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

December 12, 2000

MEMORANDUM TO: Michael R. Johnson, Chief
Performance Assessment Section
Inspection Program Branch
Division of inspection Program Management
Office of Nuclear Reactor Regulation

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

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON DECEMBER 6, 2000

On December 6, 2000 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss the Reactor Oversight Process initial implementation. An agenda of the meeting, the attendance list, and information exchanged at the meeting are attached.

Attachments:

1. List of Participants
2. Topics Discussed
3. Proposal for Revised Treatment of Fault Exposure Hours Pilot Program
4. Operator Re-qualification Human Performance SDP - 12/1/2000
5. Frequently Asked Questions, Log. 8, 9, 10, 11, 12, 13, 14, 15,16,17,18
6. RBPI Development
7. Reactor Oversight Process Physical Protection Cornerstone - Draft - 12/6/00
8. Analysis of Green-White Threshold for Scrams With Loss of Normal Heat Removal - Draft-12/5/00

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NAME:	ASpector		A. Madison			
DATE:	12/12/00		12/13/00			

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NRC Public Meeting
Reactor Oversight Process
List of Participants
December 6, 2000

W. Dean, NRC
D. Hickman, NRC.
R. Eckenrode, NRR
S. Sanders, NRC
A. Madison, NRC
A. Spector, NRC
R. Frahm, NRC
C. See, NRC
D. Trimble, NRC
J. Thompson, NRC
T. Boyce, NRC
M. Maley, NRC
J. Arildsen, NRC
A. Tardiff, NRC
H. Hamzehee, NRC
R.L. Sullivan, NRC
A. Marion, NEI
T. Houghton, NEI
A.K. Krainik, APS
S. Yim, Winston & Strawn
S. Johnson, INPO
W. Warren, Southern Nuclear
J. Nagle, PSEG
P. Loftus, COMED
M. Burzynski, TVA
A. Nelson, NEI

Attachment 1

TOPICS DISCUSSED

PUBLIC MEETING TO DISCUSS IMPLEMENTATION OF THE REVISED REACTOR OVERSIGHT PROCESS

DATE AND TIME: December 6, 2000
8:00 a.m. - 3:30 p.m.

LOCATION: U. S. Nuclear Regulatory Commission
One White Flint North

PURPOSE: *NRC conducts monthly "working session" public meetings at which time participants provide input to the NRC technical staff regarding the initial implementation of the Reactor Oversight Process. These meetings are open to the public, industry representatives, licensees, and other interested parties. Attendees are encouraged to participate in all aspects of the session.*

TOPICS DISCUSSED:

1. Consideration of issues associated with fault exposure time impact on Unavailability Performance indicators and potential approaches to resolution.
   Discussed establishment of NRC/Industry joint working group to address overall concerns and development of "clean-sheet" approach to resolution. Industry and NRC to identify proposed names for working group by 1/10 meeting.
   Discussed proposed removal of fault exposure hours associated with surveillance testing. Industry owes listing of the number of instances t/2 ≥ 336 hours for a single event by plant by 1/10. NRC will review data and compare to SDP outcomes by 2/7. Additional discussion regarding thresholds and overall impact of change for 2/7.
2. Operator re-qualification SDP:
   Discussed recent changes and planned implementation.
3. Status report on Initiating Event PI pilot study
   No significant information to report. Will be discussed further on 1/10.
4. Draft Manual Chapter 0608, Performance Indicator Program
   Industry provided favorable feedback. NRC discussed planned implementation.

ATTACHMENT 2

5. Proposed issues for revision of NEI 99-02
NRC and industry provided independent lists of FAQs proposed for incorporation into a revision to NEI 99-02. Special meeting to discuss proposed revisions planned for 1/9.
6. Review and approval of Frequently Asked Questions
Worked on. See individual outcomes. More scheduled for 1/10
7. Update by Office of Research or Risk-based Pis
Office of Research provided brief status and general description of Risk-based PI development.
8. Performance Indicators related to Maintenance Rule.
No discussion. Withdrawn.
9. Draft proposal related to unplanned transit changes
Discussed proposal for using average daily power level. NRC owes information regarding impact on inspection program and proposal for pilot study schedule by 1/10.
10. Update on NRC's ROP self assessment program -- industry trends
General update - more planned for 1/10
11. Proposed revision to SSFF PI for RCIC
Incorporated into discussion regarding revision to NEI 99-02 scheduled for 1/9. NRC owes information regarding impact on thresholds.
12. Safeguards SDP -- long term efforts
NRC provided brief discussion regarding general direction and status of changes. More discussion planned for 1/10.
13. Safeguards PI change proposals
Proposed re-write to guidance on "scheduled equipment upgrade" to be discussed further on 1/9
Proposed revision to calculation of Security Equipment Performance Index PI - Industry owes feedback by 1/10, NRC owes historical data cast with new calculation method by 1/10.
14. Determination of next meeting date and topics for discussion
Next Meetings - 1/9 (Revision to 99-02), 1/10 (Routine), 2/7 (routine)

Also discussed:

a. *Plant-specific SDP Phase 2 worksheets - revised worksheets should be available at all facilities by 2/28/2001.*
b. *Discussed schedule for completion of Initial Implementation, including discussion of Federal Register Notice and lessons learned workshops. Also discussed proposal to change annual schedule to match the calendar year (move start from April to January).*
c.

CONTACT: August K. Spector, 301-415-2140 or email AKS@NRC.GOV

Proposal for
Revised Treatment of Fault Exposure Hours Pilot Program

Background

Safety System Unavailability is currently computed under the Reactor Oversight Process (ROP) by adding, for each train, planned unavailability, unplanned unavailability and fault exposure hours and dividing the sum by the train hours, and then averaging the train values.

Fault exposure hours are intended to be a surrogate for unreliability. NEI 99-02 includes a provision for removing fault exposure hours after 4 quarters to "reset" the indicator. This provision is to remedy a condition where a single fault exposure of sufficient duration can cause the indicator to trip the G/W threshold and keep the indicator "non-green" for extended periods of time. Keeping the indicator "non-green" potentially masks future problems and falsely projects an image of system performance that is not indicative of the going-forward system performance.

It was expected that the exercise of the fault exposure removal feature would be relatively rare compared to entry into the non-green zones due to planned and unplanned unavailability. Experience in the pilots and industrywide program to date suggests otherwise. All but one of the 11 non-green indications for safety system unavailability is as a result of large, single fault exposure terms (as of second quarter 2000.) For the NRC, the action matrix dictates a supplemental inspection, yet the inspections have been very minimal because the cause of the tripped indicator was well known. This leaves the NRC open to criticism.

Proposed Remedy to Pilot

This pilot would separate fault exposure hours into two categories: fault exposure hours for which the time to failure is known, and fault exposure hours for which the time to failure is unknown (the "t over 2" approach). This categorization would be consistent with the approach used in the maintenance rule implementation (which does not include these hours in the unavailability calculation, but rather counts the occurrence as a demand failure.) For the pilot, in those cases in which the "t over 2" term exceeded 336 hours (a failure of a monthly surveillance in which the time of failure is not known), the NRC resident would conduct an SDP to determine the significance.

Attachment 3

Pilot Approach

1. Licensees continue to report all fault exposure hours per NEI 99-02.

2. All plant licensees would separately report "t over 2" fault exposure hours to NEI on a monthly basis for a six month period (including negative reports). Comments would also be provided on those cases in which hours were reported.

3. NEI would provide data information to NRC on a monthly basis.

4. The baseline inspection program would be modified to direct the inspectors to apply the SDP to those situations in which "t over 2" hours exceeded 336 hours and determine if there were any performance issues associated with the system/train failure. The results of the SDP would be used to characterize any findings. This appears to be current NRC inspection practice and would, therefore, not result in an appreciable change in inspection hours for the ROP.

5. The current green/white thresholds should remain in effect. An analysis of the green/white threshold would be performed at the end of the pilot to determine if any changes are necessary.

Participation

Due to the infrequency of fault exposure conditions, the pilot study should include all plants. No additional data is being reported than currently. As the NRC has all the actions and information to evaluate this change, there is no impact on licensees in conducting an industrywide pilot.

Operator Requalification
Human Performance
Significance Determination Process (SDP)

December 01, 2000

Introduction:

The attached flowchart and matrix comprise the proposed process for determining the risk importance of issues identified during an inspection of the licensed operator requalification program or by a Resident Inspector's observation of requalification activities. This process covers only those issues related to the operator requal program. It is the staff's current position that performance errors made by a licensed operator leading to, or during an actual operational event, are an integral part of the overall outcome of the event and would be reflected in the event risk determination or ultimately in a performance indicator. This position is being examined through a research project and an analysis of data in the Human Factors Information System.

Each issue should first be screened by using the Group 1, 2 and 3 questions of Manual Chapter 610*, Appendix E to determine whether it is a minor concern. At a minimum, Group 1 questions 2 through 5, Group 2 questions on Reactor Safety, and several of the Group 3 questions could be applicable to requal issues.

This SDP starts when an operator requal issue is identified and screened by a Regional Inspector based on IP 71111.11 and the sample of items selected or the licensee's test records, or by a Resident Inspector based on the IP 71111.11 Resident's Quarterly Review. It can be related to the programmatic aspects (e.g. exam grading, exam quality, exam security) or to the performance of licensed operators during the written exam or the annual operating test. This SDP is applicable to requal issues related to all licensed operators, including both shift and staff crews, with either active or inactive licenses. The process is applicable to all license holders since a staff crew member could, at any time, be asked to go on-shift and because an inactive license holder needs only to spend the required time on-shift to activate a license. A crew is defined as any group of individuals evaluated as a single entity by the licensee on the basis of its performance on the dynamic simulator.

Simulator Operational Evaluation Matrix:

The Simulator Operational Evaluation Matrix provides a guide to the perceived risk associated with the number of crews failing the annual operating test as related to the number of crews taking the test. The "Number of Crews that took the Annual Operating Test" includes multiple units in order to accommodate those instances where operators hold dual unit licenses. If a multiple unit site has separate unit licenses, the matrix should be used to assess the results at each of the units separately. The chart accommodates up to sixteen crews and eight UNSAT crews. If more crews are tested or are UNSAT in a particular cycle, the finding color can be determined by the percentages at the bottom of the chart. The information should be obtained

Attachment 4

by the Regional Inspector or Resident Inspector at the end of the testing cycle. Less than 20% failure rate is considered satisfactory and therefore does not constitute a finding to be recorded in an inspection report. A failure rate of 20% to 34% is considered to be a green finding to be turned over to the licensee for corrective action. An operating test failure rate greater than 34% meets the NUREG-1021, Rev 8 criteria for an UNSAT Requal Program and is considered to be a white finding up to 50%. Should more than half the crews fail, it is considered to be a serious programmatic weakness and a yellow finding. Requal operating test failure rate alone is never considered to be a red finding unless over half the crews failed and one or more of the failed crews are returned to the shift without remediation. Use of this matrix is explained below in the description of the flow chart blocks.

<u>The SDP Flow Chart:</u>

The Requal SDP process starts with a single issue (Block #1) identified by the Regional or Resident inspectors during their conduct of Inspection Procedure 71111.11, "Licensed Operator Requalification Program." It includes issues identified by the Regional and Resident Inspectors on selected samples of data, from interviews, or analyses of the operating test results by Regional or Resident Inspectors at the end of the testing cycle. The process attempts to include only those aspects of the requal program considered to be risk important. For example, the student feedback system in-and-of itself has little risk importance, but its review might lead the inspector to issues that are risk important. Issues screened out by the process should still be reported as observations if they are indicative of trends or significant extent of condition (See MC 0610*, cross cutting issues).

The process first examines inspector issues related to the licensee's grading of the exam to ensure that failed candidates or crews are properly identified and not passed inappropriately. Once again, the risk importance is not that the licensee's grading process was inadequate or flawed, but that inadequately trained operators may be allowed to go on shift. The inadequacy of the grading process may turn out to be a contributing factor, but inadequate training is probably the root cause.

The next parts of the SDP process are related to the written and walkthrough portions of requal (pages 1 and 2 of the flowchart), and address issues of exam quality and security and the performance of multiple individuals. The risk determination assumes that a single individual failure in requal does not rise to the risk significance of a green finding. However, when multiple failures are considered, more than 20% has been selected as the threshold for an unacceptable number of failures. This is generally consistent with the guidance in the examination standards of NUREG-1021, Rev. 8. Thus, more than 20% unacceptable written test items is the quality threshold; more than 20% of the operators failing the written portion is the performance threshold; more than 20% of the operators failing the operating test walkthrough is the walkthrough performance threshold, etc.

The simulator portion of the SDP (pages 3 and 4 of the flowchart) evaluates scenario quality and security and performance of crews. Again, an individual failing in the simulator portion does not rise to the risk significance of a green finding. The risk significance of crew performance depends on the percentage of crews that have failed, whether they were remediated before returning to shift, and whether the facility had a failure rate of green or

higher (as determined by the SDP Simulator Operational Evaluation Matrix) in the previous annual operating test. The risk assessment of operator performance on the simulator should include all of the crews tested based on test records, even if the inspectors witnessed testing of only some of the crews.

Finally, the SDP looks at the overall requal program by asking if less than 75% of the operators passed all portions of the exam (NUREG-1021, Rev. 8, ES 601), and if more than 20% of the operator licensing records have operationally risk important deficiencies.

Flowchart Block Descriptions

#1 - This SDP starts after a single operator requal issue is identified and screened through Manual Chapter 0610*, Appendix E questions during an inspection of the licensed operator requalification program, by analysis of test records at the end of the cycle, or by a Resident Inspector's observation of requalification activities. Each specific issue must be evaluated separately. An issue can be related to the programmatic aspects (e.g. exam grading, exam quality, operator licensing records) or to the performance of licensed operators during the written or annual operating test.

#2 - Is the issue related to incorrect or inappropriate grading of the written exam or operating test by the licensee? This can be identified, for example, as a result of the inspector's observation of the operating test or an evaluation of the grading of a sample of the written exam.

#3 - Did the inspector's review of a sample of the written exam identify an issue with the grading that would have failed a candidate that the licensee's examiner passed? Did the inspector identify a crew or individual operator performance issue in the operating test that should have resulted in a failure, but was not identified by the licensee's examiner? These are considered risk important issues, since operators or crews with unsatisfactory evaluations could be placed on shift.

#4 - Is the issue related to written exam quality, security or operator performance in taking the exam? This issue may stem from student feedback or other personnel interviews as well as inspector observation or data analysis.

#5 - Is the issue related to the individual operating test (generally JPM) quality, security or operator performance in the walkthrough? This issue may stem from student feedback or other personnel interviews as well as inspector observation or data analysis.

#6 - Is the issue related to the physical or functional fidelity of the simulator as compared to the real plant? This issue may stem from student feedback or other personnel interviews, review of simulator performance tests, as well as inspector observation.

#7 - Is the issue related to the quality of the individual operating test? This issue may stem from student feedback or other personnel interviews as well as inspector observation or data analysis. Has the appropriate significant information from the feedback system been incorporated in the individual operating test?

