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

May 3, 2001

MEMORANDUM TO: Mark Satorius, Chief
Performance Assessment Section
Inspection Program Branch
Division of inspection Program Management
Office of Nuclear Reactor Regulation

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

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON MAY 2, 2001

On May 2, 2001a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss and review the initial implementation of the revised reactor oversight process. An agenda, attendance list, and information exchanged at the meeting are attached. The following dates were established for future meetings: May 31, 2001 and July 12, 2001.

Attachments:

1. List of Participants
2. Agenda
3. NRC Regulatory Issue Summary 2001-XX Pilot Test of Proposed Changes to the Unplanned Power Changes per 7,000 Critical Hours Performance Indicator (Draft Federal Register Notice)
4. Unanticipated Power Reductions per 7,000 Critical Hours Performance Indicator (Draft)
5. Issues for Discussion by Unavailability Task Force
6. Electronic Submittal of Plant Operating Data Concept Paper
7. Fault Exposure Unavailability Reset Process for Safety System Unavailability, MS01-MS04 (Data Sheet)
8. Frequently Asked Questions, Log. 15, 16, 17, 18, 19, 20, 21
9. Nuclear Energy Institute Memorandum of May 1, 2001 distributing NEI 9902 Revision 1, *Regulatory Assessment Performance Indicator Guideline*

May 3, 2001

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NRC Public Meeting
Reactor Oversight Process
List of Participants
May 2, 2001

S. Ferrel, TVA
D. Hickman, NRC.
A. Madison, NRC
M. Johnson, NRC
M. Satorius, NRC
D. Olsen, Dominion
M. Taylor, Exelon
S. Floyd, NEI
Wade Warren, SNC
T. Houghton, NEI
R. Ritzman, PSEG
J. Sumpter, NPPD
J. Jacobson, NRC
P. Loftus, COMED
D. R. Robinson, Nebraska Public Power
D. Anderson, NMC
J. Butler, NEI
C. See, NRR
R. Frahm, NRC
L. Whitney, NRC
R. Thomas, Entergy
J. Chase, OPPD
J. Caves, CP&L
S. Sanders, NRC

Attachment 1

Agenda
May 2, 2001
Public Meeting

1. Discussion of Safeguards Rule Making and the Significance Determination Process
2. Discussion of coordination of reporting requirements and monthly operating reports
3. Discussion of Pilot Testing Replacement for Unplanned Power Changes performance indicator
4. Discussion and update on industry trends
5. Discussion of Problem Identification and Resolution Inspection program
6. Update on revision 1 to NEI 99-02
7. Review and approval of Frequently Ask Questions.
8. Conference call to discuss initiating event performance indicators pilot program
9. Discussion of process for up dating performance indicator data
10. Discussion of unavailability performance indicator issues
11. Discussion of handling industry and public questions regarding the SDP

Attachment 2

DRAFT

OMB Control No.: 3150-0195

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

May xx, 2001

NRC REGULATORY ISSUE SUMMARY 2001-XX PILOT TEST OF PROPOSED CHANGES TO THE UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS PERFORMANCE INDICATOR

ADDRESSEES

All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

INTENT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this regulatory issue summary (RIS) to inform power reactor licensees that a 6-month pilot test will be conducted to evaluate changes to the "unplanned power changes per 7,000 critical hours" performance indicator (PI) that are intended to minimize the potential for unintended consequences. This RIS also provides information on the process to be used by licensees participating in the pilot test to voluntarily submit reactor facility PI data to the NRC beginning June 21, 2000. Submittal of PI information is a voluntary activity; therefore, this RIS requires no action or written response on the part of the addressee.

BACKGROUND INFORMATION

The Reactor Oversight Process (ROP) is built upon a framework directly linked to the Agency's mission. That framework includes cornerstones of safety. Within each cornerstone, a broad sample of information on which to assess licensee performance in risk-significant areas is gathered from PI data submitted by licensees and from the NRC's risk-informed baseline inspections. The PIs are not intended to provide complete coverage of every aspect of plant design and operation, but are intended to be indicative of performance within related cornerstones. The data submitted by each licensee is used to calculate the PI values, which are then compared to risk-informed, objective thresholds.

Reporting of PI data to the NRC is a voluntary program in which all licensees participate. NEI 99-02 Revision 0, "Regulatory Assessment Performance Indicator Guideline" contains the reporting guidelines used by the licensee to report PI data to the NRC through June 2001. NEI 99-02, Revision 1, provides the reporting guidelines to be used by licensees beginning July 1, 2001 (First reports by October 2001).

NRC has established a formal process to (1) address questions and feedback from internal and external stakeholders, (2) make changes to existing PIs and thresholds based on lessons

Attachment 3

learned, and (3) develop new PIs and associated thresholds. This formal process is being used to evaluate the changes described in this RIS, and is described in the recently issued Inspection Manual Chapter - 0608, "Performance Indicator Program."

SUMMARY OF ISSUE

During the first year of implementation of the ROP that began on April 2, 2000, concerns were raised regarding the potential for the "unplanned power changes per 7,000 critical hours" PI to influence licensees to take "non conservative" actions that could adversely impact plant safety. The reporting criteria for this PI defines unplanned changes in reactor power as those changes that are initiated less than 72 hours..., or require a change in power level of greater than 20%..., are of particular concern. During initial implementation, instances were discovered in which licensees delayed maintenance activities beyond 72 hours or modified plant procedures to reduce power by <20% in order to avoid counting unplanned power change events in the PI data quarterly report.

As a part of the PI change process, numerous public meetings were held to discuss proposals for an alternate PI. NRC has agreed to pilot test " unit power reductions changes per 7000 critical hours" (see attached for a detailed description) as a replacement PI for unplanned power changes. In addition to this proposed replacement PI, NRC has also agreed to concurrently pilot test an unplanned power change PI, which counts the number of unanticipated power reducting of greater than 10% of full power due to personnel errors or equipment malfunctions or faiures. The purpose of this pilot test is to collect data to determine if the alternate PIs are as effective at providing an indication of performance in the initiating events cornerstone, while reducing the potential for unintended consequences.

The following plants have volunteered to participate in the pilot test: Dresden, Units 2&3; Three Mile Island; Comanche Peak, Units 1&2; Surry, Units 1&2; North Anna, Units 1&2; Sequoyah, Units 1&2; Browns Ferry, Units 2&3; Watts Bar, Unit 1; Salem, Units 1&2; Hope Creek; and Cooper.

