for the recirculation phase of an accident and RHR is put in standby. The recirculation pumps (2) take suction from its dedicated sump and have the capability to feed the containment spray system, low head injection lines and the suction of the high head SI pumps for high head injection. The recirculation pumps are inside containment and can not be tested during operation, but both are required to be operable above 350 degrees F and one above cold shutdown.<br><br>How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR. | ~~Set up conference call with IP2, IP3 and NRC to discuss and decide~~Discussed with IP2, IP3, NRC in 8/28 conf. call. | IP3 |
| | | **Response:** | | |
| 22. | MS04 | **Question:**<br>Function 2 of the RHR Performance Indicator monitors the ability to remove decay heat during a normal heat unit shutdown. The 2 SDSC HX's at Calvert Cliffs are supplied RCS fluid by 2 SDC pumps via a common suction and common discharge header (not single failure proof). The SDC HX's are cooled by the Component Cooling (CC) Water system. The CC system is a closed system that exchanges heat to the Salt Water system via two parallel heat exchangers (CCHX). Component Cooling is always operated cross tied before and after the CCHX's. When one of the two SW trains is removed from service only one CCHX is available. Two saltwater pumps, with independent power, are available as well as 2 component cooling water pumps with independent power. In Mode 5, RCS Loops filled, Technical Specification LCO (old: TS 3.4.1.3; ITS: 3.4.7) requires 2 SDC loops (one operable and one in operation assuming no S/G's available). We consider that one SDC loop is unavailable (SDC HX's and SDC pumps) if one Salt Water train is removed from service. Is this a proper interpretation of NEI 99-02 guidelines? | On hold. K. Borton to discuss with CC<br>8/3/00 – NEI revision of questionand proposed response. | Calvert Cliffs |
| | | **Response:**<br>Yes. Assuming the Salt Water System is a necessary support system, and the Salt Water System can provide the cooling for Component Cooling sufficient to remove heat for one loop of SDC. However, when one train of the Salt Water System is removed from service, you no longer meet the "Support System Unavailability" guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for one train of the monitored system (i.e., SDC.), since one loop of SDC is available and in operation and the other loop cannot be made available without removing heat removal capability from the operating loop of SDC. | | |
| 24. | MS04 | **Question:**<br>Are there times when RHR Shutdown Cooling can be removed from service without incurring unavailable hours, if allowed by Technical Specifications (i.e., reactor level and temperature requirements met). | Revised 6/13/00<br>Discussed 6/14/00<br>Action: NRC to discuss with Residents<br>8/29 – NEI Suggestion to remove "See FAQ ID 17" | Duane-Arnold |
| | | **Response:**<br>Yes. Unavailable hours are counted only for periods when a train is required to be available for service. However, Technical Specifications that require one subsystem remain operable and in operation above a specified temperature would be counted if one subsystem were not available or an alternate method (normally specified in the Technical Specification Action Statement) were not available. See FAQ ID 17. | | |

| FAQ Log 9 | | | | |
|---|---|---|---|---|
| **Temp. No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 9.2 | MS01<br>MS02<br>MS03<br>MS04 | **Question**<br>NEI 99-02 Revision 0 defines criteria for determining availability during surveillance testing. This definition can be found on page 26. It allows operator action to be credited for the declaration of availability. NEI 99-02 also defines criteria for determining fault exposure. This definition can be found on pages 28 & 29. Line 5, page 29 references operator action. It states, "Malfunctions or operating errors that do not prevent a train from being restored to normal operation within 10 minutes, from the control room, and that do not require corrective maintenance, or a significant problem diagnosis, are not counted as failures." In addition, page 29, line 13, states, "A train is available if it is capable of performing its safety function."<br><br>If the fault can be corrected quickly (much less than 10 minutes) by a single operator action that is contained in a written procedure, is uncomplicated, and does not require diagnosis or repair, but the operator action cannot be shown to satisfy auto-start time design assumptions (e.g., HPCI injection within 45 seconds), should fault exposure hours be assigned to a failure?<br>**Response**<br>Operator actions to restore a train to normal operation following a malfunction cannot be credited for any purpose. A failure would be reportable per 10 CFR 50.72(b)(2)(iii) and 50.73(a)(2)(v); it would be considered a maintenance-preventable functional failure; it would be counted as a demand and a failure in PRA applications; and it would counted in the performance indicators as both a safety system functional failure and a period of unavailability (if it resulted in failure of one of the four monitored functions).<br><br>Operator actions to recover from an operating error could be credited if the function can be promptly restored from the control room by an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e., the restoration actions are virtually certain to be successful during accident conditions). Note that there is no reference to a time limit since these actions must be completed promptly.<br><br>The paragraph starting on line 5 of page 29 was not intended to be in NEI 99-02, Rev. 0. All references to time constraints were intended to be removed from that document. Due to an oversight, the words were not removed. This will be corrected in the next revision of the document.<br><br>**Alternate Response (NEI 8/29)**<br>No, provided the configuration can be promptly restored in the control room without the loss of safety function. Restoration actions for the malfunction must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions) and must not require corrective maintenance or a significant problem diagnosis. | 7/12/00 – NRC action to confirm consistency with MR and expand upon response.<br>8/2/00 NRC revision to proposed response.<br>8/29 NEI Alternate response added. | ComEd |

FAQ Log 9

| Temp. No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 9.5 | IE02 | **Question**<br>During a startup following a refueling outage (reactor at 24% power w/minimal decay heat), one feed water regulating valve failed open causing a loss of feed water control. In response, one of the two feed water pumps was manually tripped to minimize overfeeding of the steam generators. SG levels continued to rise, so the reactor was manually scrammed. Within one minute of scram, with normal heat removal still available through both main feedwater bypasses, the failed open feed water regulating valve was isolated by closing it's feed water block valve as part of Standard Post Trip Actions. Operators quickly diagnosed this as an uncomplicated reactor trip and completed the remaining steps of Standard Post Trip Actions. Eleven minutes after the scram with steam generator levels continuing to slowly rise, the remaining feed water pump was stopped to terminate overfeeding of the steam generators and avoid excess RCS cooldown. Nineteen minutes after the scram, the Reactor Trip Recovery procedure was entered. Thirty nine minutes after the scram, with steam generator levels down to normal levels, AFW was established at 81 gpm for normal startup feed water alignment. Three minutes later, the Plant Startup procedure was initiated.<br><br>Mitigating systems such as Aux feed and Atmospheric Dump valves were not required nor used to establish scram recovery conditions. Rather, steam generator inventory provided by normal feed water and the normal steam path to main condenser via the normal steam bypass control system accounted for 100% capability for post scram RCS heat removal (i.e., no loss of capability for performing the heat removal function). Would this event count as a scram with loss of normal heat removal?<br>**Response**<br>No. The indicator counts events in which the normal heat removal path through the main condenser is not available and is not easily recoverable from the control room without the need for diagnosis or repair. In this event, the main feedwater system could have easily been returned to service at any time if needed. | Discussed 6/14/00 On-hold, NRC review ongoing. **7/12/00 – Response revised and approved.** 8/2 NRC proposed revision to Response | SCE |
| | | | | |

