NEI/INDUSTRY PROPOSED REV 1 Aug 4, 2000

Appendix E

Physical Protection
Significance Determination Process

1. Introduction

The objective of this cornerstone is to provide assurance that the safeguards systems can effectively protect against the design basis threat (DBT). The attributes of this cornerstone are based on defense in depth and are intended to provide protection against both internal and external threats.

Licensee performance in this cornerstone is assessed by considering both performance indicators and findings. This Physical Protection Significance Determination Process (PPSDP) consists of a logic flow chart that will allow individual findings to be categorized into one of the four response bands: GREEN - Licensee Response Band; WHITE - Increased Regulatory Response Band; YELLOW - Required Regulatory Response Band; or RED - Loss of Confidence Response Band. This PPSDP is the tool with which NRC inspectors will assess the risk significance of findings.

The input to this logic chart is a finding that has some significance (screened using the MC 0610* minimum threshold process - or those questions in Attachment 0609.02?). The source of the finding might be either licensee's problem identification systems, events, or NRC inspector observations. In order to enter the PPSDP, an observation must pass any one of the following tests:

a. Does the issue have an actual or credible potential impact on safety?;
b. Is the issue an immediate precursor to a more significant issue?;
c. If no action is taken, will the condition worsen?;
d. Will recurrence of the issue result in a more significant concern?

Once defined, the finding will be evaluated using the attached chart and definitions. The following assumptions are necessary to understand and efficiently utilize this evaluation tool.

- Substantive reduction in the effectiveness of security performance produces some increased risk, even without an actual event.
- Operational solutions are relevant in determining risk significance of a completed or the substantial potential for the successful completion of an act of radiological sabotage.
- Both the insider and external elements of the DBT are considered in the PPSDP.

- Multiple findings at a low level do not necessarily increase risk, unless the repetitiveness or ability to reproduce the problem ~~relate~~relates to the capabilities of the design basis threat.

2. Guidance

Logic Block Definitions:

Access control - All elements necessary to ensure that access of vehicles, material and personnel into the protected area and vital areas are properly implemented.

BOP - Behavioral Observation Program as defined in the licensee's plan.

DBT - Design Basis Threat. This includes the Adversary Design Characteristics (ADC as defined. [ADC currently under construction]

Evaluated exercise - A planned evolution used to evaluate the plant's integrated response to a contingency event or defend against the Design Basis Threat (DBT) or a component thereof. The exercise is judged against a set of criteria to determine if required capabilities or training objectives have been met.

Exploitable - A condition in which a potential adversary is able to capitalize on equipment~~,~~ or system deficiencies beyond their design capabilities or procedural deficiencies for which inadequate compensation has been provided.

Finding - An output/result of using the MC 0610* minimum threshold process for evaluating an observation.

Green - Performance only calling for NRC "baseline" oversight - Cornerstone objectives fully met. No significant deviation from expected performance. (NUREG-1649, "New NRC Reactor Inspection and Oversight Program.")

~~**Interdict** - Action taken by the licensee's contingency response force to successfully deny an adversarial intrusion from damaging elements of target sets.~~

Intrusion - An act of wrongfully entering a protected or vital area, during an event or evaluated exercise.

Loss of function - Incapable of performing its intended purpose.

Malevolent act - An attempt to produce harm within the scope of the DBT.

Neutralize - The act of containing a malevolent intruding force such that target sets are protected in accordance with the site protection strategy.

Performance objectives of protective strategy - The defined objectives in the licensee's plans or procedures to protect the plant against the design basis threat of radiological sabotage.

Plans - Licensee documents that detail requirements or processes for implementation of safeguards programs.

Physical protection systems - Equipment or systems installed or personnel posted at the perimeter of the protected area and vital areas for intrusion prevention, detection and assessment purposes.

Predictable - Based on the manner in which a program was implemented or how equipment or systems were operating, it could be determined in advance that a specific occurrence might be made to happen, e.g., metal detectors, intrusion detection zones could be circumvented or defeated without detection based on the special knowledge obtained beforehand.

Radiological Sabotage - [Definition deferred pending NRC evaluation.]

Red - Unacceptable Performance - Plant performance significantly outside design basis. Loss of confidence in ability of plant to provide assurance of public health and safety with continued operation. Significant reduction in margins of safety. (NUREG-1649, "New NRC Reactor Inspection and Oversight Program.")

Repeated deficiency - A similar deficiency that occurs more than twice in four quarters.

Safeguards - The general term that includes the various specific elements of processes, equipment and people that are focused on plant protection. This includes, but is not limited to physical protection, contingency response, training and qualification, fitness for duty, access authorization, behavioral observation, and tactical and operational response to DBT events.

Safeguards contingency response - An event or evaluated exercise requiring a § 73.55(h) type of response.

Significant deficiency - A deficiency that would likely render a protective strategy ineffective.

Similar findings - Findings that could have been prevented by corrective action taken for a like (in substance or essentials) finding in the past.

Site protection strategy - The licensee's contingency response strategy in accordance with its physical security plan designed to protect against radiological sabotage by a DBT adversary.

Structures, Systems and Components (SSCs) - ~~The assemblage of e~~Equipment and buildings such as valves, pumps, switches, electrical power sources, containment and buildings, piping and electrical busses ~~that make up the~~ of a Target Set. Target Set SSCs ~~are~~ include those SSCs that are specifically designed to keep the core cooled and preserve containment integrity when operated in accordance with the plant operating procedures.

Target set - A group of structures, systems or components such that all elements must be rendered non-functional to achieve radiological sabotage.

Vulnerability - A condition of systems or plans being open to attack or damage or to a required function being bypassed within the scope of the DBT, to include predictable or exploitable conditions.

White - Performance calling for increased regulatory response. Cornerstone objectives met with minimal reduction in safety margin. Outside bounds of expected performance. Changes in performance but with very small effect on accident risk. (NUREG-1649, "New NRC Reactor Inspection and Oversight Program.")

Yellow - Performance calling for required regulatory response. Cornerstone objectives met but with reduction in safety margin. Changes in performance with a small effect on accident risk. (NUREG-1649, "New NRC Reactor Inspection and Oversight Program.")