NRC will compare the results of the pilot test with the following criteria:

a. the ability of licensees to report the requested data accurately and with minimal need for clarification

b. success of the alternate PIs in reducing the potential for unintended consequences without introducing other unintended consequences

c. the correlation of the alternate PIs with the existing PI

d. changes in reporting burden for licensees (e.g., To what extent does the replacement PI add new data, reporting elements)

Industry representatives are encouraged to identify examples of unintended consequences and situations that arise from difficulty in interpreting reporting requirements.

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In order to assist in evaluation of this PI, licensee should record in the comment field information regarding all changes in ADPL that exceed 20%, regardless of whether it would be counted under this PI. This information should include a brief explanation. Additionally, licensees should note any insights regarding the evaluation criteria. Based on the results of this pilot program, including consideration of stakeholder feedback, the NRC will make a decision regarding the replacement of the current PI with the alternate PI.

A potential outcome of this pilot test may be the decision to continue the pilot should it be determine that the data collected failed to provide sufficient information to make a determination regarding the efficacy of the PI.

VOLUNTARY ACTION

Since the pilot plants will continue to be assessed using the existing PI, no thresholds will be applied to the data reported in this pilot test. Thresholds will be determined subsequent to the pilot.

Addressees that are participating in this pilot should conform to the guidance contained in this RIS for the voluntary reporting of PI data. The PI data should be provided as an attachment to an e-mail addressed to <pidata@nrc.gov> on or before June 21, 2001, for May 2001, and by the 21st of the month following the end of each month thereafter. The pilot test ends on November 21, 2001, with data submitted from the preceding month.

BACKFIT DISCUSSION

This RIS requires no action or written response. Any action on the part of addressees to collect and transmit PI data in accordance with the guidance contained in this RIS is strictly voluntary and, therefore, is not a backfit under 10 CFR 50.109. Therefore, the staff did not perform a backfit analysis.

FEDERAL REGISTER NOTIFICATION

A notice of opportunity for public comment on this RIS was not published in the Federal Register because the NRC has worked closely with NEI, industry representatives, members of the public, and other stakeholders since early 1998 on the development of NRC's ROP, including the collection of PI data. The NRC has solicited public comments on its intent to collect PI data in five Federal Register notices (dated January 22, April 19, May 26, July 19, and August 11, 1999), three Regulatory Issue Summaries: RIS 99-06, and 2000-08, "Voluntary Submission Of Performance Indicator Data," RIS 2000-21, "Changes to the Unplanned Scram and Unplanned Scram with Loss of Normal Heat Removal Performance Indicators," and at numerous public meetings. There will be an FRN issued soliciting public comment on the proposed PIs described in this RIS.

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UNIT POWER REDUCTIONS CHANGES PER 7,000 CRITICAL HOURS

Purpose
This indicator monitors the number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator is calculated per 7,000 critical hours to monitor the number of plant power changes for a typical year of operation.

Indicator Definition
The number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power during the previous four quarters per 7,000 critical hours.

Data Reporting Elements
The following data are reported for each reactor unit:

- the number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power in the previous quarter
- the number of critical hours in the previous quarter

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

$$\text{value} = \frac{\text{(number of unit shutdowns and power reductions in the previous 4 qtrs)}}{\text{(number of critical hours in the previous 4 qtrs)}} \times 7{,}000 \text{ hrs}$$

Definition of Terms
Average Daily Power Level is the net electrical energy generated during the day (measured from 0001 to 2400 hours inclusive) in megawatt-hours, divided by 24 hours.

Net electrical energy generated is the gross electrical output of the unit measured at the output terminals of the turbine-generator during the reporting period, minus the normal station service electrical energy utilization. If this quantity is less than zero, a negative number should be used.

Clarifying Notes
7,000 hours is used because it represents 1 year of reactor operation at about 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.

DRAFT

PAPERWORK REDUCTION ACT STATEMENT

This RIS contains a voluntary information collection that is subject to the Paperwork Reduction Act of 1995 (22 U.S.C. 3501 et seq.). The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The collection of this information is covered by OMB clearance number 3150-0195 which expires on October 31, 2002.

If you have any questions about this matter, please contact the person listed below.

David B. Matthews, Director
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Technical Contact: Serita Sanders, NRR
301-415-2956
E-mail: SXS5@nrc.gov

Attachments
1: Unit Power Reductions Changes Per 7000 Critical Hours Performance Indicator
2: List of Recently Issued NRC Regulatory Issue Summaries

Distribution: RIS Reading File PUBLIC

ADAMS ACCESSION NUMBER: **ML011080070** Template #: = **NRR-052**
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LMarsh	DMatthews
/ /2001	/ /2001

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Unit shutdowns and power reductions that are not counted are (1) those that are scheduled prior to startup from a refueling outage (i.e., midcycle maintenance outages and the next refueling outage); (2) those that are directed by the load dispatcher under normal operating conditions to meet load demand and for economic reasons, or for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit; (3) anticipatory unit shutdowns or power reductions due to external events, such as hurricanes, tornadoes, or range fires, that threaten the safety of the nuclear unit or its transmission lines; (4) certain proceduralized unit shutdowns or power reductions in response to expected problems, such as accumulations of marine debris or biological contaminants in certain seasons (each situation is different and should be reported to the NRC for a determination as to whether it should be counted); and (5) those that are included in the unplanned scram indicator.

Unit shutdowns and power reductions that are counted are all those not excluding by the above paragraph.

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OMB Control No.: 3150-0195

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

May xx, 2001

NRC REGULATORY ISSUE SUMMARY 2001-XX
VOLUNTARY SUBMISSION OF PERFORMANCE INDICATOR DATA

ADDRESSEES

All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

INTENT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this regulatory issue summary (RIS) to inform power reactor licensees that the NRC has endorsed Revision 1 of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline", for addressee use in the collection and reporting of performance indicator (PI) data to the NRC. PI data provide input the NRC's new process for overseeing the performance of nuclear power reactor plants, the Reactor Oversight Process (ROP). This RIS requires no action or written response on the part of the addressees.

BACKGROUND INFORMATION

The NRC began implementing the ROP on April 2, 2000. The ROP uses PI information, along with results from the reactor inspection program, as the basis for assessing plant performance and determining the appropriate regulatory response. PIs are objective, periodic measures of plant performance and the effectiveness of licensee programs. PI data is a basic element of the ROP and is expected to contribute to an overall reduction in NRC regulatory burden on licensees.

The PI data provides a broad sample of information on licensee safety performance. The PI data is not intended to cover every aspect of plant design and operation; but to provide an objective indication of the performance of plant systems and licensee programs in specific risk-significant areas. The NRC compares the PI data submitted by a licensee to risk-informed, objective thresholds to assess plant performance within cornerstone areas. Reporting of PI data to the NRC is a voluntary program in which all licensees participate.