| FAQ LOG 10 | | | | |
|---|---|---|---|---|
| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 10.4 | MS01<br>MS02<br>MS03<br>MS04 | **Question:**<br>Is it necessary to perform a risk assessment to show that an overhaul maintenance activity is of low risk in order to exclude the hours in the unavailability indicator?<br>**Response:**<br>Yes. 10 CFR 50.65a(4) requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. The rule will be effective on November 28, 2000. Guidance on actions necessary to comply with the rule are contained in NUMARC 93-01, Revision 2. Section 11, as revised February 22, 2000, of this document provides guidance for the development of an approach to assess and manage the risk impact expected to result from the performance of maintenance activities. In the interim to qualify for the exclusion of unavailable hours from the unavailability indicator, licensees must perform that assessment and demonstrate that the planned configuration meets the requirements for normal work controls, as identified in Section 11.3.7.2 of NUMARC 93-01. Otherwise the unavailability hours must be counted. | Discussed 6/14/00<br>On hold, NEI review ongoing.<br>Response revised, 7/11/00 (NRC)<br>7-12-00 On hold, NRC and NEI actions to confirm consistency with MR revision and associated guidance. Intent to finalize at next meeting.<br>8/4/00 – Discussed Under review. | NRC |
| 10.5 | MS01<br>MS02<br>MS03<br>MS04 | **Question:**<br>Is it appropriate to use the default value, that is, the period hours, for the hours that each EDG train is required to be operable when not all trains are required to be operable during shutdown? This results in a non-conservative performance indicator.<br>**Response:**<br>No. The default values in the guidance were provided as an option for licensees to use to reduce the data collection burden. In some cases, the default value is conservative. In other cases, such as with the EDGs, it may be non-conservative. The default values may be used when they are conservative. The non-conservative default values may not be used and the actual hours the train is required to be operable must be determined. | Discussed 6/14/00<br>On hold, NEI and NRC review ongoing | NRC |
| 10.7 | OR01 | | Discussed 6/14/00<br>On hold, NEI review ongoing<br>Discussed 7/12/00<br>NRC/NEI action to propose/review alternate question/response<br>8/3/00 Replacement FAQs being developed. See 12.3 | NRC |

| FAQ LOG 11 | | | | |
|---|---|---|---|---|
| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 11.3 | MS03 | **Question:**<br>Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question.<br><br>**PART A**<br>CR-3 has two EF System pumps and associated piping systems that are credited for Design Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break, and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60 seconds from initiation signal to full flow shall not be exceeded for automatic initiation. Pumps EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns in certain accident scenarios.<br><br>Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency Feedwater Pump (EFP-1) as the "A" EF Train."<br><br>The motor driven pump does not receive an automatic start signal. The motor driven pump is interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1 can be used to transfer water from the condenser hotwell into the steam generators during a seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and Control Complex HVAC Room.<br><br>CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0.<br><br>EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in depth and maintained for potential use in certain seismic and Appendix R conditions.<br><br>Should this be reported as a third train of AFW? | ~~7/12/00 – Action to establish conference between CR and NRC.~~Discussed with NRC, CR3 during 8/28 conf. call. | Crystal River |
| | | **Response:** | | |