#8 - Has security of the individual operating test content been compromised? This refers to a loss of control of the exam material such that exam validity is affected. Knowledge of an exam security breach can occur through two principal means: (1) the inspector's direct knowledge and/or evidence or information that such a breach occurred and/or, (2) an analysis of operator post exam results suspected to have been influenced by a security breach or exposure that reveals that the exam results attained are not probable or likely given the history of the operator's past performance. The second method is possible, but not likely in the operating tests.

If the compromise was determined to be inadvertent and the test is rewritten prior to administration, it is not a risk important finding and the answer to this block is "no."

#9 - Have more than 20% of the operators who took the individual operating test in this training cycle failed? This should be determined by the Regional Inspector or by the Resident Inspector by examining the licensee's test records at the end of the cycle.

#10 - Were more than 20% of the individual operating test items reviewed by the inspector unacceptable? This is based on the sample selected by the inspector and the acceptance criteria established in NUREG-1021, Rev. 8, Appendix C, Form ES-C-2.

#11 - When the security compromise was discovered did the licensee take compensatory measures immediately? The risk importance increases if the test security was compromised, the individual returned to shift and compensatory actions were not taken immediately upon discovery.

#12 - Could deviations or differences between the plant control room and the plant reference simulator negatively impact operator actions? There will always be some physical or functional differences between the simulator and the control room, but the concern here is how they impact the operator. Could the differences result in negative training? ANSI/ANS-3.5-1993/1998, "Nuclear Power Plant Simulators for Use in Operator Training and Examination," Section 4.2.1.4, provides guidance in assessing the deviations.

#13 - Is the issue related to the quality (accuracy, clarity, appropriateness, discrimination, etc.) of the written exam? Has the appropriate significant information from the feedback system been incorporated in the written exam.

#14 - Has the security of the written exam content been compromised? This refers to a loss of control of the exam material such that the exam validity is affected. Knowledge of an exam security breach can occur through two principal means: (1) the inspector's direct knowledge and/or evidence or information that a breach occurred and/or, (2) an analysis of operator post exam results suspected to have been influenced by a security breach or exposure that reveal that the exam results attained are not probable or likely given the history of the operator's past performance.

If the compromise was determined to be inadvertent and the test is rewritten prior to administration, it is not a risk important finding and the answer to this block is "no."

#15 - Have more than 20% of the operators who took the written exam in this training cycle failed? This should be determined by the Regional Inspector or by the Resident Inspector by examining the licensee's test records at the end of the cycle.

#16 - Were more than 20% of the written questions reviewed by the inspector unacceptable? This is based on the sample selected by the inspector and the acceptance criteria established in NUREG-1021, Rev. 8, ES-602, Attachment 1 and Appendix B.

#17 - When the security compromise was discovered did the licensee take compensatory measures immediately? The risk importance increases if the test security was compromised, the individual returned to shift and compensatory actions were not taken immediately upon discovery.

#18 - (intentionally left blank)

#19 - (intentionally left blank)

#20 - Is the issue related to the qualitative (realism, event sequencing, difficulty, etc.) or quantitative (number of normal evolutions, malfunctions, transients, etc.) aspects of the scenario? Has the appropriate significant information from the feedback system been incorporated in the scenarios?

#21 Has security of the scenario been compromised? This refers to loss of control of the scenario identity or material such the operating test validity is affected. Knowledge of a scenario security breach can occur through two principal means: (1) the inspector's direct knowledge and/or evidence or information that a breach occurred and/or, (2) an analysis of operator or crew post test results suspected to have been influenced by a security breach or exposure, that reveal that the operating test results attained are not probable or likely given the history of the operator's or crew's past performance. The second method is possible, but not likely in the operating tests.

If the compromise was determined to be inadvertent and the scenario was rewritten or another selected prior to administration, it is not a risk important finding and the answer to this block is "no."

#22 - Is the issue related to crew performance on the dynamic simulator operating test? Crew performance is a demonstration of the ability to effectively operate as a team while completing a series of critical tasks that measure the crews ability to safely operate the plant during normal, abnormal, and emergency situations. The facility licensee will conduct its annual operator performance evaluations in accordance with the requirements of its requalification program. If the licensee chooses to fail crews based on poor performance related to administrative tasks in addition to simulator critical tasks then they will count as failures in this SDP, unless the licensee specifically records these as administrative failures for remediation purposes.

#23 - Based on the licensee's records, did less than 75% of the operators in this training cycle pass all portions of the exam? If so, it may be indicative of an unsatisfactory requalification program (Reference NUREG-1021, Rev. 8, ES-601, E.3.a.(1)). This information should be

determined by the Regional Inspector or by the Resident Inspector by examining the licensee's test records at the end of the cycle.

#24 - Is the issue related to the licensee's program for maintaining active operator licenses and ensuring the medical fitness of its licensed operators?

#25 - Were more than 20% of the scenarios in the sample reviewed by the inspector unacceptable based on the qualitative and quantitative criteria of NUREG-1021, Rev. 8, Appendix D and the "Simulator Scenario Review Checklist," (Form ES-604-1)?

#26 - When the security compromise was discovered did the licensee take immediate compensatory measures? The risk importance increases if the operating test was compromised, individuals or crew returned to shift and compensatory actions were not taken immediately upon discovery.

27 - Based on the sample selected by the inspector, did more than 20% of the records indicate deficiencies that could pose a potential risk to operations, as described in IP 71111.11, Section 03.08? For example, are crew members maintaining active licenses and are their qualifications current? Is the licensee complying with special license conditions for medical limitations, notification of medical restrictions as required by 10 CFR 50.74(c) and are physical examinations up to date? Based on the judgement of the inspector, administrative errors in the records, having no bearing on operational safety, should not be considered as issues to be entered into the SDP.

#28 - (intentionally left blank)

#29 - (intentionally left blank)

#30 - Was the simulator operating test crew failure rate for the entire cycle greater than 50% (Yellow on matrix)? This information should be determined by the Regional Inspector or by the Resident Inspector by examining the licensee's test records at the end of the cycle.

#31 - Were the failed crews (50% or less of total number of crews) remediated and completely re-tested successfully before they were returned to shift? Even a single failed crew returning to shift is a potential risk and is considered to be at least a White Finding.

#32 - Were the failed crews (greater than 50% of total number of crews) remediated and re-tested successfully before they were returned to shift? If "yes" this remains a Yellow Finding for the shear magnitude of the programmatic problem. If "no" it is an even more serious problem (Red Finding) and deserves significant NRC attention.

#33 - Was the operating test failure rate less than 20%, or between 34% and 50%? Less than 20% failure rate and the failed crews satisfactorily remediated before returning to shift remains a No Finding. Failure rate between 34% and 50% and the failed crews satisfactorily remediated before returning to shift remains a White Finding because it still indicates an UNSAT Requal Program as defined by NUREG-1021, Rev. 8, ES-601, E.3.a.(2).

#34 - If the failure rate in the current operating test cycle is between 20% and 34% (Green Finding) and it was green or higher in the last operating test cycle, the concern is that this is a repeat issue, a potential weakness in the SAT process, and corrective actions are not working satisfactorily. Thus, the issue is escalated to a White Finding. If the failure rate in the current operating test cycle is white or higher, and it was green or higher in the last cycle, further escalation is unnecessary, and the current color remains.

Simulator Operational Evaluation

September 21, 2000

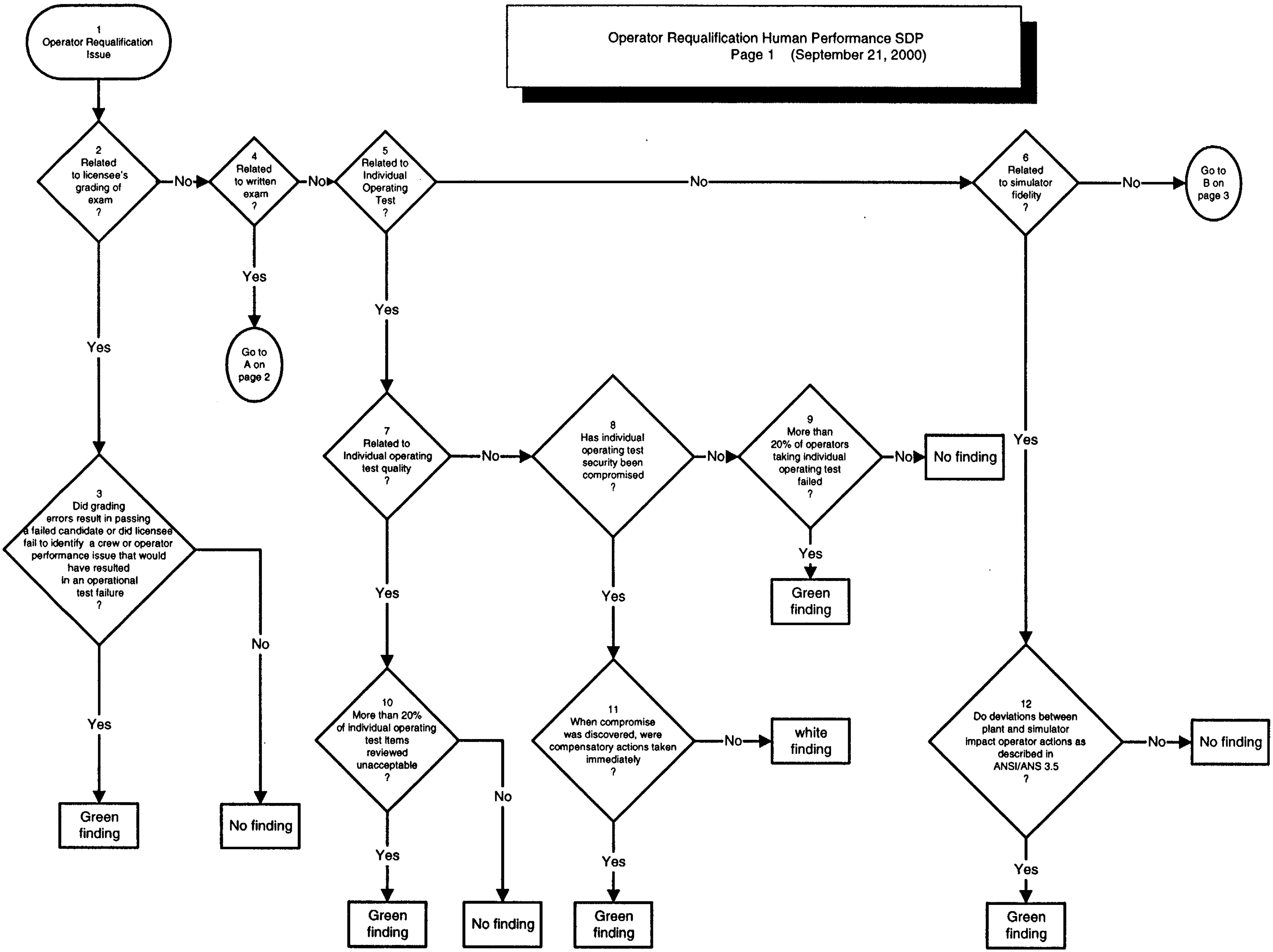
Number of Crews
with
UNSAT Performance in the
Annual Operating Test

Number of Crews that took the Annual Operating Test (Includes Dual Units)

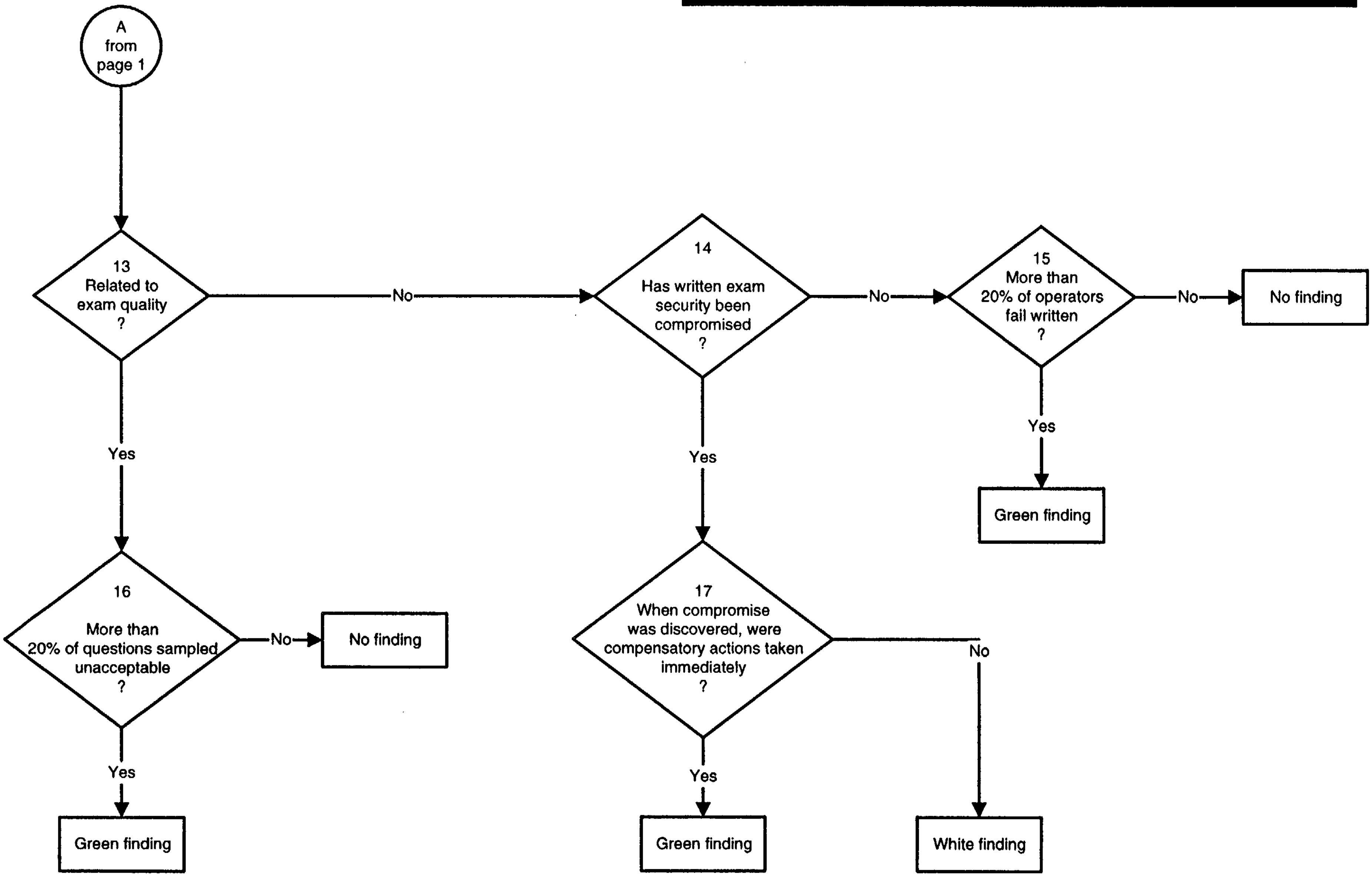
	1	2	3	4	5	6	7	8
4	G	W	Y	Y	NA	NA	NA	NA
5	G	W	Y	Y	Y	NA	NA	NA
6	NF	G	W	Y	Y	Y	NA	NA
7	NF	G	W	Y	Y	Y	Y	NA
8	NF	G	W	W	Y	Y	Y	Y
9	NF	G	G	W	Y	Y	Y	Y
10	NF	G	G	W	W	Y	Y	Y
11	NF	NF	G	W	W	Y	Y	Y
12	NF	NF	G	G	W	W	Y	Y
13	NF	NF	G	G	W	W	Y	Y
14	NF	NF	G	G	W	W	W	Y
15	NF	NF	G	G	G	W	W	Y
16	NF	NF	NF	G	G	W	W	W