SUMMARY OF ISSUE

During initial implementation of the ROP, the NRC established a formal process to (1) address questions and feedback from internal and external stakeholders, (2) make changes to existing PIs and thresholds based on lessons learned, and (3) develop new PIs and associated thresholds. The formal process provides an opportunity for NRC and industry personnel to identify questions regarding interpretation of the reporting criteria. These "frequently asked questions (FAQs)" are reviewed at periodic public meetings of the NRC/ROP Industry Working Group to resolve issues raised and develop approved responses.

The revision to NEI 99-02 incorporates changes to reflect the insights gained from the resolution of FAQs. The revised document is expected to limit unnecessary reporting burdens and provide clear guidance to power reactor licensees on the accurate and consistent reporting of PI information.

The efficacy of the PI portion of the ROP is contingent upon the submission of accurate data by addressees for their respective reactor facilities in accordance with the guidance contained in NEI 99-02, Revision 1. The NRC has endorsed this industry document for addressee use in the reporting of PI data.

PIs will continue to be refined as experience is gained with the ROP. Changes will be made in accordance with the formal change process to provide opportunity for stakeholder involvement, and will be published in the next revision to NEI 99-02.

The NRC anticipates that the voluntary reporting of PI data will contribute to a more objective assessment of plant performance and to an overall reduction of burden on licensees as a consequence of the offsetting reduction in NRC inspection under the ROP.

VOLUNTARY ACTION

Addressees should conform to the guidance contained in this RIS for the voluntary reporting of PI data. As indicated in NEI 99-02, the PI data should be provided as an attachment to an e-mail addressed to <pidata@nrc.gov> by July 1, 2001, to include data for the 3rd quarter, and on or before the 21st of the month following each calendar quarter. The data should be reported on October 21, 2001.

BACKFIT DISCUSSION

This RIS requires no action or written response. Any action on the part of addressees to collect and transmit PI data in accordance with the guidance contained in this RIS is strictly voluntary and, therefore, is not a backfit under 10 CFR 50.109. Therefore, the staff did not perform a backfit analysis.

DRAFT

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301-415-2956
E-mail: SXS5@nrc.gov

Attachment: List of Recently Issued NRC Regulatory Issue Summaries

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UNANTICIPATED POWER REDUCTIONS PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of unanticipated power reductions of greater than 20% of full power due to personnel errors and equipment malfunctions or failures. It may provide leading indication of risk-significant events but is not itself risk significant. The indicator is calculated per 7,000 critical hours to monitor the number of unanticipated power reductions for a typical year of operation.

Indicator Definition

The number of unanticipated power reductions of greater than 20% of full during the previous four quarters per 7,000 critical hours.

Data Reporting Elements

The following data are reported for each reactor unit:

- The number of unanticipated power reductions of greater than 20% of full power in the previous quarter

- The number of critical hours in the previous quarter

Calculation

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

$$\text{Value} = \frac{\text{(number of unanticipated power reductions in the previous 4 qtrs)}}{\text{(number of critical hours in the previous 4 qtrs)}} \times 7{,}000 \text{ hrs}$$

Definition of Terms

Unanticipated power changes are reductions in power that occur in one of three ways:

1. The power reduction occurs automatically and immediately with no operator action

2. The power reduction occurs as a result of prompt operator actions that are necessary to preclude an unplanned reactor shutdown or turbine trip

3. The power reduction occurs as a result of plant shutdowns conducted in accordance with technical specification action statements

Prompt operator actions are steps taken by the control room operators in a very short period of time that, if not taken, would result in an automatic turbine or reactor trip.

Attachment 4

Clarifying Notes

The primary intent of this indicator is to count greater than 20% power reductions that are not elective, i.e., prompt action is required to place the plant in a safe condition. A secondary intent of this indicator is to promote positive behavior by *not counting* pre-emptive actions taken to correct minor conditions before they degrade to the state where they are no longer elective.

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

If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is computed as N/A because rate indicators can produce misleadingly high values when the denominator is small. The data elements (unanticipated power reductions and critical hours) are still reported.

Unanticipated power reductions that *are not* counted include:

- anticipatory shutdowns or power reductions due to external events, such as hurricanes, tornadoes, or range fires, that threaten the safety of the nuclear unit or its transmission lines

- certain proceduralized shutdowns or power reductions in response to known environmental problems, such as accumulation of marine debris or biological contaminants in certain seasons (each situation may be different and should be identified to the NRC in an FAQ to determine whether it should be counted)

- those that are included in the unplanned reactor shutdown indicator

Examples of unanticipated power reductions that count include:

- A loss of a circulating water pump (due to an operator inadvertently securing the pump or a failure of the pump) causes condenser vacuum to decrease. Operators take prompt action to reduce power by more than 20% to stabilize vacuum. Failure to take the prompt reaction would have resulted in a turbine trip due to low vacuum.

- A BWR recirc pump trips (or is inadvertently deenergized due to a personnel error). The reduced flow automatically results in a reduction of reactor power by greater than 20%.

- A PWR loses a feed pump (due to equipment failure or personnel error). The resulting steamflow/feedflow mismatch would result in a reactor trip if not promptly corrected by an unanticipated power reduction of greater than 20% through operator action.

- Vibration is detected on a main feed pump (below limits for securing) and management decides to reduce power to investigate at the next opportunity a low power demand period exists. However, vibration suddenly increases above the operating limit and prompt operator action is taken to secure the pump and reduce power by more than 20%.

- A design error or equipment malfunction is identified that causes a system to enter a technical specification action statement. The system cannot be repaired to meet design requirements within the LCO period and the unit is shutdown.

- A design error or equipment malfunction is identified that causes a system to enter a technical specification action statement. System repairs are underway but it looks doubtful that they will be completed within the LCO period and the plant begins a power reduction. After reducing power by greater than 20%, the repairs are completed and the plant shutdown is terminated.

Examples of power reductions that *do not* count include:

- A small steam leak develops on a moisture separator reheater and the plant management decides to repair the leak during the backshift by reducing power and isolating the leak for repairs.

- Vibration is detected on a main feed pump (below limits for securing) and management decides to reduce power to investigate at the next opportunity a low power demand period exists.

- A plant reduces power more than 20% to perform technical specification required valve testing. While at reduced power, repairs are also made to correct a number of minor system deficiencies of an elective nature that were identified before the power reduction commenced.

