

19 November 2001

**NEI 99-02 Revision 2**

# **Regulatory Assessment Performance Indicator Guideline**

**November 2001**



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**Nuclear Energy Institute**

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Performance Indicator Guideline**

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## **ACKNOWLEDGMENTS**

This guidance document, Regulatory Assessment Performance Indicator Guideline, NEI 99-02, was developed by the NEI Safety Performance Assessment Task Force in conjunction with the NRC staff. We appreciate the direct participation of the many utilities, INPO and the NRC who contributed to the development of the guidance.

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## **EXECUTIVE SUMMARY**

The Nuclear Regulatory Commission has revised its regulatory oversight processes of inspection, assessment and enforcement for commercial nuclear power plants. The new processes rely primarily on two inputs: Performance Indicators and NRC Inspection Findings. The purpose of this manual is to provide the guidance necessary for power reactor licensees to collect and report the data elements that will be used to compute the Performance Indicators.

An overview of the complete oversight process is provided in NUREG 1649, “Reactor Oversight Process.” More detail is provided in SECY 99-007, “Recommendations for Reactor Oversight Process Improvements,” as amended in SECY 99-007A and SECY 00-049 “Results of the Revised Reactor Oversight Process Pilot Program.”

This revision is effective for data collection as of **January 1, 2002**.

**Summary of Changes to NEI 99-02**

**Revision 1 to Revision 2**

<b>Page</b>	<b>Major Changes</b>
Throughout	Incorporated NRC approved FAQs into the text, primarily in the Clarifying Notes sections
4	Added additional guidance on when comments should be included in PI submittals
5	Clarified importance of Licensees and NRC acting expeditiously and sharing information in order to resolve FAQs in a timely manner
15-16	Modified the Unplanned Scram with Loss of Normal Heat Removal Performance Indicator
24	Added guidance regarding timeliness of engineering evaluations used to determine unavailability
25, 30-31	Revised definition and treatment of fault exposure conditions
32-33, 39	Revised guidance for resetting fault exposure hours
33	Revised guidance for treatment of design deficiencies
36-37	Added guidance on reporting unavailability when support systems are being tested and considerations for crediting operator actions outside the control room
41, 44	Revised definition of function monitored by the indicator
B-4, B-5	Added data elements for resetting fault exposure hours
D	Added guidance on suggested format for plant specific PI questions and approved responses to plant specific questions since Revision 1. FAQ 282 was added as plant specific.
E-1	Updated appendix identifying where FAQs were incorporated in text

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# 1 INTRODUCTION

2 This guideline describes the data and calculations for each performance indicator in the Nuclear  
3 Regulatory Commission's (NRC) power reactor licensee assessment process. The guideline also  
4 describes the licensee quarterly indicator reports that are to be submitted to the NRC for use in  
5 its licensee assessment process.

6  
7 This guideline provides the definitions and guidance for the purposes of reporting performance  
8 indicator data. No other documents should be used for definitions or guidance unless  
9 specifically referenced in this document. This guideline should not be used for purposes other  
10 than collection and reporting of performance indicator data in the NRC licensee assessment  
11 process.

## 12 13 Background

14 In 1998 and 1999, the NRC conducted a series of public meetings to develop a more objective  
15 process for assessing a licensee's regulatory and safety performance. The new process uses risk-  
16 informed insights to focus on those matters that are of safety significance. The objective is to  
17 monitor performance in three broad areas – reactor safety (avoiding accidents and reducing the  
18 consequences of accidents if they occur); radiation safety for plant workers and the public during  
19 routine operations; and protection of the plant against sabotage or other security threats.

20  
21 The three broad areas are divided into cornerstones: initiating events, mitigating systems, barrier  
22 integrity, emergency preparedness, public radiation safety, occupational radiation safety and  
23 physical protection. Performance indicators are used to assess licensee performance in each  
24 cornerstone. The NRC will use a risk-informed baseline inspection process to supplement and  
25 complement the performance indicator(s). This guideline focuses on the performance indicator  
26 segment of the assessment process.

27  
28 The thresholds for each performance indicator provide objective indication of the need to modify  
29 NRC inspection resources or to take other regulatory actions based on licensee performance.  
30 Table 1 provides a summary of the performance indicators and their associated thresholds.

31  
32 The overall objectives of the process are to:

- 33
- 34 • improve the objectivity of the oversight processes so that subjective decisions and  
35 judgment are not central process features,
- 36 • improve the scrutability of the NRC assessment process so that NRC actions have a clear  
37 tie to licensee performance, and
- 38 • risk-inform the regulatory assessment process so that NRC and licensee resources are  
39 focused on those aspects of performance having the greatest impact on safe plant  
40 operation.

41  
42 In identifying those aspects of licensee performance that are important to the NRC's mission,  
43 adequate protection of public health and safety, the NRC set high level performance goals for  
44 regulatory oversight. These goals are:

45

- 1 • maintain a low frequency of events that could lead to a nuclear reactor accident;
- 2 • zero significant radiation exposures resulting from civilian nuclear reactors;
- 3 • no increase in the number of offsite releases of radioactive material from civilian nuclear
- 4 reactors that exceed 10 CFR Part 20 limits; and
- 5 • no substantiated breakdown of physical protection that significantly weakens protection
- 6 against radiological sabotage, theft, or diversion of special nuclear materials.

7  
8 These performance goals are represented in the new assessment framework as the strategic  
9 performance areas of Reactor Safety, Radiation Safety, and Safeguards.

10  
11 Figure 1.0 provides a graphical representation of the licensee assessment process.

### 12 13 **General Reporting Guidance**

14 At quarterly intervals, each licensee will submit to the NRC the performance assessment data  
15 described in this guideline. The data is submitted electronically to the NRC by the 21<sup>st</sup> calendar  
16 day of the month following the end of the reporting quarter. If a submittal date falls on a  
17 Saturday, Sunday, or federal holiday, the next federal working day becomes the official due date  
18 (in accordance with 10 CFR 50.4). The format and examples of the data provided in each  
19 subsection show the complete data record for an indicator, and provide a chart of the indicator.  
20 These are provided for illustrative purposes only. Each licensee only sends to the NRC the data  
21 set from the previous quarter, as defined in each *Data Reporting Elements* subsection (See  
22 Appendix B) along with any changes to previously submitted data.

23  
24 The reporting of performance indicators is a separate and distinct function from other NRC  
25 reporting requirements. Licensees will continue to submit other regulatory reports as required by  
26 regulations; such as, 10 CFR 50.72 and 10 CFR 50.73.

27  
28 Performance indicator reports are submitted to the NRC for each power reactor unit. Some  
29 indicators are based on station parameters. In these cases the station value is reported for each  
30 power reactor unit at the station.

31  
32 Issues regarding interpretation or implementation of NEI 99-02 guidance may occur during  
33 implementation. Licensees are encouraged to resolve these issues with the Region. In those  
34 instances where the NRC staff and the Licensee are unable to reach resolution, **or to address**  
35 **plant specific exceptions**, the issue should be escalated to appropriate industry and NRC  
36 management using the FAQ process.<sup>1</sup> In the interim period until the issue is resolved, the  
37 Licensee is encouraged to maintain open communication with the NRC. Issues involving  
38 enforcement are not included in this process.

39  
40

---

<sup>1</sup> See additional information on Frequently Asked Questions later in this section and Appendix D.

## 1 **Guidance for Correcting Previously Submitted Performance Indicator Data**

2 In instances where data errors or a newly identified faulted condition are determined to have  
3 occurred in a previous reporting period, previously submitted indicator data are amended only to  
4 the extent necessary to correctly calculate the indicator(s) for the current reporting period.<sup>2</sup> This  
5 amended information is submitted using a “change report” following the guidance provided on  
6 the NEI performance indicator website (PIWeb) in the “edit” mode. For performance indicators  
7 with a long data evaluation period, e.g., 12 quarters, and depending on which reporting period  
8 the data error affects, the amended data may go back into the historical data period. The values  
9 of previous reporting periods are revised, as appropriate, when the amended data is used by the  
10 NRC to recalculate the affected performance indicator. The current report should reflect the new  
11 information, as discussed in the detailed sections of this document. In these cases, the quarterly  
12 data report should include a comment to indicate that the indicator values for past reporting  
13 periods are different than previously reported. If an LER was required and the number is  
14 available at the time of the report, the LER reference is noted.

15  
16 If a performance indicator data reporting error is discovered, an amended “mid-quarter” report  
17 does not need to be submitted if both the previously reported and amended performance indicator  
18 values are within the “green” performance indicator band. In these instances, corrected data  
19 should be included in the next quarterly report along with a brief description of the reason for the  
20 change(s). If a performance indicator data error is discovered that causes a threshold to be  
21 crossed, a “mid-quarter” report should be submitted as soon as practical following discovery of  
22 the error.

23  
24 In January 2000, all licensees submitted “historical performance indicator data” to support the  
25 start of the revised regulatory oversight process. This data was used by the NRC to validate  
26 performance indicator thresholds and to develop licensee inspection schedules for the revised  
27 process. The January submittal represented a “best effort” to collect and report historical data.  
28 Safety system unavailability data reported as part of the WANO performance indicators was  
29 allowed to be used without modification. A supplemental review of the WANO data to ensure it  
30 met applicable NEI 99-02 guidance was not required for the January historical data submittal.  
31 Errors in the historical data submission for any performance indicator, found subsequent to  
32 January 2000, do not require correction except as described above.

## 33 34 **Comment Fields**

35 The quarterly report allows comments to be included with performance indicator data. A general  
36 comment field is provided for comments pertinent to the quarterly submittal that are not specific  
37 to an individual performance indicator. A separate comment field is provided for each  
38 performance indicator. Comments included in the report should be brief and understandable by  
39 the general public. Comments provided as part of the quarterly report will be included along  
40 with performance indicator data as part of the NRC Public Web site on the oversight program. If  
41 multiple PI comments are received by NRC that are applicable to the same unit/PI/quarter, the  
42 NRC Public Web site will display all applicable comments for the quarter in the order received

---

<sup>2</sup> Changes to data collection rules or practices required by the current revision of this document will not be applied retroactively to previously submitted data. Previously submitted data will not require correction or amendment provided it was collected and reported consistent with the NEI 99-02 revision and FAQ guidance in effect at the time of submittal.

1 (e.g., If a comment for the current quarter is received via quarterly report and a comment for the  
2 same PI is received via a change report, then both comments will be displayed on the Web site.  
3 For General Comments, the NRC Public Web site will display only the latest “general” comment  
4 received for the current quarter (e.g., A “general” comment received via a change report will  
5 replace any “general” comment provided via a previously submitted quarterly report.)  
6

7 Comments should be generally limited to instances as directed in this guideline. These instances  
8 include:

- 9 • Exceedance of a threshold (Comment should include a brief explanation and should be  
10 repeated in subsequent quarterly reports as necessary to address the threshold exceedance)
- 11 • Revision to previously submitted data (Comment should include a brief characterization of  
12 the change, should identify affected time periods and should identify whether the change  
13 affects the “color” of the indicator.)
- 14 • Identification of a **T/2 fault exposure situation or certain** design deficiencies affecting safety  
15 system unavailability (See **specific instructions in the** Safety System Unavailability **section**)
- 16 • Resetting of fault exposure hours (See Safety System Unavailability discussion on resetting  
17 fault exposure hours)
- 18 • Unavailability of data for quarterly report (Examples include unavailability of RCS Activity  
19 data for one or more months due to plant conditions that do not require RCS activity to be  
20 calculated.)  
21

22 In specific circumstances, some plants, because of unique design characteristics, may typically  
23 appear in the “increased regulatory response band,” as shown in Table 1. In such cases the  
24 unique condition and the resulting impact on the specific indicator should be explained in the  
25 associated comment field. Additional guidance is provided under the appropriate indicator  
26 sections.  
27

28 The quarterly data reports are submitted to the NRC under 10 CFR 50.4 requirements. The  
29 quarterly reports are to be submitted in electronic form only. Separate submittal of a paper copy  
30 is not requested. Licensees should apply standard commercial quality practices to provide  
31 reasonable assurance that the quarterly data submittals are correct. Licensees should plan to  
32 retain the data consistent with the historical data requirements for each performance indicator.  
33 For example, data associated with the barrier cornerstone should be retained for 12 months, data  
34 for safety system unavailability should be retained for 12 quarters.  
35

36 The criterion for reporting is based on the time the failure or deficiency is identified, with the  
37 exception of the Safety System Functional Failure indicator, which is based on the Report Date  
38 of the LER. In some cases the time of failure is immediately known, in other cases there may be  
39 a time-lapse while calculations are performed to determine whether a deficiency exists, and in  
40 some instances the time of occurrence is not known and has to be estimated. Additional  
41 clarification is provided in specific indicator sections.  
42

### 43 **Numerical Reporting Criteria**

44 Final calculations are rounded up or down to the same number of significant figures as shown in  
45 Table 1. Where required, percentages are reported and noted as: 9.0%, 25%.  
46

## 1 Submittal of Performance Indicator Data

2 Performance indicator data should be submitted as a delimited text file (data stream) for each  
3 unit, attached to an email addressed to [pidata@nrc.gov](mailto:pidata@nrc.gov). The structure and format of the  
4 delimited text files is discussed in Appendix B. The email message can include report files  
5 containing PI data for the quarter (quarterly reports) for all units at a site and can also include  
6 any report file(s) providing changes to previously submitted data (change reports). The  
7 title/subject of the email should indicate the unit(s) for which data is included, the applicable  
8 quarter, and whether the attachment includes quarterly report(s) (QR), change report(s) (CR) or  
9 both. The recommended format of the email message title line is "<Plant Name(s)>-  
10 <quarter/year>-PI Data Elements (QR and/or CR)" (e.g., "Salem Units 1 and 2 – 1Q2000 – PI  
11 Data Elements (QR)"). Licensees should not submit hard copies of the PI data submittal (with  
12 the possible exception of a back up if the email system is unavailable).