**FAQ LOG 11**

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 11.4 | MS03 | **Question:**<br>Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question.<br><br>**PART B**<br>CR-3 has an independent motor driven pump and independent piping system for the Auxiliary Feedwater (AFW) System that is separate from the EF System. The AFW pump (FWP-7) and associated components are designed to provide an additional non-safety grade source of secondary cooling water to the steam generators should a loss of all main and EF occur. This reduces reliance on the High Pressure Injection/Power Operated Relief Valve (HPI/PORV) mode of long term cooling. This AFW source was added to CR-3 in 1988 in response to NRC concerns on the issue of EF reliability (Generic Issue 124).<br><br>Per the FSAR, "The AFW source is non-safety grade and is not Class 1E powered or electrically connected to the emergency diesel generators. As such, it is not relied upon during design basis events and is intended for use on an "as available" basis only. AFW performs no safety function and there is no impact on nuclear safety if it fails to operate.....It is not environmentally qualified nor Appendix R protected......Although the AFW source is non-safety grade it is credited by the NRC as a compensating feature in enhancing the reliability of secondary decay heat removal. Auxiliary feedwater may be used, as defense-in depth, during emergency situation when steam generator pressure has been reduced to the point where EFP-2 is no longer available or to avoid EFP-2 cyclic operation."<br><br>FWP-7 is powered by an independent, non-safety related, diesel. FWP-7 is a manually started pump and the associated control valves are manually controlled from the Main Control Room.<br><br>FWP-7 is not safety related.<br>FWP-7 is not required by ITS to be OPERABLE in any MODE.<br>FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements.<br>CR-3 design and usage of FWP-7 does not fit the NEI definition of either an "installed spare" or a "redundant extra train" as given on pages 30 and 31 of NEI 99-02, Rev. 0.<br>FWP-7 is credited in the FSAR for providing defense-in depth and as an additional source non-safety grade source of secondary cooling water to steam generators.<br><br>Should this be reported as a third train of AFW?<br>**Response:** | ~~7/12/00 – Action to establish conference between CR and NRC to discuss.~~<br>Discussed with NRC, CR3 during 8/28 conf. call. | Crystal River |
| 11.5 | MS01<br>MS02<br>MS03<br>MS04 | **Question:**<br>FAQ 178 states that the exemption of planned unavailable hours due to overhaul maintenance can be applied "once per train per operating cycle". Does the limitation of "once per train per operating cycle" extend to support systems for a monitored system? In other words, if planned unavailable hours for a monitored system result from both planned overhaul maintenance of the monitored system and planned overhaul maintenance of a system that supports the monitored system; can both sets of hours be excluded (provided all other exclusion criteria are met)?<br>**Response:**<br>**For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exclusion.** | 7/12/00 – Discussed. NEI action to propose response.<br>8/3/00 – NEI proposed response. | NEI |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 11.6 | Gen | **Question:** FAQ 170 discusses correcting past unavailability hours for Emergency AC System surveillance testing which were found to be incorrectly reported to WANO. The FAQ response states that historical data does not have to be revised, except to ensure that the data is accurate back to the first quarter of 2000. Can this response be applied to any correction of performance indicator data that occurred in the historical (prior to first quarter of 2000) data time period?<br>**Response:** Data in the historical submittal (through the end of 1999) does not require correction. However, ~~previous~~ data may be revised by the licensee if desired and as described and allowed by NEI 99-02. | 7/12/00 – Discussed. On hold for review. 8/29 NEI response revision | |
| 11.7 | MS02 | **Question:** In NEI 99-02, under the Support System Unavailability header, it is identified that in some instances, unavailability of a monitored system that is caused by unavailability of a support system used for cooling *need not be reported* if cooling water from another source can be substituted. The rules further state that if both the monitored and support system pumps are powered by a class 1E electric power source, then a pump powered by a non- class 1E source may be substituted provided the redundancy requirements to accommodate single failure requirements for electric power and cooling water are met.<br><br>At ~~RBS~~our site, the HPCS pump room is cooled by a safety related unit cooler, HVR-UC5. This unit cooler has non-safety related/non-Class 1E powered Normal Service Water (NSW) supplied to it and a safety related/Class 1E Standby Service Water (SSW) supplied to it as a backup cooling source. The SSW system has four 50% capacity pumps, two per train. Both trains of SSW merge into a common header at the unit cooler. If we remove one train of SSW from service can NSW be credited as a substitute thus keeping HVR-UC5 and the HPCS pump available?<br>**Response:** In this case, no substitution is required, since the HPCS system is still available. Removal of one 100% train of SSW from the unit cooler has no effect on the availability of HPCS since one 100% train of SSW is still available to service the HVR-UC5 unit cooler.<br>The single failure criteria should only be applied to cases where there is substitution of the support system and in cases where the mitigating systems have installed spares or redundant trains. | 7/12/00 Discussed. On hold for review. 8/29 NEI removed plant name from response. | River Bend |
| 11.8 | MS01<br>MS02<br>MS03<br>MS04 | **Question:** Our Standby Service Water System (SSW) is designated as a Support System for each of the four mitigating systems. The system has two trains and each train has two 50% capacity pumps. At the mitigating system interface, the SSW support system either has both trains of SSW supplied to the cooling load or one SSW train exclusively supplying the cooling load. A train with one pump in service will supply the required SSW loads except the RHR train. The RHR train is normally valved out of service and is manually lined up to support a design basis accident condition some time after the automatic initiation sequence is completed. We consider all mitigating systems within a train, except RHR in that train, available with one SSW pump out of service. However, RHR, with the SSW from the other train available, is considered available. Have we calculated the availability correctly?<br>**Response:** Yes. The mitigating systems that can be supplied by a single SSW train with one SSW pump in service are available. | 7/12/00 Discussed. On hold for review. | River Bend |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
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| 11.9 | MS02 | **Question:**<br>On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank **or** [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI?<br>**Response:**<br>Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of the suction path from the suppression pool. The guidance in NEI 99-02 will be changed to eliminate the words "from the condensage storage tank or," leaving only "from the suppression pool.". | 7/12/00 Discussed. On hold for review. 8/2/00 NRC – Proposed response revised. | NRC |
| 11.10 | BI01 | **Question:**<br>**Proposed replacement for FAQ 193**<br>The definition of the RCS Specific Activity PI is the maximum RCS activity as a percentage of the technical specification limit. Should licensees with limits more restrictive than the technical specifications use the more restrictive limit or the TS limit?<br>**Response:**<br>Licensees should use the most restrictive regulatory limit (e.g., technical specifications[TS] or license condition). However, if the most restrictive regulatory limit is insufficient to assure plant safety, then NRC Administrative Letter 98-10 applies, which states that imposition of administrative controls is an acceptable short-term corrective action. When an administrative control is in place as a temporary measure to ensure that TS limits are met and to ensure public health and safety, that administrative limit should be used for this PI. | 7/12/00 Discussed. On hold for review. 8/2/00 – NRC revision to proposed response. | NRC |
| 11.11 | IE03 | **Question:**<br>Regarding the Unplanned power change PI, I have the following questions:<br>1. Is the 20% full power intended to be 20% of 100% power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97)= 19%]<br>2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI?<br>3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?<br>**Response:**<br>1. It is intended to be 20% of 100%.<br>2. In general, y~~Y~~es, however the specific scenario needs to be evaluated.<br>3. Licensees should use the ~~nuclear instrumentation~~ power indication that is used to control the plant. | 7/12/00 Discussed. On hold for review. 8/2/00 NRC revision to question and response. 8/29 NEI response revision. | NRC |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 11.12 | IE03 | **Question:**<br><br>The licensee reduced power on both units to support grid stability in response to a fault on off-site transmission line 15616. Each of the licensee's two operating units are supplied from two 345 kilovolt (kV) lines. Line 15616, which supplies Unit 1 from a~~Silver~~ Lake, was lost as a result of a static line failure. The power reduction was requested by the system load dispatcher in accordance with System Planning Operating Guide (SPOG) 1-3-F-1, "Station Operating Guidelines," Revision 1, to allow disabling the Unit 1 turbine generator trip scheme while line 15616 was out of service. With line 15616 out of service, a fault on the second line supplying Unit 1 (line 15501 from ~~Nelson~~) would cause a Unit 1 turbine trip. The turbine trip would then cause a reactor trip (if reactor power is greater than the P-8 interlock setpoint of 32.1%). The turbine trip is intended to prevent overloading remaining grid circuits, causing the grid to become unstable. It is not a Reactor Protection System function. Reducing power and disabling the Unit 1 turbine trip scheme would prevent Unit 1 from tripping if line 15501 was faulted or lost. There were no on-site problems associated with the loss of the transmission line. The first paragraph of SPOG 1-3-F-1 states that "it is not necessary to take any corrective measures for stability for the outage of any single line provided that the protection system is normal. However, it may be desirable to disable the unit trip scheme(s) during single line outages." The power reductions requested by the load dispatcher (just over 20%) met the procedurally recommended output limitations for the~~Byron~~ Sstation with line 15616 out of service with the stability trip scheme disabled.<br><br>Does this situation count? | 7/12/00 Discussed. Action, NRC to rewrite question and response for clarification.<br>8/2/00 NRC rewrite of question and response.<br>8/3/00 NEI Removal of plant name. | NRC |
| | | **Response:**<br>No. In the situation described, the power reduction would not count. The exception from counting unplanned power changes when directed by the load dispatcher is intended to exclude power changes directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, and for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator. | | |
| 11.13 | EP01 | **Question:**<br>Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills.<br><br>Can credit can be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations), with no actual verbal contact, as long as the procedures are completed up to the time the notification is made.? | 7/12/00 – On hold, NRC review/revision | NRC |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | **Response:**<br>99-02 allows for the simulation of notification of offsite agencies in the case of simulator based drills. There is no reason not to allow the same simulation for other EP drills. However, since the guidance in NEI 99-02 seems specific to simulator drills, it has been interpreted as not allowing such simulation for other drills. The guidance will be clarified in a future revision of the document.<br><br>It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment. Generally, the contact is simulated through the use of a controller answering a phone. Although this method will not test the equipment, communications tests are required by Appendix E to 10 CFR 50 and the Emergency Plan should delineate such tests. | | |
| 11.14 | EP03 | **Question:**<br>A licensee recently had a regularly scheduled silent siren test failure. Immediately following the test failure, a request to test the sirens from an alternate location (the local county has 74 sirens that can be activated from either one of two locations) was performed and it failed as well. ~~My question is h~~How many tests should be counted in the PI? ~~My read on the guidance leads me to believe that only the first set of failures should be counted since that was the "regularly scheduled" test. The second test was somewhat of a troubleshooting test. There is some confusion among the licensee's staff as to how many tests should count. Some people also think that the post maintenance tests should be counted. I don't think that this indicator should be treated like the EP drill and exercise performance PI (i.e., if the PI is low, a licensee can do more drills to bring up the PI). Counting more successful siren tests (either post maintenance or troubleshooting) would mask the true reliability of the siren system that's being measured during the regularly scheduled tests.~~ | 7/12/00 – On hold, NRC review/revision 8/29 NEI proposed response revision. | NRC |
| | | **Response:**<br>One. The failure of the first system should be a failure and the backup system should not be an additional failure, nor should it be counted as a success if it were successful. The purpose of the PI is to give an indication of the manner in which the licensee maintains important EP equipment. ~~This being the case, it is not appropriate to count the back-up system success rate.~~<br><br>~~The test should not be 2 failures (by the way since all the sirens failed, we are talking about 1 or 2 times the # of sirens as the number of failures).~~<br><br>~~Site procedures for activation of the siren system vary. Some procedures may include use of the back-up system should the main system fail.~~ | | |
| 11.15 | PP01 | **Question:**<br>If perimeter intrusion equipment, CCTV monitoring equipment or systems supporting their functionality are damaged or destroyed by environmental conditions and remains unable to perform their intended function after the condition subsides (e.g., a lightning strike, wind, ice, flood ) do you need to count any hours towards the performance indicator? | 7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. | \ComEd |
| | | **Response:**<br>No. Compensatory hours are not counted for environmental conditions beyond the design of the equipment. | | |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 11.16 | PP01 | CLARIFICATION NEEDED ON "FAQ" # ID-59 ISSUED WITH NEI 99-02 REV. 0 MARCH 28 2000 -- "COMP. POSTING FOR NON-FAILURE OF EQUIPMENT"<br><br>In FAQ 59 and resulting response it states in part that, if an IDS system segment needs to be declared inoperable due to a Security Plan commitment of "x" number of false alarms received, the zone would need to be comped, repair / test the segment, return to operable and remove the comp post. In the response it goes on to state that if there is no equipment malfunction and the system would still have alarmed during intrusion (still capable of performing its intended function) then the man hours that were established as part of the "precautionary maintenance" activity would not be counted.<br><br>**Question:**<br>If the zone / segment remains operable (still capable of performing its intended function) but is "declared" inoperable due to a Security Plan commitment of "x" number of false alarms received is it necessary to have maintenance "check" the zone / segment prior to declaring the zone operable? Or, can functional testing be conducted by security on that zone / segment assuring that it was capable of alarming during an intrusion? | 7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 8/29 NEI response revision. | ComEd |
| | | **Response:**<br>If in the scenario identified above, a zone/segment tests "OK" as performing its intended function (per the normal test procedures for zone operability) there would be no need to have maintenance perform any actions prior to declaring the zone operable. ~~There would be no added value to have maintenance "checkout" the zone/segment when it tests "OK".~~ Therefore, the hours associated with this situation would not be counted ~~against the Performance Indicator~~. | | |
| 11.18 | MS01 | **Question:**<br>The station UFSAR states that operator actions are required to restore the EDG room ventilation system following: 1) a fire protection system actuation 2) a HELB occurring outside of the EDG rooms. The restoration actions (manually open several sets of dampers) are directed by an operating procedure. During certain fire protection system surveillances, the EDG room ventilation system dampers are closed to the same configuration as when a HELB or fire protection system actuation occurs. No other actions are taken that would otherwise affect EDG start and load capability. The steps necessary to return the ventilation <u>subsystem</u> to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individual specifically involved with restoring the ventilation is briefed on the time restraints and dedicated to the testing. Since the UFSAR credits the operator actions required to restore the system to its normal operating configuration following a fire protection actuation or HELB, the actions taken to restore ventilation during testing would be similar to those credited in the UFSAR. Can the EDG be considered available during the period the room vent fan is unavailable due to the fire protection surveillances? | -8/17/00 – Licensee proposed response added. | Braidwood /ComEd |