NF = < 20% Failure Rate - No Finding
G = 20 - 34% Failure Rate
W = >34 - 50% Failure Rate (NUREG-1021, Rev 8 - UNSAT Requal Program)
Y = >50% Failure Rate
NA = Not Applicable

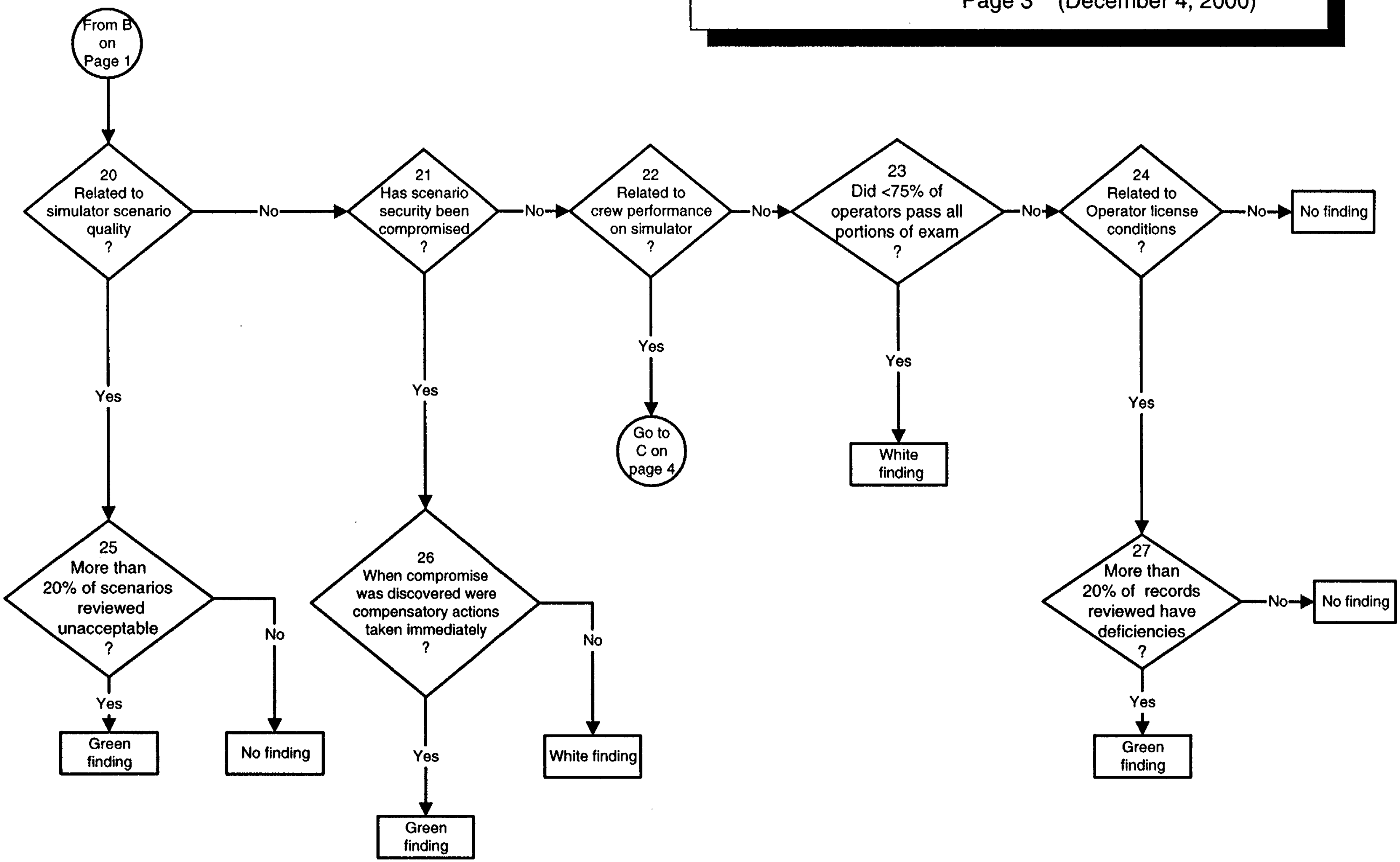
Note: If more than 16 crews are tested, or more than 8 crews are UNSAT in a given cycle, use the percentages above to determine the appropriate color.

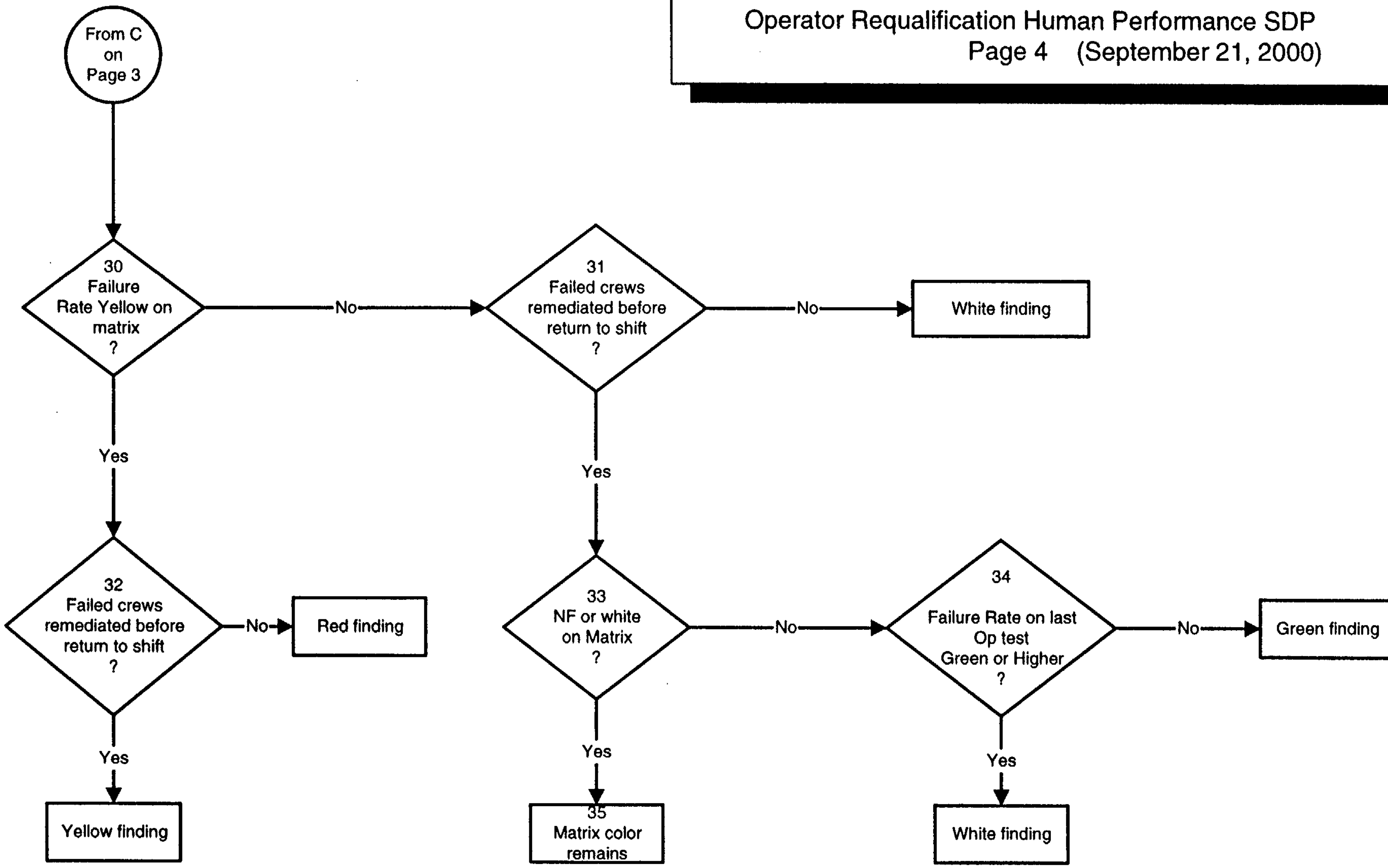

Operator Requalification Human Performance SDP
Page 1 (September 21, 2000)
1 Operator Requalification Issue
2 Related to licensee's grading of exam ?
4 Related to written exam ?
Go to A on page 2
5 Related to Individual Operating Test ?
6 Related to simulator fidelity ?
Go to B on page 3
3 Did grading errors result in passing a failed candidate or did licensee fail to identify a crew or operator performance issue that would have resulted in an operational test failure ?
7 Related to Individual operating test quality ?
8 Has individual operating test security been compromised ?
9 More than 20% of operators taking individual operating test failed ?
10 More than 20% of individual operating test items reviewed unacceptable ?
11 When compromise was discovered, were compensatory actions taken immediately ?
12 Do deviations between plant and simulator impact operator actions as described in ANSI/ANS 3.5 ?
Green finding
No finding
white finding
Yes
No

Operator Requalification Human Performance SDP
Page 2 (September 21, 2000)



Operator Requalification Human Performance SDP
Page 3 (December 4, 2000)




From C on Page 3
30 Failure Rate Yellow on matrix ?
No
31 Failed crews remediated before return to shift ?
No
White finding
Yes
Yes
32 Failed crews remediated before return to shift ?
No
Red finding
Yes
Yellow finding
33 NF or white on Matrix ?
No
34 Failure Rate on last Op test Green or Higher ?
No
Green finding
Yes
35 Matrix color remains
Yes
White finding

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 safety injection recirculation pumps, the recirculation ~~containment~~ sump inside containment, piping and associated valves located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to RHR pumps), 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, and is secured during the transfer to the recirculation phase of the accident. The recirculation pumps remain~~are~~ in standby in the injection phase and are started~~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 their~~its~~ dedicated sump and have the capability to feed the low head injection lines, the containment spray headers~~system~~, ~~low head injection lines~~ and the suction of the high head SI pumps for high head injection. The RHR head exchangers can provide cooling for both the RHR and recirculation flowpaths. 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.~~ The RHR pumps perform the normal decay heat removal function during shutdown operations, and can also be aligned for post accident recirculation. However, the two redundant recirculation pumps represent the primary providers of the low head recirculation function. If a single active failure were to occur, then one recirculation pump would remain available and provides sufficient capacity to meet the core and containment cooling requirements. Only in the event of a passive failure or multiple active failures would it be necessary to align the RHR pumps for recirculation. Use of the RHR pumps for recirculation requires opening two motor operated valves aligned in series to allow suction from the containment sump. How should the recirculation subsystem unavailability be reported under the mitigating system PI for RHR.	Discussed with IP2, IP3, NRC in 8/28 conf. call. 11/1 – IP2, IP3 revision to question and identification of proposed response. **12/6 – Discussed. Tentative Approval**	IP3

Attachment 5

FAQ Log 8				
Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: The Safety System Unavailability Performance Indicator for RHR monitors two functions: 1. The ability of the RHR system to draw suction from the containment sump, cool the fluid, inject at low pressure to the RCS, and 2. The ability of the RHR System to remove decay heat from the reactor during normal shutdown for refueling and maintenance. At Indian Point Units 2 & 3, the two SI Recirculation Pumps and associated valves and components should be counted as two trains of RHR providing post accident recirculation cooling, function 1. The two RHR pumps and associated valves and components should be counted as two trains of RHR providing decay heat removal, function 2. The RHR Heat Exchangers and associated components and valves which serve both RHR and recirculation functions should be shared by an RHR and an SI Recirculation Pump train, functions 1 and 2. The two RHR pumps are also capable of providing backup to function 1. Except as specifically stated in the indicator definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems (or sets of components) that add diversity to the mitigation or prevention of accidents. The RHR pump suction flowpath from the Containment Sump provides passive failure mitigation features which, while supporting a system diversity function, are not included as part of the RHR system components monitored for this indicator. Four (4) trains should be monitored as follows: <u>Train 1 (shutdown cooling mode)</u> "A" train consisting of the "A" RHR pump, "A" RHR heat exchanger, and associated valves. <u>Train 2 (shutdown cooling mode)</u> "B" train consisting of the "B" RHR pump, "B" RHR heat exchanger, and associated valves. <u>Train 3 (recirculation mode)</u> "A" train consisting of the "A" SI Recirculation pump, "A" RHR heat exchanger, and associated valves. <u>Train 4 (recirculation mode)</u> "B" train consisting of the "B" SI Recirculation pump, "B" RHR heat exchanger, and associated valves. The required hours for trains 1 & 2 differ from trains 3 & 4, and will be determined using existing guidelines. Reporting of RHR data should follow this guidance beginning with the first quarter 2001 data submittal.		

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? **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. **Alternate Response (NEI 8/29)** No, provided the configuration can be promptly restored in the control room without the loss of safety function. Restoration actions for the malfunction must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions) and must not require corrective maintenance or a significant problem diagnosis.	. 7/12/00 – NRC action to confirm consistency with MR and expand upon response. 8/2/00 NRC revision to proposed response. 8/29 NEI Alternate response added. 9/20 – Discussed. On hold, NRC to continue review. 10/31 – Discussed. NRC review ongoing. 12/6 -HOLD. NRC to develop wording for NEI99-02 Rev 1	ComEd

FAQ LOG 10				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
10.5	MS01 MS02 MS03 MS04	**Proposed Replacement for FAQ 151** **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. This guidance applies to all safety system unavailability indicators **Alternate Response:** It is appropriate to use the default values. The additional effort to count small numbers of hours is not worthwhile. It is also inconsistent with the approach used in the Maintenance Rule, WANO, and PRA	Discussed 6/14/00 On hold, NEI and NRC review ongoing 10/31 – Discussed. NRC to discuss with Maint. Rule personnel. 12/6 – Discussed. Need to determine Maintenance Rule approach	NRC

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.16	PP01	**Question** For Security Intrusion Detection Systems (IDS), if the number of IDS false alarms exceeds "x" number per hour, the licensee considers the IDS segment failed and implements compensatory measures for the IDS segment. There are two questions: 1) If an IDS segment is declared failed (but left in service) and security personnel's inspection identifies no reason to contact the maintenance organization for resolution and operability testing of the IDS segment by security personnel is successful (without performing corrective maintenance) should compensatory hours be counted for the time period that the IDS was considered as failed? 2) If an IDS segment is declared failed (but left in service) and security personnel contact the maintenance organization for resolution, the maintenance evaluation does <u>not</u> disclose any malfunction, and operability testing of the IDS segment by security personnel is successful, should compensatory hours be counted for the time period that the IDS was considered as failed?	7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 8/29 NEI response revision. 9/21 – Discussed. On hold. 10/27 ComEd revision of FAQ and proposed response. 10/31 – Discussed. NRC to review proposed revision. 12/6 – Discussed. HOLD for discussion on 1/10/01	ComEd
		Licensee Proposed Response: 1) No. Because security's operability test is sufficient in demonstrating that the IDS is performing its intended function, compensatory hours would <u>not</u> be counted. 2) No, Because security's operability test is sufficient in demonstrating that the IDS is performing its intended function and maintenance activities did not repair, replace or identify a malfunction, compensatory hours would <u>not</u> be counted.		