13  
14 The NRC will send return emails with the licensee's submittal attached to confirm and  
15 authenticate receipt of the proper data, generally within 2 business days. The licensee is  
16 responsible for ensuring that the submitted data is received without corruption by comparing the  
17 response file with the original file. Any problems with the data transmittal should be identified  
18 in an email to [pidata@nrc.gov](mailto:pidata@nrc.gov) within 4 business days of the original data transmittal.

19  
20 Additional guidance on the collection of performance indicator data and the creation of quarterly  
21 reports and change reports is provided at the NEI performance indicator website (PIWeb).

22  
23 The reports made to the NRC under the new regulatory assessment process are in addition to the  
24 standard reporting requirements prescribed by NRC regulations.

## 25 26 Frequently Asked Questions

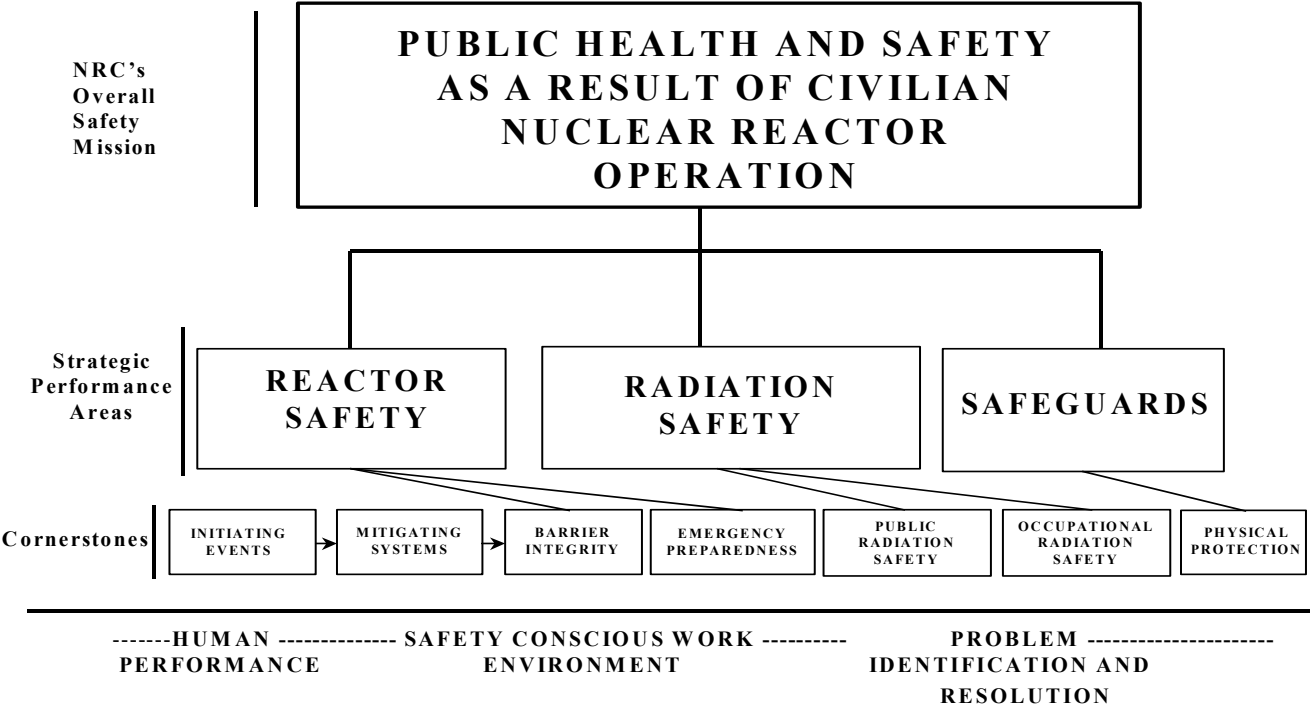
27 **The mechanism for resolving interpretation issues with NEI 99-02 is the** Frequently Asked  
28 Questions (FAQ) **process.** FAQs and responses regarding interpretations of this guideline will be  
29 posted on the NRC Website ([www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html](http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html)). FAQs  
30 posted on the NRC Website represent NRC approved interpretations of performance indicator  
31 guidance and should be treated as an extension of NEI 99-02.

32  
33 **FAQs should be submitted as soon as possible once the Licensee and resident inspector or region**  
34 **have identified an issue on which there is not agreement. If the Licensee is not sure how to**  
35 **interpret a situation and the quarterly report is due, an FAQ should be submitted and a comment**  
36 **in the PI comment field would be appropriate. It is incumbent on NRC and the Licensee to work**  
37 **expeditiously and cooperatively, sharing concerns, questions and data in order that the issue can**  
38 **be resolved quickly.**

39  
40 The NRC Website will identify the date of original posting for FAQs and responses. Unless  
41 otherwise directed in an FAQ response, FAQs are to be applied to the data submittal for the  
42 quarter in which the FAQ was posted and beyond. For example, an FAQ with a posting date of  
43 3/31/2000 would apply to 1<sup>st</sup> quarter 2000 PI data, submitted in April 2000 and subsequent data  
44 submittals. However, an FAQ with a posting date of 4/1/2000 would apply on a forward fit basis  
45 to 2<sup>nd</sup> quarter 2000 PI data submitted in July 2000. Licensees are encouraged to check the NRC  
46 Web site frequently, particularly at the end of the reporting period, for FAQs that may have  
47 applicability for their sites.

1  
2 Questions on this guideline may be submitted by email to [pihelp@nei.org](mailto:pihelp@nei.org). The email should  
3 include “FAQ” as part of the subject line. The emails should also provide the question and a  
4 proposed answer as well as the name and phone number of a contact person. The proposed  
5 question and answer will be reviewed by NEI staff and will be discussed with NRC staff at a  
6 public meeting. Once approved by NRC, the accepted response will be posted on the NRC  
7 Website and incorporated into the text of this guideline when the next revision is issued (no more  
8 frequently than once per quarter).

1  
2  
3



4  
5  
6  
7

Figure 1 - Regulatory Oversight Framework

**Table 1 – PERFORMANCE INDICATORS**

Cornerstone	Indicator	Thresholds (see Note 1)			
		Increased Regulatory Response Band	Required Regulatory Response Band	Unacceptable Performance Band	
<b>Initiating Events</b>	Unplanned Scrams per 7000 Critical Hours (automatic and manual scrams during the previous four quarters)	>3.0	>6.0	>25.0	
	<b>Unplanned</b> Scrams with a Loss of Normal Heat Removal (over the previous 12 quarters)	>2.0	>10.0	>20.0	
	Unplanned Power Changes per 7000 Critical Hours (over previous four quarters)	>6.0	N/A	N/A	
<b>Mitigating Systems</b>	Safety System Unavailability (SSU) (average of previous 12 quarters)	<b>All Plants</b>			
		≤2EDG	>2.5%	>5.0%	>10.0%
		>2EDG	>2.5%	>10.0%	>20.0%
		Hydro Emerg. Power	TBD	TBD	TBD
		<b>BWRs</b>			
		HPCI	>4.0%	>12.0%	>50.0%
		HPCS	>1.5%	>4.0%	>20.0%
		RCIC	>4.0%	>12.0%	>50.0%
		RHR	>1.5%	>5.0%	>10.0%
		<b>PWRs</b>			
HPSI	>1.5%	>5.0%	>10.0%		
AFW	>2.0%	>6.0%	>12.0%		
RHR	>1.5%	>5.0%	>10.0%		
	Safety System Functional Failures (over previous four quarters)	BWRs	>6.0	N/A	N/A
		PWRs	>5.0	N/A	N/A

1  
 2 Note 1: Thresholds that are specific to a site or unit will be provided in Appendix D when identified.  
 3



1

<b>Table 1 - PERFORMANCE INDICATORS Cont'd</b>				
<b>Cornerstone</b>	<b>Indicator</b>	<b>Thresholds (see Note 1)</b>		
		<b>Increased Regulatory Response Band</b>	<b>Required Regulatory Response Band</b>	<b>Unacceptable Performance Band</b>
<b>Barriers</b> Fuel Cladding	Reactor Coolant System (RCS) Specific Activity (maximum monthly values, percent of Tech. Spec limit)	>50.0%	>100.0%	N/A
	Reactor Coolant System	RCS Identified Leak Rate (maximum monthly values, percent of Tech. Spec. limit)	>50.0%	>100.0%
<b>Emergency Preparedness</b>	Drill/Exercise Performance (over previous eight quarters)	<90.0%	<70.0%	N/A
	ERO Drill Participation (percentage of Key ERO personnel that have participated in a drill or exercise in the previous eight quarters)	<80.0%	<60.0%	N/A
	Alert and Notification System Reliability (percentage reliability during previous four quarters)	<94.0%	<90.0%	N/A
<b>Occupational Radiation Safety</b>	Occupational Exposure Control Effectiveness (occurrences during previous 4 quarters)	>2	>5	N/A
<b>Public Radiation Safety</b>	RETS/ODCM Radiological Effluent Occurrence (occurrences during previous four quarters)	>1	>3	N/A
<b>Physical Protection</b>	Protected Area Security Equipment Performance Index (over a four quarter period)	>0.080	N/A	N/A
	Personnel Screening Program Performance (reportable events during the previous four quarters)	>2	>5	N/A
	Fitness-for-Duty (FFD)/Personnel Reliability Program Performance (reportable events during the previous four quarters)	>2	>5	N/A

2 Note 1: Thresholds that are specific to a site or unit will be provided in Appendix D when identified.

3



1 **2 PERFORMANCE INDICATORS**

2 **2.1 INITIATING EVENTS CORNERSTONE**

3 The objective of this cornerstone is to limit the frequency of those events that upset plant  
4 stability and challenge critical safety functions, during shutdown<sup>3</sup> as well as power operations. If  
5 not properly mitigated, and if multiple barriers are breached, a reactor accident could result  
6 which may compromise the public health and safety. Licensees can reduce the likelihood of a  
7 reactor accident by maintaining a low frequency of these initiating events. Such events include  
8 reactor scrams due to turbine trips, loss of feedwater, loss of off-site power, and other significant  
9 reactor transients.

10

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

12

13 There are three indicators in this cornerstone:

14

- 15 • Unplanned (automatic and manual) scrams per 7,000 critical hours
- 16 • Scrams with a loss of normal heat removal per 12 quarters
- 17 • Unplanned Power Changes per 7,000 critical hours

18

19 **UNPLANNED SCRAMS PER 7,000 CRITICAL HOURS**

20 **Purpose**

21 This indicator monitors the number of unplanned scrams. It measures the rate of scrams per year  
22 of operation at power and provides an indication of initiating event frequency.

23

24 **Indicator Definition**

25 The number of unplanned scrams during the previous four quarters, both manual and automatic,  
26 while critical per 7,000 hours.

27

28 **Data Reporting Elements**

29 The following data **are** reported for each reactor unit:

30

- 31 • the number of unplanned automatic and manual scrams while critical in the previous quarter
- 32
- 33 • the number of hours of critical operation in the previous quarter

34

35

---

<sup>3</sup>Shutdown indicators are being developed and will be included in later revisions.

1 **Calculation**

2 The indicator is determined using the values for the previous four quarters as follows:  
3

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

5  
6 **Definition of Terms**

7 *Scram* means the shutdown of the reactor by the rapid addition of negative reactivity by any  
8 means, e.g., insertion of control rods, boron, use of diverse scram switch, or opening reactor trip  
9 breakers.

10  
11 *Unplanned scram* means that the scram was not an intentional part of a planned evolution or test  
12 as directed by a normal operating or test procedure. This includes scrams that occurred during  
13 the execution of procedures or evolutions in which there was a high chance of a scram occurring  
14 but the scram was neither planned nor intended.

15  
16 *Criticality*, for the purposes of this indicator, typically exists when a licensed reactor operator  
17 declares the reactor critical. There may be instances where a transient initiates from a subcritical  
18 condition and is terminated by a scram after the reactor is critical—this condition would count as  
19 a scram.

20  
21 **Clarifying Notes**

22 | The value of 7,000 hours is used because it represents one year of reactor operation at **about** an  
23 | 80% capacity factor.

24  
25 | If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is  
26 | **displayed** as N/A because rate indicators can produce misleadingly high values when the  
27 | denominator is small. The data elements (unplanned scrams and critical hours) are still reported.

29  
30 | Dropped rods, single rod scrams, or half scrams are not considered reactor scrams. **Partial rod**  
31 | **insertions, such as runbacks, also do not count unless the resulting conditions subsequently cause**  
32 | **a reactor scram.**

33  
34 | Anticipatory plant shutdowns intended to reduce the impact of external events, such as tornadoes  
35 | or range fires threatening offsite power transmission lines, are excluded.