FAQ LOG 11

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| | | **Licensee Proposed Response:**<br>The EDG should be considered available and Fault Exposure Hours should not be reported for this event because the EDG never enters a condition where system or subsystems necessary for operability (as determined by formal engineering analysis) are unavailable during the surveillance. This will maintain a consistent approach in comparison with the industry WANO indicator reporting.<br><br>The EDG automatic start and load features are still available during all phases of the testing. The EDG would start and load on an accident signal in accordance with its design. The room cooling subsystem could be returned to service prior to the room temperature reaching the previously analyzed limit and precautions in the procedure specify the previously analyzed time limit for restoration. The steps necessary to return the ventilation subsystem to available are specified in an operating procedure and the guidance is accessible for the personnel performing the steps. Operations personnel are briefed on the status of the DG and its room ventilation subsystem as part of the prejob briefing for the performance of the surveillance. The individuals specifically involved with returning the room cooler subsystem to available are briefed, aware of their responsibility and dedicated to the testing. The actions required to restore ventilation are consistent with the system design basis assumptions in the UFSAR and are acceptable. | | |
| | | **Question:**<br>**Response:** | | |
| | | **Question:**<br>**Response:** | | |

| FAQ LOG 12 | | | | |
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| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 12.1 | MS01<br>MS02<br>MS03<br>MS04 | **Revise FAQ 178 as follows:**<br><br>**Question 1. What defines overhaul versus non-overhaul maintenance?**<br>**Change the response to read as follows:** Overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. Overhauls include disassembly of major components, replacement of parts as necessary, cleaning, adjustment, lubrication as necessary, and reassembly.<br><br>**Add a new question 2 (and renumber the remaining questions appropriately) to read as follows: What is considered to be a major component for overhaul purposes?**<br>**Response** A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor.<br><br>**Question 3 (old question 2). Is application of planned overhaul hours limited to systems for which a risk-informed AOT extension has been approved?**<br>**Change the answer to read as follows:** No. Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify for the exclusion of unavailable hours, licensees must perform a quantitative risk assessment. This assessment must demonstrate that the planned configuration meets either the requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2. In addition, all other requirements described in the response to this FAQ must be met. Otherwise the unavailable hours must be counted.<br><br>The Safety System Unavailability indicator excludes maintenance-out-of-service hours on a train that is not required to be operable per technical specifications (TS). This normally occurs during reactor shutdowns. Online maintenance hours for systems that do not have installed spare trains would normally be included in the indicator. However, some licensees have been granted extensions of certain TS allowed outage times (AOTs) to perform online maintenance activities that have, in the past, been performed while shut down. Acceptance guidelines for such TS changes are given in Sections 2.2.4 and 2.2.5 of Regulatory Guide 1.174 and Section 2.4 of Regulatory Guide 1.177. These guidelines include demonstration that the change has only a small quantitative impact on plant risk (less than $5\times10^{-7}$ incremental conditional core damage probability). It is appropriate and equitable, for licensees who have demonstrated that the increased risk to the plant is small, to exclude unavailable hours for those activities for which the extended AOTs were granted. However, in keeping with the NRC's increased emphasis on risk-informed regulation, it is *not* appropriate to exclude unavailable hours for licensees who have not demonstrated that the increase in risk is small. In addition, 10 CFR 50.65a(4), which goes into effect on November 28, 2000, requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. Guidance on a quantitative approach to assess the risk impact of maintenance activities is contained in the latest revision of Section 11.3.7.2 (dated February 22, 2000) of NUMARC 93-01, Revision 2. That section allows the use of normal work controls for plant configurations in which the incremental core damage probability is less than $10^{-6}$. Licensees must demonstrate that their proposed action complies with either the requirements for a risk-informed TS change or the requirements for normal work controls described in NUMARC 93-01.<br><br>**Add FAQ 11.5 as a new question 9 as follows: Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of "once per train per operating cycle" extend to support systems for a monitored system?**<br>**Response** For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exclusion. | | NRC |
| | | **Response:** | | |
| 12.2 | IE02 | **Question:**<br>Following a plant trip, operators closed the MSIVs due to a stuck open steam dump valve. RCS temperature was maintained using atmospheric dump valves. Does this count as a scram with loss of normal heat removal? | | NRC |
| | | **Response:**<br>Yes. The MSIVs could not be recovered because of the stuck open steam dump valve. | | |