ISSUES FOR DISCUSSION BY UNAVAILABILITY TASK FORCE
(other issues will evolve; this is a starting list)

Issue	WANO	NRC PI	Maintenance Rule	NEI Strawman
Design Basis Function vs Risk basis	More risk	Design	Risk	Risk
Default vs Required Hours	Default	Default		
Scope -reporting availability	3 or 5 systems per unit	3 or 5 systems per unit	30 to 50 systems per unit	3 or 5 systems per unit
Support system unavailability	Support system unavailability added to monitored system unavailability	Support system unavailability added to monitored system unavailability	Support system unavailability included in supported system as appropriate	Under review. Support system unavailability cascades to monitored system OR add a support system
Fault Exposure Hours (T/2)	Included	Included	Not Included	Not included, recognizes different reporting to WANO
Credit for Operator Action	1)Proceduralize d, 2) restore in minutes	Single action or few simple actions	Single action or few simple actions	Single action or few simple actions
Planned Hours	Unavailability planned in advance, reported separately	Unavailability planned in advance, reported separately	No segregation of planned or unplanned	No segregation of planned or unplanned
Threshold Basis	Industry set	NRC Established	PSA/Expert Panel	Prefer MR
Exclusion of unavailability for Overhaul Hours	Overhaul hours included in Unavailability	Overhaul hours not included	Overhaul hours included in Unavailability	Overhaul hours included in Unavailability
Combine Unavailable hours during shutdown and at Power	Unavailability for time required to perform its function	Unavailability for time required to perform its function	Unavailability for time required to perform its function	Add Unavailable hours during shutdown and at Power
Shutdown unavailable hours	Unavailability for time required to perform its function	Unavailability for time required to perform its function	Unavailability for time required to perform its function (for systems that are high risk significance in that mode when system is required)	Unavailability when the equipment is credited as the primary or first back-up for performing safety function

Attachment 5

DRAFT

ELECTRONIC SUBMITTAL OF PLANT OPERATING DATA

CONCEPT

In order to potentially increase efficiency and effectiveness and reduce unnecessary regulatory burden, the NRC is evaluating the feasibility of permitting licensees to submit plant operating data electronically to the NRC instead of on paper. The data requirements will need to be revisited to determine the data elements and their frequency, but an initial thought is that this operating data could be submitted along with the quarterly PI data submittals under the ROP. We'd need to work closely with NEI to determine the protocol and data file specifics. We'd need to determine whether to include this submittal as part of the ROP PI file, as a separate file to include with the PI submittal to "pidata", or as a completely separate submittal and process.

MILESTONES

1. Brief NEI/ industry on concept
2. Determine data needs (elements and frequency)
3. Obtain internal stakeholder and management buy-in (and coordination)
4. Obtain external stakeholder buy-in
5. Work with NEI/IT to develop data file specifics
6. Develop a strawman/ plan for pilot test
7. Run pilot test on selected plants
8. Publish Regulatory Issue Summary
9. Implement for ALL plants

Attachment 6

Fault Exposure Unavailability Reset Process for Safety System Unavailability, MS01-MS04

Data Element	
1	PI code for Fault exposure hours removal
2	Quarter and year of occurrence
3	Quarter and year to start reset of hours; must be greater than 4 quarters from time of occurrence
4-11	Fault exposure unavailable hours to be reset; item 5 to 11 are repeated for each train

New PI Codes for removal of fault exposure unavailable hours:

- FRMS01 - Emergency AC Power System
- FRMS02 - High Pressure Injection System
- FRMS03 - Heat Removal System
- FRMS04 - Residual Heat Removal System

Data will be submitted as a change report. Below are sample data on MS01 with 2 trains showing partial removal of 1000 hours in 2Q/2001 and a second change report submitted the subsequent quarter showing removal of additional hours:

1st change report submitted for 2Q/2001

[FRMS01|1Q2000|2Q2001|1000|1000]

2nd change report submitted for 3Q/2001

[FRMS01|1Q2000|3Q2001|400|400]

	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12	Q13
	1Q/2000	2Q/2000	3Q/2000	4Q/2000	1Q/2001	2Q/2001	3Q/2001	4Q/2001	1Q/2002	2Q/2002	3Q/2002	4Q/2002	1Q/2003
FR hrs (1st change report)	0	0	0	0	0	-1000	-1000	-1000	-1000	-1000	-1000	-1000	0
FR hrs (2nd change report)	0	0	0	0	0	0	-400	-400	-400	-400	-400	-400	0
Total FR hrs	**0**	**0**	**0**	**0**	**0**	**-1000**	**-1400**	**-1400**	**-1400**	**-1400**	**-1400**	**-1400**	**0**

Attachment 7

FAQ Log 15				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
15.12	MS01 MS02 MS03 MS04	**Question:** 1. Should support system unavailability be counted in the monitored safety system unavailability PI if analysis or engineering judgement has determined that the support system can be restored to available status such that the monitored system remains available to perform its intended safety function? 2. Do the criteria for determining availability described in NEI 99-02, Revision 0, page 26 lines 31-40 apply to this situation? **Licensee Proposed Response:** 1. No. During both testing and non-testing situations, the criteria described in NEI 99-02, Revision 0, page 33, lines 7-9 should apply, "In these cases, analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system." If the analysis or engineering judgment determines that the unavailability of the support system does not impair the ability of the monitored system to perform its intended safety function, then the support system unavailability should not be counted in the monitored system PI. For example, if engineering analysis determines that the unavailability of a ventilation support system for the emergency diesel generator does not adversely impact the availability of the emergency diesel generator to perform its intended function, the unavailability of the support system would not be counted in the emergency diesel generator PI. The engineering analysis must evaluate such things as; the length of time between an event and the time the ventilation system is required to be available to support the safety function of the emergency diesel generator, the complexity the actions required by plant operators to restore the availability of the ventilation system, and the probability of success for the restoration actions. Restoration actions should be contained in a written procedure and must not require diagnosis or repair. The engineering analysis must provide a high degree of assurance that the unavailability of the ventilation support system does not impact the ability of the emergency diesel generator to perform its safety function. This treatment is consistent with maintenance rule and PRA. 2. No. In NEI 99-02, Revision 0, page 26, lines 31-40, criteria for exclusion of planned unavailability for testing activities of monitored systems are described. The criteria established in this section describe required actions or barriers which must be in place during *testing* so that unavailability of the monitored system is not counted in the monitored system PI.	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added. 3/2/01 – Discussed. FAQ to be discussed as part of SSU focus group.	ComEd