36  
37 | Examples of the types of scrams that **are included**:

- 38  
39 • Scrams that resulted from unplanned transients, equipment failures, spurious signals, human  
40 error, or those directed by abnormal, emergency, or annunciator response procedures.  
41  
42 • A scram that is initiated to avoid exceeding a technical specification action statement time  
43 limit.  
44

- 1 • A scram that occurs during the execution of a procedure or evolution in which there is a high  
2 likelihood of a scram occurring but the scram was neither planned nor intended.  
3

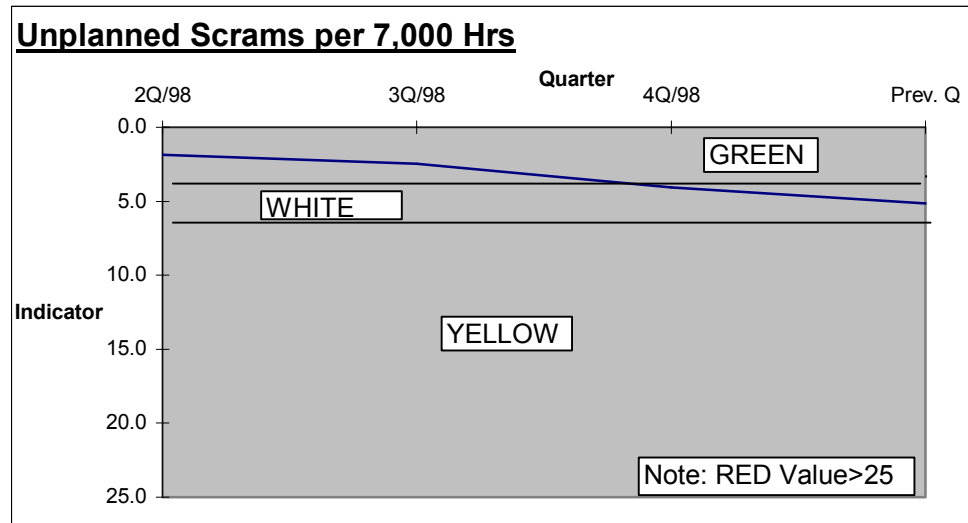
4 Examples of scrams that **are not** included:  
5

- 6 • Scrams that are planned to occur as part of a test (e.g., a reactor protection system  
7 actuation test), or scrams that are part of a normal planned operation or evolution.  
8
- 9 • Reactor protection system actuation signals that occur while the reactor is sub-critical.  
10
- 11 • Scrams that occur as part of the normal sequence of a planned shutdown and scram signals  
12 that occur while the reactor is shut down.  
13
- 14 • Plant shutdown to comply with technical specification LCOs, if conducted in accordance  
15 with normal shutdown procedures which include a manual scram to complete the  
16 shutdown.  
17  
18

1 **Data Example**

Unplanned Scrams per 7,000 Critical Hours								
	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
# of Scrams critical in qtr	1	0	0	1	1	1	2	2
Total Scrams over 4 qtrs				2	2	3	5	6
# of Hrs Crit in qtr	1500	1000	2160	2136	2160	2136	2136	1751
Total Hrs Critical in 4 qtrs				6796	7456	8592	8568	8183
					2Q/98	3Q/98	4Q/98	Prev. Q
Indicator value					1.9	2.4	4.1	5.1

Thresholds	
Green	≤3.0
White	>3.0
Yellow	>6.0
Red	>25.0



2  
3

## **UNPLANNED SCRAMS WITH LOSS OF NORMAL HEAT REMOVAL**

### **Purpose**

This indicator monitors that subset of unplanned automatic and manual scrams **that were complicated by the loss of the normal heat removal path either prior to the scram or during the scram recovery**. Such events or conditions are more risk-significant than uncomplicated scrams.

### **Indicator Definition**

The number of unplanned scrams while critical, both manual and automatic, during the previous 12 quarters that **were either caused by or** involved a loss of the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

### **Data Reporting Elements**

The following data **are** reported for each reactor unit:

- the number of unplanned automatic and manual scrams while critical in the previous quarter **that were either caused by or involved a loss of** the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

### **Calculation**

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

value = total **unplanned** scrams while critical in the previous 12 quarters **that were either caused by or involved a loss of** the normal heat removal path prior to establishing reactor conditions that allow use of the plant's normal long term heat removal systems.

### **Definition of Terms**

*Normal heat removal path:* for purposes of this performance indicator, the path used for heat removal from the reactor during normal plant operations. It is the same for all plants – the path from the main condenser through the main feedwater system, **the steam generators (PWRs)** or reactor vessel (**BWRs**), the main steam isolation valves (**MSIVs**), **the turbine bypass valves**, and back to the main condenser.

*Loss of the normal heat removal path:* when any of the following conditions have occurred and cannot be easily recovered from the control room without the need for diagnosis or repair to restore the normal heat removal path:

- complete loss of all main feedwater **flow**
- insufficient main condenser vacuum to remove decay heat
- complete closure of at least one **MSIV** in each main steam line

- failure of turbine bypass capacity that results in insufficient bypass capability remaining to maintain reactor temperature and pressure

*Scram* means the shutdown of the reactor by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, use of diverse scram switch, or opening reactor trip breakers.

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

### **Clarifying Notes**

*Loss of normal heat removal path* means the loss of the normal heat removal path as defined above. The determining factor for this indicator is whether or not the normal heat removal path is *available*, not whether the operators choose to use that path or some other path.

*Operator actions or design features to control the reactor cooldown rate or water level*, such as closing the main feedwater valves or closing all MSIVs, are not reported in this indicator as long as the normal heat removal path can be readily recovered from the control room without the need for diagnosis or repair. However, operator actions to mitigate an off-normal condition or for the safety of personnel or equipment (e.g., closing MSIVs to isolate a steam leak) are reported.

*Examples of a complete loss of all main feedwater flow: loss of all feedwater pumps during startup or while operating at reduced power; loss of all startup and auxiliary feedwater pumps normally used during plant startup; loss of all operating feed pumps following a scram due to trips caused by low suction pressure, loss of seal water, or high water level (BWR reactor level or PWR steam generator level); unplanned scram due to loss of all operating feed pumps; manual scram in response to feed problems characteristic of a total loss of feedwater flow but prior to automatic reactor protection system signals; and inadvertent isolation or closure of all feedwater control valves prior to an unplanned scram.*

*Example of loss of turbine bypass capability: sustained use of one or more atmospheric dump valves (PWRs) or safety relief valves to the suppression pool (BWRs) after an unplanned scram.*

*Examples that do not count: loss of all main feedwater flow, condenser vacuum, or turbine bypass capability caused by loss of offsite power; partial losses of condenser vacuum or turbine bypass capability after an unplanned scram in which sufficient capability remains to remove decay heat; momentary operation of PORVs or safety relief valves; and an unplanned scram at low power within the capability of the PORVs if the main condenser has not yet been placed in service or has been removed from service prior to the unplanned scram.*

This indicator includes unplanned scrams. Unplanned scrams counted for this indicator are also counted for the *Unplanned Scrams per 7000 Critical Hours* indicator.

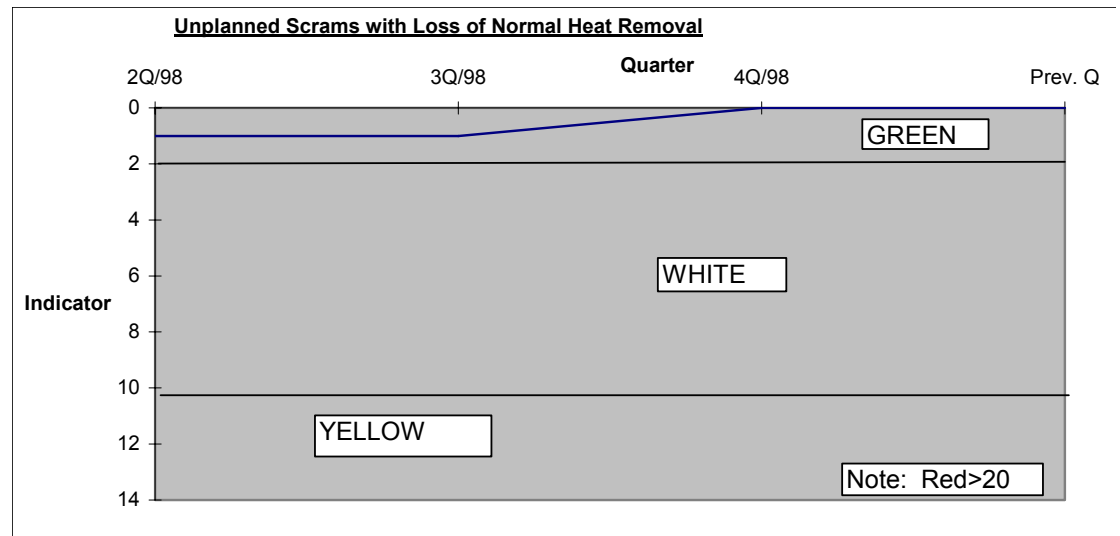


1 **Data Examples**

**Unplanned Scrams with Loss of Normal Heat Removal**

	3Q/95	4Q/95	1Q/96	2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
# of Scrams with loss of NHR in prev qtr	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Total over 12 qtrs												1	1	0	0
Indicator value												2Q/98	3Q/98	4Q/98	Prev. Q
												1	1	0	0

Thresholds	
Green	≤2.0
White	>2.0
Yellow	>10.0
Red	>20.0



2  
3

## UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS

### Purpose

This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator measures the number of plant power changes for a typical year of operation at power.

### Indicator Definition

The number of unplanned changes in reactor power of greater than 20% of full-power, per 7,000 hours of critical operation excluding manual and automatic scrams.

### Data Reporting Elements

The following data is reported for each reactor unit:

- the number of unplanned power changes, excluding scrams, during the previous quarter
- the number of hours of critical operation in the previous quarter

### Calculation

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

$$\text{value} = \frac{\text{(total number of unplanned power changes over the previous 4 qtrs)}}{\text{total number of hours critical during the previous 4 qtrs}} \times 7,000 \text{ hrs}$$

### Definition of Terms

*Unplanned changes in reactor power* are changes in reactor power that are initiated less than 72 hours following the discovery of an off-normal condition, and that result in, or require a change in power level of greater than 20% of full power to resolve. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test.

### Clarifying Notes

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

The 72 hour period between discovery of an off-normal condition and the corresponding change in power level is based on the typical time to assess the plant condition, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews, to effect a repair. The key element to be used in determining whether a power change should be counted as part of

1 this indicator is the 72 hour period and not the extent of the planning that is performed between  
2 the discovery of the condition and initiation of the power change.

3  
4 In developing a plan to conduct a power reduction, additional contingency power reductions  
5 may be incorporated. These additional power reductions are not counted if they are implemented  
6 to address the initial condition.

7  
8 Equipment problems encountered during a planned power reduction greater than 20% that alone  
9 may have required a power reduction of 20% or more to repair are not counted as part of this  
10 indicator if they are repaired during the planned power reduction. However, if during the  
11 implementation of a planned power reduction, power is reduced by more than 20% of full power  
12 beyond the planned reduction, then an unplanned power change has occurred.

13  
14 Unplanned power changes and shutdowns include those conducted in response to equipment  
15 failures or personnel errors and those conducted to perform maintenance. They do not include  
16 automatic or manual scrams or load-follow power changes.

17  
18 Apparent power changes that are determined to be caused by instrumentation problems are not  
19 included.

20  
21 Unplanned power changes include runbacks and power oscillations greater than 20% of full  
22 power.

23  
24 Anticipatory power reductions intended to reduce the impact of external events such as  
25 hurricanes or range fires threatening offsite power transmission lines, and power changes  
26 requested by the system load dispatchers, are excluded.

27  
28 Anticipated power changes greater than 20% in response to expected problems (such as  
29 accumulation of marine debris and biological contaminants in certain seasons) which are  
30 proceduralized but cannot be predicted greater than 72 hours in advance may not need to be  
31 counted if they are not reactive to the sudden discovery of off-normal conditions. The  
32 circumstances of each situation are different and should be identified to the NRC in a FAQ so  
33 that a determination can be made concerning whether the power change should be counted.

34  
35 Power changes to make rod pattern adjustments are excluded.

36  
37 Power changes directed by the load dispatcher under normal operating conditions due to load  
38 demand and economic reasons, and for grid stability or nuclear plant safety concerns arising  
39 from external events outside the control of the nuclear unit are not included in this indicator.  
40 However, power reductions due to equipment failures that are under the control of the nuclear  
41 unit are included in this indicator.

42  
43 Licensees should use the power indication that is used to control the plant to determine if a  
44 change of greater than 20% of full power has occurred.

45  
46 This indicator captures changes in reactor power that are initiated following the discovery of an  
47 off-normal condition. If a condition is identified that is slowly degrading and the licensee  
48 prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have

1 elapsed since the condition was first identified, the power change does not count. If, however,  
2 the condition suddenly degrades beyond the predefined limits and requires rapid response, this  
3 situation would count.

4  
5 Off-normal conditions that begin with one or more power reductions and end with an unplanned  
6 reactor trip are counted in the unplanned reactor scram indicator only. However, if the cause of  
7 the downpower(s) and the scram are different, an unplanned power change and an unplanned  
8 scram must both be counted. For example, an unplanned power reduction is made to take the  
9 turbine generator off line while remaining critical to repair a component. However, when the  
10 generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs.  
11 In this case, both an unplanned power change and an unplanned scram would be counted. If an  
12 off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor  
13 trip using normal operating procedures, only an unplanned power change is counted.

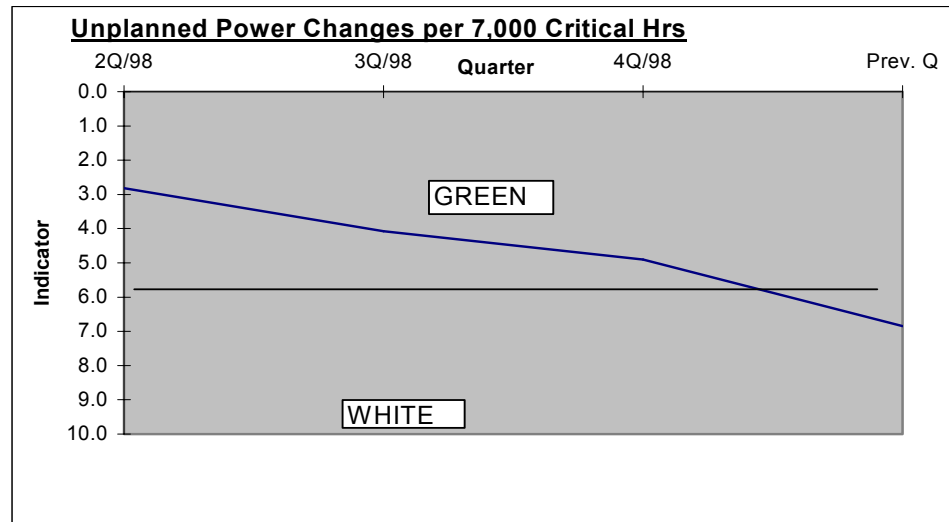
14  
15 Downpowers of greater than 20% of full power for ALARA reasons are counted in the indicator.