FAQ LOG 12				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
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? **Response**: ~~Yes. In accordance with the current guidance (see FAQ 65), this event would not count. However, for purposes of this PI, the normal heat removal path includes main feedwater, regardless of the plant design or response to a trip. Auxiliary feedwater is not to be considered the normal path.~~ No, this is not an appropriate interpretation, because the MFW system was not available to perform its post trip cooldown function due to a faulted condition	NRC Alternate question and response, 8/28 9/19 NEI Revision of "licensee proposed response" 9/21 – Discussed. On hold. 10/27 NRC revision of response to alternate question. 10/31 – Revised, Tentative Approval 12/6 – Discussed. HOLD revised response.	Kewaunee
12.5	EP01	**Question**: NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators ~~(TSC and EOF),~~ who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of ~~the~~ tracking drill participation. ~~These individuals ultimately approve all offsite communications from their respective facilities, however, they do not collect data for the notification form. The licensee's basis is that NEI 99-02 addresses the desire to not track "phone talkers".~~ The basis for this is that these senior manager are "responsible" for off site notifications because they approve them before they are communicated to off site agencies. ~~1)~~ Is this an appropriate interpretation of 99-02?	8/30 NRC alternate question and response provided and discussed. 9/21 – On hold 10/27 Discussed during 10/27 public meeting. Agreement	Kewaunee

FAQ LOG 12

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response ~~1)~~ No. The expectation of 99-02 is that the participation of the communicators in drills will be tracked through the ERO Drill Participation PI. The communicator is the key ERO position that collects data for the notification form, fills out the form, seeks approval and usually communicates the information to off site agencies. Performance of these duties is assessed for accuracy and timeliness and contributes to the DEP PI. The senior managers in the above example do not perform these duties and should not be considered communicators even though they approve the form and may supervise the work of the communicator. ~~responsible for collection of timely and accurate data for the notification form will be tracked.~~ However, there are cases where the ~~position responsible for approval (the~~ senior manager~~s in the above example)~~ actually collects the data for the form, fills it out, approves it and then communicates it or hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked.	reached on "alternate" question and response. 10/31 -- On hold **12/6 – Final Approval. Post 1/1/01. To apply to 1Q01 data submittal 4/21/01**	

FAQ Log 13				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
13.1	IE03	**Question:** You have a slow leak on a feedwater pump and a work request is initiated and placed on the 12 week schedule, then after 72 hours passes the leakage increases, but the work package is still applicable. You immediately decrease power to fix the pump. Is this considered an unplanned power change since you had a work package written and there was greater than 72 hours? **Response:** The event would count as an Unplanned Power Change. Power changes caused by or in response to off-normal events during the course of a pre-planned activity, count as unplanned power changes when a determination is made that the off-normal events necessitated a course of action that was **outside contingency planning** in place for the pre-planned activities. In these instances, the off-normal events cause, in effect, an **exiting of the preplanned course of action** and any power changes that occur following the exit of the plan are counted toward the performance indicator. Minor modifications to a planned activity in response to events are not considered unplanned power changes and are not counted toward the performance indicator.	**12/6 – Discussed. Tentative Approval**	Beaver Valley
13.2	IE02	**Question:** Crystal River Unit 3 (CR-3) is configured with two once-through steam generators (OTSGs). Two Main Steam Isolation Valves (MSIVs) are installed in each of the two main steam lines. On August 27, 1998, CR-3 was in MODE 1 operating at 100 percent RATED THERMAL POWER. While troubleshooting a half trip signal on the Emergency Feedwater Initiation and Control (EFIC) System Channel A Main Steam Line Isolation (MSLI), both MSIVs to OTSG A closed. This action isolated steam relief to the condenser through the turbine bypass valves from the A OTSG and isolated the steam supply to Main Feedwater Pump (MFP) A. As required by administrative procedures, the reactor operator initiated a manual trip upon closure of the MSIVs. After the manual trip, the OTSG A level lowered enough to initiate Emergency Feedwater (EFW). EFW controlled level in both OTSGs as designed, although MFP B remained in service and available at all times. OTSG B provided RCS heat removal to the condenser with EFW maintaining OTSG level. Does this count? **Response:** No. It must be a complete loss of normal heat removal to count in this indicator.	10/30 NEI addition of proposed response. **12/6 – Discussed. Tentative Approval**	Crystal River 3

FAQ Log 14				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
14.1	MS01 MS02 MS03 MS04	**Proposed Replacement for FAQ 190 (FAQ 190 and current response shown in , followed by proposed replacement)** **Question (Proposed Replacement for FAQ 190):** The guidance in NEI 99-02 states that fault exposure hours may be removed after certain criteria are met. One criterion is that supplemental inspection activities by the NRC have been completed and all open items have been closed out. If a licensee has fault exposure hours that meet all other stated criteria (≥336 hours, corrective actions completed, and four quarters have elapsed) but the indicator is still green, does the baseline inspection count in place of the supplemental inspection? Also, please clarify the intent of the phrase "after 4 quarters have elapsed from discovery." **Response:** 1. No. Fault exposure hours may be removed only if the indicator is outside the green band so that supplemental inspection is necessary (and all other stated criteria are met). The intent of this provision was to allow the removal a large number of fault exposure hours due to a single event or condition so that a licensee would not be outside the green band for an extended time period. There are two reasons for this: (1) after the stated criteria are met, the PI is no longer considered to be indicative of current performance; and (2) unavailable hours accumulated later would put the licensee further into the white band but would not trigger any further NRC action, since the white band is 1.5 to 2 times as wide as the green band. For these reasons, the hours may be removed to reset the indicator so that further fault exposure hours could trigger further NRC response. 2. The intent of the phrase "after 4 quarters have elapsed from discovery" was that the indicator would be non-green for 4 quarters minimum, regardless of when the corrective actions were completed and the supplemental inspection closed out. The quarter in which the fault exposure hours is identified would be the first non-white quarter, and 12 months (four quarters) later, assuming all required conditions are met, the hours could be removed from the calculation for that quarter.	**12/6 – Discussed. Tentative Approval**	NRC feedback form from Catawba
14.2	MS05	**Proposed Replacement for FAQ 143** **Question:** Are failures of the RCIC system included in the Safety System Functional Failure indicator only if RCIC is reportable in accordance with 10 CFR 50.73(a)(2)(v)?	12/5 NEI alternative response added	NRC

FAQ Log 14

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: No. Because RCIC has safety significance at BWRs, and because the ROP is a risk-informed process, failures of RCIC that are reported are included in the SSFF. While the intention of NEI 99-02 was to report only failures meeting the reporting criteria of 10 CFR 50.73(a)(2(v), RCIC reporting has been inconsistent among licensees. To provide consistency in reporting and in the ROP, all failures of RCIC should be reported. The question of RCIC reportability per 10 CFR 50.73 is currently under review by the NRC. **Alternative response:** Yes. That is the way the manual is written.	12/6 -- Discussed. HOLD for NEI 99-02 Rev 1. Need manual wording and threshold review	
14.3	IE02	**Proposed Replacement for FAQ 142** **Question:** Under the Scram with Loss of Normal Heat Removal performance indicator in NEI 99-02 Draft D, 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 or loss of turbine bypass capability. The purpose of the indicator is to count scrams 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,~~ To illustrate, would the following two examples constitute scrams with loss of normal heat removal? 1) A~~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. 2) 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:** 1) No. The determining factor in this indicator is whether or not the normal heat removal path is *available* to the operators, not whether the operators choose to use that or some other path. The indicator excludes events in which the normal heat removal path through the main condenser is easily recoverable from the control room without the need for diagnosis or repair. ~~There was no intent to provide incentive for operators to operate the plant in a manner contrary to best practices for a given situation.~~ 2) Yes. The normal flow path is not being used in this example.	12/5 NEI alternative response added 12/6 - Discussed. Hold for 1/10/01 discussion	NRC
14.4		~~**Proposed replacement for FAQ 151**~~ ~~**Question:**~~ ~~Section 2.2, Mitigating Systems Cornerstone, Safety System Unavailability, Clarifying Notes, Hours Train Required states the Emergency AC power system value is estimated by the number of hours in the reporting period because emergency generators are normally expected to be available for service during both plant operations and shutdown. Considering only one train of Emergency AC power systems may be required in certain operational modes (e.g. when defueled), should actual required hours be determine for each train in place of using the default period hours? In certain operational modes it appears inconsistent to use period hours for hours required, yet not report the unavailable hours if a train is removed from service and Technical Specifications are still satisfied.~~	10/27 NRC revision to proposed response. 12/5 NEI alternative response added **12/6 – Discussed.**	NRC

FAQ Log 14

Temp No.	PI	Question/Response	Status	Plant/ Co.
		~~Response:~~ ~~Use of the default value (period hours) in this case is non-conservative and can produce train unavailable hours that are anywhere from 7.5% to 20% too low. Therefore the use of the default value for EDG unavailability is inappropriate. Licensees should report the actual hours each EDG train is required to be operable. Note: NEI 99-02 will be revised to conform to this guidance.~~ **~~Alternate Response:~~** ~~No. See FAQ 10.5 It is appropriate to use the default~~ values. The ~~additional effort to count small numbers of hours is not worthwhile. It is also inconsistent with the approach used in the Maintenance Rrule, WANO, and PRA.~~	**FAQ deleted. Issued addressed by FAQ 10.5.**	
14.5	MS01 MS02 MS03 MS04	**Question:** NEI 99-02 [page 26] allows for exclusion of test activities from Planned Unavailable Hours if "... the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." NEI 99-02 goes on to state that "The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions." During the performance of certain routine surveillance's, such as Slave Relay Testing, a control switch in the Control Room may be temporarily placed in an "out-of-normal" position to support the test. An example would be placing a Residual Heat Removal Pump switch in the "Pull-to-Lock" position. Can the time that this switch is in this position be excluded from Planned Unavailability Hours if the following conditions are met? 1) This switch is not danger tagged or otherwise restricted from being promptly returned to its normal position, and 2) this switch is within the control responsibilities of a regularly assigned control room operator(s), and 3) this switch can be virtually certain to be successfully restored to its proper position by initial steps taken per the station's Emergency Operating Procedures for immediate response to an accident condition. Does a control room operator have to be specifically designated as responsible for the restoration of a component in the control room, under the same conditions noted above, if such restoration can be virtually certain to be successful under the station's Emergency Operating Procedures for immediate response to an accident condition?	12/5 NEI HOLD. To be rewritten	Seabrook
		Licensee Proposed Response: The answer to the first question is "Yes". Positioning a switch in the Control Room to support test/surveillance activities does not render the respective system or train "unavailable" if that switch position is either overridden by an actual emergency actuation signal or that switch can be returned to its normal position promptly by a control room operator without requiring additional actions such as clearing tags. If the position of this switch would be verified or returned to "normal" by procedures intended to guide the control room operators through a sequenced, directed response to an actual emergency, it can be considered to be virtually certain to be successfully restored. The answer to the second question is "No". A specifically designated (i.e., "dedicated") control room operator is not required to be assigned for component restoration if the component can be promptly returned to its normal condition by a control room operator without requiring additional actions such as clearing tags. The position of the component would be verified or returned to "normal" by procedures intended to guide the control room operators through a sequenced, directed response to an actual emergency.		

FAQ Log 15				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
15.1	PP01	**Question:** If a new Intrusion Detection System (IDS) or Closed Circuit Television (CCTV) design change package has been prepared by Engineering and funding for the new upgrade has been approved by management but the physical installation will not occur immediately, when does the NEI 99-02 "Scheduled equipment upgrade" exemption occur to stop counting the compensatory hours?	Introduced 10/31 12/5 NEI response revision	SONGS
		~~Licensee Proposed~~ Response: Licensees have established business work practices to design, fund, procure, and install upgrades -- such as to the IDS/CCTV. As stated in NEI 99-02, "Compensatory hours stop being counted for the PI when such an evaluation is made and the station has formally initiated the modification/upgrade action". Therefore, once a licensee has committed funding, ~~the licensee should not be penalized~~ compensatory hours should not be counted for the period between funding approval and final installation turnover.		
15.2	OR01	**Question:** A Technical Specification High Radiation Area Performance Indicator occurrence is defined as a nonconformance with technical specifications and comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) that results in the loss of radiological control. What are the comparable requirements in 10CFR20 applicable to these high radiation areas?	Introduced 10/31 **12/6 – Discussed. Tentative Approval**	NEI
		Response: The comparable requirements in 10CFR20 applicable to high radiation areas (>1 rem per hour) are found in 10CFR20.1601 "Control of access to high radiation areas". Paragraphs (a), (b), (c), and (d) apply.		
15.3	BI02	**Question:** In the clarifying notes section of the Reactor Coolant System Leakage indicator, required data is identified as, "All calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator." Within our Technical Specifications identified leakage is calculated on a set frequency using a surveillance procedure. The procedure measures various drain and relief tank levels over time and requires the test to be run for at least 120 minutes to produce acceptable results. The test is required to be performed at steady state conditions to guarantee accuracy. During off-normal conditions, for example leakage past a drain valve of a pump, control room operators may estimate leakage by monitoring drain/relief tank level over time and produce a leakage value within a few minutes. This estimation does not meet the Technical Specification surveillance prerequisites, the acceptance criteria, does not maintain the same measurement accuracy, and does not meet the surveillance requirements. The only similarity is that a tank level over time is being measured. Are leakage estimations as described above to be included as part of the data elements for the RCS identified Leakage indicator?	Introduced 10/31 12/6/00 – Discussed. Response revision. NEI HOLD	Beaver Valley

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
		~~Licensee Proposed~~ Response: No. The TS surveillance procedure was not followed, in that the 120 minute period was not used~~The clarifying note applied to RCS Identified Leakage which discusses "calculational methodology" was not intended to represent portions of a TS surveillance, like that used for the leakage estimation or "hand calculations" discussed above. The calculational methodology represents those RCS Identified Leakage calculations conducted using the same conditions and processes as those described by Technical Specifications, but conducted outside of the normal Technical Specification required frequency. An example of this would be administratively performing daily RCS Identified Leakage calculations for trending purposes using the TS surveillance procedure.~~		
15.4	MS01 MS02 MS03 MS04	**Question:** NEI 99-02 Revision 0, states the following regarding Planned Unavailable Hours: "Testing, unless the test configuration is automatically overridden by a valid staring signal or the function can be promptly restored either by an operator in the control room or a dedicated operator stationed locally for that purpose. Restoration actions must be contained in a written procedure, must be uncomplicated (a simple action or a few simple actions) and must not require diagnosis or repair. Credit for a dedicated 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. The intent of this paragraph is to allow licensees to take credit for restoration action that are virtually certain to be successful (i.e. probability nearly equal to 1) during accident conditions." The question is whether normal surveillance test restoration steps (normally used to re-align the system after the surveillance testing is complete) are adequate to satisfy the requirements for a "written procedure." Example: The Low Pressure Injection (LPI) surveillance procedure (SP) has the LPI pump discharge aligned to the "recirculation line" and flowing to the Borated Water Storage Tank. Closing one motor operated valve (MOV), if an accident were to take place, would isolate this flow path. The MOV would be closed from the control room. The restoration actions for the SP have closure of this valve as part of the normal plant restoration. In this case, CR-3 engineering personnel believe that the restoration instructions in the surveillance procedure are adequate to meet the intent of a "written procedure" identified in the above paragraph from NEI 99-02. **Response:** Yes, normal surveillance test restoration steps are adequate to satisfy the requirements for a "written procedure." A separate restoration procedure need not be prepared.	Introduced 10/31 **12/6 – Discussed. Response added. Tentative Approval**	Crystal River
15.5	EP01	**Question:** Can ainitial notification be considered accurate if some of the elements on that notification form are in error?	Introduced 10/31 12/5 NRC --	NEI