Attachment 8

FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.5	MS03	**Question:** **Appendix D** NEI 99-02 states (p 26) that Planned Unavailable Hours include "…testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "…an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator within 10 minutes. Should this be counted as unavailable time? **Licensee Proposed Response:** **No, t**The PI should not count them **since this is an NRC approved design.**	Introduced 12/6 Discussed. Need to confirm compliance with NUREG 0737 **This question applies to the 2 standby AFWP, not the 3 auto start AFW pumps. The pumps are provided for HELB; An AO is required by procedure to manually start the standby AFW pumps in ten minutes.**	Ginna
16.6	MS01 MS02 MS03 MS04	**Question:** NOTE: This is similar to FAQ Log 15, Temp No. 15.4 NEI 99-02 states (p 26) "Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur." Station Results and Test personnel are qualified to perform valve lineups and are in the control room and/or stationed locally during testing. Do the R&T personnel with the written test procedure meet the guidance of NEI 99-02 for being able to restore equipment to service when needed and thus not counting the testing time as planned unavailable hours? **Proposed Response:** Yes, provided the plant personnel are qualified and designated to perform the restoration function and are not performing any restoration steps for which they are not qualified. The Station considers the restoration steps of the test procedures to be the "written procedure" for the required "restoration actions". The qualified R&T personnel (rather than a dedicated operator) with the test procedures allow the Station to take credit for restoration actions that are virtually certain to be successful during accident conditions while performing tests and thus this time should not count towards Planned Unavailable Hours.	Introduced 12/6 Discussed. Need more information on qualification of R&T tech and actions required 3/2/01 – Response revision. Tentative Approval as revised. **4/4/2001 – Tentative Aprroval**	Ginna

FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.11	MS02 MS04	**Question:** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. This process is carried out over a six hour period in which the temperature is raised slowly in order to chase fish toward the fish elevator so they can be removed from the intake and thus minimize the consequential fish kill. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. The ability of the safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Licensee Proposed Response:** No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis	San Onofre

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.14	MS03	**Question:** **Appendix D Question** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of **100% capacity** turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated? (Note: this FAQ is similar to **Appendix D questions for Palo Verde and** Crystal River regarding the auxiliary feedwater system) **Response:** **Based on the information provided, this pump should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.**	Introduced 12/6	Davis-Besse

FAQ Log 17

Temp No.	PI	Question/Response	Status	Plant/ Co.
17.2	PP01	**Question:** For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated? **NRC Proposed Response:** For sites that do not use CCTV for primary assessment, as stated in their approved security plan, use only the IDS Unavailability index for the Indicator Value. The Indicator value will be the IDS Unavailability Index divided by one for sites where these conditions exist. The exclusion of the CCTV index from the performance indicator calculation should be indicated by reporting a CCTV normalization factor of zero and zero CCTV compensatory hours for each affected unit. **Industry Proposed Response:** **Continue calulating the indicator in accordance with NEI 99-02. This issue will be resolved in future meetings.**	Introduced 1/10 1/10/2001 – Tentative Approval – NRC action to confirm acceptability with C. See 2/7/01 – NEI proposed alternate responses. 3/2/01 – Discussed.	NRC

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.1	MS01 MS02 MS03 MS04	**Question:** Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited. **Response:**	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.2	MS01 MS02 MS03 MS04	**Question:** When reporting safety system unavailable time there are periodic (such as weekly) evolutions that although they may not be simple actions to restore a safety system, they result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.6	IE03	**Question:** **On January 6th and 7th, the FitzPatrick Nuclear Power Plant performed unscheduled power reductions in excess of 20% due to environmental conditions. Lake temperature, wind speed and wind direction combined to create conditions resulting in the main condenser water box fouling which required the power reductions to correct. These power reductions have not been included in the "Unplanned Power Change per 7,000 Critical Hours" Performance Indicator based on previous FAQ's concerning unscheduled power reductions arising from external conditions.** **On 01/06/01 power was reduced to 60% to allow the A2 waterbox to be cleaned & inspected. The "C" traveling screen was removed from service and the remaining waterboxes were de-fished. A recommendation to clean the forebay when divers became available was made to the Shift. Because the availability of divers was expected to be 24 to 96 hours, normal power level was restored.** **Divers arrived on site 01/07/01, and preparations for forebay cleaning were ongoing. After "C" traveling screen was returned to service condenser delta T and delta P rose slightly. Subsequent lowering of a stop-log (to isolate "A" traveling screen for forebay cleaning) caused condenser delta T and delta P to rise and condenser vacuum dropped. The Shift responded by raising the stop-log, reducing power to 60 percent and de-fishing the waterboxes. Previously, these stop-logs have been lowered without significant effect on condenser performance. Divers confirmed that a large amount of silt and zebra mussel shells had collected in the forebays, which had been cleaned during RO-14.** **As outlined above, power was reduced on these two successive occasions 01/06/01 (for ~15 hours) and 01/07/01 due to waterbox fouling caused by external environmental conditions. The 01/07/01 down power was an unexpected evolution to be implemented based on when divers were available to perform the cleaning operation. Therefore, both power reductions were the result of the same environmentally caused influx of debris into the forebay. The initial mitigating action (de-fishing) was known to be a temporary measure to allow full power operation until long-term corrective action could be implemented.** **Since the second power reduction was caused by additional zebra mussels and prior intake cleaning evolutions were done at full power, should this count as an unplanned power change?** **Response:** **No. When external conditions are the fundamental cause of the power reduction it should not count in the Performance Indicator regardless of the period of time between power reductions**	Introduced 2/8 Need more information **4/23 Question revised**	FitzPatrick

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.1	IE03	**Question:** If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is <u>not</u> required by the license bases would this reduction be counted?	Introduced 3/1	River Bend

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: **If the ALARA program determines that a power reduction of >20% is appropriate to conduct the maintenance/ repair, and the downpower is conducted in less than 72 hours, the downpower would count.**		
19.2	MS01 MS02 MS03 MS04	**Question:** Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis…", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements? **Response:** **If the conditions have been met to reset fault exposure hours, in accordance with NEI 99-02, for fault exposure hours experienced during the historical data period, the hours can be reset without having to revise the remaining historical data to conform with all 99-02 requirements.However, because the green/white threshold was not crossed, the fault exposure hours cannot be removed.**	Introduced 3/1	Susquehanna
19.3	MS04	**Question:** **(Potential Appendix D question –** Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because, **as stated in the FSAR, the system's response to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of 10% is acceptable. The probability of the event of concern is 6.4 E-10.** If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing? **Response:** **No, because the plant is being operated in accordance with technical specifications.**	Introduced 3/1	Susquehanna