Assumptions for Entering Reactor Safety SDP:

Assumptions must be made prior to entering the Reactor Safety SDP from the PPSDP precipitated by the successful demonstration of a malevolent act(s) that resulted in the loss of function of one or more structures, systems or components specifically protected in the defense-in-depth context of the site protection strategy ~~of a target set~~. In order that the Reactor Safety SDP may be used, the following assumptions are given:

- Any assumption made pursuant to the use of the Reactor Safety SDP would be based upon conditions that existed only after the threat is known to have been terminated, neutralized or contained.

- Undamaged equipment out of service for maintenance during the safeguards contingency response would be considered as initially unavailable (but potentially recoverable under the guidelines established under the Reactor Safety SDP). This presumes that the adversaries used advanced knowledge of plant maintenance conditions to enhance the chance of success to commit radiological sabotage.

- The "exposure time" input needed for the Reactor Safety SDP is the length of time that the plant was being operated or was transitioning to achieve and maintain stable shutdown conditions with equipment degraded due to the attack. The exposure time would presumably not be greater than three days so that the Reactor Safety SDP Table 1, third column would be applicable.

Proposed Frequently Asked Questions:

1. The MC 0610* minimum threshold process questions are somewhat different than those in 0609. Until made identical, which should we use?

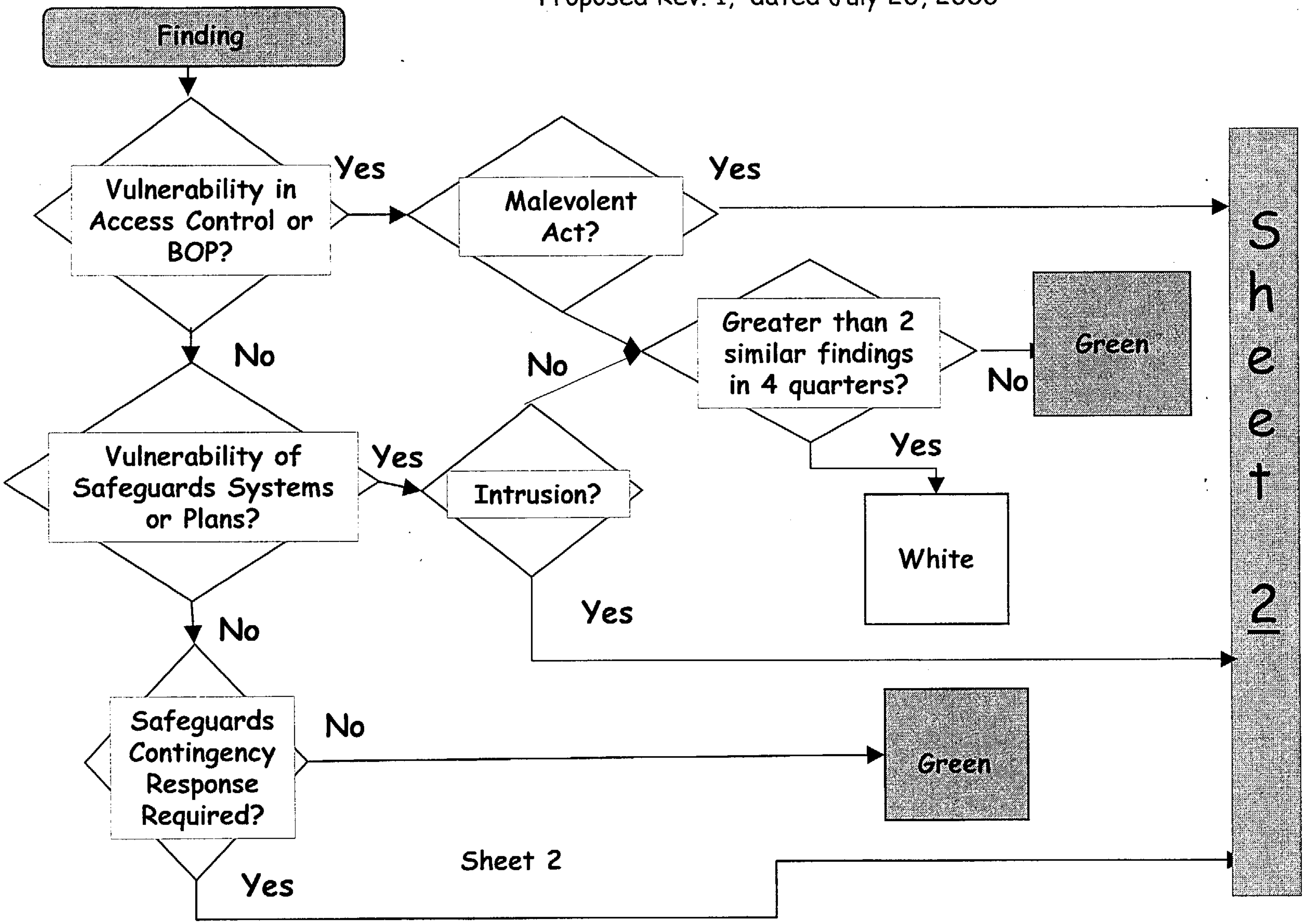
2. When determining whether a deficiency is significant or repeated, why base the answer on 0610* minimum threshold criteria?

3. The Reactor SDP is entered (Logic chart Sheet 2) if there has been a loss of function of one or more protected SSCs due to failure in the site protection strategy. Does this mean that the protection strategy has failed if the function of one SSC is lost even though the strategy allowed for this occurrence by a fall back depth-in-depth strategy? If so, why?

4. On Logic chart Sheet 1–Why does one branch block have "Intrusion?" while another branch block has "Safeguards Contingency Response Required?" if the first automatically leads to the second? Please provide some examples/scenarios using the thought processes expected for making determinations with these fault-trees.