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: ~~Yes. NUREG-0654 specifies the required elements to be provided in initial notifications. Those elements are:~~ ~~Class of emergency~~ ~~Whether a release is taking place~~ ~~Potentially affected population and areas~~ ~~(and) whether protective measures may be necessary~~ ~~If these elements are accurately completed, the critical elements necessary to address the public health and safety have been appropriately communicated.~~ ~~Inaccuracies in other information should be addressed through the corrective action process.~~ Yes. NEI 99-02 indicates on page 91, line 27 that accuracy is defined by the approved Emergency Plan and implementing procedures. However, it is realized that functionally, some of the items on an initial notification form may not be significant in that mistakes in that information will not affect the offsite response. The elements which should be assessed for accuracy on the initial notification include: Class of emergency EAL # Description of emergency (Note: the description of the event causing the classification may be brief and should not include all plant conditions. At some sites, the EAL # fulfills the need for a description.) Wind direction and speed Whether offsite protective measures are necessary Potentially affected population and areas Whether a release is taking place (Note: "release" means a radiological release attributable to the emergency event.) Date and time of declaration of emergency Whether the event is a drill or actual event Plant and/or unit, as applicable It is understood that initial notification forms are negotiated with offsite authorities. If the approved form does not include these elements, they need not be added. Alternately, if the form includes elements in addition to these, those elements need not be assessed for accuracy when determining the DEP PI. It is, however, expected that errors in such additional elements would be critiqued and addressed through the corrective action system	Revision to question and response based on discussions during 11/30 public meeting. **12/6 – Discussed. Tentative Approval**	

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
15.6	EP01	**Question:** Part A – Indication of the event was available to the operators A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was available to the operators. a) Should the condition described be considered as a missed classification opportunity? b) Should the condition described be considered as a missed notification opportunity? Part B – Indication of the event was not available to the operators A licensee may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. Indication of the event was not available to the operators. In determination of whether indications were indeed not available to the operators, the timeliness of necessary calculations, verification efforts, etc. as required by EALs or physical reality, must be considered. c) Should the condition described be considered as a missed classification opportunity? d) Should the condition described be considered as a missed notification opportunity? **Response:** Part A – Indication of the event was available to the operators a) Yes, this classification was not timely. b) No. NUREG 1022 described the notification requirements for this consideration. Part B – Indication of the event was not available to the operators c) No, indication of the emergency was not available to operators until the basis for the emergency no longer existed. d) No. NUREG 1022 describes the notification requirements for this consideration.	Introduced 10/31 10/31 – Tentative Approval **12/6 Discussed. Revised. Tevtative Approval.**	NEI
15.7	EP01	**Question:** Assume that an event has occurred that has resulted in an Emergency Classification. Subsequently, a utility review of the event reveals that the classification was made conservatively and that, in fact, no emergency classification criterion was exceeded. Should the event be considered as an opportunity? **Response:** Yes, the event should be considered as an opportunity. The classification opportunity should **not** be considered as a success because it was not declared accurately according to the review conducted by the utility.	Introduced 10/31 10/31 – Tentative Approval **12/6 – Approved. Post 1/1/01. Applies to 1Q01 results going forward**	NEI

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Temp No.	PI	Question/Response	Status	Plant/ Co.
15.8	MS01	**Question:** The Emergency AC Power System monitored function for the indicator is, "The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power." However, on page 26 of NEI 99-02, Rev 0 under testing where simple operator action is allowed for restoration, it states "The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions." For purposes of this indicator are we to assume a simultaneous loss of off-site power and also accident conditions? ~~Or only loss of off-site power?~~ This may make a difference on the diesel generator response, operator restoration actions and ultimately whether or not we count unavailability during our surveillance test runs. **Response:** No. NEI 99-02 says on page 46 lines 10 to 13: The function monitored for the indicator is: The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power.	Introduced 10/31 12/5 NEI Response added	VY
15.9	MS02	**Question:** ~~The Harris Plant requests assistance in determining "Fault Exposure" time for a unique equipment arrangement. Harris has three installed Charging Safety Injection Pumps (CSIPs), which can provide normal charging as well as become the High-Head Safety Injection Pumps in the event of a Safety Injection Actuation. Only two of these pumps can be in service at a time, one per safety train. The third pump, usually C CSIP, is in a standby condition. In standby, the C CSIP can be aligned to either train to substitute for the normal A or B CSIP while either is out of service (cannot have two pumps on the same train simultaneously due to electrical bus loading limitations).~~ ~~In September 2000, it was discovered that C CSIP had experienced bearing damage at some point since May 1999. This was determined by the results of routine periodic oil analysis for the pump after pump maintenance uncovered the bearing damage. Over the time span from May 1999 to September 2000, the C CSIP had been used on both A and B safety trains at various times. During the times it was used, C CSIP satisfactorily passed all surveillance tests and there was no indication of bearing damage from high vibrations. Only after pump disassembly, and an engineering assessment, was it clear that the pump would potentially not have fulfilled its safety function for all design basis accidents.~~ ~~Determining when and how to count Fault Exposure time is the problem. The pump was last in service in January 2000. If you count the hours since time of discovery back to last known time of availability (last good oil analysis), the T/2 or halfway point chronologically is around January 8th, 2000. Since C CSIP was not in service on either safety train since January 2000, this would allow you to not count any of the hours as Fault Exposure Time. However, if you count all of the actual time C CSIP was in service in November and December 1999, the Performance Indicator is white. Furthermore, counting the time in service for C CSIP in May and June of 1999 would send the indicator into the white zone even earlier.~~ How should "t over 2" Fault Exposure time be counted for an installed spare? ~~**Licensee Proposed**~~ **Response:** ~~While the current definition for calculating Fault Exposure would allow us to not count any time for this event, this approach does not seem to be in keeping with what we are trying to demonstrate with this PI. Harris Plant believes that~~ The most appropriate way to count "t over 2" Fault Exposure time for intermittently used equipment, is to count half the time the equipment was actually required to be available.~~in service. Another option is to not count time for this type of equipment if it is already over a year since it was last in service or only count time in service during the last year.~~	Introduced 10/27 12/5 NEI revision 12/6 – Discussed NRC rewrite to be provided 1/10/01	Harris

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Temp No.	PI	Question/Response	Status	Plant/ Co.
15.10	IE03	**Question:** FAQ 6 describes a situation where degraded equipment conditions are monitored and plans are made for repairs. The monitoring continues beyond 72 hours from the problem identification until an administratively established limit is achieved. FAQ 6 indicates this would not be counted in the unplanned power change indicator. Similarly we have a situation of known potential degradation, however, it involves multiple equipment components. Specifically cooling tower components that may require power reductions of >20% power to repair the degraded condition(s). There is a monitoring program established that identifies off-normal conditions as well as establishing administrative limits for the components at which time a plant shutdown should be initiated. If the time period between discovery of an off-normal condition (identification of specific degraded component) and the power reduction exceeds 72 hours until the administratively established limit is reached, does this count as an unplanned power change. ~~Licensee Proposed~~ **Response:** No. Provided the time period between the discovery of an off-normal condition of the specific component (that would require a power reduction upon reaching the administrative limits) and the power reduction exceeds 72 hours for each degradation occurrence.	Introduced 10/31 **10/31 – Discussed. Tentative Approval.**	Southern Co.
15.11	PP01	**Question:** NEI 99-02 Rev. 0, page 127, "Definition of Terms" defines "CCTV" as "The closed circuit television cameras that support the IDS." and "CCTV Normalization Factor." as "the total number of perimeter cameras divided by 30." At our plant, and possibly other larger plants, other cameras referred to as "pan-tilt-zoom" or "PTZ" cameras "support" the IDS, thus could be construed to meet the definition of "CCTV." The PTZ cameras can be positioned to monitor most perimeter zones (e.g., when perimeter cameras are unavailable), but are not physically on the perimeter. It is unclear if the PTZ cameras meet the definition of perimeter camera for inclusion in the CCTV Normalization Factor. The stated purpose of the CCTV normalization factor to compensate for larger than nominal plant sizes. Can PTZ cameras be credited in the CCTV normalization factor? **Response:** PTZ cameras are used to provide additional information to the perimeter cameras or as backup to perimeter cameras should they be out of service. PTZ cameras therefore would not be included in calculating the CCTV normalization factor. Note however: IF a PTZ camera is the primary perimeter camera, it would count in the normalization factor.	Introduced 10/31	APSC
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?	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added.	ComEd

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		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. 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.		
15.13	All	**Question:** How does uncertain data resulting from missing information or lack of credible information (i.e., willful acts) impact current and past PI data reporting? **Response:** The past or current data must be revised when the correct information is determined, regardless of the cause.	Introduced 10/31 12/5 NEI, Response added	PECO

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Temp No.	PI	Question/Response	Status	Plant/ Co.
16.1	IE01	**Question:** Following a forced outage during which work was performed on a reactor coolant pump motor to reduce vibration, the unit was restarted. It should be noted the forced outage was not the result of the reactor coolant pump problem; the unit tripped for other reasons. During the unit restart while increasing power, an annunciator came in indicating excessive vibration on the reactor coolant pump in question. The annunciator response procedure directed the unit operator to an emergency shutdown procedure. The emergency shutdown procedure then instructed the unit operator to rapidly shut down the unit, however this particular procedure accomplishes rapid shut down <u>without a reactor trip</u> in that it directs the power level to be brought down to a nominal value prior to instructing the reactor trip breaker to be opened. This shutdown sequence is consistent with normal shutdown procedures. Would this be considered an unplanned SCRAM or an unplanned power change? **Response:** It would count as an unplanned power change.	Introduced 12/6	TVA
16.2	MS03	**Question:** The Nuclear Service Water (NSW) system provides assured suction supply to the Auxiliary Feedwater (AFW) system under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal non-safety related, non-seismic condensate suction sources are be assumed to be unavailable. Flow testing is performed under the plant's Generic Letter 89-13 program to assure adequate flow. The alignment used in this testing renders this flowpath unavailable to fulfill its assured supply function. However, the normal condensate source remains available. Recently a reactor trip occurred during the performance of this testing. The testing was terminated, but due to resource limitations during event recovery, the normal operating alignment was not restored. Therefore, the assured AFW supply remained unavailable for an extended period. However, during the event, the AFW system started automatically on a valid autostart signal (2/4 lo-lo SG level in 1/4 SGs, loss of both main feedwater pumps) and continued to operate for a period of two days to maintain steam generator levels drawing suction from the normal condensate supply. Previously, whenever the assured supply has been unavailable, whether for testing or other alignments, the entire AFW system has been deemed unavailable based on a hypothetical design basis event scenario. However, the real world event described above results in the dichotomy of calling a system unavailable because its assured supply is unavailable while it was in fact fulfilling its design basis function. Under the NEI 99-02 guidelines, how should unavailability be addressed in conditions where the assured supply is unavailable with the normal supply available? **Response:**	Introduced 12/6	Catawba

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16.3	MS01 MS02 MS03 MS04	**Question:** Concerning removal of fault unavailable hours NEI 99-02 states: "Fault exposure hours associated with a single item may be removed after 4 quarters have elapsed from discovery…" In the case we are considering, the hours were discovered in the third calendar quarter. When do the four elapsed quarters begin? At the start of the fourth calendar quarter? and end at the conclusion of next year's third quarter? If the period of calculation of the indicator value was only four calendar quarters beginning the quarter after they occurred, and the fault unavailable hours are reported in the quarter in which they occurred, what's the point in removing them after they are no longer a factor in the calculation of the indicator? "Fault exposure hours are removed by submitting a change report that provides a revision to the reported hours for the affected quarter(s). The change report should include a comment to document this action." **Response:**	Introduced 12/6	IP2
16.4	BI01	**Question:** NRC Performance Indicator BI-01 monitors the integrity of the fuel cladding. We are required to report the maximum monthly RCS activity in micro-Curies per gram dose equivalent Iodine-131 and express it as a percentage of the technical specification limit. FAQ 226 asks if licensees with limits more restrictive than the technical specification limit should use the more restrictive limit or the TS limit. The FAQ answer states that the licensee should use the most restrictive regulatory limit unless it is "insufficient to assure plant safety." If administrative controls are imposed "... to ensure that TS limits are met and to ensure the public health and safety, that limit should be used for this PI." Vermont Yankee has a Basis for Maintaining Operation (BMO) that is in effect that limits the Reactor Coolant System to 0.05 uCi/gm I-131 dose equivalent. This BMO, 98-36, entitled "Effect of Main steam Tunnel and Turbine Building HELBs on the HVAC Rooms," is concerned with Control Room habitability and the regulatory dose limits to the operators. It states that there is no concern with increased radiological dose to the public from the VY HELB off-site dose analyses in FSAR Section 14.6. FAQ 226 mentions the concern for both assuring plant safety and public health and safety as the intent for the more restrictive administrative controls that may be in effect. NRC Administrative Letter 98-10, which is mentioned in the answer to this FAQ, states in the Discussion that the concern is the safe operation of the facility. Our question is this: "Is Vermont Yankee required to use the lower administrative limit imposed by the BMO (0.05 uCi/gm I-131 dose equivalent) even though public health and safety is not compromised if this limit is exceeded?" **Response:**	Introduced 12/6	VY

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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 (not a "dedicated" operator) within 10 minutes. Should this be counted as unavailable time? **Licensee Proposed Response:** Ginna Station should be allowed to use their Tech Spec requirements (manually started within 10 minutes) as guidance for counting Planned Unavailable Hours for the SDAFW pumps during testing, i.e. if the Standby Aux Feedwater Pumps are available by Tech Spec, the PI should not count them as not available.	Introduced 12/6 Discussed. Need to confirm compliance with NUREG 0737	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." Ginna 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? **Licensee Proposed Response:** Yes, this meets the NEI 99-02 guidance for not counting the testing as planned unavailable hours. Ginna 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 Ginna 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	Ginna
16.7	EP03	**Question:** If a siren is out of service during a planned overhaul or upgrade project does this need to count as both a siren test and a siren failure?	Introduced 12/6 . **12/6 Tentative Approval**	NRC