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.4	IE03	**Question:** **In February 2000, a leak was identified in main generator hydrogen cooler No. 34. At that time the leak rate was considered low enough for continued plant operation in accordance with Main Generator Gas System Operating Procedure (SOP-TG-001). Development of an Action Plan and outage schedule was initiated, daily trending of the hydrogen leakage rate was initiated, and plans for repair formulated. By the end of February 2000, an outage schedule was developed, Work Requests planned, material identified and orders placed. The schedule and work package was set aside for use if it became necessary to effect repairs prior to Refueling Outage 11 (scheduled for April 2001). In October 2000, the hydrogen leak rate increased (exceeded approximately 500 cu ft per day) and in accordance with the procedure additional monitoring via a special log was initiated. The approved Action Plan recommended that hydrogen coolers No. 33 and 34 be replaced with available spares. The leak continued to increase and after a maintenance shutdown October 25, the leakage increased to 843 cu ft per day by November 1. By the beginning of December the leak had increased to approximately 1200 cu ft per day and on December 18, the hydrogen leak rate increased to 2054 cu-ft per day. After assessing the condition, plant management decided to shut down the plant and perform the repairs as detailed in the outage schedule based on holiday resource scheduling. On December 19, the plant was shut down, repairs made and the unit returned to service close to the original outage schedule. This forced outage was evaluated for determining if it was applicable under the classification rules for an unplanned outage. In accordance with the guidelines of NEI-99-02, if the outage was planned more than 72 hours in advance, the outage could be classified as planned. Since the off-normal condition (leak) was identified in February and planning developed, although not all details completed, the shutdown met the criteria of identifying and planning 72 hours prior to the shutdown, and it was classified as a "planned" shutdown. The additional clarification in NEI-99-02, under FAQ No. 6 reinforced that determination. The shutdown was planned and per the examples in NEI-99-02, the time period between discovery of the off-normal condition exceeded 72 hours allowing assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown. The NRC Resident Inspector questioned the date identified for when the leak started and considered the appropriate date was December 18, when the leak rate was considered to have exhibited a "step" increase. This date was less than 72 hours prior to the actual shutdown, and included consideration of factors not previously considered in the action plan (such as availability of people due to the approaching holiday. Does this event qualify as a unplanned shutdown?** **Response:** **No, the degraded condition was identified in February 2000, and an Action Plan was developed to address the condition, including a outage schedule, Work Request, material identification and procurement. Therefore, the degraded condition was identified and planning had been performed more than 72 hours prior to the initiation of plant shutdown. The increased leak rate in December 2000 was not a different condition, only a continuing degradation of the off-normal condition discovered in February 2000. The December leak rate did not exceed procedural limits requiring assessment of operability and plant shutdown**	Introduced 3/1	IP3

<table>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td>19.5</td><td>MS01</td><td>Question:
NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states:
"When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria:
- a load run of any duration that resulted from a real (e.g., not a test) manual or automatic start signal
- a load-run test that successfully satisfied the plant's load and duration test specifications
- other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load
When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above."

The following sentence states:
"For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault."

If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test.

Licensee Proposed Response:

The key to interpreting this section of the guideline is determining the cause of the surveillance failure. If the cause is known (and the time of failure cannot be ascertained) the fault exposure time would be calculated as half the time since the last test which could have revealed the failure. This could be any of the load run tests described in the section.</td><td>Introduced 3/1
3/2/01 – Discussed. NEI action to revise to clarify question and proposed response.</td><td>APSC</td></tr>
<tr><td>19.6</td><td>MS01
MS02
MS03
MS04</td><td>(Potential Appendix D Question)

Response:</td><td>Introduced 3/1
QUESTION BEING REVISED</td><td>Prairie Island</td></tr>
</table>

Temp No.	PI	Question/Response	Status	Plant/ Co.
20.2	BI02	**Question:** **Appendix D Question:** The definition for the Reactor Coolant System (RCS) Leakage performance indicator is "The maximum RCS Identified Leakage in gallons per minute each month per the technical specification limit and expressed as a percentage of the technical specification limit." Cook Nuclear Plant Unit 1 and 2 report Identified Leakage since the Technical Specifications have a limit for Identified Leakage with no limit for Total Leakage. Plant procedures for RCS leakage calculation requires RCS leakage into collection tanks to be counted as Unidentified Leakage due to non-RCS sources directed to the collection tanks. All calculated leakage is considered Unidentified until the leakage reaches an administrative limit at which point an evaluation is performed to identify the leakage and calculate the leak rate. Consequently, Identified Leakage is unchanged until the administrative limit is reached. This does not allow for trending allowed RCS Leakage. The procedural requirements will remain in place until plant modifications can be made to remove the non-RCS sources from the drain collection tanks. What alternative method should be used to trend allowed RCS leakage for the Barrier Integrity Cornerstone? **Response:** Report the maximum RCS Total Leakage calculated in gallons per minute each month per the plant procedures instead of the calculated Identified Leakage. This value will be compared to and expressed as a percentage of the combined Technical Specification Limits for Identified and Unidentified Leakage. This reporting is considered acceptable to provide consistency in reporting for plants with the described plant configuration.	**4/4 – Tentative Approval.**	Cook
20.3	MS04	**Question:** FAQ for Mitigating System MS04 concerning CE Designed NSSS systems, "Alternative historical data correction method to convert 2 trains to 4 trains." Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde, San Onofre, St. Lucie, and Waterford 3 In FAQ # 172, approved on May 2, 2000 for use by CE plants, two methods for changing historical data from an initial 2 train report to a revised 4 train report were outlined. Specifically, the change report methodology was to perform one of the following changes to historical data: **1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.** **2. Recalculate and revise all historical data using this guidance.** For CE plants incorporating method 1, a non-performance related degradation in the PI calculation for Trains 3 and 4 (and the overall PI) was subsequently observed. This degradation occurred due to a decrease in the required hours in the denominator as the historical data was replaced by typically zero (0) or low required hours reported in the revised data (post Jan, 2000) in combination with artificially high unavailability hours in the numerator (due to the doubling of non-shutdown cooling related unavailability hours from the historical data). As a result, PI values would generally degrade over time regardless of performance until the historical data drops from the PI calculation. In some cases, plants projected a fall below the GREEN/WHITE threshold in 2002, even if perfect performance was used in the projection.	4/4 – Discussed. Need CE owners to provide additional input.	CE Plants