FAQ LOG 12

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 12.3 | OR01 | **Question:** Because of a breakdown in communications between the rad waste and health physics groups, a post-job survey was not performed following completion of a resin sluicing evolution. ~~Approximately four hours~~ Several hours later, health physics became aware of the breakdown in communication and ~~completed~~performed a survey of the area that found dose rates greater than 1500 mrem per hour at 30 cm from the spent resin liner. The licensee's Technical Specifications require areas with dose rates greater than 1000 mrem per hour to be controlled as a locked high radiation area. However, ~~due to an additional communications breakdown within the health physics group,~~ follow-up action to the survey was not properly prioritized within the health physics group and the area remained unguarded and unlocked ~~for an additional 20 hours~~until the next day before it was controlled in accordance with the Technical Specifications. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence?<br>**Response:** No. The definitions for both the *Technical Specification High Radiation Area Occurrence* and the *Very High Radiation Area Occurrence* refer to "A nonconformance (or concurrent nonconformances) with technical specifications … and comparable requirements in 10 CFR 20 applicable to technical specification high radiation areas (>1 rem per hour) that results in the loss of radiological control over access or work activities."~~…"[Technical Specifications, or 10 CFR 20, respectively]~~. As used in these definitions, *concurrent* means "at the same time and resulting from the same cause." During the ~~first four hours~~ initial events in~~of~~ this example, the failure to perform a timely radiation survey was the cause of the failure to post the area, control access to the area and provide dosimetry as required by Technical Specifications. They are therefore concurrent nonconformances and constitute a single PI count. However, after the survey was ~~completed~~performed, the failure to establish proper controls over access to the area in a timely manner was caused by a separate ~~programmatic~~ breakdown that could not be considered concurrent with the initial failure to perform the survey. This is an example of a *sequential* failure that warrants a second PI count. | 8/4/00 – Discussed. Tentative Approval. 8/17/00 – NEI revisions to question and response 8/18/00 – NEI revisions to question and response. 8/29 NEI response revision, "completed" changed to "performed" 8/29 Hold approval for companion FAQ? | NEI |
| 12.4 | IE02 | **Question:** In the Scrams With a Loss of Normal Heat Removal performance indicator, the definition of "loss of normal heat removal path" includes loss of main feedwater. Our plant is designed to isolate main feedwater after a trip by closing the main feedwater control valves. The auxiliary feedwater pumps then are designed to start on low steam generator level (which is expected following operation above low power conditions), providing our normal heat removal. A clarifying note in the Guideline clearly states that "Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a reactor scram, are not counted in this indicator." Also, the response to FAQ 65 states that "The PI is monitoring the use of alternate means of decay heat removal following a scram." If our plant receives a spurious or invalid feedwater isolation signal, our main feedwater pumps will trip and a plant scram will occur. The auxiliary feedwater pumps will start on the loss of the main feedwater pumps, prior to reaching a low SG level condition. In this example, main feedwater still isolates, although not in the normal fashion, auxiliary feedwater provides the normal heat removal, and no alternate means of decay heat removal is required. This is not believed to be a Scram with a Loss of Normal Heat Removal. Is this the correct interpretation?<br>**Licensee Proposed Response:** Yes. Since the normal heat removal path was utilized and an alternate heat removal system was not required, this would not count toward the "Scram with Loss of Normal Heat Removal" performance indicator. | | Kewaunee |
| 12.5 | EP01 | **Question:** Currently the "Communicator" key ERO positions for event notification are defined as the ERO position responsible for the notifications, not just a telephone talker. If the key position person delegates completion of the notification form to another individual, but keeps responsibility for approval (must review and sign the form before offsite notifications are made), must the person completing the form be considered a Key ERO position also? It is understood that responsibility for approving the notification implies responsibility to verify the data recorded and to challenge inconsistencies before authorizing the notification. | | Kewaunee |

| FAQ LOG 12 | | | | |
|---|---|---|---|---|
| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| | | **Licensee Proposed Response:**<br>In the example provided, the person completing the form does NOT have to be considered a Key ERO position. | | |
| 12.6 | IE03 | **Question:**<br>**Question rewritten by Pallisades (see 8/4/00 log for prior version)**<br>This FAQ raises a question regarding the proper interpretation of the wording of this PI. NEI 99-02 states the purpose of this PI as: "This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions." Our plant planned a sequence of power changes and equipment manipulations to deal with a secondary chemistry problem. The plan was ready >72 hours in advance, and a written schedule existed. During execution of the plan, an additional equipment problem was discovered, but plant management chose to continue with the planned sequence of power changes, and to address the emergent equipment issue later in the planned outage. Had it occurred by itself, the equipment problem may have required a power change in excess of 20%. However, the problem did not cause significant departure from the already planned and scheduled activities, and did not cause urgent response from Operations staff to mitigate the equipment problem. There were no reactor safety implications. Consistent with the intent of the PI, we believe this event should not be counted against this PI.<br><br>However, part of the PI definition on page 18 of NEI 99-02 states that "Unplanned changes in reactor power are changes in reactor power that are initiated in less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% full power to resolve." This wording could be viewed in two ways:<br>• This was a newly emergent off-normal condition that, by procedure, would have "required" the plant to reduce power if the condition were not fixed, it should be counted whether or not the power reduction was already planned and scheduled.<br>Or<br>• The emergent condition was not what initially caused the planned reduction in power, but was simply a secondary reason to proceed with the existing plan, the condition did not "result in" a change in power level greater than 20%.<br><br>Should the sequence of power changes be counted as an unplanned power change? | 8/4/00- Discussed. Pallisades to prepare shortened version of FAQ for consideration. 8/15/00 – Question rewritten by Pallisades. Proposed response added by NEI. | Pallisades |
| | | **Response:**<br>No. This sequence of power changes would not count. Minor modifications to a planned power change protocol in response to events are not considered unplanned power changes and are not counted toward the performance indicator. | | |

FAQ LOG 12

| Temp No. | PI | Question/Response | Status | Plant/ Co. |
|---|---|---|---|---|
| 12.7 | IE03 | **Question:**<br>Should the unplanned power change outlined below be counted from the point the off-normal condition is discovered or from the point that action is taken in response to the off-normal condition?<br><br><u>May 14, 2000</u>:<br>• The station was operating at approximately 24% power in order to repair steam leaks.<br>• 11:57 AM - Power ascension was initiated with the intent to go to 73% power in a mode of load following.<br><u>May 15, 2000</u>:<br>• The crew on shift has a goal of reaching 61% power.<br>• 2:55 AM - One main steam isolation valve (MSIV) closed due to loss of air. The other three main steam lines are unaffected. No power change results from the MSIV closure. Power level is 54.3%. (one-minute average heat balance power data) **Point #1.**<br>• 4:48 AM - The MSIV is discovered to be closed. Power level is 58.8% (one-minute average power data). **Point #2.** Power ascension is continued using reactor recirculation flow<br>• 5:12 AM - Suspended reactor power ascension for the shift. Reactor Power is 62% **Point #3.** Several times over the next few hours the peak one-minute average power reached 62.1%.<br>• 12:00 Noon - A management meeting is conducted and a decision is made to reduce power for ALARA concerns and enter the steam tunnel to investigate the cause of the MSIV closure. There is no technical specification driver involved. Specifically, there is no regulatory driver to complete a repair by a specific time or to be at a specific power level within a given time. Power level has decreased to 60.6% (one-minute average power) due to xenon. **Point #4.**<br>• 2:35 PM - The Control Room Log entry notes reactor power at 61%. The one-minute average power level is 59.3%. The power reduction was initiated by reducing reactor recirculation flow in preparation for inserting control rods. **Point #5.**<br>• 3:34 PM - Completed moving control rods for the down power. The power reduction for the steam tunnel entry is complete. The Control Room Log entry notes power at 43%. The one-minute average power is 43.6%. **Point #6.**<br>• 5:15 PM - Power reduction complete. The one-minute average power is generally 42%. However, it varies from 41.9% to 42.3%.<br>• 8:40 PM - The power level is being controlled using control rods and reactor recirculation flow. Power went as low as 41.4%(one-minute average) after movement of control rods. **Point #7.**<br>• About 11:00 PM - Power is raised slightly over the next few hours to ensure that power fluctuations don't inadvertently increase the magnitude of the total power change.<br><br>In the case study above, the off-normal condition was discovered at 4:48 AM, noted as Point #2, and the power level was 58.8%. The power ascension continued to Point 3, with one-minute average power level of 62.1%, and then reduced to 42% (Point #6) to investigate the cause of the condition. | 8/29 NEI action to obtain clarification from Columbia. | Columbia |