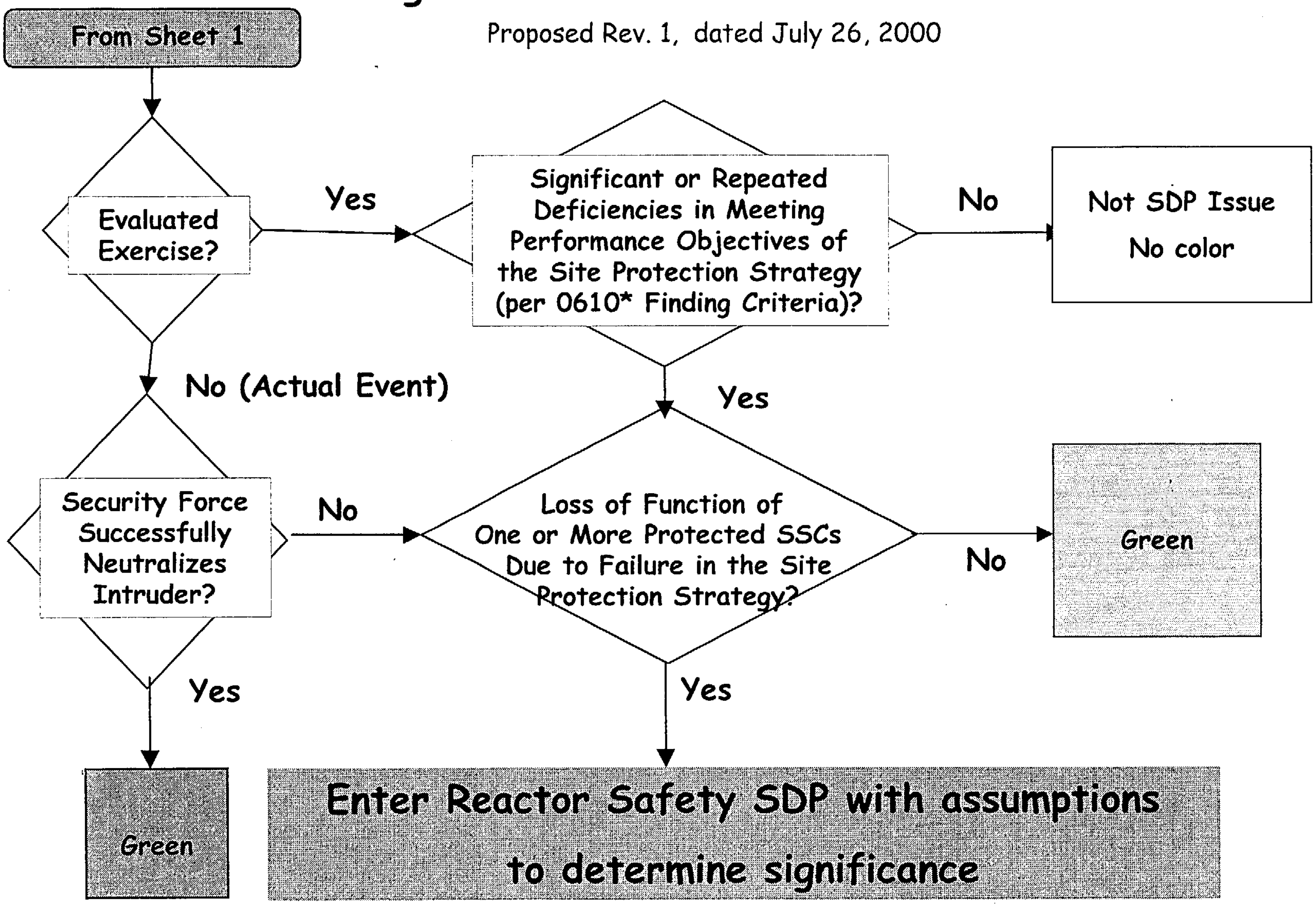
Physical Protection (Sheet 1)
Significance Determination Process

Proposed Rev. 1, dated July 26, 2000



Physical Protection (Sheet 2)
Significance Determination Process

Proposed Rev. 1, dated July 26, 2000



2 PERFORMANCE INDICATORS

2.1 INITIATING EVENTS CORNERSTONE

The objective of this cornerstone is to measure the frequency of those events that upset plant stability and challenge critical safety functions, during shutdown as well as power operations. If not properly mitigated, and if multiple barriers are breached, a reactor accident could result which may compromise the public health and safety. Licensees can reduce the likelihood of a reactor accident by maintaining a low frequency of these initiating events. Such events include reactor shutdowns due to turbine trips, loss of feedwater, loss of off-site power, and other significant reactor transients.

The indicators for this cornerstone are reported and calculated per reactor unit.

There are three indicators in this cornerstone:

- Reactor shutdowns per 7,000 critical hours
- Reactor shutdowns with loss of normal heat removal per 12 quarters
- Secondary Plant Shutdowns per 7,000 critical hours

REACTOR SHUTDOWNS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of times the reactor is taken from critical to subcritical within 15 minutes of commencing to insert negative reactivity due to off-normal plant conditions or events. It measures the frequency of such shutdowns and provides an indication of initiating event frequency. Thresholds are set assuming these events are uncomplicated by equipment or human failures.

Indicator Definition

The number of reactor shutdowns due to off-normal plant conditions or events per 7,000 critical hours during the previous four quarters.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of reactor shutdowns due to off-normal plant conditions or events in the previous quarter

- the number of hours of critical operation in the previous quarter

Calculation

$$\text{value} = \frac{\text{(number of reactor shutdowns in the previous four quarters)}}{\text{(number of critical hours in the previous four quarters)}} \times 7{,}000 \text{ hours}$$

Definition of Terms

Reactor shutdown, for the purposes of this indicator, occurs when, due to off-normal plant conditions or events, a critical reactor is taken subcritical within 15 minutes of commencing to insert negative reactivity by any means, e.g., boron, insertion of control rods, opening reactor trip breakers.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a reactor shutdown after the reactor is critical. Such an event would count in this indicator.

Clarifying Notes

Reactor shutdowns comprise primarily those events that are reportable per 10 CFR 50.73(a)(2)(iv)(A) and (a)(2)(iv)(B)(1).

10 CFR 50.73(a)(2)(iv)(A) requires reporting of any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section except when:
(1) the actuation resulted from and was part of a pre-planned sequence during testing or reactor operation; or
(2) the actuation was invalid and
 (i) occurred while the system was properly removed from service or
 (ii) occurred after the safety function had already been completed.

10 CFR 50.73(a)(2)(iv)(B) states that the systems to which the requirements of paragraph (a)(2)(iv)(A) of this section apply are:
 (1) Reactor Protection System (RPS) including reactor scram or reactor trip.

7,000 critical hours represent one year of reactor operation with an 80% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

Reactor shutdowns that occur during the execution of a procedure in which there is a high probability of a shutdown but the shutdown is not intended are included in the indicator.