1 **Data Example**

**Unplanned Power Changes per 7,000 Critical Hours**

	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
# of Power Changes in previous qtr	1	0	0	1	2	2	1	3
Total Power Changes in previous 4 qtrs	1	1	1	2	3	5	6	8
# of Hrs Critical in qtr	1500	1000	2160	2136	2160	2136	2136	1751
Total Hrs Critical in previous 4 qtrs				6796	7456	8592	8568	8183
Indicator value					2Q/98 2.8	3Q/98 4.1	4Q/98 4.9	Prev. Q 6.8

Thresholds	
Green	≤6.0
White	>6.0
Yellow	N/A
Red	N/A



2  
3

1  
2  
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5  
6  
7

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## 1 2.2 MITIGATING SYSTEMS CORNERSTONE

2 The objective of this cornerstone is to monitor the availability, reliability, and capability of  
3 systems that mitigate the effects of initiating events to prevent core damage. Licensees reduce  
4 the likelihood of reactor accidents by maintaining the availability and reliability of mitigating  
5 systems. Mitigating systems include those systems associated with safety injection, decay heat  
6 removal, and their support systems, such as emergency AC power. This cornerstone includes  
7 mitigating systems that respond to both operating and shutdown events.  
8

9 The definitions and guidance contained in this section, while similar to guidance developed in  
10 support of INPO/WANO indicators and the Maintenance Rule, are unique to the **Reactor**  
11 **Oversight Process (ROP)**. Differences in definitions and guidance in most instances are  
12 deliberate and are necessary to meet the unique requirements of the **ROP**.  
13

14 While safety systems are generally thought of as those that are designed to mitigate design basis  
15 accidents, not all mitigating systems have the same risk importance. PRAs have shown that risk  
16 is often influenced not only by front-line mitigating systems, but also by support systems and  
17 equipment. Such systems and equipment, both safety- and non-safety related, have been  
18 considered in selecting the performance indicators for this cornerstone. Not all aspects of  
19 licensee performance can be monitored by performance indicators, and risk-informed baseline  
20 inspections are used to supplement these indicators.  
21

### 22 SAFETY SYSTEM UNAVAILABILITY

#### 23 Purpose

24 The purpose of the safety system unavailability indicator is to monitor the readiness of important  
25 safety systems to perform their safety functions in response to off-normal events or accidents.  
26

#### 27 Indicator Definition

28 The average of the individual train unavailabilities in the system. Train unavailability is the ratio  
29 of the hours the train is unavailable to the number of hours the train is required to be able to  
30 perform its intended safety function.  
31

32 The performance indicator is calculated separately for each of the following four systems for  
33 each reactor type.

#### 34 BWRs

- 35 • high pressure injection systems -- (high pressure coolant injection, high pressure core spray,  
36 feedwater coolant injection)
- 37 • heat removal systems - (reactor core isolation cooling)
- 38 • residual heat removal system
- 39 • emergency AC power system  
40

#### 41 PWRs

- 42 • high pressure safety injection system
- 43 • auxiliary feedwater system

- 1 • emergency AC power system
- 2 • residual heat removal system

3  
4 **Data Reporting Elements**

5 The following elements are reported for each train for the previous quarter:

- 6
- 7 • planned unavailable hours,
- 8 • unplanned unavailable hours,
- 9 • fault exposure hours,
- 10 • **reset data<sup>5</sup> (if applicable), and**
- 11 • hours the train was required to be available for service.
- 12
- 13

14 Sources for identifying unavailable hours can be obtained from system failure records, control  
15 room logs, event reports, maintenance work orders, etc. Preventive maintenance and  
16 surveillance test procedures may be helpful in determining if activities performed using these  
17 procedures cause systems or trains to be unavailable. These procedures may also assist in  
18 identifying the frequency of such maintenance and test activities.

19  
20 **In some instances, engineering evaluation is necessary to determine whether or not a train may**  
21 **be considered available. The engineering evaluation should be completed as soon as practicable.**  
22 **If an engineering evaluation for determining unavailability cannot be completed in time to**  
23 **support submittal of the PI report for the current quarter, the comment field shall note that an**  
24 **evaluation is pending. The evaluation must be completed in time to accurately report the**  
25 **unavailability in the next quarterly report. Exceptions to this guidance are expected to be rare**  
26 **and will be treated on a case-by-case basis.**

27  
28 **Calculation**

29 **The indicator for each of the monitored systems is the average system unavailability over the**  
30 **previous 12 quarters.**

31  
32 The system unavailability is determined for each reporting quarter as follows:

33  
34 Train unavailability during previous 12 quarters:

35 
$$\frac{(\text{planned unavailable hrs}) + (\text{unplanned unavailable hrs}) + (\text{fault exposure hrs}) - (\text{effective reset hrs})}{(\text{hours train required during the previous 12 quarters})}$$

36

37 System unavailability is the sum of the train unavailabilities divided by the number of system  
38 trains.

39  
40 For some multi-unit stations the calculation for the emergency diesel generator value could be  
41 affected by a “swing” emergency diesel generator for either unit or other units. (See Emergency  
42 AC Power section for further details.)

43

---

<sup>5</sup> See Appendix B for reset data elements



1 **Definition of Terms**

2 *Planned unavailable hours:* These hours include time the train was out of service for  
3 maintenance, testing, equipment modification, or any other time equipment is electively removed  
4 from service and the activity is planned in advance.  
5

6 *Unplanned unavailable hours:* These hours include corrective maintenance time or elapsed time  
7 between the discovery and the restoration to service of an equipment failure or human error that  
8 makes the train unavailable (such as a misalignment).  
9

10 *Fault exposure hours:* The hours that a train was in an undetected, failed condition **and the time**  
11 **of failure has been determined.** (This item is explained in more detail in the Clarifying Notes.)

13  
14 *T/2 fault exposure hours:* The hours that a train was in an undetected, failed condition and the  
15 time of failure cannot be determined. (This item is explained in more detail in the Clarifying  
16 Notes.)  
17

18 *Effective reset hours:* The sum of reset hours (fault exposure reset hours, minus delta planned  
19 hours, minus delta unplanned hours) during the previous 12 quarters that are *effective* (i.e.,  
20 applicable) during the current quarter. (This term is explained in more detail in the Clarifying  
21 Notes.)  
22

23 *Hours required* are the number of hours a monitored safety system is required to be available to  
24 satisfactorily perform its intended safety function.  
25

26 *A train* consists of a group of components that together provide the monitored functions of the  
27 system and as explained in the enclosures for specific reactor types. Fulfilling the design basis  
28 of the system may require one or more trains of a system to operate simultaneously. The number  
29 of trains in a system is determined as follows:  
30

- 31 • for systems that primarily pump fluids, the number of trains is equal to the number of parallel  
32 pumps or the number of flow paths in the flow system (e.g., number of auxiliary feedwater  
33 pumps). The preferred method is to use the number of pumps. For a system that contains an  
34 installed spare pump, the number of trains would equal the number of flow paths in the  
35 system.  
36
- 37 • for systems that provide cooling of fluids, the number of trains is determined by the number  
38 of parallel heat exchangers, or the number of parallel pumps, whichever is fewer.  
39
- 40 • emergency AC power system: the number of class 1E emergency (diesel, gas turbine, or  
41 hydroelectric) generators at the station that are installed to power shutdown loads in the event  
42 of a loss of off-site power -- This includes the diesel generator dedicated to the BWR HPCS  
43 system.  
44

45 *Off-normal events or accidents:* These are events specified in a plant's design and licensing  
46 bases. Typically these events are specified in a plant's safety analysis report, however other  
47 events/analysis should be considered (e.g. Appendix R analysis).

1  
2 Note: Additional guidance for specific systems is provided later in this section.

3  
4 **Clarifying Notes**

5 The systems have been selected for this indicator based on their importance in preventing reactor  
6 core damage or extended plant outage. The selected systems include the principal systems  
7 needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat  
8 removal following a reactor trip or loss of main feedwater, and for providing emergency AC  
9 power following a loss of plant off-site power.

10  
11 Except as specifically stated in the indicator definition and reporting guidance, no attempt is  
12 made to monitor or give credit in the indicator results for the presence of other systems at a given  
13 plant that add diversity to the mitigation or prevention of accidents. For example, no credit is  
14 given for additional power sources that add to the reliability of the electrical grid supplying a  
15 plant because the purpose of the indicator is to monitor the effectiveness of the plant's response  
16 once the grid is lost.

17  
18 Some components in a system may be common to more than one train, in which case the effect  
19 of the performance (unavailable hours) of a common component is included in all affected trains.

20  
21 Unavailable hours for a multi-function system should be counted only during those times when  
22 any function monitored by this indicator is required to be available.

23  
24 Trains are generally considered to be available during periodic system or equipment  
25 realignments to swap components or flow paths as part of normal operations.

26  
27 It is possible for a train to be considered operable yet unavailable per the guidance in this section.  
28 The purpose of this indicator is to monitor the readiness of important safety systems to perform  
29 their safety function in response to off-normal events or accidents.

30  
31 **If a licensee is required to take a component out of service for evaluation and corrective actions**  
32 **related to a Part 21 Notification, (or if a Part 21 Notification is issued in response to a licensee**  
33 **identified condition), the unavailable hours must be reported.**

34  
35

1 Planned Unavailable Hours  
2

3 Planned unavailable hours are hours that a train is not available for service for an activity that is  
4 planned in advance. The beginning and ending times of planned unavailable hours are known.<sup>6</sup>  
5 Causes of planned unavailable hours include, but are not limited to, the following:  
6

- 7 • preventive maintenance, corrective maintenance on non-failed trains, or inspection  
8 requiring a train to be mechanically and/or electrically removed from service  
9
- 10 • planned support system unavailability causing a train of a monitored system to be  
11 unavailable (e.g., AC or DC power, instrument air, service water, component cooling  
12 water, or room cooling)  
13
- 14 • testing, unless the test configuration is automatically overridden by a valid starting signal,  
15 or the function can be promptly restored either by an operator in the control room or by a  
16 dedicated operator<sup>7</sup> stationed locally for that purpose. Restoration actions must be  
17 contained in a written procedure<sup>8</sup>, must be uncomplicated (*a single action or a few simple*  
18 *actions*), and must not require diagnosis or repair. Credit for a dedicated local operator  
19 can be taken only if (s)he is positioned at the proper location throughout the duration of  
20 the test for the purpose of restoration of the train should a valid demand occur. The intent  
21 of this paragraph is to allow licensees to take credit for restoration actions that are  
22 virtually certain to be successful (i.e., probability nearly equal to 1) during accident  
23 conditions.  
24

25 The individual performing the restoration function can be the person conducting the test  
26 and must be in communication with the control room. Credit can also be taken for an  
27 operator in the main control room provided s(he) is in close proximity to restore the  
28 equipment when needed. Normal staffing for the test may satisfy the requirement for a  
29 dedicated operator, depending on work assignments. In all cases, the staffing must be  
30 considered in advance and an operator identified to take the appropriate prompt response  
31 for the testing configuration independent of other control room actions that may be  
32 required.  
33

34 Under stressful chaotic conditions otherwise simple multiple actions may not be  
35 accomplished with the virtual certainty called for by the guidance (e.g., lift test leads and  
36 land wires; or clearing tags). In addition, some manual operations of systems designed to  
37 operate automatically, such as manually controlling HPCI turbine to establish and control  
38 injection flow are not virtually certain to be successful.  
39

- 40 • any modification that requires the train to be mechanically and/or electrically removed  
41 from service.  
42

---

<sup>6</sup>Accumulation of unavailable hours ends when the train is returned to a normal standby alignment. However, if a subsequent test (e.g., post-maintenance test) shows the train not to be capable of performing its safety function, the time between the return to normal standby alignment and the unsuccessful test is reclassified as unavailable hours.

<sup>7</sup>Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

<sup>8</sup> This may, for example, include restoration steps in an approved test procedure

1 If a maintenance activity goes beyond the originally scheduled time frame, the additional hours  
2 can be considered planned unavailable hours except when due to detection of a new failed  
3 component that would prevent the train from performing its intended safety function.  
4

5 Planned unavailable hours are included because portions of a system are unavailable during these  
6 planned activities when the system should be available to perform its intended safety function.  
7

8 Note: It is recognized that such planned activities can have a net beneficial effect in terms of  
9 reducing unplanned unavailable hours and fault exposure hours (as discussed further below). If  
10 planned activities are well managed and effective, fault exposure hours and unplanned  
11 unavailable hours are minimized.  
12

### 13 Treatment of Planned Overhaul Maintenance

14  
15 Plants that perform on-line planned overhaul maintenance (i.e., within approved Technical  
16 Specification Allowed Outage Time) do not have to include planned overhaul hours in the  
17 unavailable hours for this performance indicator under the conditions noted below. Overhaul  
18 maintenance comprises those activities that are undertaken voluntarily and performed in  
19 accordance with an established preventive maintenance program to improve equipment  
20 reliability and availability. Overhauls include disassembly and reassembly of major components  
21 and may include replacement of parts as necessary, cleaning, adjustment, and lubrication as  
22 necessary. Typical major components are: diesel engine or generator, pumps, pump motor or  
23 turbine driver, or heat exchangers.  
24

25 Any AOT sufficient to accommodate the overhaul hours may be considered. However, to qualify  
26 for the exemption of unavailable hours, licensees must have in place a quantitative risk  
27 assessment. This assessment must demonstrate that the planned configuration meets either the  
28 requirements for a risk-informed TS change described in Regulatory Guide 1.177, or the  
29 requirements for normal work controls described in NUMARC 93-01, Section 11.3.7.2.  
30 Otherwise the unavailable hours must be counted. The Safety System Unavailability indicator  
31 excludes maintenance-out-of-service hours on a train that is not required to be operable per  
32 technical specifications (TS). This normally occurs during reactor shutdowns. Online  
33 maintenance hours for systems that do not have installed spare trains would normally be included  
34 in the indicator. However, some licensees have been granted extensions of certain TS allowed  
35 outage times (AOTs) to perform online maintenance activities that have, in the past, been  
36 performed while shut down.  
37

38 The criteria of Regulatory Guide 1.177 include demonstration that the change has only a small  
39 quantitative impact on plant risk (less than  $5 \times 10^{-7}$  incremental conditional core damage  
40 probability). It is appropriate and equitable, for licensees who have demonstrated that the  
41 increased risk to the plant is small, to exclude unavailable hours for those activities for which the  
42 extended AOTs were granted. However, in keeping with the NRC's increased emphasis on risk-  
43 informed regulation, it is not appropriate to exclude unavailable hours for licensees who have not  
44 demonstrated that the increase in risk is small. In addition, 10 CFR 50.65(a)(4), requires  
45 licensees to assess and manage the increase in risk that may result from proposed maintenance  
46 activities. Guidance on a quantitative approach to assess the risk impact of maintenance activities  
47 is contained in the latest revision of Section 11.3.7.2 of NUMARC 93-01. That section allows  
48 the use of normal work controls for plant configurations in which the incremental core damage  
49 probability is less than  $10^{-6}$ . Licensees must demonstrate that their proposed action complies with

1 either the requirements for a risk-informed TS change or the requirements for normal work  
2 controls described in NUMARC 93-01.