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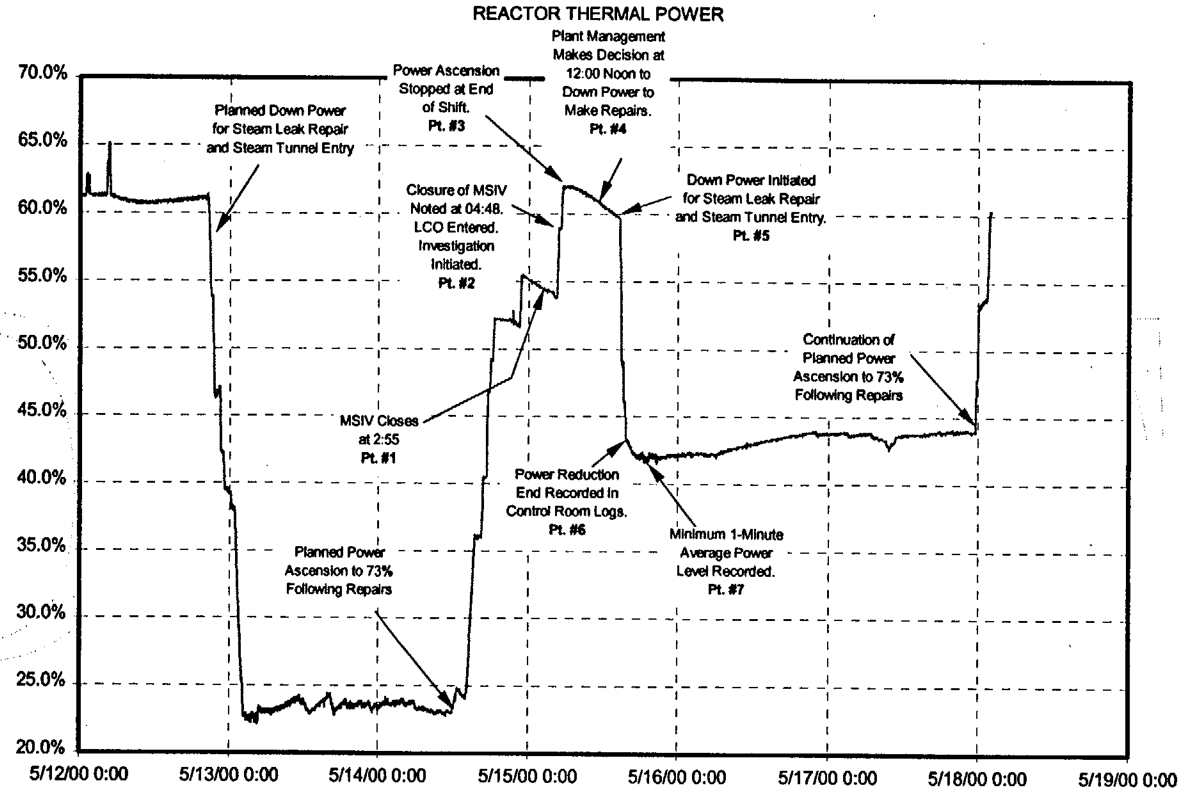
<tr><td></td><td></td><td><br>Response:</td><td></td><td></td></tr>
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| FAQ Log 13 | | | | |
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| **Temp No.** | **PI** | **Question/Response** | **Status** | **Plant/ Co.** |
| 1. | IE03 | **Question:**<br>You have a slow leak on a feedwater pump and a work request is initiated and placed on the 12 week schedule, then after 72 hours passes the leakage increases, but the work package is still applicable. You immediately decrease power to fix the pump. Is this considered an unplanned power change since you had a work package written and there was greater than 72 hours?<br>**Response:**<br>The event would count as an Unplanned Power Change. Power changes caused by or in response to off-normal events during the course of a pre-planned activity, count as unplanned power changes when a determination is made that the off-normal events necessitated a course of action that was outside contingency planning in place for the pre-planned activities. In these instances, the off-normal events cause, in effect, an exiting of the preplanned course of action and any power changes that occur following the exit of the plan are counted toward the performance indicator. Minor modifications to a planned activity in response to events are not considered unplanned power changes and are not counted toward the performance indicator. | | Beaver Valley |
| 2. | IE03 | **Question:**<br>Crystal River Unit 3 (CR-3) is configured with two once-through steam generators (OTSGs). Two Main Steam Isolation Valves (MSIVs) are installed in each of the two main steam lines.<br><br>On August 27, 1998, CR-3 was in MODE 1 operating at 100 percent RATED THERMAL POWER. While troubleshooting a half trip signal on the Emergency Feedwater Initiation and Control (EFIC) System Channel A Main Steam Line Isolation (MSLI), both MSIVs to OTSG A closed. This action isolated steam relief to the condenser through the turbine bypass valves from the A OTSG and isolated the steam supply to Main Feedwater Pump (MFP) A. As required by administrative procedures, the reactor operator initiated a manual trip upon closure of the MSIVs.<br><br>After the manual trip, the OTSG A level lowered enough to initiate Emergency Feedwater (EFW). EFW controlled level in both OTSGs as designed, although MFP B remained in service and available at all times. OTSG B provided RCS heat removal to the condenser with EFW maintaining OTSG level.<br><br>Does this count?<br>**Response:** | | Crystal River 3 |

Log 11.13 PotentialFAQ DRAFT 8/30/00

PERFORMANCE INDICATOR INTERPRETATION FEEDBACK FORM

Instructions: Fill out the form and send it to the DRP branch chief, who will coordinate a review with the appropriate DRS branch chief, if needed, and forward comment via E-mail to"PIISSUES". A hard copy of the form should also be provided to Chief, Performance Assessment Section, IIPB.

| 1. Cornerstone: | 2. PI: ERO | 3. Plant Name |
|---|---|---|
| Emergency Preparedness | Drill/Exercise Performance | Sequoyah |

**A. Licensee Disagreement On NRC 's Interpretation of an Issue**

1. Description of Interpretation Issue:

Regarding taking credit for notification performance opportunities, NEI 99-02, page 91 defines opportunities for notifications as those made to the state and/or local government authorities. The guidance further defines timely as those offsite notifications that are initiated must be verbal in nature. On page 92 under clarifying notes (second paragraph), NEI 99-02 states that notifications may be included in the PI if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification. This particular note applies to operating shift simulator evaluations, not emergency drills.

2. Licensee's Interpretation:

The licensee believes that credit can be taken for the notification performance opportunity when notifications are simulated during emergency drills (i.e., not operator simulator evaluations). The licensee believes that actual verbal contact is not required as long as the procedures are completed up to the time the notification is made.

3.Region's Interpretation:

The clarifying note on page 92 which appears to accept no verbal contact for notification credit may be acceptable for operating simulator evaluations, but its acceptability for emergency planning drills is not specified. Therefore, the licensee should not take credit for notification opportunities during emergency drills when no verbal contact is made. When the verbal contact is not established, the communicator and the equipment needed to make the notification are not challenged.

**B. Licensee and NRC Agreement On Interpretation of an Issue, But the NEI-99-02 Guidance Needs Clarification or Revision**

Attachment 5

| Date Rcv'd | IIPB Action | | | IIPB Contact |
|---|---|---|---|---|
| | Immediate | Pending | Complete | |

| IIPB FINAL RESOLUTION | Approved By/Date |
|---|---|
| | |

FAQ DRAFT 8/30/00

As a result of a Public Meeting between NRC and NEI on 8/17/00 the following FAQs were drafted. These will be reviewed in the next public meeting between NRC and the industry committee on RROP, revised as appropriate and issued.

1.0

ANS FAQ

During a scheduled siren test, a siren (or sirens) fail or cannot be verified to have responded to the initial test. A subsequent test is done to troubleshoot the problem.

1) Should the troubleshooting test(s) be counted as siren test opportunities?

2) Should failures during troubleshooting be considered failures?

3) Should post maintenance testing or system retests after maintenance be counted as opportunities?

4) If subsequent testing shows the siren to be operable (verified by telemetry or simultaneous local verification) without any corrective action having been performed, can the initial test be considered a success?

Response

1) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.

2) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.

3) No. These tests are not regularly scheduled tests because they are only conducted if there are siren failures.