Off-normal plant conditions that may lead to a reactor shutdown that would be included in this indicator are as follows:

Turbine Trip *Loss of Main Feedwater Flow* *Loss of Normal Heat Sink (main condenser)* *MSIV Closure* *Loss of Offsite Power* *Loss of Electrical Load (includes generator trip)* *Excessive Feedwater (overcooling transient)* *Loss of Auxiliary/Station Power* *Small Loss of Coolant Accident (includes reactor/recirculation pump seal failures)* *Loss of Service Water/Component Cooling Water*	*Loss of Vital AC/DC bus* *Secondary/balance-of-plant Piping/Component Ruptures* *Reactivity Control Anomaly (e.g., dropped or misaligned rod)* *Other Initiators Leading to Automatic Actuation of Reactor Protection System* *Reactor shutdowns conducted in response to plant conditions in accordance with off-normal procedures (e.g., emergency procedures, abnormal operating procedures, and alarm response procedures)*

Pre-planned sequences that are not included in the indicator include the following:

Reactor shutdowns that are planned to occur as part of a test (e.g., a reactor protective system actuation test).
Reactor shutdowns that are part of a normal evolution made in accordance with normal plant procedures.

Frequently Asked Questions

ID Question

If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted?

Response

If the plant shutdown to comply with the Technical Specification LCO was conducted in accordance with the normal plant shutdown procedure, and that procedure includes a manual scram to complete the shutdown, the scram would not be counted. However, the power reduction would be counted as an unplanned power change (assuming the shutdown resulted in a power change greater than 20%). However, if the actions to meet the Technical Specification LCO required a manual shutdown outside of the normal plant shutdown procedure, then the scram would be counted.

ID Question
With the Unit in Operational Condition 2 (Startup), a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. A manual scram was inserted in accordance with the normal shutdown procedure. Should this count as a reactor shutdown?

Response
No. If it was part of a normal shutdown (plant was following normal shut down procedure), the reactor shutdown would not count.

SECONDARY PLANT SHUTDOWNS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of times the generator was taken off line per year of critical operation. Because the contribution to risk of secondary plant shutdowns varies considerably, it is not possible to assign a risk significance to this indicator. It is believed to provide leading indication of the frequency of risk-significant initiating events.

Indicator Definition

The number of times the generator was taken off line per 7,000 critical hours during the previous four quarters.

Data Reporting Elements

Report the following data for each reactor unit each quarter:

- the number of times the generator was taken off line in the previous quarter
- the number of critical hours in the previous quarter

Calculation

$$\text{value} = \frac{\text{(number of times generator taken off line in the previous four quarters)}}{\text{(number of critical hours in the previous four quarters)}} \times 7{,}000 \text{ hours}$$

Definition of Terms

Secondary plant shutdown occurs when the generator is taken off line for any reason.

Clarifying Notes

7,000 critical hours represent one year of reactor operation with an 80% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

2 PERFORMANCE INDICATORS

2.1 INITIATING EVENTS CORNERSTONE

The objective of this cornerstone is to measure the frequency of those events that upset plant stability and challenge critical safety functions, during shutdown as well as power operations. If not properly mitigated, and if multiple barriers are breached, a reactor accident could result which may compromise the public health and safety. Licensees can reduce the likelihood of a reactor accident by maintaining a low frequency of these initiating events. Such events include reactor shutdowns due to turbine trips, loss of feedwater, loss of off-site power, and other significant reactor transients.

The indicators for this cornerstone are reported and calculated per reactor unit.

There are three indicators in this cornerstone:

- Rapid reactor shutdowns per 7,000 critical hours
- Rapid reactor shutdowns with a loss of normal heat removal per 12 quarters
- Unplanned Power Changes per 7,000 critical hours

RAPID REACTOR SHUTDOWNS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of rapid shutdowns of the reactor in response to adverse conditions. It measures the frequency of rapid shutdowns per 7,000 critical hours and provides an indication of initiating event frequency.

Indicator Definition

The number of occurrences of rapid shutdown of the reactor in response to adverse conditions during the previous four quarters while critical per 7,000 hours.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of rapid shutdowns of the reactor in response to adverse conditions while critical in the previous quarter

- the number of hours of critical operation in the previous quarter

Calculation

The indicator is determined using the values for the previous four quarters as follows:

$$\text{value} = \frac{\text{(total number of rapid reactor shutdowns while critical in the previous 4 qtrs)}}{\text{(total number of hours critical in the previous 4 qtrs)}} \times 7{,}000 \text{ hrs}$$

Definition of Terms

Rapid shutdown means the shutdown of the reactor in response to adverse conditions by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Rapid shutdowns are those that bring the reactor from criticality to a shutdown state within 15 minutes of commencing to insert negative reactivity.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a rapid shutdown after the reactor is critical—this condition would count as a rapid shutdown.

Clarifying Notes

The value of 7,000 hours is used because it represents one year of reactor operation at about an 80% capacity factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

Examples of adverse conditions include:

Turbine Trip
Loss of Main Feedwater Flow
Loss of Normal Heat Sink (main condenser)
MSIV Closure
Loss of Offsite Power
Loss of Electrical Load (includes generator trip)
Excessive Feedwater (overcooling transient)
Loss of Auxiliary/Station Power
Small Loss of Coolant Accident (includes reactor/recirculation pump seal failures)

Loss of Service Water/Component Cooling Water
Loss of Vital AC/DC bus
Secondary/balance-of-plant Piping/Component Ruptures
Reactivity Control Anomaly (e.g., dropped or misaligned rod)
Other Initiators Leading to Automatic Actuation of Reactor Protection System
Rapid shutdowns made in response to plant conditions in accordance with off-normal procedures (e.g., emergency procedures, abnormal operating procedures, and alarm response procedures)

Rapid reactor shutdowns that **are not** included:

Rapid shutdowns that are planned to occur as part of a test (e.g., a reactor protective system actuation test).
Rapid shutdowns that are part of a normal evolution made in accordance with normal plant procedures.

Frequently Asked Questions

ID Question
The Clarifying Notes for the conditions requiring rapid shutdown per 7000hrs PI states that "rapid shutdowns that are part of a normal planned operation or evolution" are not counted. If a licensee enters an LCO requiring the plant to be in Mode 2 within 7 hours, applies a standing operational procedure for assuring the LCO is met, and a manual scram is executed in accordance with that procedure, is this event counted as a rapid shutdown?