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		Discussion: The ANS PI measures the percentage of ANS sirens that are capable of performing their safety function, as measured by periodic siren testing in the previous four quarters. NEI 99-02 states, "If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test is conducted, then it counts as both a siren test and a siren failure." ANS systems are aging and many sites are considering and/or performing siren overhaul or system upgrade projects. The ANS PI threshold may impact project planning in an unintended manner. It is not the intent to create a disincentive for performing ANS overhaul or upgrade projects. When sirens are out of service for such projects, it is expected that the utility arrange for back-up public alerting in the appropriate siren coverage areas. This support is typically provided by local offsite agencies and often involves route alerting. The acceptable time frame for allowing a siren to remain out of service for system upgrade or preventive maintenance should be coordinated with the cognizant offsite agencies. Based on the impact to local agencies and the ANS functionality, outage time frames should be minimized and specified in ANS Upgrade/Overhaul Project Documents. When the time frame is identified in advance as part of an upgrade or overhaul project, and back-up public alerting coverage agreed to by offsite agencies, regularly scheduled tests during the siren outage may be excluded from the ANS PI statistics. Deviations from the advance outage schedule would constitute unplanned siren reliability and siren-test failures outside of the preplanned outage window would be included in the PI. This modification of the PI is not intended for preventative or corrective maintenance, i.e., siren-test failures due to preventative or corrective maintenance must be included in the ANS PI. **Response:** No, if the ANS overhaul or upgrade project meets certain requirements as delineated in the discussion section of this FAQ. However, the exclusion is not intended for preventative or corrective maintenance.		
16.8	MS04	**Question:** If a plant is allowed to secure a SDC Train and NOT be in a LCO "action" statement, are they required to take SDC train unavailability? **Licensee Proposed Response:** No. A SDC train "is required" as specified in the plants Technical Specifications. If the plant is not in a SDC LCO action statement then no SDC (RHR) unavailability is incurred.	Introduced 12/6 12/6 Discussed. HOLD need more information	Calvert Cliffs
16.9	MS04	**Question:** If plant conditions only require 1 SDC (RHR) loop to be operable and in operation, may it be replaced with an alternate NRC approved means of decay heat removal without incurring SDC (RHR) unavailability? **Licensee Proposed Response:** Yes,. See FAQ ??	Introduced 12/6	Calvert Cliffs

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16.10	MS01	**Question:** Turkey Point's Unit 3 Emergency Diesel Generators EDGs) are air-cooled, using very large radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant decided to replace them. Replacing all eight radiator assemblies is a labor-intensive activity, that requires that sections of the missile shield grating be removed, heat deflecting cowling be cut away, and support structures be built above and around the existing radiators to facilitate the fitup process. This activity could not have been completed within the standard 72 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02 allows for the exclusion of planned overhaul maintenance hours from the EAC performance indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the majority of the cooling system, for which an extended AOT was granted, qualify as overhaul maintenance?	Introduced 12/6	Turkey Point
		Licensee Proposed Response: In this specific case, yes, for three reasons: (1) that activity involves disassembly and reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine alone (every 12 years); and (3) the NRC specifically granted an AOT extension for this activity.		
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?	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question	San Onofre
		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.		

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Temp No.	PI	Question/Response	Status	Plant/ Co.
16.12		**Question:** A recently issued FAQ for the NRC Performance Indicators Program revised the positions taken for unavailability associated with planned overhaul hours. FAQ 178 was withdrawn from NEI 99-02 and replaced with FAQ 219. The new FAQ, effective for fourth quarter reporting, adds two clarifying questions and answers to the previous FAQ 178. These two additional items are: Q. What is considered to be a major component for overhaul purposes? A. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its motor or turbine driver or heat exchangers. Q. 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? A. For this indicator, only planned overhaul maintenance of the four monitored systems (not to include support systems) may be considered for the exemption of planned unavailable hours. At Catawba Nuclear Station, periodic testing indicated that crud and rust accumulation in the Nuclear Service Water System (NSWS) headers and piping was reducing water flow. To restore the water flow and the prevent further deterioration of the headers and piping, a refurbishment project was planned to clean the system, replace part of the piping, and rearrange certain piping access to the headers to avoid water stagnation. Since the NSWS is a shared system between both Catawba units, it was decided that the optimum time to perform this work would be while Unit 1 was in a refueling outage and Unit 2 was at power. This project included both "A" and "B" redundant trains of the system and was sequenced independently during the recent Catawba Nuclear Station Unit 1 End of Cycle 12 (1EOC12) refueling outage. Approximately 8,000 feet of piping was cleaned that included 4,260 feet of 42 inch, 760 feet of 30 inch, 330 feet of 24 inch, 660 feet of 18 inch, 1,935 feet of 10 inch, and 100 feet of 8 inch. Due to the extensive nature of the work performed, each train of NSWS was unavailable for approximately ten days. Applicable technical specifications were revised through the standard NRC approval process (reference Amendment No. 189 to FOL NPF-35 and Amendment No. 182 to FOL NPF-52 approved October 4, 2000) to allow this project to be performed. These amendments allowed specific systems, including mitigating systems monitored under the NRC performance indicator program, to be inoperable beyond the normal technical specification allowable outage times (AOT) of 72 hours for up to a total of 288 hours on a one-time basis. A significant part of the justification for the license amendment request was a discussion of the risk assessment of the proposed change and the NRC concluded in the SER that the results and insights of the risk analysis supported the proposed temporary AOT extensions. The NSWS itself is not a monitored system under the performance indicators; however, its unavailability does affect various systems and components, many of which are considered major components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps). The specific performance indicators affected by unavailability of the NSWS are contained in the Mitigating Systems Cornerstone and include: Emergency AC Power System Unavailability, High Pressure Safety Injection System Unavailability, Auxiliary Feedwater System Unavailability, and Residual Heat Removal System Unavailability. If the hours that this overhaul of the NSWS made its supported systems unavailable cannot be excluded from reporting under the performance indicators, it will result in Catawba Unit 2 reporting two white indicators for the 4Q2000 data. These two white indicators for Emergency AC Power System Unavailability and Residual Heat Removal System Unavailability would result in a degraded cornerstone situation as defined in the NRC Action Matrix. Additionally, since these indicators are twelve quarter averages, carrying these hours for the next three years would result in decreased margin to the white/yellow threshold and greatly increase the consequences of additional unavailable hours that might occur during that period of time. Based on input from NRC and NEI individuals who participated in discussions related to FAQ 219, Duke Energy understands that there was a desire to eliminate exclusion of monitored systems unavailable hours caused by minor "overhaul" type activities on supporting systems. However, it seems unreasonable to require reporting of unavailable hours for situations such as this when the overhaul activities are extensive enough to have required NRC review and approval of a change in technical specifications to allow the increased AOT.	Introduced 12/6 12/6 Discussed. HOLD: did the risk analysis for extension consider the impact on front line systems?	Catawba

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		Licensee Proposed Response: Situations for which a licensee has sought and received NRC approval of a technical specification change to allow increased AOT to accomplish overhaul activities permit exemption of reporting those unavailable hours even for situations where the overhaul activities were performed on a support system.		
16.13	MS04	**Question:** **Appendix D** Since South Texas Project has a unique design for the systems that satisfy the RHR function of the performance indicator, how should unavailability hours be counted for those systems?	Introduced 12/6 12/6 Discussed. HOLD needs detailed	South Texas

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		Response: NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions: • The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS • The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger. Due to the unique design South Texas project has interpreted the requirements of NEI 99-02 and is applying that interpretation as follows: • In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low Head Safety Injection Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS". The RHR pump does not contribute to the performance of this safety function since it can not take suction on the containment sump. • In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in Modes 1, 2, and 3 due to the system design. This requirement prevents the system from performing its intended cooling function until plant pressure and temperature are lowered to a value consistent with the system design. Overlap times when both functions/systems are required will be adjusted to eliminate double counting the same time periods. This position is consistent with the direction published in Frequently Asked Question #149. We need to add words to the effect: In mode 1,2,3, the time that the Component Cooling and Essential Cooling support systems are out of service, thus the cooling medium to the RHR Heat Exchanger should be excluded because the injection method uses cooled water from the Reactor Water Storage Tank. In the recirculation phase we need to be able to declare the RHR Heat Exchangers as two 100% heat exchangers capable of performing their design function as required by design basis analysis and meeting the single failure criteria. I think that evaluation of CR 00-16902 should cover the issue. We also need the words to discuss the fact that our PRA for RHR is greater than 200 days for a RHR train in a year.	discussion w/ STP	

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.14	MS03	**Question:** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of 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 (like the Palo Verde startup feedwater pump) 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. Based upon discussions with Palo Verde, their startup feedwater pump is Class 1E powered and automatically connected to an EDG. 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. However, the Palo Verde startup feedwater pump appears to be even more risk significant due to the lack of power-operated relief valves on the reactor coolant system, which inhibits their ability to cool the primary utilizing "feed and bleed." 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 FAQs 205 and 206 submitted by Crystal River regarding the auxiliary feedwater system) **Response:**	Introduced 12/6	Davis-Besse

Review of FAQs in NEI 99-02 (Rev 0)

FAQs currently on NRC Website were reviewed by cornerstone and placed into one of the following categories shown below. The Website contains 233 FAQs with a printed date of November 02, 2000. The purpose of the review is to provide input to changes to the next revision of NEI 99-02.

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS,

B. ADD TO CLARIFYING NOTES SECTION,

C. UNIQUE PLANT SITUATION,

D. NO LONGER NECESSARY,

E. WITHDRAWN.

DUPLICATES.

FAQ CORNERSTONE REVIEW - INITIATING EVENTS

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

217, 228, 227.

B. ADD TO CLARIFYING NOTES SECTION:

180, 142, 4, 231, 158, 157, 2, 1.

C. UNIQUE PLANT SITUATION:

D. NO LONGER NECESSARY:

159, 5, 220, 204, 65, 166, 165, 6, 3.

E. WITHDRAWN:

196.

DUPLICATES:

FAQ CORNERSTONE REVIEW - MITIGATING SYSTEMS

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

225.

B. ADD TO CLARIFYING NOTES SECTION:

201, 170, 151, 150, 219, 154, 86, 74, 11, 153, 148, 145, 10, 9, 8.

C. UNIQUE PLANT SITUATION:

218, 194, 224, 199, 191, 187, 167, 165, 73, 87, 71, 18, 15, 12, 223, 188, 206, 205, 182, 221, 172, 149, 143.

D. NO LONGER NECESSARY:

171, 192, 181, 179, 175, 168, 152, 147, 88, 70, 19, 14, 21, 20, 17, 13, 176, 222, 183, 164, 155, 146, 144.

E. WITHDRAWN:

169, 178.

DUPLICATES:

175~147, 192~88.

FAQ CORNERSTONE REVIEW - BARRIER INTEGRITY

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

B. ADD TO CLARIFYING NOTES SECTION:

226, 177, 23.

C. UNIQUE PLANT SITUATION:

22, 135, 79.

D. NO LONGER NECESSARY:

72, 84, 25, 24.

E. WITHDRAWN:

DUPLICATES:

193.

FAQ CORNERSTONE REVIEW - EMERGENCY PREPAREDNESS

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

202.

B. ADD TO CLARIFYING NOTES SECTION:

198, 197, 173, 43, ,40, 34, 29, 233, 54, 50, 44, 123, 122.

C. UNIQUE PLANT SITUATION:

200, 124.

D. NO LONGER NECESSARY:

195, 125, 41, 39, 38, 37, 36, 35, 33, 32, 31, 30, 28, 27, 26, 126, 85, 53, 52, 51, 49, 48, 47, 46, 45, 232, 229, 174, 56, 55.

E. WITHDRAWN:

DUPLICATES:

FAQ CORNERSTONE REVIEW - OCCUPATIONAL RADIATION SAFETY

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

B. ADD TO CLARIFYING NOTES SECTION:

132, 131, 110, 109, 101, 99.

C. UNIQUE PLANT SITUATION:

D. NO LONGER NECESSARY:

203, 130, 95, 112, 111, 108, 107, 106, 105, 104, 103, 102, 100, 98, 97, 96, 94, 93, 92, 91.

E. WITHDRAWN:

DUPLICATES:

FAQ CORNERSTONE REVIEW - PUBLIC RADIATION SAFETY

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

B. ADD TO CLARIFYING NOTES SECTION:

90.

C. UNIQUE PLANT SITUATION:

D. NO LONGER NECESSARY:

E. WITHDRAWN:

DUPLICATES:

FAQ CORNERSTONE REVIEW - PHYSICAL PROTECTION

A. WILL CHANGE NEI 99-02 TEXT UP TO THE DEFINITION OF TERMS:

128, 121.

B. ADD TO CLARIFYING NOTES SECTION:

230, 160, 83, 82, 81, 80, 61, 60, 59, 58.

C. UNIQUE PLANT SITUATION:

185, 184, 161, 77.

D. NO LONGER NECESSARY:

189, 163, 162, 141, 140, 139, 138, 137, 136, 68, 57, 134, 133, 127, 129, 67.

E. WITHDRAWN:

120, 119, 118, 117, 116, 115, 114, 113.

DUPLICATES:

12.5

EP-01

NEI 99-02, Rev 0, page 100, lines 11-15, discusses the role of communicators who provide offsite notifications. A site has identified the TSC and EOF senior managers as communicators for the purposes of the tracking drill participation. The basis for this is that these senior managers are "responsible" for off site notifications because they approve them before they are communicated to off site agencies.

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

Answer

1) No. The expectation of 99-02 is that the participation of communicators in drills will be tracked through the ERO Drill Participation PI. The communicator is the key ERO position that collects data for the notification form, fills out the form, seeks approval and usually communicates the information to off site agencies. Performance of these duties is assessed for accuracy and timeliness and contributes to the DEP PI. The senior managers in the above example do not perform these duties and should not be considered communicators even though they approve the form and may supervise the work of the communicator.

However, there are cases where the senior manager actually collects the data for the form, fills it out, approves it and then communicates it or hands it off to a phone talker. Where this is the case, the senior manager is also the communicator and the phone talker need not be tracked

FAQ DEP accurate notification 11/30/00

15.5

EP01

Question

Can **initial** notification be considered accurate if some of the elements on that notification form are in error?

NRC Proposed Response:

Yes. NEI 99-02 indicates on page 91, line 27 that accuracy is defined by the approved Emergency Plan and implementing procedures. However, It is realized that functionally, some of the items on an initial notification form may not be significant in that mistakes in that information will not affect the offsite response. The elements which should be assessed for accuracy on the initial notification include:

- Class of emergency
- EAL #
- Description of emergency (Note: the description of the event causing the classification may be brief and should not include all plant conditions. At some sites, the EAL # fulfills the need for a description.)
- Wind direction and speed
- Whether offsite protective measures are necessary
- Potentially affected population and areas
- Whether a release is taking place (Note: "release" means a radiological release attributable to the emergency event.)
- Date and time of declaration of emergency
- Whether the event is a drill or actual event
- plant and/or unit, as applicable

It is understood that initial notification forms are negotiated with offsite authorities. If the approved form does not include these elements, they need not be added. Alternately, if the form includes elements in addition to these, those elements need not be assessed for accuracy when determining the DEP PI. It is, however, expected that errors in such additional elements would be critiqued and addressed through the corrective action system.

FAQ DEP - Discover After the Fact, 11/30/00

15.6 (a) <u>Indication of the event was available to the operators</u>

A license may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the basis for the emergency class no longer exist at the time of discovery. <u>Indication of the event was available to the operators</u>.

a) Should the condition described be considered as a missed classification opportunity?

b) Should the condition described be considered as a missed notification opportunity?

Response:

a) Yes, this classification was not timely.

b) No. NUREG 1022 describes the notification requirements for this consideration.