3  
4 The planned overhaul maintenance may be applied once per train per operating cycle. The work  
5 may be done in two segments provided that the total time to perform the overhaul does not  
6 exceed one AOT period.

7  
8 If additional time is needed to repair equipment problems discovered during the planned  
9 overhaul that would prevent the fulfillment of a safety function, the additional hours would be  
10 non-overhaul hours and/or potential fault exposure hours, and would count toward the indicator.

11  
12 Other activities may be performed with the planned overhaul activity as long as the outage  
13 duration is bounded by overhaul activities. If the overhaul activities are complete, and the outage  
14 continues due to non-overhaul activities, the additional hours would be non-overhaul hours and  
15 would count toward the indicator.

16  
17 Major rebuild tasks necessitated by an unexpected component failure that would prevent the  
18 fulfillment of a safety function cannot be counted as overhaul maintenance.

19  
20 This overhaul exemption does not normally apply to support systems except under unique plant-  
21 specific situations on a case-by-case basis. The circumstances of each situation are different and  
22 should be identified to the NRC so that a determination can be made. Factors to be taken into  
23 consideration for an exemption for support systems include (a) the results of a quantitative risk  
24 assessment, (b) the expected improvement in plant performance as a result of the overhaul  
25 activity, and (c) the net change in risk as a result of the overhaul activity.

### 26 27 Unplanned Unavailable Hours

28  
29 Unplanned unavailable hours are the hours that a train is not available for service for an activity  
30 that was not planned in advance. The beginning and ending times of unplanned unavailable  
31 hours are known. Causes of unplanned unavailable hours include, but are not limited to, the  
32 following:

- 33
- 34 • corrective maintenance time following detection of a failed component that prevented the  
35 train from performing its intended safety function. (The time between failure and  
36 detection is counted as fault exposure unavailable hours, as discussed below.)
  - 37
  - 38 • unplanned support system unavailability causing a train of a monitored system to be  
39 unavailable (e.g., AC or DC power, instrument air, service water, component cooling  
40 water, or room cooling)
  - 41
  - 42 • human errors leading to train unavailability (e.g., valve or breaker mispositioning-- only  
43 the time to restore would be reported as unplanned unavailable hours-- the time between  
44 the mispositioning and discovery would be counted as fault exposure unavailable hours  
45 as discussed below)
  - 46

1 Treatment of Fault Exposure Conditions

2  
3 Fault Exposure Hours: The failure's time of occurrence and its time of discovery are known.  
4 Examples of this type of failure include events external to the equipment (e.g., a lightning strike,  
5 some mispositioning by operators, or damage caused during test or maintenance activities) that  
6 caused the train failure at a known time. For these cases, the fault exposure hours are the lapsed  
7 time between the occurrence of a failure and its time of discovery. These hours are reported as  
8 fault exposure hours and included in the calculation of safety system unavailability.  
9

10 For instances where the time of occurrence is determined to have occurred more than three years  
11 ago (12 quarters) fault exposure hours are only computed back for a maximum of 12 quarters.  
12

13 T/2 Fault Exposure Hours: Only the time of the failure's discovery is known with certainty. The  
14 intent of the use of the term "with certainty" is to ensure that an appropriate analysis and review  
15 to determine the time of failure is completed, documented in the corrective action program, and  
16 reviewed by management. The use of component failure analysis, circuit analysis, or event  
17 investigations are acceptable. Engineering judgment may be used in conjunction with analytical  
18 techniques to determine the time of failure. It is improper to assume that the failure occurred at  
19 the time of discovery for these failures because the assumption ignores what could be significant  
20 unavailable time prior to their discovery. Fault exposure hours for this case must be estimated.  
21 The value used to estimate the fault exposure hours for this case is: one half the time since the  
22 last successful test or operation that proved the system was capable of performing its safety  
23 function. However, the time reported is never greater than three years (12 quarters). For  
24 example, if the last successful surveillance test was 24 months ago, then the time reported would  
25 be 8760 hours (12 months). If the time since the last test was 74 months, the time reported  
26 would be 26,280 hours (36 months).  
27

28 The unavailable hours can be amended in a future report if further analysis identifies the time of  
29 failure or determines that the affected train would have been capable of performing its safety  
30 function during the worst case event for which the train is required.  
31

32 If a failure is identified when a train is not required to be available, fault exposure hours are  
33 estimated by counting from the date of the failure back to one-half the time since the last  
34 successful operation and including only those hours during that period when the train was  
35 required to be available.  
36

37 T/2 Fault Exposure Hours, in which the time of failure is not known, are reported only in the  
38 comment section of the NRC PI data file and are not included in the calculation of safety system  
39 unavailability. (For example, the comment might read: "EDG train 1, 352 hours of T/2 fault  
40 exposure hours.") The NRC inspection process will assess the significance of the deficiency.  
41  
42

## Additional Fault Exposure Considerations

When a failed or mispositioned component that results in the loss of train function is discovered during an inspection or by incidental observation (without being tested), fault exposure hours are still reported, **either as Fault Exposure Hours (data element) or T/2 Fault Exposure Hours (comment field)**.

Operator actions to recover from an equipment malfunction or an operating error can be credited if the function can be promptly restored from the control room by a qualified operator taking 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 under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance<sup>9</sup> (e.g., lift test leads and land wires). In addition, some manual operations of systems designed to operate automatically, such as manually controlling the HPCI turbine to establish and control injection flow, are not virtually certain to be successful.

Small oil, water or steam leaks that would not preclude safe operation of the component during an operational demand and would not prevent a train from satisfying its safety function are not counted.

A train is available if it is capable of performing its safety function. For example, if a normally open valve is found failed in the open position, and this is the position required for the train to perform its function, fault exposure hours would not be counted for the time the valve was in a failed state. However, unplanned unavailable hours would be counted for the repair of the valve, if the repair required the valve to be closed or the line containing the valve to be isolated, and this degraded the full capacity or redundancy of the system.

Fault exposure hours are not counted for a failure to meet design or technical specifications, if engineering analysis determines the train was capable of performing its safety function during an operational event. For example, if an emergency generator fails to reach rated speed and voltage in the precise time required by technical specifications, the generator is not considered unavailable if the test demonstrated that it would start, load, and run as required in an emergency.

### Reporting Fault Exposure Time

The fault exposure hours associated with a component failure may include unavailable hours covering several reporting periods (e.g., several quarters). The fault exposure hours should be assigned to the appropriate reporting periods. For example, if a failure is discovered on the 10th day of a quarter and the number of unavailable hours is 300 hours, then 240 hours should be counted for the current quarter and 60 unavailable hours should be counted for the previous quarter. Note: This will require an update of the previous quarter's data. Remove the double count by removing the planned and unplanned hours which overlap with the fault exposure hours. Put an explanation in the comment field. If you later **reset** the fault exposure hours, restore the **planned and unplanned** hours which had been removed.

---

<sup>9</sup> These situations should be resolved on a case-by-case basis through an FAQ. See Appendix D for additional guidance on FAQs and examples from other licensees.

1  
2 | Resetting Fault Exposure Hours<sup>10</sup>

3  
4 | Fault exposure hours may be reset , provided the following criteria are met:

- 6  
7 | 1. Four quarters have elapsed since the green-white threshold was crossed.  
8 | 2. The fault exposure hours in any single increment of unavailability are greater than or  
9 | equal to 336 hours and the green-white threshold has been exceeded. (Note: The green-  
10 | white threshold may have been crossed in the same quarter, or in a subsequent quarter.)  
11 | 3. Corrective actions associated with that increment of unavailability to preclude recurrence  
12 | of the condition have been completed by the licensee, and  
13 | 4. Supplemental inspection activities by the NRC have been completed and any resulting  
14 | open inspection items related to the condition causing the fault exposure have been  
15 | closed out in an inspection report.

16  
17 | Fault exposure hours are reset by submitting a change report that provides the hours to be reset  
18 | and the first quarter in which the reset hours become effective (i.e., the first quarter in which all  
19 | the conditions for reset are met). The reset hours should include any planned and unplanned  
20 | hours that were previously unreported. The change report should include a comment to document  
21 | this action.

22  
23 | Reset Example (see illustration at end of this section)

24 | The fault exposure hours reported for 1Q00 reflect a single item. As such, the item must meet  
25 | the requirements for reset.

- 26  
27 | Requirement 1 – Four quarters have elapsed from exceedance of Green-White threshold  
28 | Requirement 2 – Fault exposure hours in any single increment equal to or greater than 336 hours  
29 | Requirement 3 – Corrective actions associated with that increment of unavailability to preclude  
30 | recurrence of the condition have been completed  
31 | Requirement 4 – Supplemental inspection activities by the NRC have been completed and any  
32 | resulting open inspection items related to the condition causing the fault  
33 | exposure have been closed out in an inspection report.

34  
35 | The example meets the first requirement beginning with 1Q01 (the threshold was exceeded in  
36 | 1Q00). The second requirement is met since the total event hours exceed 336 hours. The third  
37 | and fourth requirements, for the purposes of this example, are assumed to be fully met by 1Q01.

38  
39 | The reset data for Train 1 shows that the reset data will first become effective beginning with the  
40 | calculation of the performance indicator for 1Q01 (i.e., effective quarter = 1Q01). Beginning  
41 | with 1Q01, 500 fault exposure hours will be removed from the calculation and 20 planned  
42 | unavailable hours will be added to the calculation. The 20 delta planned unavailable hours  
43 | reflect unavailable hours that were excluded from the original reporting to avoid overlap (double  
44 | counting) with fault exposure hours and must now be re-added. The combination of 500 reset  
45 | hours and 20 delta hours results in 480 effective reset hours. These effective reset hours are

---

<sup>10</sup> Fault exposure (both time known and T/2) reported prior to this revision should be reset using the process described in this guidance. However, the criteria for reset should use the revision of NEI 99-02 in effect at the time the reset was permitted.



1 carried forward into future quarters for a period equivalent to the original quarter plus 11  
2 quarters. Expressed in a different way, the reset hours associated with a quarter are carried  
3 forward as long as the original fault exposure hours are included in a calculation. (Note that  
4 reset data need be input only one time. Carryover and use in the calculation for future quarters,  
5 as appropriate, is performed as part of the performance indicator calculation.)  
6

#### 7 Equipment Unavailability due to Design Deficiency

8  
9  
10 Equipment failures due to design deficiency will be treated in the following manner:

11  
12 Failures that are capable of being discovered during surveillance tests: These failures should be  
13 evaluated for inclusion in the equipment unavailability indicators. Examples of this type are  
14 failures due to material deficiencies, subcomponent sizing/settings, lubrication deficiencies, and  
15 environmental degradation problems.  
16

17 Failures that are not capable of being discovered during normal surveillance tests: These failures  
18 are usually of longer fault exposure time. These failures are amenable to evaluation through the  
19 NRC's Significance Determination Process and are excluded from the unavailability indicators.  
20 Examples of this type are failures due to pressure locking/thermal binding of isolation valves or  
21 inadequate component sizing/settings under accident conditions (not under normal test  
22 conditions). While not included in the calculation of the unavailability indicators, these failures  
23 and the associated hours should be reported in the comment field of the PI data submittal.  
24

#### 25 Hours Train Required

26  
27 The term "hours train required" is associated with the hours a train is required to be available to  
28 satisfactorily perform its safety function. Unavailable hours are counted only for periods when a  
29 train is required to be available for service.  
30

31 The default values identified below are typical; however, differences may exist in the number of  
32 trains required during different modes of operation. The calculational methodology  
33 accommodates differences in required train hours in these cases. The default value in the  
34 denominator can be used to simplify data collection. However, the numerator must include all  
35 unavailable hours during periods that the train is required regardless of the default value.  
36

- 37 • Emergency AC power system. This value is estimated by the number of hours in the  
38 reporting period, because emergency generators are normally expected to be available for  
39 service during both plant operation and shutdown.  
40
- 41 • Residual Heat Removal System. This value is estimated by the number of hours in the  
42 reporting period, because the residual heat removal system is required to be available for  
43 decay heat removal at all times.  
44
- 45 • All other systems. This value is estimated by the number of critical hours during the  
46 reporting period, because these systems are usually required to be in service only while the  
47 reactor is critical, and for short periods during startup or shutdown. In some cases this value

1 is already provided as part of the calculation, as in unplanned automatic scrams per 7,000  
2 hours critical data.

#### 3 4 Component Failures

5  
6 Unavailable hours (planned, unplanned, and fault exposure) are not reported for the failure of  
7 certain ancillary components unless the safety function of a principal component (e.g., pump,  
8 valve, emergency generator) is affected in a manner that prevents the train from performing its  
9 intended safety function. Such ancillary components include equipment associated with control,  
10 protection, and actuation functions; power supplies; lubricating subsystems; etc. For example, if  
11 there are three pressure switches arranged in a two-out-of-three logic provide low suction  
12 pressure protection for a PWR auxiliary feedwater pump, and one becomes defective,  
13 unavailable hours would not be counted because the single failure would not affect operability of  
14 the pump.