Response
If the plant shutdown to comply with the Technical Specification LCO, was conducted in accordance with the normal plant shutdown procedure, which includes a manual scram to complete the shutdown, the scram would not be counted as a rapid shutdown. However, the power reduction would be counted as a condition requiring a significant power change (assuming the shutdown resulted in a power change greater than 20%). However, if the actions to meet the Technical Specification LCO required a manual rapid shutdown outside of the normal plant shutdown procedure, then the scram would be counted as a rapid shutdown.

ID Question
With the Unit in Operational Condition 2 (Startup) a shutdown was ordered due to an insufficient number of operable Intermediate Range Monitors (IRM). The reactor was critical at 0% power. "B" and "D" IRM detectors failed, and a plant shutdown was ordered. A manual scram was inserted in accordance with the normal shutdown procedure. Should this count as a rapid reactor shutdown?

Response

No. If part of a normal shutdown, (plant was following normal shut down procedure) the rapid reactor shutdown would not count.

RAPID REACTOR SHUTDOWNS WITH A LOSS OF NORMAL HEAT REMOVAL

Purpose

This indicator monitors that subset of rapid reactor shutdowns that necessitate the use of mitigating systems and are therefore more risk-significant than uncomplicated rapid shutdowns.

Indicator Definition

The number of rapid reactor shutdowns during the previous 12 quarters that also involved a loss of the normal heat removal path through the main condenser prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of rapid reactor shutdowns while critical in the previous quarter in which the normal heat removal path through the main condenser was lost prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems

Calculation

The indicator is determined using the values reported for the previous 12 quarters as follows:

value = total number of rapid reactor shutdowns while critical in the previous 12 quarters in which the normal heat removal path through the main condenser was lost prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

Definition of Terms

Loss of normal heat removal path: decay heat cannot be removed through the main condenser when any of the following conditions occur:

- loss of main feedwater
- loss of main condenser vacuum
- closure of main steam isolation valves
- loss of turbine bypass capability

Rapid shutdown means the shutdown of the reactor in response to adverse conditions by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, or opening reactor trip breakers. Rapid shutdowns are those that bring the reactor from criticality to a shutdown state within 15 minutes of commencing to insert negative reactivity.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a rapid shutdown after the reactor is critical—this condition would count as a rapid shutdown.

Clarifying Notes

Intentional operator actions to control the reactor cooldown rate, such as securing main feedwater or closing the MSIVs, are not counted in this indicator.

Design features to limit the reactor cooldown rate, such as closing the main feedwater valves on a rapid reactor shutdown, are not counted in this indicator.

Partial losses of condenser vacuum in which sufficient capability remains to remove decay heat are not counted in this indicator.

This indicator consists of rapid shutdowns in which the normal heat removal path through the main condenser was lost. This indicator is also counted for the Rapid Reactor Shutdowns per 7,000 Critical Hour indicator.

Rapid shutdowns with loss of normal heat removal at low power within the capability of the PORVs are not counted if the main condenser has not yet been placed in service, or has been removed from service.

Momentary operations of PORVs or safety relief valves are not counted as part of this indicator.

Frequently Asked Questions

ID Question
The NEI 99-02 instructions for Conditions Requiring Rapid Reactor Shutdowns with a Loss Of Normal Heat Removal (LONHR) equate LONHR with "loss of main feedwater." At some plants the feedwater pumps trip on high reactor water level, which normally occurs on most rapid shutdowns. To prevent the feedwater pumps from tripping during a rapid shutdown, the operator has to quickly take manual control of level. Since the operators often have more important concerns during a rapid shutdown (e.g., trying to figure out what happened, verifying all the rods are in, etc.) they have been instructed (correctly) to let the pumps trip. When this occurs steam continues to flow to the

condenser and make up to the reactor is accomplished using other means (e.g., CRD pumps). Does this count against the LONHR indicator?

Response

In this instance, because the system actions and operator response for this plant are normal expected actions following a rapid shutdown, this would not count against the LONHR indicator.

ID Question

Does the Conditions Requiring Rapid Reactor Shutdowns with a Loss Of Normal Heat Removal PI include main condenser perturbations that result in rapid shutdown. For example, if a scram occurs due to a partial or total loss of main feedwater and then, as expected, main feedwater is isolated as part of the plant design following the scram, does this count as a Condition Requiring Rapid Reactor Shutdown with a Loss of Normal Heat Removal. Similarly, do rapid shutdowns that occur due to a partial loss of condenser vacuum affect this PI.

Response

The PI is monitoring the use of alternate means of decay heat removal following a rapid shutdown. Therefore, the described feedwater scenario would not be included in the PI. Similarly, a partial loss of condenser vacuum that results in a rapid shutdown yet provides adequate decay heat removal following the rapid shutdown would not be included in the PI.

ID Question

Under the "Condition Requiring Rapid Reactor Shutdown with Loss of Normal Heat Removal" performance indicator in NEI 99-02, the Definition of Terms states that a "loss of normal heat removal path" has occurred whenever any of the following conditions occur:

- loss of main feedwater
- loss of main condenser vacuum
- closure of main steam isolation valves
- loss of turbine bypass capability

The purpose of the indicator is to count rapid shutdowns that require the use of mitigating systems, however, instances that meet the above criteria in a literal sense could occur without the necessity of using mitigating systems. For example, a short term loss of main feedwater injection capability due to pump trip on high reactor water level post-scram is a common BWR event. Under these conditions, there is ample time to restart the main feed pumps before addition of water to the vessel via HPCI or RCIC is required. A second example would be a case where the turbine bypass valves (also commonly called steam dump valves) themselves are unavailable, but sufficient steam flow path to the main condenser exists via alternate paths (such as steam line drains, feed pump turbine exhausts, etc.) such that no mitigating systems are called upon.