5.6 (b) <u>Indication of the event was not available to the operators</u>

A license may discover after the fact (greater that 15 minutes) that an event or condition had existed which met the emergency plan criteria but that no emergency had been declared and the bases for the emergency class no longer exist at the time of discovery. <u>Indication of the event was not available to the operators</u>. In determination of whether indications were indeed not available to operators, the timeliness of necessary calculations, verification efforts, etc. as required by EALs or physical reality, must be considered.

a) Should the condition described be considered as a missed classification opportunity?

b) Should the condition described be considered as a missed notification opportunity?

Response:

a) No, indication of the emergency was not available to operators until the basis for the emergency no longer existed.

b) No. NUREG 1022 describes the notification requirements for this consideration.

New FAQ

Siren Upgrade or Replacement – 12/04/00

Discussion:

The ANS PI measures the percentage of ANS sirens that are capable of performing their safety function, as measured by periodic siren testing in the previous four quarters. NEI 99-02 states, "If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test is conducted, then it counts as both a siren test and a siren failure."

ANS systems are aging and many sites are considering and/or performing siren overhaul or system upgrade projects. The ANS PI threshold may impact project planning in an unintended manner. It is not the intent to create a disincentive for performing ANS overhaul or upgrade projects.

When sirens are out of service for such projects, it is expected that the utility arrange for back-up public alerting in the appropriate siren coverage areas. This support is typically provided by local offsite agencies and often involves route alerting. The acceptable time frame for allowing a siren to remain out of service for system upgrade or preventive maintenance should be coordinated with the cognizant offsite agencies. Based on the impact to local agencies and the ANS functionality, outage time frames should be minimized and specified in ANS Upgrade/Overhaul Project Documents. When the time frame is identified in advance as part of an upgrade or overhaul project, and back-up public alerting coverage agreed to by offsite agencies, regularly scheduled tests during the siren outage may be excluded from the ANS PI statistics. Deviations from the advance outage schedule would constitute unplanned siren reliability and siren-test failures outside of the preplanned outage window would be included in the PI. This modification of the PI is not intended for preventative or corrective maintenance, i.e., siren-test failures due to preventative or corrective maintenance must be included in the ANS PI.

Question:

If a siren is out of service during a planned overhaul or upgrade project does this need to count as both a siren test and a siren failure?

Response:

No, if the ANS overhaul or upgrade project meets certain requirements as delineated in the discussion section of this FAQ. However, the exclusion is not intended for preventative or corrective maintenance.

FAQ 174

Question

For plants where scheduled monthly siren tests are initiated by local or state governments, if a scheduled test is not performed either (intentionally or accidentally), is this considered a failure?

Answer

No. For purposes of the NRC PI, missed tests should be considered non-opportunities.

RBPI DEVELOPMENT

BACKGROUND

- SECY 99-007 recognized limitations of current indicators and potential for improvements.

- March 2000 User Need Letter from NRR requested specific RBPI development activities.
  - Reliability indicators.
  - Improved availability indicator.
  - Shutdown indicators.
  - Fire indicators.
  - Containment indicators.

- SECY 00-0146 provided RBPI "White Paper" to Commission describing the program overview for RBPI development.

Attachment 6

<u>RBPI DEVELOPMENT</u>

<u>PROCESS</u>

- Part of established program for ROP changes.
  - RES develops technical feasibility.
  - Early interaction w/stakeholders on technical as well as implementation/policy issues.
  - Resolution of internal/external stakeholder comments.

- ROP change process engaged <u>after</u> publication of final report.

- Implementation through ROP change process will likely involve:
  - Similar process for developing current indicator.
  - Pilot activity and feedback.
  - Final implementation decision.

RBPI DEVELOPMENT

SCHEDULE

- Draft Phase1 Report sent to internal stakeholders for review in 09/00.
- Phase1 Report for external stakeholder review 01/01.
- Public meeting to describe content to stakeholders 02/01.
- Public meeting to discuss external stakeholder comments 03/01.
- ACRS meeting 04/01.
- SECY to Commission 07/01.
- Commission Briefing 08/01.
- Issue final Phase1 Report 11/01.

DRAFT

Reactor Oversight Process
Physical Protection Cornerstone

December 6, 2000

DRAFT

Attachment 7

Proposed Rewrite to Scheduled Equipment Upgrade (clarification note on pg. 128 of rev. 0, NEI 99-02)

- When a security system upgrade has been identified, the compensatory hours posted for the equipment involved in the upgrade do not have to be counted towards the PI (for those conditions addressed in the modification) when site management has committed to the upgrade in writing. The commitment must specify the financial resources, the schedule and the scope of the upgrade. Counting of the compensatory hours posted resumes after the appropriate site entities (engineering, security, etc.) have signed off indicating the upgrade is functioning as intended. Reasonableness should be applied with respect to a justifiable length of time the compensatory hours are excluded from the PI.

DRAFT

Proposed Calculation Method for the Protected Area Security Performance Index

DRAFT

PROPOSED REVISION TO PI CALCULATION METHOD FOR PHYSICAL PROTECTION CORNERSTONE 12/06/2000

IN ORDER TO ALLEVIATE SKEWING THE CALCULATION IN FAVOR OF THOSE SITES THAT HAVE LESS THAN 30 CCTV OR LESS THAN 20 IDS ZONES THE FOLLOWING IS RECOMMENDED.

GIVEN;

$$\text{CCTV UNAVAILABILITY INDEX} = \frac{\text{CCTV COMP HRS IN THE PREVIOUS 4 QTRS}}{\text{NORMALIZATION FACTOR (8760HRS)}}$$

SINCE THE NORMALIZATION FACTOR FOR CCTV IS 30:

$$\frac{8760}{30} = 292$$, THEREFORE

THE PROPOSED EQUATION FOR THE CCTV UNAVAILABILITY INDEX IS:

$$\text{CCTV UNAVAILABILITY INDEX} = \frac{\text{CCTV COMP HRS IN THE PREVIOUS 4 QTRS}}{\text{\#OF CCTV THAT ASSESS THE IDS (292)}}$$

USING THE SAME REASONING FOR THE IDS,

$$\frac{8760}{20} = 438$$, AND THEREFORE THE PROPOSED EQUATION FOR THE IDS UNAVAILABILITY INDEX IS:

$$\text{IDS UNAVAILABILITY INDEX} = \frac{\text{IDS COMP HRS IN THE PREVIOUS 4 QTRS}}{\text{\#OF IDS ZONES IN THE PERIMETER (438)}}$$

THE INDICATOR VALUE CALCULATION WOULD REMAIN THE SAME,

$$\text{Indicator Value} = \frac{\text{CCTV UNAVAILABILITY INDEX + IDS UNAVAILABILITY INDEX}}{2}$$

11/24/2000

DRAFT

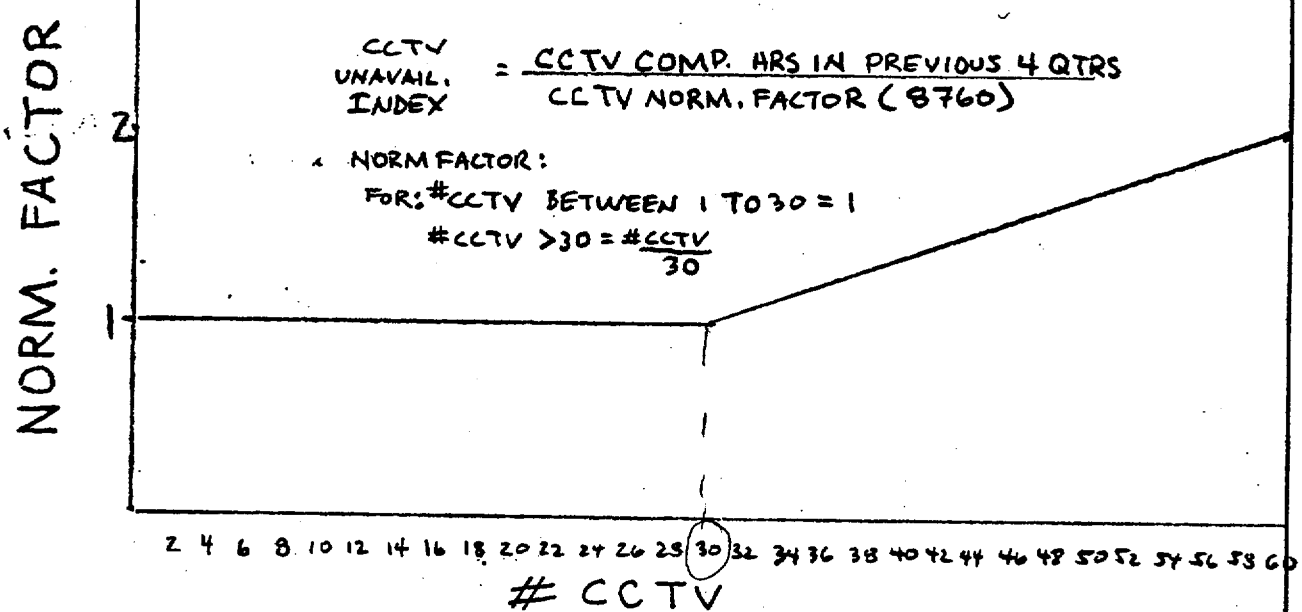
OLD METHOD FOR CALCULATING PA SECURITY EQUIP. PERF. INDEX

$$\text{CCTV UNAVAIL. INDEX} = \frac{\text{CCTV COMP. HRS IN PREVIOUS 4 QTRS}}{\text{CCTV NORM. FACTOR (8760)}}$$

NORM FACTOR:

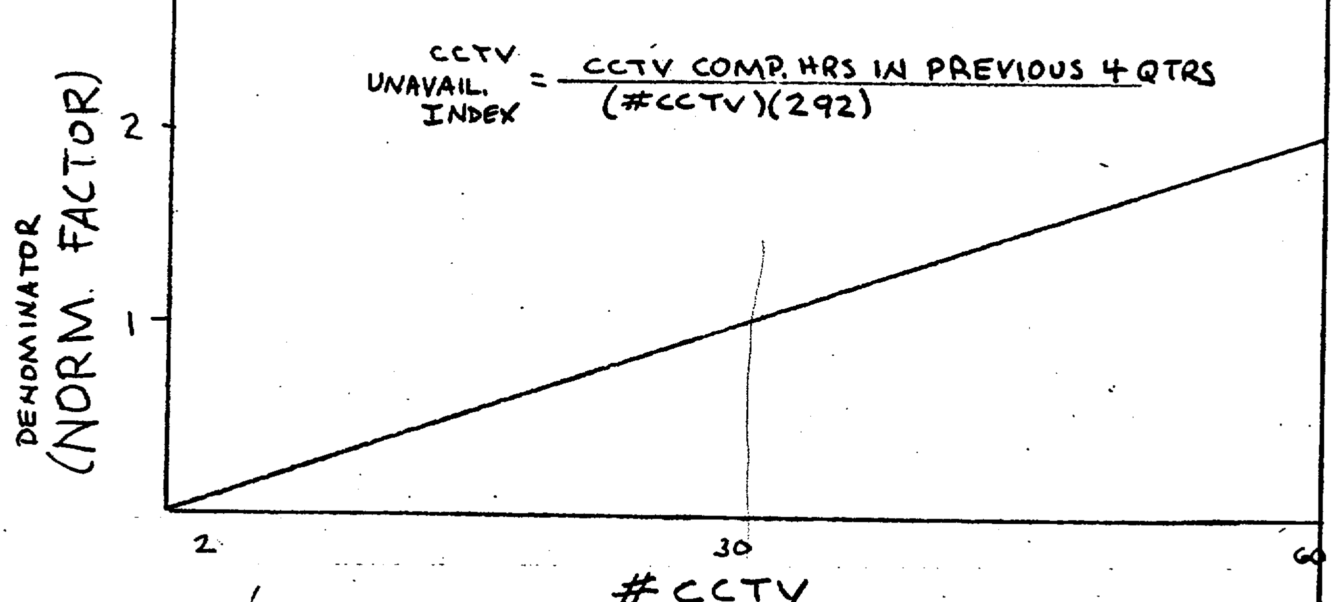
FOR: #CCTV BETWEEN 1 TO 30 = 1

$\#\text{CCTV} > 30 = \frac{\#\text{CCTV}}{30}$



PROPOSED METHOD FOR CALCULATING PA SECURITY PERF. INDEX

$$\text{CCTV UNAVAIL. INDEX} = \frac{\text{CCTV COMP. HRS IN PREVIOUS 4 QTRS}}{(\#\text{CCTV})(292)}$$