#### 15 16 Installed Spares and Redundant Maintenance Trains

17  
18 Some power plants have safety systems with extra trains to allow preventive maintenance to be  
19 carried out with the unit at power without violating the single failure criterion (when applied to  
20 the remaining trains). That is, one of the remaining trains may fail, but the system can still  
21 achieve its safety function as required by the design basis safety analysis. Such systems are  
22 characterized by a large number of trains (usually a minimum of four, but often more). To be a  
23 maintenance train, a train must not be required in the design basis safety analysis for the system  
24 to perform its safety function.

25  
26 An "installed spare" is a component (or set of components) that is used as a replacement for other  
27 equipment to allow for the removal of equipment from service for preventive or corrective  
28 maintenance without violating the single failure criterion. To be an "installed spare," a  
29 component must not be required in the design basis safety analysis for the system to perform its  
30 safety function.

31  
32 The following examples will help illustrate the system requirements in order to benefit from this  
33 provision:

- 34
- 35 • A system containing three 50% (flow rate and/or cooling capacity) trains would not meet the  
36 requirement since full design flow rate would not be available with one train in maintenance  
37 and one train failed (single failure criterion).
  - 38  
39 • A system with four 50% trains or three 100% trains may meet the criterion, assuming the  
40 system design flow rate and cooling requirements can be met during a design basis accident  
41 anywhere within the reactor coolant or secondary system boundaries, including unfavorable  
42 locations of LOCAs and feedwater line breaks. This statement is not intended to set new  
43 design criteria, but rather, to define the level of system redundancy required if reporting of  
44 unavailable hours on a redundant train is to be avoided.

45  
46 Unavailable hours for an installed spare are counted only if the installed spare becomes  
47 unavailable while serving as replacement for another component. This includes planned and  
48 | unplanned unavailable hours, and fault exposure hours.

1 Planned unavailable hours (e.g., preventive maintenance) and unplanned unavailable hours (e.g.,  
2 corrective maintenance) are not counted for a component when that component has been  
3 replaced by an installed spare.

4  
5 In some designs, specific systems have a complete spare train, allowing the total replacement of  
6 one train for on-line maintenance, or increased system availability. Systems that have such extra  
7 trains generally must meet design bases requirements with one train in maintenance and a single  
8 failure of another train.

9  
10 Trains that are required as backup in case of equipment failure to allow the system to meet  
11 redundancy requirements or the single failure criterion (e.g., swing components that  
12 automatically align to different trains or units) are not installed spares.

13  
14 In systems where there are installed spare components or trains, unavailable hours for the spare  
15 component or train are only counted against the replaced component or train. For example, if a  
16 system has an installed spare train that is valved into the system, any unavailable hours are  
17 counted against the replaced train, not the spare train. Thus, in a three train system that has one  
18 installed spare train, the number of trains in the safety system unavailability equation is two. The  
19 system unavailability is the sum of the unavailable hours divided by two.

#### 20 21 Systems Required to be in Service at All Times

22  
23 The Emergency AC power system and the residual heat removal RHR system are normally  
24 required to be in service at all times. However, planned and unplanned unavailable hours are not  
25 reported under certain conditions. The specific conditions for the emergency diesel generator are  
26 described in the Emergency Diesel Generator Section. For RHR systems, when the reactor is  
27 shutdown with fuel in the vessel, those systems or portions of systems that provide shutdown  
28 cooling can be removed from service without incurring planned or unplanned unavailable hours  
29 under the following conditions:

- 30
- 31 • RHR trains may be removed from service provided an NRC approved alternate method of  
32 decay heat removal is verified to be available for each RHR train removed from service. The  
33 intent is that at all times there will be two methods of decay heat removal available, at least  
34 one of which is a forced means of heat removal.
  - 35  
36 • When the reactor is defueled or the decay heat load is so low that forced recirculation for  
37 cooling purposes, even on an intermittent basis, is no longer required (ambient losses are  
38 enough to offset the decay heat load), any train providing shutdown cooling may be removed  
39 from service without incurring planned or unplanned unavailable hours.
  - 40  
41 • When the bulk reactor coolant temperature is less than 200 F, those trains or portions of  
42 trains whose sole function is to provide suppression pool cooling (BWR) may be removed  
43 from service without incurring planned or unplanned unavailable hours.
  - 44  
45 • When portions of a single train provide both the shutdown cooling and the suppression pool  
46 cooling function, the most limiting set of reportability requirements should be used (i.e.  
47 unavailable hours and required hours are reported whenever at least one function is required.)
- 48

1 | Fault exposure hours are always counted, even when portions of the system are removed from  
2 | service as described above.

3  
4 | When the plant is operating, selected components that help provide the shutdown cooling  
5 | function of the RHR system are normally de-energized or racked out. This does not constitute an  
6 | unavailable condition for the trains that provide shutdown cooling, unless the de-energized  
7 | components cannot be placed back into service before the minimum time that the shutdown  
8 | cooling function would be needed (typically the time required for a plant to complete a rapid  
9 | cooldown, within maximum established plant cooldown limits, from normal operating  
10 | conditions).

### 11 12 | Support System Unavailability

13  
14 | If the unavailability of a support system causes a train **of the monitored system** to be unavailable,  
15 | then the hours the support system was unavailable are counted against the train as planned,  
16 | unplanned, or fault exposure hours. Support systems are defined as any system required for the  
17 | safety system to remain available for service. The technical specification criteria for determining  
18 | operability may not apply when determining train unavailability. In these cases, analysis or  
19 | sound engineering judgment (**with the appropriate documentation**) will be used to determine the  
20 | effect of support system unavailability on the monitored system. **In many cases, for example, to**  
21 | **determine whether operator actions outside the control room can be credited for restoring support**  
22 | **systems, an FAQ should be submitted.**<sup>11</sup>

23  
24 | If the unavailability of a single support system causes a train in more than one of the monitored  
25 | systems to be unavailable, the hours the support system was unavailable are counted against the  
26 | affected train in each system. For example, a train outage of 3 hours in a PWR service water  
27 | system caused the emergency generator, the RHR heat exchanger, the HPSI pump, and the AFW  
28 | pump associated with that train to be unavailable also. In this case, 3 hours of unavailability  
29 | would be reported for the associated train in each of the four systems.

30  
31 | If a support system is dedicated to a system and is normally in standby status, it should be  
32 | included as part of the monitored system scope. In those cases, fault exposure hours caused by a  
33 | failure in the standby support system that results in a loss of a train function should be reported  
34 | because of the effect on the monitored system. By contrast, failures of continuously-operating  
35 | support systems do not contribute to fault exposure hours in the monitored systems they support.

37  
38 | Unavailable hours are also reported for the unavailability of support systems that maintain  
39 | required environmental conditions in rooms in which monitored safety system components are  
40 | located, if the **failure to maintain** those conditions **under routine, accident and off-normal events**  
41 | is determined to have rendered a train unavailable for service at a time it was required to be  
42 | available.

43  
44 | **Unavailable hours are also reported for monitored systems due to testing of support systems**  
45 | **unless the test configuration is automatically overridden by a valid starting signal, or the function**  
46 | **can be promptly restored either by an operator in the control room or by a dedicated operator**<sup>12</sup>

---

<sup>11</sup> See Appendix D for additional guidance on FAQs and examples from other licensees.

<sup>12</sup> Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

1 stationed locally for that purpose. Restoration actions must be contained in a written  
2 procedure<sup>13</sup>, must be uncomplicated (*a single action or a few simple actions*), and must not  
3 require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is  
4 positioned at the proper location throughout the duration of the test for the purpose of restoration  
5 of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take  
6 credit for restoration actions that are virtually certain to be successful (i.e., probability nearly  
7 equal to 1) during accident conditions.

8  
9 The individual performing the restoration function can be the person conducting the test and  
10 must be in communication with the control room. Credit can also be taken for an operator in the  
11 main control room provided (s)he is in close proximity to restore the equipment when needed.  
12 Normal staffing for the test may satisfy the requirement for a dedicated operator, depending on  
13 work assignments. In all cases, the staffing must be considered in advance and an operator  
14 identified to take the appropriate prompt response for the testing configuration independent of  
15 other control room actions that may be required.

16  
17 Under stressful chaotic conditions otherwise simple multiple actions may not be accomplished  
18 with the virtual certainty called for by the guidance<sup>14</sup> (e.g., lift test leads and land wires; or  
19 clearing tags). In addition, some manual operations of systems designed to operate automatically,  
20 such as manually controlling the HPCI turbine to establish and control injection flow are not  
21 virtually certain to be successful.

22  
23 In some instances, unavailability of a monitored system that is caused by unavailability of a  
24 support system used for cooling need not be reported if cooling water from another source can be  
25 substituted. Limitations on the source of the cooling water are as follows:

- 26
- 27 • for monitored fluid systems with components cooled by a support system, where both the  
28 monitored and the support system pumps are powered by a class IE (i.e., safety grade or an  
29 equivalent) electric power source, cooling water supplied by a pump powered by a normal  
30 (non class IE--i.e., non-safety grade) electric power source may be substituted for cooling  
31 water supplied by a class IE electric power source, provided that redundancy requirements to  
32 accommodate single failure criteria for electric power and cooling water are met.  
33 Specifically, unavailable hours must be reported when both trains of a monitored system are  
34 being cooled by water provided by a single cooling water pump or by cooling water pumps  
35 powered by a single class IE power (safety grade) source.
  - 36  
37 • for emergency generators, cooling water provided by a pump powered by another class IE  
38 (safety grade) power source can be substituted, provided a pump is available that will  
39 maintain electrical redundancy requirements such that a single failure cannot cause a loss of  
40 both emergency generators.
- 41

---

<sup>13</sup> This may, for example, include restoration steps in an approved test procedure

<sup>14</sup> These situations should be resolved on a case-by-case basis through an FAQ. See Appendix D for additional guidance on FAQs and examples from other licensees.

- 1 Emergency AC power is not considered to be a support system. Unavailability of a train because
- 2 of loss of AC power is counted when both the normal AC power supply and the emergency AC
- 3 power supply are not available.
- 4

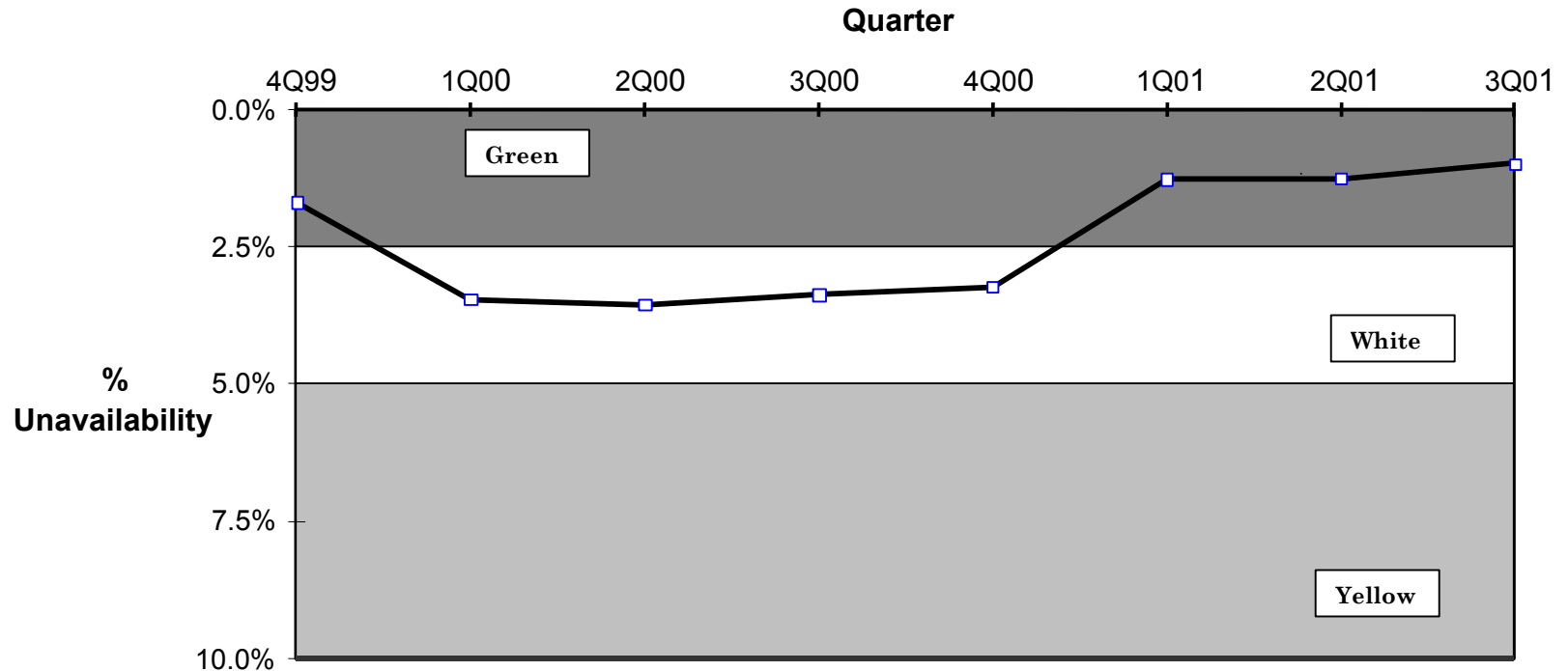
1  
2  
3  
4

	1Q97	2Q97	3Q97	4Q97	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00	1Q01
<b>Train 1</b>																	
Planned Unavailable Hours (quarter)	5	0	45	0	12	0	67	12	0	148	34	0	0	0	0	10	0
Unplanned Unavailable Hours (qtr)	48	0	0	48	0	5	0	0	0	0	0	0	0	24	0	0	0
Fault Exposure Unavailable (quarter)	0	0	0	0	0	0	0	0	0	0	0	0	500	0	0	0	0
Hours Train Required (quarter)	2160	2184	2208	2208	2160	2184	2208	2208	2160	2184	1104	2208	2160	2184	2208	2208	2208

Δ Planned Unavailable Hours (qtr)														20			
Δ Unplanned Unavailable Hours (qtr)														0			
Fault Exposure Reset Hours (quarter)														500			
Effective Quarter for Reset Hours													1Q01				
Reset Hours (quarter)	0	0	0	0	0	0	0	0	0	0	0	0	480	0	0	0	0
Effective Reset Hours (12 quarter)													0	0	0	0	480
Total Hours Unavailable (12 quarter rolling sum)													424	871	895	850	800
Total Hours Unavailable, adjusted (Hrs Unavailable – Effective Reset Hrs)													424	871	895	850	320
Total Hours Train Required for Service (12 quarter rolling sum)													25176	25176	25176	25176	25224
Train Unavailability (Hours Unavailable after adjustment/Hours Required for Service)													1.7%	3.5%	3.6%	3.4%	1.3%

Performance Indicator Value	1.7%	3.5%	3.6%	3.4%	3.2%	1.3%
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**Safety System Unavailability (12 quarter rolling average)**







## 1 ADDITIONAL GUIDANCE FOR SPECIFIC SYSTEMS

### 2 Emergency AC Power Systems

#### 3 Definition and Scope

4 This section provides additional guidance for reporting performance of the emergency AC power  
5 system. The emergency AC power system is typically comprised of two or more independent  
6 emergency generators that provide AC power to class 1E buses following a loss of off-site  
7 power. The emergency generator dedicated to providing AC power to the high pressure core  
8 spray system in BWRs is also within the scope of emergency AC power.