Response

If an alternate heat removal system is put into use, it counts toward the performance indicator

FAQ Log 8				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
15.	MS02	**Question:** 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. 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. ***Alternate Question:*** *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?*	Discussed 6/14/00 Revised 6/14/00 Action: NEI discuss revised response with APS 7/11/00 – awaiting response from APS 7/12/00 – Discussed, on hold *8/2 – Alternate question and response provided by NRC*	APS
		Response: 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. ***Alternate 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.*		

FAQ Log 8

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.	MS04	**Question:** **Appendix D Indian Point 2, Indian Point 3** 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. How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR. **Response:**	Set up conference call with IP2, IP3 and NRC to discuss and decide.	IP3
22.	MS04	**Question:** 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 ~~(~~assume*ing* no S/G's available). We consider that *one* ~~both~~ SDC loops *is unavailable*~~are available~~ (SDC HX's and SDC pumps) if *one*~~a~~ Salt Water train is removed from service. Is this a proper interpretation of NEI 99-02 guidelines? **Response:** ~~Based on the information provided, this is not a proper interpretation of NEI guidance. Assuming the Salt Water System is a necessary support system, when one train of Salt Water is removed from service, you no longer meet the "Service System Unavailability" guidance of NEI 99-02 for not reporting unavailable hours. In this situation you are required to report unavailable hours for both trains of the monitored system (i.e., SDC.)~~*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.*	On hold. K. Borton to discuss with CC *8/3/00 – NEI revision of questionand proposed response.*	Calvert Cliffs

FAQ Log 8

Temp No.	PI	Question/Response	Status	Plant/ Co.
~~23.~~	~~MS04~~	~~**Question:**~~ ~~At our plant, when in Mode 5, our Technical Specifications require two SDC loops to be operable with one of the SDC loops to be in operation. Infrequently, during this mode, we fill our Safety Injection Tanks (SIT) using a Containment Spray Pump. This evolution isolates the SDC pump from its SDC HX. The evolution to realign the standby SDC loop is a simple evolution and can be done promptly (i.e. evolution can easily be accomplished well within the time frame before the standby SDC loop would be required to perform its safety function). The SDC function has no automatic start function associated with the initiation of an SDC loop. Is it necessary to station a dedicated operator during this evolution in order to avoid incurring unavailable hours for those functions that do not have an automatic start requirement?~~ ~~**Response:**~~ ~~No credit may be taken for operator actions for planned or unplanned unavailable hours other than for testing as discussed on page 26 of NEI 99-02.~~	~~On hold. K. Borton to discuss with CC 7/11/00 – Withdrawn per request of Calvert Cliffs 7/12/00 – Withdrawn~~	~~Calvert Cliffs~~
24.	MS04	**Question:** 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). **Response:** 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.	Revised 6/13/00 Discussed 6/14/00 Action: NRC to discuss with Residents	Duane-Arnold

FAQ Log 9

Temp. No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
9.2	MS01 MS02 MS03 MS04	**Question** 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." 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?	. 7/12/00 – NRC action to confirm consistency with MR and expand upon response. *8/2/00 NRC revision to proposed response.*	ComEd
		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.*		

FAQ Log 9				
Temp. No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
9.5	IE02	**Question** 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. 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?	Discussed 6/14/00 On-hold, NRC review ongoing. **7/12/00 – Response revised and approved.** *8/2 NRC proposed revision to Response*	SCE
		Response 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.*		

FAQ LOG 10				
Temp No.	PI	Question/Response	Status	Plant/ Co.
10.4	MS01 MS02 MS03 MS04	**Question:** 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? **Response:** 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 On hold, NEI review ongoing. Response revised, 7/11/00 (NRC) 7-12-00 On hold, NRC and NEI actions to confirm consistency with MR revision and associated guidance. Intent to finalize at next meeting. *8/3/00 – NEI modification of response (11.3.7 instead of 11.3.7.2)*	NRC
10.5	MS01 MS02 MS03 MS04	**Question:** 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. **Response:** 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 On hold, NEI and NRC review ongoing	NRC
10.7	OR01	~~**Question:**~~ ~~A post survey was not completed until approximately 4 hours after a sluicing evolution was completed, which revealed exposure levels between 1000 and 1100 millirem per hour at 30 centimeter from the spent resin liner, representing a locked high radiation area as defined by the licensee procedures. Although the survey results were documented, the entrance to the pit remained unguarded and unlocked for approximately an additional 20 hours before the access to the area was secured. Are these concurrent occurrences or two separate occurrences?~~ ~~**Question (proposed alternate wording, NRC, 7/11)**~~ ~~A post survey was not completed until approximately 4 hours after a resin sluicing evolution was completed, which produced dose rates greater than 1000 mrem per hour at 30 cm from the spent resin liner. The licensee's Technical Specifications require such an area to be controlled as a locked high radiation area. Once performed the radiation survey indicated that the dose rates exceeded those allowed by Technical Specifications. However, the area remained unguarded and unlocked for an additional 20 hours before it was controlled in accordance with the Technical Specification. Do these events constitute "concurrent nonconformances" as used in the Performance Indicator definition, and therefore, one PI occurrence?~~	Discussed 6/14/00 On hold, NEI review ongoing Discussed 7/12/00 NRC/NEI action to propose/review alternate question/response *8/3/00 Replacement FAQs being developed. See 12.3*	NRC

FAQ LOG 10				
Temp No.	PI	Question/Response	Status	Plant/ Co.
		~~**Response:**~~ ~~These are two separate occurrences. Timeliness of securing the high radiation area was the determining factor in this being two separate occurrences. Once the area was surveyed, and the licensee recognized that the area needed to be controlled per TS, the licensee had a second program failure in that they did not provide those controls for an additional 20 hours. This second failure does not meet the intent of "concurrent non-conformances" in the PI definition and is a second, separate, PI hit.~~ ~~**Alternate Response to alternate question (NRC 7/11/00)**~~ ~~No. The definitions for both the Technical Specification High Radiation Area Occurrence and the Very High Radiation Area Occurrence start out "A nonconformance (or concurrent nonconformances) with .." [Technical Specifications, or 10CFR20, respectively]. As used in these definitions, concurrent means "existing at the same time and resulting from the same cause." During the first four hours 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 performed, the failure to establish proper controls over access to the area in a timely manner was caused by another programmatic breakdown that could not be considered the same as or concurrent with the failure to perform the survey. This is an example of a sequential failure that warrants a second PI count.~~ ~~**Alternate Response to original question (NEI 7/11/00)**~~ ~~Although the occurrence may involve several nonconformances, there was only one occurrence of "loss of radiological control over access or work activities within the respective high-radiation area (>1 rem per hour)." However, follow-up inspection of the occurrence using the significance determination process (SDP) may result in more than one finding, e.g., in the areas of occupational radiation safety and problem identification and resolution, due to the number and the nature of the nonconformances.~~		

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.3	MS03	**Question:** Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question. **PART A** 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. 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." 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. 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. 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. Should this be reported as a third train of AFW?	7/12/00 – Action to establish conference between CR and NRC.	Crystal River
		Response:		

FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
11.4	MS03	**Question:** Question from Crystal River Unit 3 (CR-3) regarding FAQ 182 resolution. Potential Appendix D question. **PART B** 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). 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." 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. FWP-7 is not safety related. FWP-7 is not required by ITS to be OPERABLE in any MODE. FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements. 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. 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. Should this be reported as a third train of AFW? **Response:**	7/12/00 – Action to establish conference between CR and NRC to discuss.	Crystal River
11.5	MS01 MS02 MS03 MS04	**Question:** 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)? **Response:** ***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. *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? **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.	
11.7	MS02	**Question:** In NEI 99-02, under the <u>Support System Unavailability</u> 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 *<u>need not be reported</u>* 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. At RBS, 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? **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. The single failure criteria should only be applied to cases where there is <u>substitution of the support system</u> and in cases where the <u>mitigating systems have installed spares or redundant trains.</u>	7/12/00 Discussed. On hold for review.	River Bend
11.8	MS01 MS02 MS03 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? **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.
11.9	MS02	**Question:** 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 ~~both paths~~ *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:** **Proposed replacement for FAQ 193** 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? **Response:** Licensees should use the most restrictive regulatory limit (e.g., technical specifications*[TS]* or license condition). However, if ~~an administrative limit is in place due to uncertainty about compliance with 10 CFR Part 100 using the regulatory limits, licensees should use the highest administrative limit that ensures compliance with 10 CFR Part 100.~~ *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:** 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?* ~~2.~~*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%. *2. Yes.* ~~2.~~*3.* Licensees should use the *nuclear instrumentation*~~most reliable indication of power~~.	7/12/00 Discussed. On hold for review. *8/2/00 NRC revision to question and response.*	NRC

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.12	IE03	**Question:** ~~**(Question being rewritten for clarification)**~~ *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 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 Byron 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.*	7/12/00 Discussed. Action, NRC to rewrite question and response for clarification. *8/2/00 NRC rewrite of question and response.* *8/3/00 NEI Removal of plant name.*	NRC
11.13	EP01	**Question:** 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. 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: 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. 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:** 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 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	NRC
		Response: 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. 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). 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**: 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: *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" 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. **Question:** 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.*	ComEd
		Response: *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:** 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?	Pending	Braidwood /ComEd
		Response:		
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FAQ LOG 12				
Temp No.	***PI***	***Question/Response***	***Status***	***Plant/ Co.***
12.1	*MS01* *MS02* *MS03* *MS04*	***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.* ***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 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.* *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 50.65a(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.* ***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 exclusion.*		*NRC*
		Response:		
12.2	*IE02*	***Question:*** *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: *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 ~~the~~ health physics groups, a post-job survey was not performed following completion of a resin sluicing evolution. Approximately four hours later, health physics became aware of the breakdown in communication and completed a survey of the area that 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. Once completed, the radiation survey indicated that the dose rates exceeded those allowed by Technical Specifications. However, due to an additional communications breakdown within the health physics group, the area remained unguarded and unlocked for an additional 20 hours 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? **Response:** No. The definitions for both the Technical Specification High Radiation Area Occurrence and the Very High Radiation Area Occurrence refer to ~~start out~~ "A nonconformance (or concurrent nonconformances) with.."[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 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, 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 failure to perform the survey. This is an example of a sequential -failure that warrants a second PI count.		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? **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.		Kewau nee
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.		Kewau nee

FAQ LOG 12				
Temp No.	***PI***	***Question/Response***	***Status***	***Plant/ Co.***
		Licensee Proposed Response: *In the example provided, the person completing the form does NOT have to be considered a Key ERO position.*		