4) Yes, but only if it is reasonably verified that the failure was in the testing equipment and not the siren control equipment, i.e., the siren would have sounded when called upon, even though the testing equipment would not have indicated the sounding. In the process of verifying that the failure is only with testing equipment, items such as radio signal transmission weakness or intermittent signal interference should be eliminated as the cause. Maintenance records should be complete enough to support such determinations and validation during NRC inspection.

2.0

ANS FAQ

Attachment 6

Siren systems may be designed with equipment redundancy or feedback capability. It may be possible for sirens to be activated from multiple control stations. Feedback systems may indicate siren activation status, allowing additional activation efforts for some sirens.

1) A siren system has two normally attended control stations from which the system may be activated. If a siren test from one station is unsuccessful can a test performed from the second station be considered as a part of the regularly scheduled test?

2) A siren test technician sent multiple activation signals to a siren that initially appeared not to respond. The siren responded. Can the multiple signals be considered as the regularly scheduled test and hence a success?

Answer

1) Yes, if the use of redundant control stations is in approved procedures and is part of the actual system activation process. A failure of both systems would only be considered one failure, where as the success of either system would be considered a success.

If the redundant control station is not normally attended, requires set up or initialization, it may not be considered as part of the regularly scheduled test. Specifically, if the station is only made ready for the purpose of siren tests it should not be considered as part of the regularly scheduled test.

2) Yes, if the use of multiple signals is in approved procedures and part of the actual system activation process.

3.0

ERO Drill Participation FAQ

NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators (TSC and EOF), who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of the tracking drill participation. These individuals ultimately approve all offsite communications from their respective facilities, however, they do not collect data for the notification form. The licensee's basis is that NEI 99-02 addresses the desire to not track "phone talkers".

1) Is this an appropriate interpretation of 99-02?

Answer

1) No. The expectation of 99-02 is that the participation of the communicators responsible for collection of timely and accurate data for the notification form will be tracked. However, there are cases where the position responsible for approval (the senior managers in the above example) actually collects the data for the form, approves it and hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked.

4.0

ERO and DEP Scenario Confidentiality

A licensee used same scenario for each of the three response teams. The drills contributed to DEP and ERO statistics. Repetitive use of the scenario has the potential to skew the PI success rate if scenario confidentiality is not maintained. There was no indication that drill participants were intentionally informing other teams about the scenario, but discussions of the drill could inadvertently reveal facts about the scenario.

1) Is it permissible to repeat the use of scenarios in drills that contribute to DEP and/or ERO statistics?

2) What is the NRC expectation with regard to scenario confidentiality?

Answer

1) Yes, if a reasonable level of scenario confidentiality is maintained.

2) NRC does not expect the licensee to develop new scenarios for each drill or each team. However, it is expected that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a proficiency-enhancing evolution. There are many processes for the maintenance of scenario confidentiality that are generally successful. These include confidentiality statements on the signed attendance sheets, spoken admonitions by drill controllers and the like. A reasonable level of confidentiality means that some scenario information could be inadvertently revealed and the drill still be a valid proficiency-enhancing evolution. However, it is expected that the licensee will remove from the statistics drill opportunities that were not valid due to scenario compromise and address the reasons for such a compromise.

Viewed from another perspective, the RROP SDP process can't address willful violation and similarly, the PI process can't address willful manipulation. Should NRC discover same, the affected PI data could be considered as invalid and replaced with inspection.

DRAFT
8/30/00

**Revise FAQ 178 as follows:**

**Question 1. What defines overhaul versus non-overhaul maintenance?**

**Change the response to read as follows:**
Overhaul maintenance comprises those activities that are undertaken voluntarily and performed in accordance with an established preventive maintenance program to improve equipment reliability and availability. Overhauls include disassembly of major components, replacement of parts as necessary, cleaning, adjustment, lubrication as necessary, and reassembly.

**Add a new question 2 (and renumber the remaining questions appropriately) to read as follows: What is considered to be a major component for overhaul purposes?**

**Response**
A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver.

**Question 3 (old question 2). Is application of planned overhaul hours limited to systems for which a risk-informed AOT extension has been approved?**

**Change the answer to read as follows:**
No. Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify for the exemption of unavailable hours, licensees must perform a quantitative risk assessment. This assessment must demonstrate that the planned configuration meets either the requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2. In addition, all other requirements described in the response to this FAQ must be met. Otherwise the unavailable hours must be counted.

The Safety System Unavailability indicator excludes maintenance-out-of-service hours on a train that is not required to be operable per technical specifications (TS). This normally occurs during reactor shutdowns. Online maintenance hours for systems that do not have installed spare trains would normally be included in the indicator. However, some licensees have been granted extensions of certain TS allowed outage times (AOTs) to perform online maintenance activities that have, in the past, been performed while shut down. Acceptance guidelines for such TS changes are given in Sections 2.2.4 and 2.2.5 of Regulatory Guide 1.174 and Section 2.4 of Regulatory Guide 1.177. These guidelines include demonstration that the change has only a small quantitative impact on plant risk (less than $5x10^{-7}$ incremental conditional core damage probability). It is appropriate and equitable, for licensees who have demonstrated that the increased risk to the plant is small, to exclude unavailable hours for those activities for which the extended AOTs were granted. However, in keeping with the NRC's increased emphasis on risk-informed regulation, it is *not* appropriate to exclude unavailable hours for licensees who have not demonstrated that the increase in risk is small. In addition, 10 CFR 50.65(a)(4), which goes into effect on November 28, 2000, requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities. Guidance

Attachment 7

on a quantitative approach to assess the risk impact of maintenance activities is contained in the latest revision of Section 11.3.7.2 (dated February 22, 2000) of NUMARC 93-01, Revision 2. That section allows the use of normal work controls for plant configurations in which the incremental core damage probability is less than $10^{-6}$. Licensees must demonstrate that their proposed action complies with either the requirements for a risk-informed TS change or the requirements for normal work controls described in NUMARC 93-01.

**Add FAQ 11.5 as a new question 9 as follows: Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of "once per train per operating cycle" extend to support systems for a monitored system?**

**Response**
For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours.

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**Question (NRC feedback form from Catawba - to replace part 2 of FAQ 190)**
The guidance in NEI 99-02 states that fault exposure hours may be removed after certain criteria are met. One criterion is that supplemental inspection activities by the NRC have been completed and all open items have been closed out. If a licensee has fault exposure hours that meet all other stated criteria (≥336 hours, corrective actions completed, and four quarters have elapsed) but the indicator is still green, does the baseline inspection count in place of the supplemental inspection? Also, please clarify the intent of the phrase "after 4 quarters have elapsed from discovery."

**Response**
1. No. Fault exposure hours may be removed only if the indicator is outside the green band so that supplemental inspection is necessary (and all other stated criteria are met). The intent of this provision was to allow the removal a large number of fault exposure hours due to a single event or condition so that a licensee would not be outside the green band for an extended time period. There are two reasons for this: (1) after the stated criteria are met, the PI is no longer considered to be indicative of current performance; and (2) unavailable hours accumulated later would put the licensee further into the white band but would not trigger any further NRC action, since the white band is 1.5 to 2 times as wide as the green band. For these reasons, the hours may be removed to reset the indicator so that further fault exposure hours could trigger further NRC response.

2. The intent of the phrase "after 4 quarters have elapsed from discovery" was that the indicator would be non-green for 4 quarters minimum, regardless of when the corrective actions were completed and the supplemental inspection closed out. The quarter in which the fault exposure hours is identified would be the first non-white quarter, and 12 months (four quarters) later, assuming all required conditions are met, the hours could be removed from the calculation for that quarter.

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**Question (NRC, to replace FAQ 143)**
Are failures of the RCIC system included in the Safety System Functional Failure indicator only if RCIC is reportable in accordance with 10 CFR 50.73(a)(2)(v)?