9  
10 The function monitored for the indicator is:

- 11 • The ability of the emergency generators to provide AC power to the class 1E buses upon a  
12 loss of off-site power (and, if specified in the design and licensing basis, accident  
13 conditions).

14  
15 Most emergency generator trains include dedicated subsystems such as air start, lube oil, fuel oil,  
16 cooling water, etc. Support systems can include service water, DC power, and room cooling.  
17 Generally, unavailable hours are counted if a failure or unavailability of a dedicated subsystem  
18 or a support subsystem prevents the emergency generator from performing its function. Some  
19 examples are discussed in the clarifying notes for this attachment.

20  
21 The electrical circuit breaker(s) that connect(s) an emergency generator to the class 1E buses that  
22 are normally served by that emergency generator are considered to be part of the emergency  
23 generator train.

24  
25 Emergency generators that are not safety grade, or that serve a backup role only (e.g., an  
26 alternate AC power source), are not required to be included in the performance reporting.

#### 27 28 Train Determination

29 The system unavailability is calculated on a per unit basis using the train unavailability value for  
30 each emergency diesel generator (EDG) that provides emergency AC power to that unit. The  
31 number of emergency AC power system trains for a unit is equal to the number of class 1E  
32 emergency generators that are available to power safe-shutdown loads in the event of a loss of  
33 off-site power for that unit. There are three typical configurations for EDGs at a multi-unit  
34 station:

- 35 1. EDGs dedicated to only one unit.
- 36 2. One or more EDGs are available to “swing” to either unit
- 37 3. All EDGs can supply all units

38  
39 For configuration 1, the number of trains for a unit is equal to the number of EDGs dedicated to  
40 the unit. For configuration 2, the number of trains for a unit is equal to the number of dedicated  
41 EDGs for that unit plus the number of “swing” EDGs available to that unit (i.e., The “swing”  
42 EDGs are included in the train count for each unit). For configuration 3, the number of trains is  
43 equal to the number of EDGs.

44

1 **Clarifying Notes**

2 Emergency diesel generators that are dedicated to the High Pressure Core Spray (HPCS) in some  
3 BWRs should be included as a train in the Emergency AC Power calculation.

4  
5 When a unit(s) is shutdown, emergency AC power trains may be removed from service in  
6 accordance with the plant's technical specifications without incurring planned or unplanned  
7 unavailable hours.

8  
9 Fault exposure hours for failures of an EDG to start or load-run **should be determined and**  
10 **reported based on** the General Clarifying Notes for Safety System Unavailability. **Fault exposure**  
11 **hours would not be reported in the following situations:**

- 13
- 14 • spurious operation of a trip that would be bypassed in the loss of offsite power emergency  
15 operating mode (e.g., high cooling water temperature trip that erroneously tripped an EDG  
16 although cooling water temperature was normal).
  - 17 • malfunction of equipment that is not required to operate during the loss of offsite power  
18 emergency operating mode (e.g., circuitry used to synchronize the EDG with off-site power  
19 sources, but not required when off-site power is lost)
  - 20 • a failure to start because a redundant portion of the starting system was intentionally disabled  
21 for test purposes, if followed by a successful start with the starting system in its normal  
22 alignment

23  
24 When determining fault exposure hours for a failure of an EDG to load-run following a  
25 successful start, **and the time the failure mechanism occurred is unknown**, the last successful  
26 operation or test is the previous successful load-run (not just a successful start). To be  
27 considered a successful load-run operation or test, an EDG load-run attempt must have followed  
28 a successful start and satisfied one of the following criteria:

- 29
- 30 • a load-run of any duration that resulted from a real (e.g., not a test) manual or automatic start  
31 signal
  - 32 • a load-run test that successfully satisfied the plant's load and duration test specifications
  - 33 • other operation (e.g., special tests) in which the emergency generator was run for at least one  
34 hour with at least 50 percent of design load.

35  
36 **If the EDG is shut down during a surveillance test because of a failure that would prevent the**  
37 **EDG from satisfying the surveillance criteria, the fault exposure hours would be computed**  
38 **based upon the time of the last surveillance test that would have exposed the discovered fault.**  
39 **The key is determining the cause of the surveillance failure. If the cause is known (and the time**  
40 **of failure cannot be ascertained) the T/2 fault exposure time would be reported as half the time**  
41 **since the last test which could have revealed the failure. This could be any of the load run tests**  
42 **described above, provided it was capable of identifying the failure. (The T/2 fault exposure time**  
43 **in this case would be reported as a comment, and would not be included in the calculation of**  
44 **unavailability.)**

47

1 The emergency diesel generators are not considered to be available during the following portions  
2 of periodic surveillance tests unless the requirement that recovery be virtually certain during  
3 accident conditions can be satisfied:

- 4 • Load-run testing
- 5 • Fire Protection “puff” testing
- 6 • Barring
- 7

## 1 **BWR High Pressure Injection Systems**

### 2 **(High Pressure Coolant Injection, High Pressure Core Spray, and Feedwater Coolant** 3 **Injection)**

#### 5 **Definition and Scope**

6 This section provides additional guidance for reporting the performance of three BWR systems  
7 used primarily for maintaining reactor coolant inventory at high pressures: the high pressure  
8 coolant injection (HPCI), high pressure core spray (HPCS), and feedwater coolant injection  
9 (FWCI) systems. Plants should monitor either the HPCI, HPCS, or FWCI system, depending on  
10 which is installed. These systems function at high pressure to maintain reactor coolant inventory  
11 and to remove decay heat following a small-break Loss of Coolant Accident (LOCA) event or a  
12 loss of main feedwater event.

13  
14 The function monitored for the indicator is:

- 16 • The ability of the monitored system to take suction from the suppression pool (and from  
17 the condensate storage tank, if credited in the plant's accident analysis) and inject into  
18 the reactor vessel.

19  
20 This capability is monitored for the injection and recirculation phases of the high pressure system  
21 response to an accident condition.

22  
23 Figures 2.1, 2.2, and 2.3 show generic schematics for the HPCI, HPCS, and FWCI systems,  
24 respectively. These schematics indicate the components for which train unavailable hours  
25 normally are monitored. Plant-specific design differences may require other components to be  
26 included.

#### 28 **Train Determination**

29 The HPCI system is considered a single-train system. The booster pump and other small pumps  
30 shown in Figure 2.1 are ancillary components not used in determining the number of trains. The  
31 effect of these pumps on HPCI performance is included in the system unavailability indicator to  
32 the extent their failure detracts from the ability of the system to perform its monitored function.  
33 The HPCI turbine, governor, and associated valves and piping for steam supply and exhaust are  
34 in the scope of the HPCI system. Valves in the feedwater line are not considered within the scope  
35 of the HPCI system.

36  
37 The HPCS system is also considered a single-train system. Unavailability is monitored for the  
38 components shown in Figure 2.2. The HPCS diesel generator is considered to be part of the  
39 emergency AC power system.

40  
41 For the feedwater injection system, the number of trains is determined by the number of main  
42 feedwater pumps that can be used at one time in this operating mode (typically one). Figure 2.3  
43 illustrates a typical FWCI system.

44

1 **Clarifying Notes**

2 The HPCS system typically includes a "water leg" pump to prevent water hammer in the HPCS  
3 piping to the reactor vessel. The "water leg" pump and valves in the "water leg" pump flow path  
4 are ancillary components and are not directly included in the scope of the HPCS system for the  
5 performance indicator.

6  
7 For the feedwater coolant injection system, condensate and feedwater booster pumps are not  
8 used to determine the number of trains.

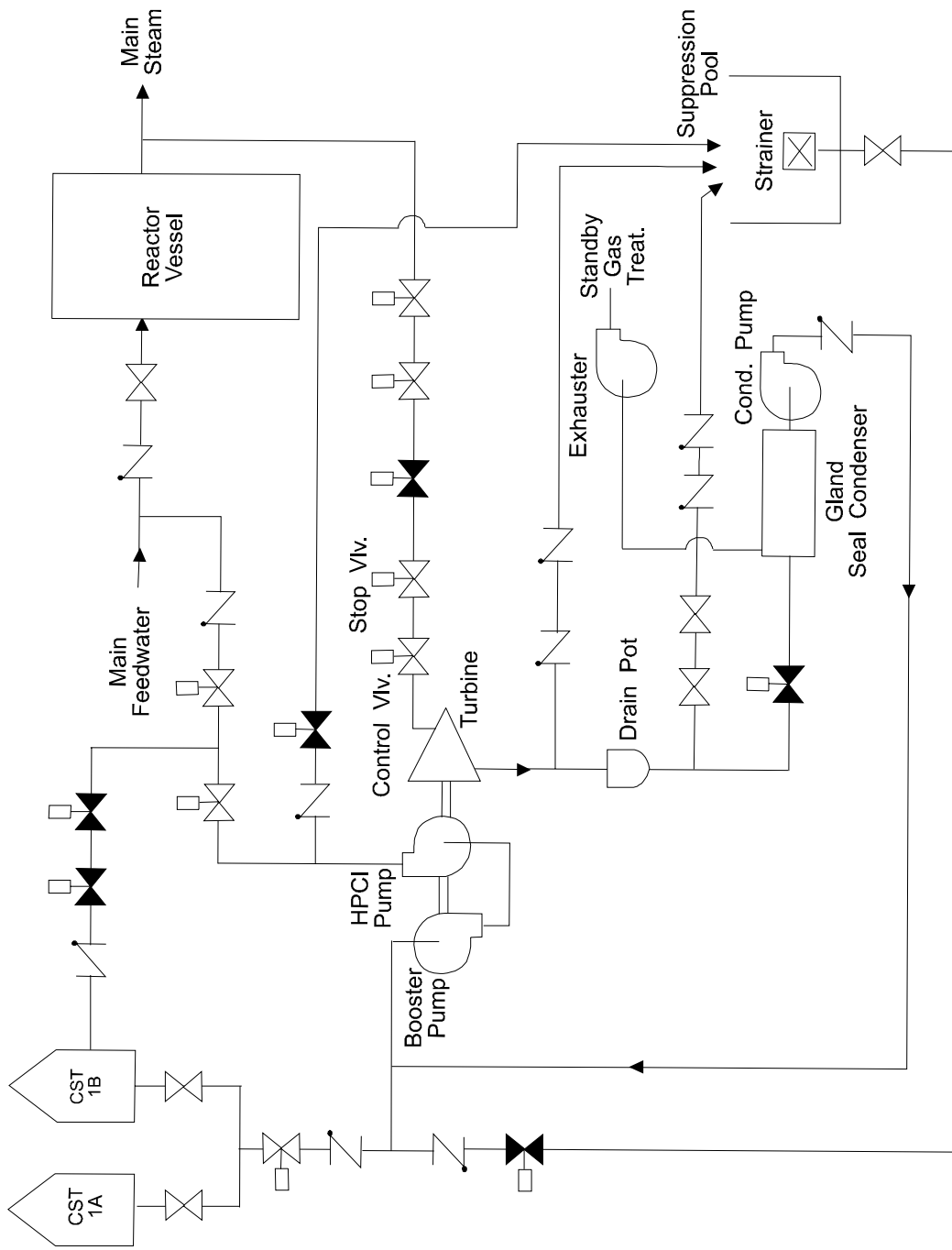


Figure 2.1  
High Pressure Coolant Injection System  
(Example of Reporting Scope)