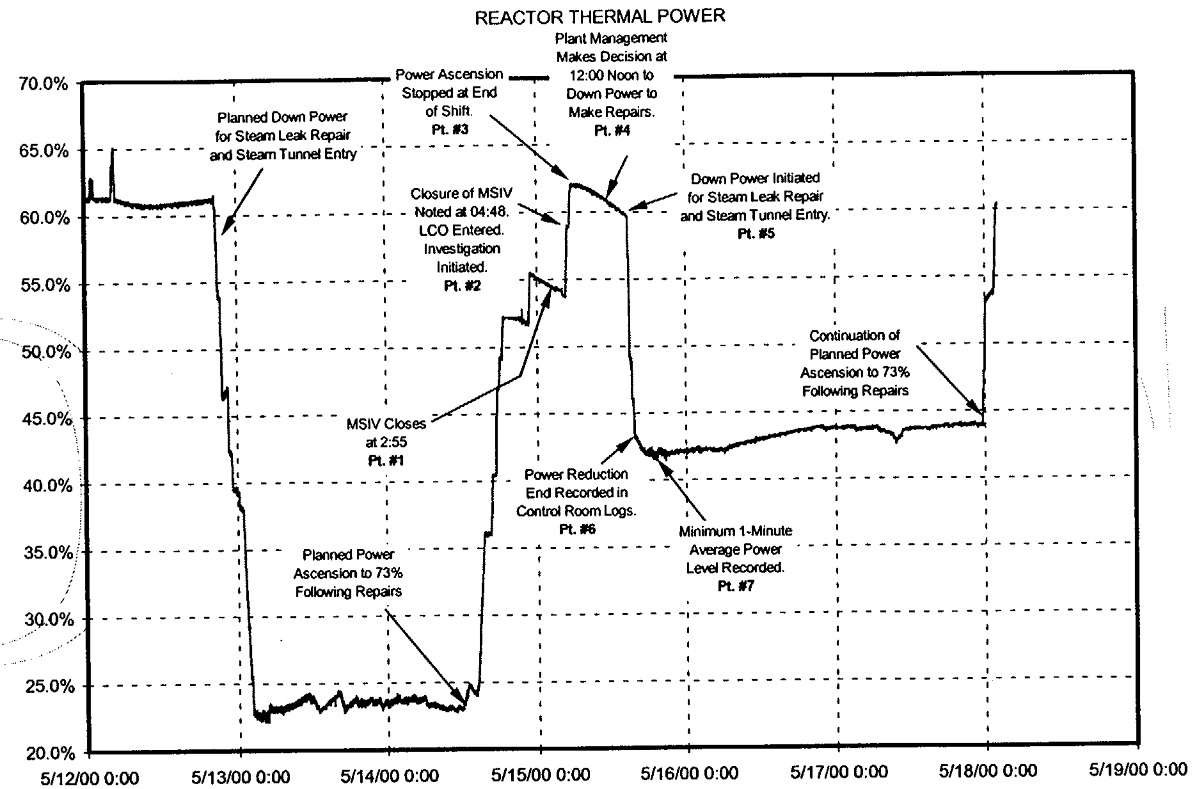
FAQ LOG 12				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
12.6	IE03	**Question:** An outage was planned ahead more than the 72 hour limit used in the PI definition in order to perform hide-out return sampling on the steam generators following an extended power escalation due to sodium contamination. This would require taking the plant off-line. Part of the outage plan called for secondary side equipment manipulations intended to shake up any remaining sodium contaminants. Equipment evolutions included moisture separator reheater (MSR) and turbine valve cycling (the use of SOP-8, Main Turbine and Generating Systems, provided a convenient, procedurally controlled way to tell operators what to do to give the desired system shake-up, as well as providing actions to take in response to unexpected valve malfunctions), and swapping main feed pumps (at the reduced power that allowed stable plant operation on a single feedpump). The planned sequence included a power reduction to ~85% for MSR and turbine valve cycling. Once valve cycling was completed, power reduction to ~55% was planned to allow feedpump maneuvering. The day-shift crew completed a pre-job briefing for the turbine valve exercising, which included a review of SOP-8 and its contingency actions. As planned, power was reduced to 85%, and held stable at 85% for valve cycling scheduled for between 8 AM and 4 PM. Per schedule, Operators were to begin further power reduction at 4 PM (to reach ~55% by 6 PM). Per the SS Log, an MSR intercept valve failed to re-open following exercising about mid-day. Immediate troubleshooting re-opened this valve. In the early afternoon, a second intercept valve failed to re-open during exercising. The same efforts were made to re-open this valve, but were not successful. It was concluded the test solenoid valve would need to be removed, but, based on the fact the desired chemistry effect had been achieved, a decision was made to not put forth additional effort to try to replace the solenoid valve for the intercept valve, but to stay with the original outage plan/schedule and begin the next planned power reduction. This decision resulted in changing the time for beginning the already planned power change, it did not result in exiting the existing plan. By following SOP-8, power was directed to be reduced to 50% within approximately 3 hours, which was the same amount as the originally planned power reduction. Boration to begin power reduction began at 2:57 PM (thus, power was still at ~85% at about 3 o'clock). Per the Plant Process Computer (PPC), power was at 70% at 4:00 PM. (Note that 4 PM was when the original schedule called for the next power reduction to commence.) Per the SS Log, reactor power was steady at 50% at 5:28 PM. This was about half an hour earlier than called for by the original schedule. The remainder of the shutdown went off close to the schedule. <u>Evaluation</u> The valve cycling had been placed in the schedule just before the next planned power change because this was the logical point to do it. The schedule was prepared with 8 hours allotted for valve cycling. The next scheduled action for the operators was to reduce power from ~85% to ~55%. The success criteria for the valve cycling, for this part of the outage, was achieving the desired chemistry effects, not passing the SOP-8 valve tests. Regardless of valve test results, the next planned step was another power change. This information leads to the following conclusions: 1. There was <u>no unplanned</u> power change. The purpose of this PI is to "monitor the number of unplanned power changes (excluding scrams) that could have, under other conditions, challenged safety functions." "Unplanned changes in reactor power are changes ... that result in, or require a change in power level of greater than 20% full power to resolve." From 100% power to 0% power, the power changes that occurred for this outage were planned ahead of time. The valve exercising that was done was not a required test; it was part of the planned evolution. The power change following valve cycling was not made to provide for resolving the valve performance issue, it was made, as planned, to continue the sequence of plant operations for chemistry cleanup. The only change made was changing the time for beginning the already planned power change; management did not exit the existing plan in response to the valve problem. In fact, the valve was not repaired until after the plant had completed the chemistry cleanup phase of the outage (2/6). 2. The decision to continue with the planned power reduction following the second MSR intercept valve failing to open was consistent with the shutdown plan. Had valve testing been the only purpose for the downpower to 85%, every effort would have been made to re-open the valve, in accordance with the operating/test procedure, prior to having to take a further downpower to 50%. With adequate pre-test contingency preparations, the necessary repair (replacement of the test solenoid valve) could be completed such that further power reduction would not be necessary. (We agree that, in such a circumstance, if repairs were to be unsuccessful, then the 35% required power change would count against this PI.) Turbine valve testing is done at about a six month frequency according to the FSAR. SOP-8 testing is done during each <u>return to power,</u> following a shutdown, which restarts the six month clock. The use of SOP-8 in this part of the outage plan was not intended to be credited as the required valve test, it was a matter of convenience that a procedure already existed that would provide the necessary valve exercising to "shake-up" the secondary side to achieve the desired chemistry effects. **<u>Question</u>** Does this event meet the criteria for counting as an Unplanned Power Change greater than 20%? It is the licensee position that it does not, because the provisions of the outage schedule provided for a power change following MSR/turbine valve exercising (which is what occurred). There were no unexpected challenges to the operating crews or safety functions. The power change that occurred had been planned for in advance as part of the effort to improve system chemistry. Once the objectives of this evolution were satisfied, the scheduled power reduction was continued. The power change following valve cycling was not made to provide for resolving the valve performance issue, it was made, as planned, to continue the sequence of plant operations for chemistry cleanup. This decision resulted in changing the time for beginning the already planned power change, it did not result in exiting the existing plan.		Pallisades
		Response:		

FAQ LOG 12

Temp No.	*PI*	*Question/Response*	*Status*	*Plant/ Co.*
12.7	*IE03*	***Question:*** *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?* *May 14, 2000:* • *The station was operating at approximately 24% power in order to repair steam leaks.* • *11:57 AM - Power ascension was initiated with the intent to go to 73% power in a mode of load following.* *May 15, 2000:* • *The crew on shift has a goal of reaching 61% power.* • *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.*** • *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* • *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%.* • *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****.* • *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****.* • *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****.* • *5:15 PM - Power reduction complete. The one-minute average power is generally 42%. However, it varies from 41.9% to 42.3%.* • *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.* • *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.* *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.*		*Columbia*

FAQ LOG 12

Temp No.	*PI*	*Question/Response*	*Status*	*Plant/ Co.*



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