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Proposed Response: To address the calculation anomaly in the determination of the RHR PI, a third alternative is suggested for the estimation of Train 3 and Train 4 data: **3) Maintain Train 1 and Train 2 historical data as is. For Train 3 and Train 4, estimate the number of unavailable hours and required hours for the historical data period.** If changes to historical data are made, then provide comments with the change report to identify the manner in which the historical data has been revised.		
20.4	PP01	**Question:** Scheduled Equipment Upgrade During a recent NRC Security Inspection (IP 71130.03), NRC Contractors were able to defeat the Intrusion Detection System (IDS) in several areas, by using assisted jumps. An engineering evaluation was issued and formal Modification/ upgrade action was initiated that directed the installation of additional razor wire to prohibit attempts to circumvent the IDS system without being detected. Is a physical modification to a protected area boundary, that is designed to prohibit the defeat of a Intrusion Detection System (IDS) component considered to be a system/ component modification or upgrade as stated in the Clarifying Notes to NEI 99-02 under Scheduled Equipment Upgrade (and as augmented by FAQ 259)? **Response:** Yes. A physical modification to a protected area boundary is considered to be a system/ component modification or upgrade that deters or prohibits the defeat of the IDS system components.	4/4 - Introduced and discussed.	**Turkey Point**
20.5	MS04	**Question** **APPENDIX D** Calvert Cliffs monitors the Safety System Unavailability Performance Indicator for PWR RHR using the guidance in NEI 99-02 provided for Combustion Engineering (CE) designed plants. When a unit is in Mode 6 and with water level in the Refueling Pool, at 23 feet or more above the top of the irradiated fuel assemblies seated in the reactor vessel, the Technical Specifications only require one Shutdown Cooling (SDC) loop to be operable and in operation. Unlike most of the other CE designed plants, at Calvert Cliffs, the two SDC loops on each unit have a common suction piping line. As a result, to permit required local leak rate testing and other maintenance activities on this common suction line, both trains of SDC would be taken out-of-service. Recognizing this plant specific design feature, the Technical Specifications specifically allow this required testing and maintenance to be performed without entering the action statements while the plant is in this particular condition. While the SDC trains are unavailable, decay heat is removed by natural convection to the volume of water in the Refueling Pool. Calvert Cliffs Technical Specifications Bases indicates that "a minimum refueling water level of 23 feet above the irradiated fuel assemblies seated in the reactor vessel provides an adequate available heat sink." In this situation, should unavailable hours be counted against the SDC loop given the plant design at Calvert Cliffs?	Introduced 4/3 **4/4/2001 – Tentative Approval.**	Calvert Cliffs

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: It is appropriate to not count unavailable hours for the above-described situation at Calvert Cliffs. Removing the SDC suction headers from service for the circumstances specifically allowed by the applicable Technical Specification is a reflection of plant design rather than an indication of adequate component or train maintenance practices. Unavailable hours would be counted while operating in accordance with this applicable Technical Specification if a situation occurred that required entering the action statement.		
21.1	MS02	**Question:** **Appendix D** **Page 62 of NEI 99-02, Rev 0, states in part:** **"...the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system."** **Ginna Station's system design has three MOV's meeting this definition: 857A and 857C (two valves in series from the A RHR train) and 857B from the B RHR train. Each RHR train is a 100% train. MOVs 857 A and 857C are in parallel with 857B. If Ginna Station was to have a fault exposure to one of these three valves, it would not prevent any of the three HPSI pumps from performing its function of taking a suction from the containment emergency sump. Rather, a fault exposure to one of these three valves would prevent its associated RHR train from supplying a suction from the containment emergency sump to any of the three HPSI pumps. Thus, the boundary between the RHR and HPSI systems needs to be adjusted for Ginna Station.** **Licensee Proposed Response:** **The down-stream side of the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system for Ginna Station. The isolation valve(s) themselves will be in the RHR system and be associated with their respective RHR train.**		**Ginna**
21.2	MS01 -04	**Question:** **Removing (Resetting) Fault Exposure Hours** **Question being reviewed** **Licensee Proposed Response:**		**Ginna**

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<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td rowspan="2">21.3</td><td rowspan="2">IE03</td><td>Question: (Appendix D)

The response to PI FAQ #158 states "Anticipatory power changes greater than 20% in response to expected problems (such as accumulation of marine debris and biological contaminants in certain seasons) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted if they are not reactive to the sudden discovery of off-normal conditions."

Due to its location on the Pacific coast, Diablo Canyon is subject to kelp/debris intrusion at the circulating water intake structure under extreme storm conditions. If the rate of debris intrusion is sufficiently high, the traveling screens at the intake of the main condenser circulating water pumps (CWPs) become overwhelmed. This results in high differential pressure across the screens and necessitates a shutdown of the affected CWP(s) to prevent damage to the screens.
To minimize the challenge to the plant should a shutdown of the CWP(s) be necessary in order to protect the circulating water screens, the following operating strategy has been adopted:
• If a storm of sufficient intensity is predicted, reactor power is procedurally curtailed to 50% in anticipation of the potential need to shut down one of the two operating CWPs. Although the plant could remain at 100% power, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing a CWP. One CWP is fully capable of supporting plant operation at 50% power.
• If one CWP must be secured based on adverse traveling screen/condenser differential pressure, the procedure directs operators to immediately reduce power to less than 25% in anticipation of the potential need to secure the remaining CWP. Although plant operation at 50% power could continue indefinitely with one CWP, this anticipatory action is taken to avoid a reactor trip in the event that intake conditions necessitate securing the remaining CWP. Reactor shutdown below 25% power is within the capability of the control rods, being driven in at the maximum rate, in conjunction with operation of the atmospheric dump valves.
• Should traveling screen differential pressure remain high and cavitation of the remaining CWP is imminent/occurring, the CWP is shutdown and a controlled reactor shutdown is initiated. Based on anticipatory actions taken as described above, it is expected that a reactor trip would be avoided under these circumstances.

How should each of the above power reductions (i.e., 100% to 50%, 50% to 25%, and 25% to reactor shutdown) count under the Unplanned Power Changes PI?</td><td rowspan="2"></td><td rowspan="2">Diablo Canyon</td></tr>
<tr><td>Response:
Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%, that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours in advance. Neither of these anticipatory power reductions would count under the Unplanned Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power change since such a reduction is forced and can therefore not be considered anticipatory.</td></tr>
<tr><td>21.4</td><td>MS01 -04</td><td>Question:
By the NEI guidance, fault exposure hours can only be removed for "a single item" when the fault exposure hours associated with the item are greater than or equal to 336 hours. How are multiple failures of the same component handled when some of the failures have fault exposure hours less than 336 hours, yet the total of all the failures attributed to the same failed component are greater than 336 hours.</td><td></td><td>Southern Co.</td></tr>
</table>