**Response**
No. Because RCIC has safety significance at BWRs, and because the ROP is a risk-informed process, failures of RCIC that are reported are included in the SSFF. While the intention of NEI 99-02 was to report only failures meeting the reporting criteria of 10 CFR 50.73(a)(2(v), reporting of RCIC failures in LERs has been inconsistent among licensees. To provide consistency in reporting and in the ROP, all failures of RCIC should be reported. The question of RCIC reportability per 10 CFR 50.73 is currently under review by the NRC.

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**Question (Replacement for FAQ 142)**

**Response**
The determining factor in this indicator is whether or not the normal heat removal path is *available* to the operators, not whether the operators chose to use that path or some other path. The Indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable from the control room without the need for diagnosis or repair. There was no intent to provide incentive for operators ton operate the plant in a manner contrary to best practices in a given situation.

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**Question (NRC feedback form from Kewaunee - combine with FAQ 142)**
During a typical plant trip, auxiliary feedwater auto-starts on low steam generator level, main feedwater isolation valves auto-close, and, per emergency procedures, the main feedwater pumps are stopped. Based on this sequence of events, the licensee considers auxiliary feedwater as the "normal heat removal path" and not main feedwater. Consequently, the licensee did not classify a plant trip caused by loss of all feedwater as a scram with loss of normal heat removal. Is this correct?

**Response**
No. Any reactor scram caused by the loss of all feedwater (or decreasing condenser vacuum) counts as a scram with loss of normal heat removal. For purposes of this PI, the normal heat removal path includes main feedwater, regardless of the plant design or response to a trip; auxiliary feedwater is <u>not</u> to be used as the normal path.

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**Question (FAQ Log 9, Temp. No. 9.5, SONGS, to replace FAQ196, combine with 142)**

**Response**
No. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable from the control room without the need for diagnosis or repair. In this event, the main feedwater system could have easily been returned to service at any time if needed.

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**Question (FAQ Log 11, Temp. No. 11.10, to replace FAQ 193)**

**Response**
Licensees should use the most restrictive regulatory limit (e.g., technical specifications [TS] or license condition). However, if the most restrictive regulatory limit is insufficient to assure plant safety, then NRC Administrative Letter 98-10 applies, which states that imposition of administrative controls is an acceptable short-term corrective action. When an administrative control is in place as a temporary measure in lieu of non-conservative TS limits to ensure public health and safety, that administrative limit should be used for this PI.

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**Question (Replacement for FAQ 151)**

**Response**
For the situation described above, it is acceptable to report the default value, or period hours, given the current NEI 99-02 guidance. This guidance is being evaluated to account for the above noted scenario, as it relates to a non-conservative SSU value being reported.

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**Question (FAQ Log 8, Temp. No. 15, Palo Verde HPSI valve):**
Is it acceptable, in the assessment of NEI 99-02 availability, to employ realistic component performance assumptions in a system level analysis, or is the utility required to use all design basis assumptions, consistent with those used in the associated safety analysis?

**Response**
Guidance on operability determinations and the resolution of degraded and nonconforming conditions is provided in Generic Letter 91-18. However, for the purposes of the safety system unavailability indicator, each train of a system must be capable of meetings all of its design basis requirements. To demonstrate that a train is available, then, requires that all design basis assumptions used in the FSAR safety analyses be employed.

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**Question (FAQ Log 9, Temp. No. 9.2)**

**Response**
Operator actions to restore a train to normal operation following a malfunction cannot be credited for any purpose. A failure would be reportable per 10 CFR 50.72(b)(2)(iii) and 50.73(a)(2(v); it would be considered a maintenance-preventable functional failure; it would be counted as a demand and a failure in PRA applications; and it would counted in the performance indicators as both a safety system functional failure and a period of unavailability (if it resulted in failure of one of the four monitored functions).

Operator actions to recover from an operating error could be credited if the function can be promptly restored from the control room by an uncomplicated action (a single action or a few simple actions) without diagnosis or repair (i.e., the restoration actions are virtually certain to be successful during accident conditions). Note that there is no reference to a time limit since these actions must be completed promptly.

The paragraph starting on line 5 of page 29 was not intended to be in NEI 99-02, Rev. 0. All references to time constraints were intended to be removed from that document. Due to an oversight, the words were not removed. This will be corrected in the next revision of the document.

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**Question (FAQ Log 11, Temp. No. 11.9, NRC)**
On page 49 of NEI 99-02, the monitored function of the BWR HPCI system is described as "The ability of the monitored system to take suction from the condensate storage tank **or** [emphasis added] from the suppression pool and inject at rated pressure and flow into the reactor vessel." However, the CST only provides about 30 minutes of water and the safety analysis assumes HPCI availability for about 8 hrs. If the suction path from the CST is available but the path from the suppression pool is not, are unavailable hours counted for HPCI?

**Response**
Yes. The intent of the indicator is to monitor the ability of a system to perform its safety function. In this case, the safety function requires the availability of the suction path from the suppression pool. The guidance in NEI 99-02 will be changed to eliminate the words "from the condensate storage tank or," leaving only "from the suppression pool."

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**Question (FAQ Log 11, Temp. No. 11.11, NRC)**
Regarding the Unplanned power change PI, I have the following questions:

1. Is the 20% full power intended to be 20% of 100%power, or 20% of the maximum allowed power for a particular unit, say 97% [(.2)(.97) = 19%].
2. If an unplanned transient occurs which is greater than 20%, the operators stabilize the plant briefly and then cause a transient greater than 20% in the opposite direction, does that count as 2 hits against the PI?
3. For calculating the change in power, should secondary power data be used, nuclear instruments or which ever is more accurate?

**Response**

1. It is intended to be 20% of 100% power.
2. Yes.
3. Licensees should use the nuclear instruments.

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**Question (FAQ Log 11, Temp. No. 11.12, NRC)**
The licensee reduced power on both units to support grid stability in response to a fault on off-site transmission line 15616. Each of the two operating units are supplied from two 345 kilovolt (kV) lines. Line 15616 was lost as a result of a static line failure. The power reduction was requested by the system load dispatcher in accordance with System Planning Operating Guide (SPOG) 1-3-F-1, Revision 1, to allow disabling the Unit 1 turbine generator trip scheme while line 15616 was out of service. With line 15616 out of service, a fault on the second line supplying Unit 1 (line 15501) would cause a Unit 1 turbine trip. The turbine trip would then cause a reactor trip (if reactor power is greater than the P-8 interlock setpoint of 32.1%). The turbine trip is intended to prevent overloading remaining grid circuits, causing the grid to become unstable. It is not a Reactor Protection System function. Reducing power and

disabling the Unit 1 turbine trip scheme would prevent Unit 1 from tripping if line 15501 was faulted or lost. There were no on-site problems associated with the loss of the transmission line. The first paragraph of SPOG 1-3-F-1 states that "it is not necessary to take any corrective measures for stability for the outage of any single line provided that the protection system is normal. However, it may be desirable to disable the unit trip scheme(s) during single line outages." The power reductions requested by the load dispatcher (just over 20%) met the procedurally recommended output limitations for the station with line 15616 out of service with the stability trip scheme disabled.

**Response**
In the situation described, the power reduction would not count. The exception from counting unplanned power changes when directed by the load dispatcher is intended to exclude power changes directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, and for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit. However, power reductions due to equipment failures that are under the control of the nuclear unit are included in this indicator.

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**Question (NRC feedback form from IP3)**
Following a plant trip, operators closed the MSIVs due to a stuck open steam dump valve. RCS temperature was maintained using atmospheric dump valves. Does this count as a scram with loss of normal heat removal?

**Response**
Yes. The MSIVs could not be recovered because of the stuck open steam dump valve.

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