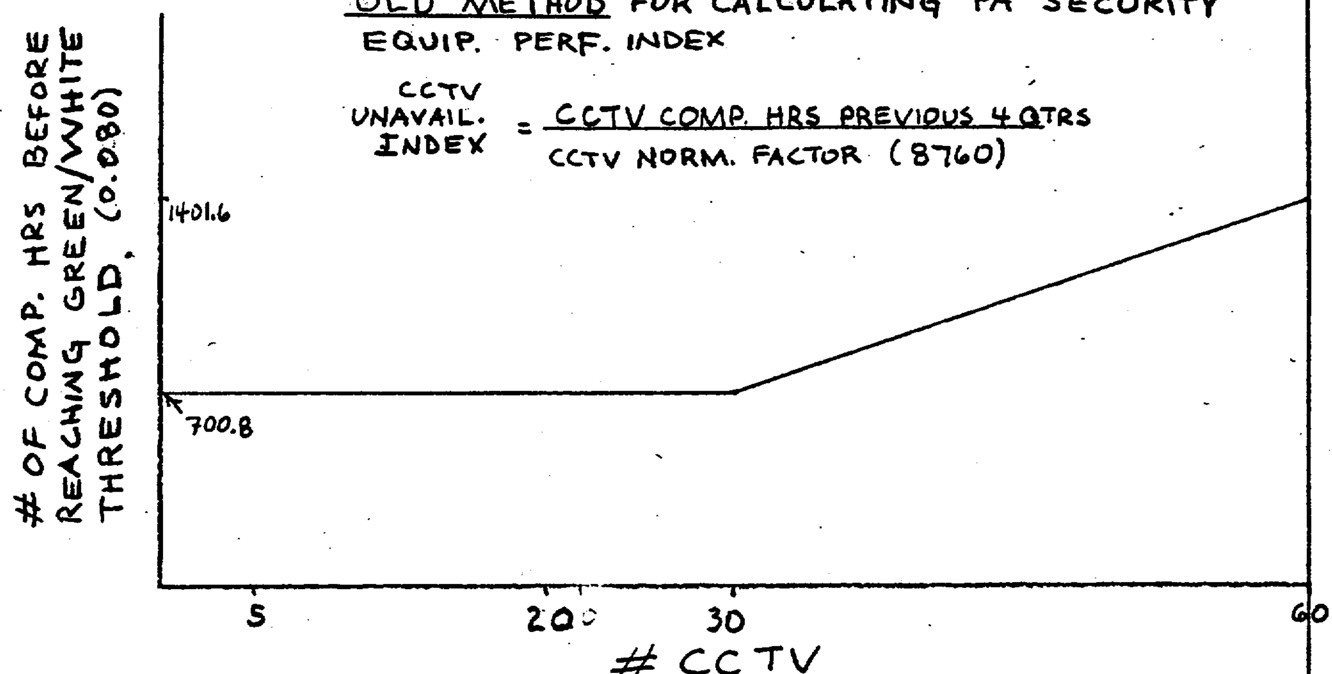
DRAFT

11/24/2000

DRAFT

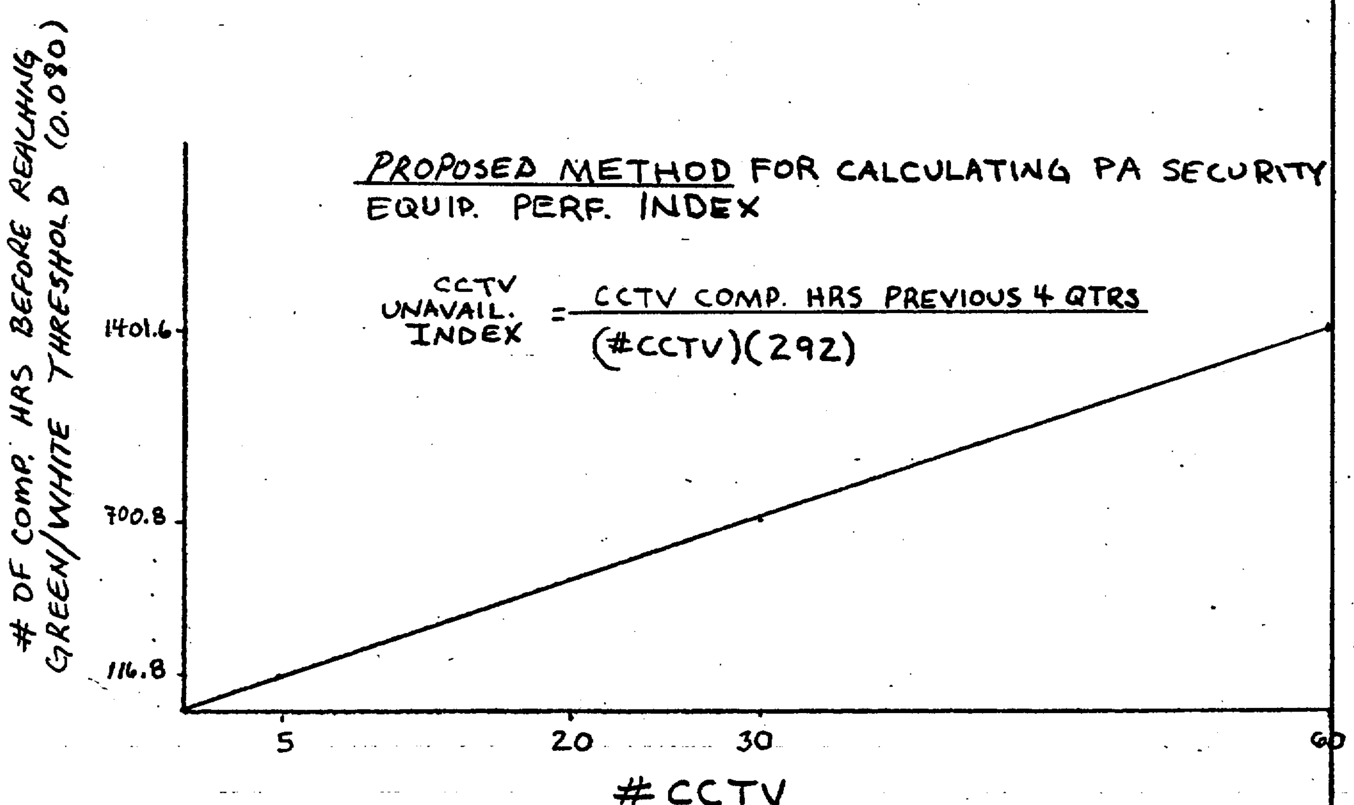
OLD METHOD FOR CALCULATING PA SECURITY EQUIP. PERF. INDEX

$$\text{CCTV UNAVAIL. INDEX} = \frac{\text{CCTV COMP. HRS PREVIOUS 4 QTRS}}{\text{CCTV NORM. FACTOR (8760)}}$$



PROPOSED METHOD FOR CALCULATING PA SECURITY EQUIP. PERF. INDEX

$$\text{CCTV UNAVAIL. INDEX} = \frac{\text{CCTV COMP. HRS PREVIOUS 4 QTRS}}{(\#\text{CCTV})(292)}$$



DRAFT

Analysis of Green-White Threshold for Scrams With Loss of Normal Heat Removal

The scrams with loss of normal heat removal indicator monitors scrams in which the normal heat removal path through the main condenser is lost. The green-white threshold for this indicator was calculated from data taken from NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995." The events included in the initiating events study that would cause a loss of the normal heat removal path through the main condenser are (1) a total loss of feedwater flow and (2) a total loss of condenser heat sink. For the threshold to be valid then, it is important that the indicator count all of those events and only those events. They are defined in the study as follows:

1. Total loss of all feedwater:
   a. *Includes the following*:
      - The complete loss of all main feedwater flow following a scram
      - The complete loss of all main feedwater flow that results in an automatic or manual reactor trip
   b. *Excludes the following*:
      - Main feedwater isolation caused by a valid automatic system response after a reactor trip or by intentional operator action to limit the cooldown rate after the trip (as long as feedwater is capable of being restored by operator demand)
      - Total loss of feedwater caused by the loss of offsite power

2. Total loss of condenser heat sink
   a. *Includes the following*:
      - The complete closure of at least one MSIV in each main steam line
      - A decrease in condenser vacuum that leads to an automatic or manual reactor trip or a manual turbine trip
      - A loss of condenser vacuum that prevents the condenser from removing decay heat following a reactor trip
      - The failure of one or more turbine bypass valves to maintain reactor pressure and temperature at the desired operating condition
   b. *Excludes the following*:
      - Manual closure of all MSIVs to limit the cooldown rate after a reactor trip (as long as the MSIVs are capable of being reopened by operator demand)
      - Loss of condenser vacuum caused by the loss of offsite power
      - Turbine bypass valve closure caused by the loss of offsite power

Table 3.3 of NUREG/CR-5750 provides two rate values for each initiating event: (1) the mean value of the IPE population frequency per critical year and (2) the calculated mean functional impact frequency per critical year. Those values for the two initiating events used in this indicator are shown in Table 1. The green-white threshold was initially set at 4 scrams with loss of normal heat removal per 3 years. This value was obtained from the IPE PWR mean value of 1.3 scrams per year, which is equivalent to about 4 scrams per three years. From the pilot program, however, the staff determined that the threshold was set too high and should be lowered to 2 scrams per 3 years. The authors of the study found that the 1987 to 1995 data supported this lower threshold. The Functional Impact Industry Mean value of 0.262 per year becomes 0.786 for three years and, using a factor of 3.5 between the mean and the 95th percentile (which is consistent with the IPE values), the threshold for the 1987 to 1995 time frame would be about 3. This, along with the finding that the overall initiating event frequency

Attachment 8

decreased by a factor of two to three over the nine year span of the study, and the more risk-significant initiators (such as total loss of feedwater flow and total loss of condenser vacuum in BWRs) decreased at a faster rate than that, leads to the conclusion that the current threshold is set appropriately. It also suggests that licensee reporting is consistent with the two event types of interest in the study.

Table 1

Initiating Event	IPE PWR Mean	IPE BWR Mean	IPE Total Mean	FI PWR Mean	FI BWR Mean	FI Total Mean
Total Loss of Feedwater Flow	1.00	0.57	0.86	0.085	0.085	0.085
Total Loss of Condenser Heat Sink	0.30	0.43	0.34	0.120	0.290	0.177
Loss of Normal Heat Removal	1.30	1.00	1.20	0.205	0.375	0.262

Cold Shutdown or Refueling Days 1997-1999
Time to Reach EDG Threshold Using Default Time - 27.4 Days

PLANT NAME	DOCKET	Days ≤ Cold Shutdown	Days to Threshold Using Actual Time	% Difference
ARKANSAS 1	313	64		
ARKANSAS 2	368	**106**	**24.7**	**10.7%**
BEAVER VALLEY 1	334	**342**	**18.8**	**45.4%**
BEAVER VALLEY 2	412	**349**	**18.7**	**46.8%**
BIG ROCK POINT	155	108		
BRAIDWOOD 1	456	**114**	**24.5**	**11.6%**
BRAIDWOOD 2	457	59		
BROWNS FERRY 1	259	1092		
BROWNS FERRY 2	260	45		
BROWNS FERRY 3	296	52		
BRUNSWICK 1	325	44		
BRUNSWICK 2	324	76		
BYRON 1	454	**158**	**23.4**	**16.9%**
BYRON 2	455	52		
CALLAWAY	483	56		
CALVERT CLIFFS 1	317	70		
CALVERT CLIFFS 2	318	**124**	**24.3**	**12.8%**
CATAWBA 1	413	76		
CATAWBA 2	414	76		
CLINTON 1	461	850		
COMANCHE PEAK 1	445	64		
COMANCHE PEAK 2	446	65		
COOK 1	315	888		
COOK 2	316	844		
COOPER STATION	298	**147**	**23.7**	**15.5%**
CRYSTAL RIVER 3	302	421		
DAVIS-BESSE	346	60		
DIABLO CANYON 1	275	70		

PLANT NAME	DOCKET	Days ≤ Cold Shutdown	Days to Threshold Using Actual Time	% Difference
DIABLO CANYON 2	323	60		
DRESDEN 2	237	**100**	**24.9**	**10.1%**
DRESDEN 3	249	**156**	**23.5**	**16.6%**
DUANE ARNOLD	331	**107**	**24.7**	**10.8%**
FARLEY 1	348	**155**	**23.5**	**16.5%**
FARLEY 2	364	98		
FERMI 2	341	**178**	**22.9**	**19.4%**
FITZPATRICK	333	96		
FORT CALHOUN	285	92		
GINNA	244	71		
GRAND GULF	416	**104**	**24.8**	**10.5%**
HARRIS	400	85		
HATCH 1	321	89		
HATCH 2	366	**103**	**24.8**	**10.4%**
HOPE CREEK	354	**130**	**24.1**	**13.5%**
INDIAN POINT 2	247	**373**	**18.1**	**51.7%**
INDIAN POINT 3	286	**182**	**22.8**	**19.9%**
KEWAUNEE	305	**200**	**22.4**	**22.3%**
LASALLE 1	373	610		
LASALLE 2	374	827		
LIMERICK 1	352	64		
LIMERICK 2	353	72		
MAINE YANKEE	309	215		
MCGUIRE 1	369	**157**	**23.5**	**16.7%**
MCGUIRE 2	370	**121**	**24.4**	**12.4%**
MILLSTONE 1	245	543		
MILLSTONE 2	336	830		
MILLSTONE 3	423	546		
MONTICELLO	263	**149**	**23.7**	**15.8%**

PLANT NAME	DOCKET	Days ≤ Cold Shutdown	Days to Threshold Using Actual Time	% Difference
NINE MILE PT 1	220	**287**	**20.2**	**35.5%**
NINE MILE PT 2	410	**110**	**24.6**	**11.2%**
NORTH ANNA 1	338	50		
NORTH ANNA 2	339	52		
OCONEE 1	269	**242**	**21.3**	**28.4%**
OCONEE 2	270	**154**	**23.5**	**16.4%**
OCONEE 3	287	**143**	**23.8**	**15.0%**
OYSTER CREEK	219	79		
PALISADES	255	**116**	**24.5**	**11.8%**
PALO VERDE 1	528	67		
PALO VERDE 2	529	72		
PALO VERDE 3	530	65		
PEACH BOTTOM 2	277	32		
PEACH BOTTOM 3	278	64		
PERRY	440	82		
PILGRIM	293	**122**	**24.3**	**12.5%**
POINT BEACH 1	266	**425**	**16.8**	**63.4%**
POINT BEACH 2	301	**397**	**17.5**	**56.9%**
PRAIRIE ISLAND 1	282	**116**	**24.5**	**11.8%**
PRAIRIE ISLAND 2	306	**129**	**24.2**	**13.4%**
QUAD CITIES 1	254	**226**	**21.7**	**26.0%**
QUAD CITIES 2	265	**352**	**18.6**	**47.4%**
RIVER BEND	458	**145**	**23.8**	**15.3%**
ROBINSON 2	261	59		
SALEM 1	272	443		
SALEM 2	311	252		
SAN ONOFRE 2	361	**171**	**23.1**	**18.5%**
SAN ONOFRE 3	362	**136**	**24.0**	**14.2%**
SEABROOK	443	**153**	**23.6**	**16.2%**

PLANT NAME	DOCKET	Days ≤ Cold Shutdown	Days to Threshold Using Actual Time	% Difference
SEQUOYAH 1	327	71		
SEQUOYAH 2	328	44		
SOUTH TEXAS 1	498	50		
SOUTH TEXAS 2	499	57		
ST LUCIE 1	335	**105**	**24.8**	**10.6%**
ST LUCIE 2	389	61		
SUMMER	395	65		
SURRY 1	280	97		
SURRY 2	281	62		
SUSQUEHANNA 1	387	91		
SUSQUEHANNA 2	388	**127**	**24.2**	**13.1%**
THREE MILE ISL 1	289	80		
TURKEY POINT 3	250	67		
TURKEY POINT 4	251	51		
VERMONT YANKEE	271	**122**	**24.3**	**12.5%**
VOGTLE 1	424	62		
VOGTLE 2	425	66		
WASH NUCLEAR 2	397	**291**	**20.1**	**36.2%**
WATERFORD 3	382	**169**	**23.2**	**18.3%**
WATTS BAR 1	390	82		
WOLF CREEK	482	78		
ZION 1	295	307		
ZION 2	304	363		
TOTAL		20294		

Notes:

1. Data cover 1997 through 1999 with three days missing: 5/31/97, 1/16/98, and 5/8/99.
2. Days were calculated using the daily status data provided by the NRC Ops Center.
3. If a plant reported cold shutdown or refueling mode during the morning phone call, it was assumed the plant was in that mode the entire day.
4. Days after permanent shutdown were not included.
5. Plants in italics are not included in calculations.
6. Plants in bold are not included due to known performance problems.

Analysis of Plants With ≥ 25% Difference

Plant Name	Required Hours	Reported Value (%)	Range for Correct Value
Beaver Valley 1	D	0.7	0.8 - 1.0
Beaver Valley 2	D	0.3	0.4 - 0.4
Indian Point 2	D	*3.7*	*4.2 - 5.6*
Nine Mile Point 1	D	*1.5*	*1.7 - 2.0*
Oconee 1	D	*1.7*	*1.9 - 2.2*
Point Beach 1	*D*	*1.9*	*2.2 - 2.9*
Point Beach 2	D	*1.2*	*1.5 - 1.9*
Quad Cities 1	A	2.1	2.1
Quad Cities2	A	1.6	1.6
Columbia GS (WNP 2)	D	0.3	0.3 - 0.4

Notes:
All plants on this list reported values a significant percentage lower than the correct value.
Plants in italics reported values significantly lower in magnitude than the correct value.
D signifies the licensee used the default value for the time the trains were required.
A signifies the licensee used the actual value for the time the trains were required.