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: The intent is that the removal of fault exposure hours is associated with the identification of cause to preclude recurrence of the condition. A failure to adequately identify cause (such as intermittent failures) which leads to additional failures are considered the same condition and may be grouped for removing of fault exposure hours. However, it is also the intent that the NRC supplemental inspection considered all failures associated with this condition. Under these restrictions, multiple items may be considered as a single item since they represent a single condition. Therefore, the fault exposure hours may be removed for the applicable failures. However, situations involving multiple failures due to different components or causes can not be grouped. For example, a valve failure and a subsequent pump controller failure can not be grouped for fault exposure hour removal even if they are considered in the supplemental inspection.		
21.5	IE01	**Question** A plant is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately insert a manual scram. Afterwards, the operators determine that the actual field condition was minor, and the suspected equipment failure would not have occurred. Therefore, there would not have been an automatic scram. Should the manual scram be counted as an unplanned scram? **Response** Yes, the manual scram should be conuted because the scram was inserted above the 25% level specified in the plant shutdown procedure.		Nine Mile
21.6	IE02	**Question:** Some plants are designed to have a residual transfer of the non-safety electrical buses from the generator to an off-site power source when the turbine trip is caused by a generator protective feature. The residual transfer automatically trips large electrical loads to prevent damaging plant equipment during reengization of the switchgear. These large loads include the reactor feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual transfer is completed the operators can manually restart the pumps. The turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be counted as a scram with a loss of normal heat removal? **Response** In this instance, the electrical transfer scheme performed as designed following a scram and a residual transfer; therefore, this would not count as a scram with a loss of normal heat removal		Nine Mile

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.7	MS02 MS04	**Question** NEI 99-02, Rev. 0 states in the Definition and Scope section for PWR High Pressure Safety Injection Systems that: "Because the residual heat removal system has been added to the PWR scope, the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system. The RHR pumps used for piggyback operation are no longer in HPSI scope." It is further stated later in the same section that the function monitored for HPSI is: "the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure." These two statements appear to conflict. For our plant design the RHR / HPSI piggyback mode is the only path available for HPSI to get water from the containment sump and inject it into the RCS. Therefore, we have been counting unavailability of the RHR system upstream of the isolation valves between the RHR system and the HPSI pump suction as unavailability for RHR and HPSI. This would include component unavailability for containment sump isolation valves, RHR heat exchangers and the isolation valves between the RHR and HPSI systems. Should the RHR and HPSI systems be treated independently such that RHR system unavailability should not count against HPSI even though the RHR system is required for the HPSI system to fulfill the function of taking a suction from the containment sump? If so, should unavailability of the isolation valves between the RHR and HPSI pumps' suction be only counted against HPSI?		Kewaunee
		Response Because RHR and HPSI are monitored as separate systems with each having its own performance indicator, there is no need to cascade RHR system unavailability into HPSI. RHR system unavailability includes the system upstream of the RHR system to HPSI system isolation valves. Unavailability of the isolation valves between the RHR system and the HPSI pump suction are only counted against the HPSI system.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.8	MS01,02,03,04	**Question** NEI 99-02, Rev. 0 states in the Support System Unavailability section that "If the unavailability of a single support system causes a train in more than one of the monitored systems to be unavailable, the hours the support system was unavailable are counted against the affected train in each system. For example, a train outage of 3 hours in a PWR service water system caused the emergency generator, the RHR heat exchanger, the HPSI pump, and the AFW pump associated with that train to be unavailable also. In this case, 3 hours of unavailability would be reported for the associated train in each of the four systems." This example may have led some stations to automatically count monitored systems unavailability when the associated train of support system is unavailable even though the redundant train of support system could support either train of the monitored systems. In the ROP Lessons Learned Workshop (held March 26-28, 2001), handout on page 2 of the Reactor Safety Performance Indicator Issues section under Proposed Resolution "c." it states: "...the support system is available if a single train of that system is available (i.e., support systems are not required to be single-failure proof)." The NEI guideline does not contain any information that would lead one to the conclusion that support system unavailability is anything other than a train-to-train relationship to the monitored systems. Our plant design incorporates two service water (SW) trains made up of two pumps per train. If one pump is out-of-service, the entire train of SW is declared out-of-service. Our technical specifications allow for a 72 hour LCO which we may use to take one train out for periodic maintenance or pump replacement. Normally, only one pump of a train is taken out-of-service at a time. The SW headers are normally cross connected which would provide design flow to either train of the monitored systems. While cross connected, if a safety injection signal is received, the SW trains will be automatically isolated from each other. If we have one SW pump out-of-service when we receive the safety injection signal, we would be left with two SW pumps serving one train and one serving the other. The SW trains can be returned to the cross-connected status using a few simple steps. Thus providing the capability to support either train of the monitored mitigating systems. 1) If, while one train of a support system is unavailable, and the opposite train of the support system has the capability to support either train of the monitored systems, is unavailability counted against the monitored systems? 2) Does this single support system train capability to support either train of the monitored systems need to be automatic or promptly established. **Response** 1) No. As long as the support system train that is available is capable of supporting either train of the monitored systems, no unavailability is counted against the monitored systems. 2) 2) No. The automatic or promptly established only applies to the monitored systems during testing.	Requires additional information	Kewaunee

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.9	MS01	**Question:** NEI 99-02 Revision 0, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.) If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred? **Response:**	5/2 Introduced	FitzPatrick

NUCLEAR ENERGY INSTITUTE

Stephen D. Floyd
SENIOR DIRECTOR,
REGULATORY REFORM
NUCLEAR GENERATION

May 1, 2001

TO: NEI Administrative Points of Contact

SUBJECT: NEI 99-02 Revision 1, *Regulatory Assessment Performance Indicator Guideline*

The NEI Plant Safety Assessment Task Force and the Nuclear Regulatory Commission have completed work on Revision 1 of NEI 99-02 which incorporates Frequently Asked Questions (FAQs) into the text. Revision 1 is provided as an attachment to this email. Two pdf files are provided. The first file provides the document itself. The second file is a line-in line-out version which may be helpful to you in reviewing changes between Revision 0 and Revision 1.

Please keep in mind that Revision 1 goes into effect on July 1, 2001 and does not apply to second quarter data to be submitted July 23, 2001. It does apply to third quarter data which will be submitted October 22, 2001. NRC will be issuing a RIS to implement Revision 1. NEI is conducting a workshop on Revision 1 June 5 at the Renaissance Airport Hotel in St. Louis. Information on this workshop was sent out to APCs previously.

We very much appreciated all of the comments provided to us on the draft version of NEI 99-02 Revision 1. While many of the comments were incorporated in the text, others were not. Some comments went beyond a mere incorporation of an FAQ; others conflicted with an approved FAQ; and some were issues still under discussion with the NRC. The FAQ process will continue in the same fashion as before. FAQs incorporated in the text of NEI 99-02 Revision 1 will be retained by NRC in an inactive historical file.

If you have any questions, please contact Tom Houghton at (202) 739-8107 or me.

Sincerely,

Stephen D. Floyd

Stephen D. Floyd

Enclosures

Attachment 9