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7

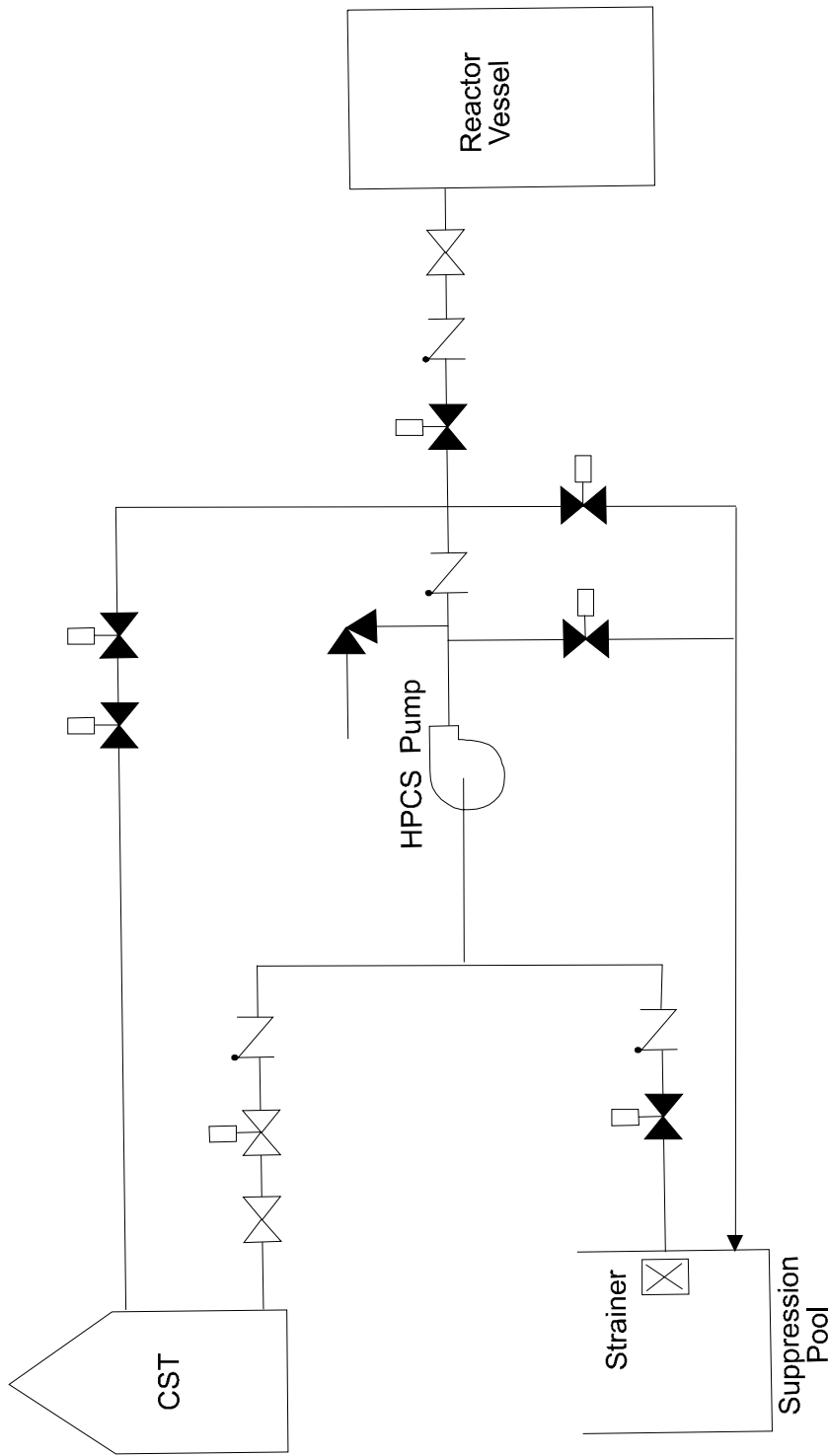


Figure 2.2  
High Pressure Core Spray System  
(Example of Reporting Scope)

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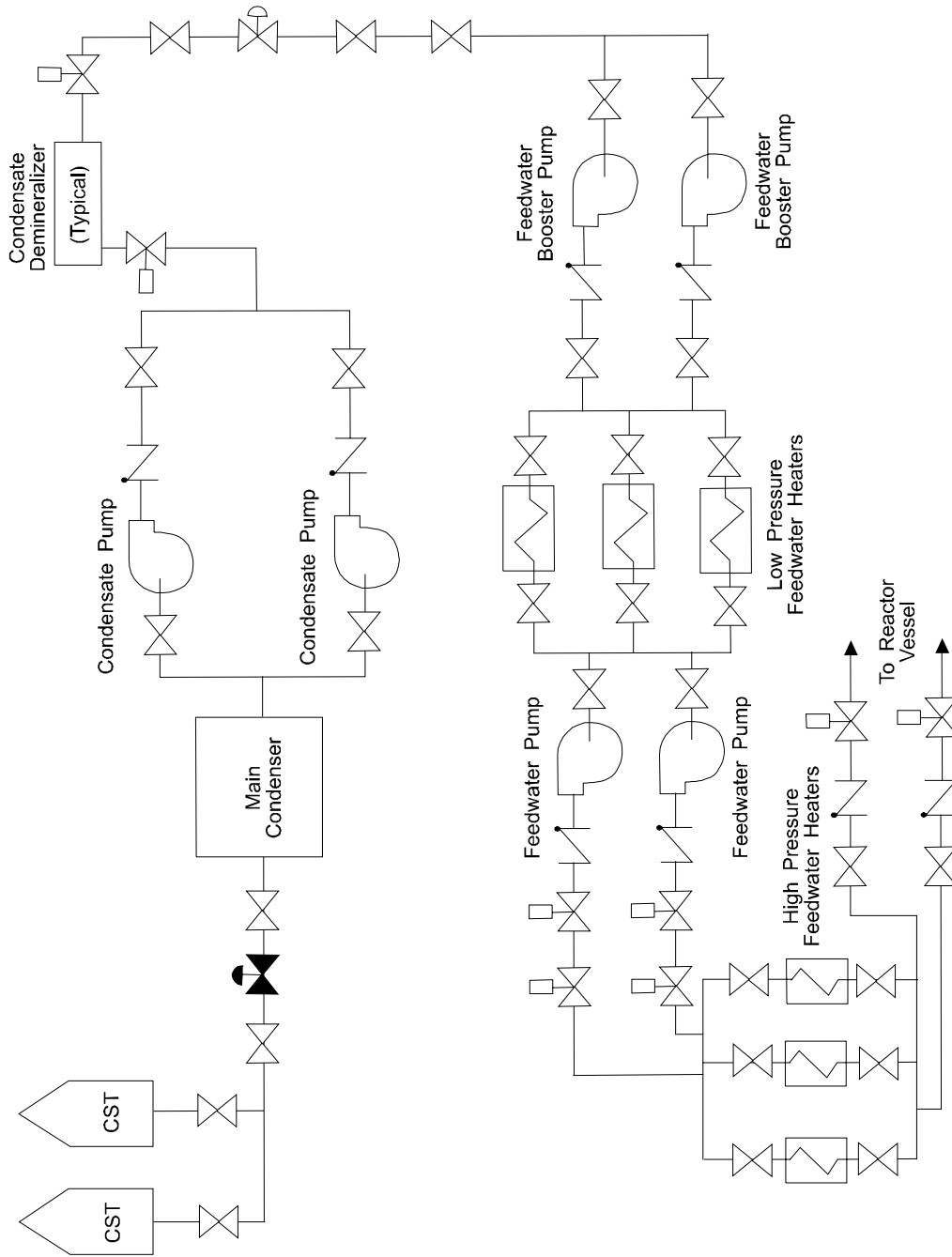


Figure 2.3  
 Feedwater Coolant Injection System  
 (Example of Reporting Scope)



1 **BWR Heat Removal Systems**

2 **(Reactor Core Isolation Cooling)**

3

4 **Definition and Scope**

5 This section provides additional guidance for reporting the performance of a BWR system that is  
6 used primarily for decay heat removal at high pressure: reactor core isolation cooling (RCIC)  
7 system. This system functions at high pressure to remove decay heat following a loss of main  
8 feedwater event. The RCIC system also functions to maintain reactor coolant inventory  
9 following a very small LOCA event.

10

11 The function monitored for the indicator, is:

12

- 13 • the ability of the RCIC system to cool the reactor vessel core and provide makeup  
14 water by taking a suction from either the condensate storage tank or the suppression  
15 pool and injecting at rated pressure and flow into the reactor vessel

16

17 Figures 3.1 shows a generic schematic for the RCIC system. This schematic indicates the  
18 components for which train unavailability is monitored. Plant-specific design differences may  
19 require other components to be included.

20

21 **Train Determination**

22 The RCIC system is considered a single-train system. The condensate and vacuum pumps shown  
23 in Figure 3.1 are ancillary components not used in determining the number of trains. The effect  
24 of these pumps on RCIC performance is included in the system unavailability indicator to the  
25 extent that a component failure results in an inability of the system to perform its monitored  
26 function. The RCIC turbine, governor, and associated valves and piping for steam supply and  
27 exhaust are in the scope of the RCIC system. Valves in the feedwater line are not considered  
28 within the scope of the RCIC system.

29

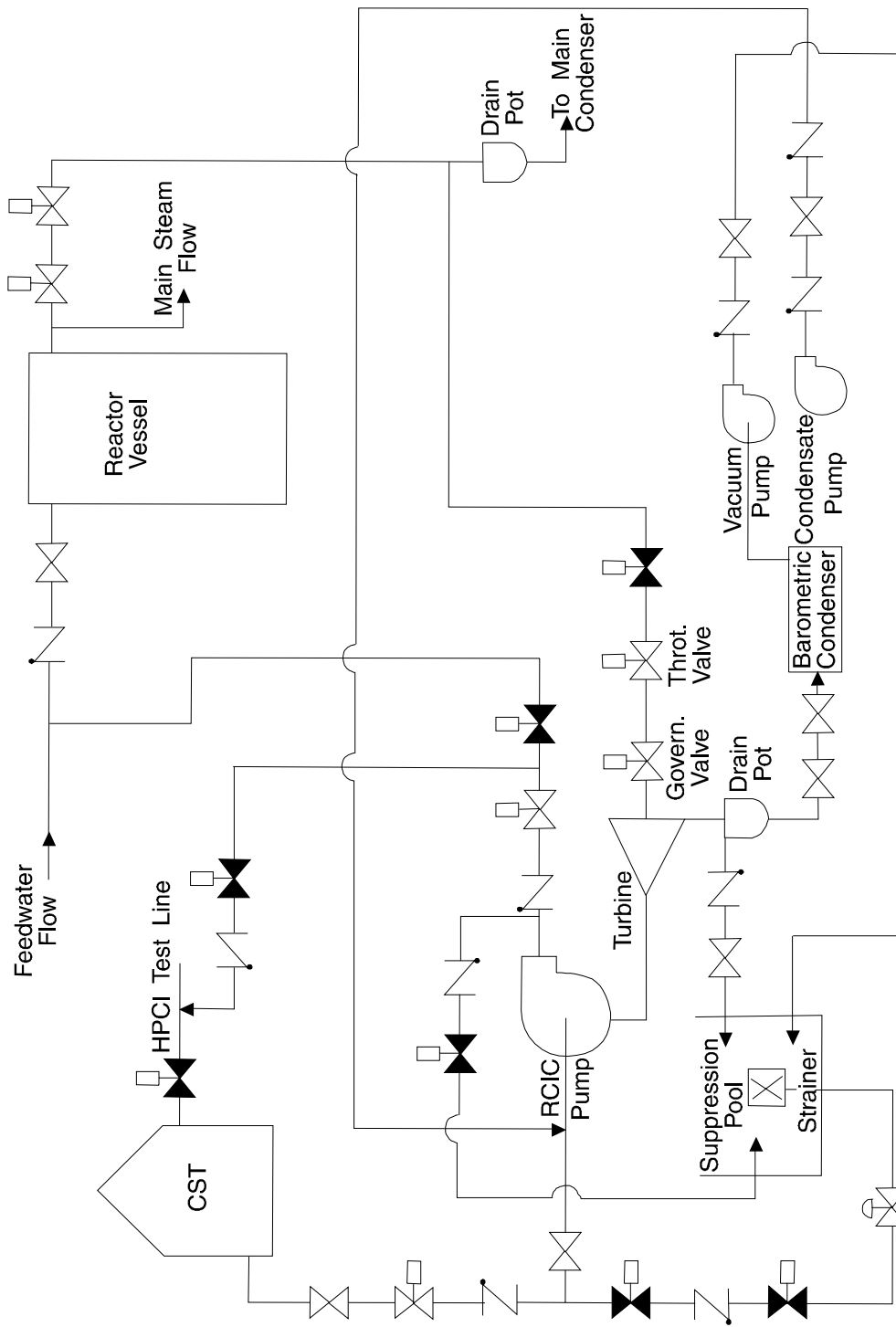


Figure 3.1  
 Reactor Core Isolation Cooling System  
 (Example of Reporting Scope)

1  
 2  
 3  
 4  
 5  
 6  
 7  
 8

## 1 **BWR Residual Heat Removal Systems**

### 2 **Definition and Scope**

3 This section provides additional guidance for reporting the performance of the BWR residual  
4 heat removal (RHR) system for the suppression pool cooling and shutdown cooling modes. The  
5 attachment also includes guidance for reporting performance of other systems used to remove  
6 heat to outside containment under low pressure conditions at early BWRs where two separate  
7 systems provide these functions with unique designs. The suppression pool cooling function is  
8 used whenever the suppression pool (or torus) water temperature exceeds or is expected to  
9 exceed a high-temperature setpoint (for example, following most relief valve openings or during  
10 some post-accident recoveries). The shutdown cooling function is used following any transient  
11 requiring normal long-term heat removal from the reactor vessel.  
12

13 The functions monitored for the indicator are:

- 14
- 15 • the ability of the RHR system to remove heat from the suppression pool so that pool  
16 temperatures do not exceed plant design limits, and  
17
- 18 • the ability of the RHR system to remove decay heat from the reactor core during a  
19 normal unit shutdown (e.g., for refueling or for servicing).  
20

21 Figures 4.1 and 4.2 show generic schematics with the RHR system in the suppression pool  
22 cooling and shutdown cooling modes, respectively. Two variations of basic RHR system design  
23 are shown in Figures 4.3 and 4.4. These are included to illustrate reporting for systems with  
24 redundant and series components, respectively. The figures indicate the components for which  
25 train unavailability is monitored. Plant-specific design differences may require other components  
26 to be included.  
27

### 28 **Train Determination**

29 The number of trains in the RHR system is determined by the number of parallel RHR heat  
30 exchangers capable of performing suppression pool cooling or shutdown cooling. The following  
31 discussion demonstrates train determination for various generic system designs.  
32

33 Figures 4.1 and 4.2 illustrate a common RHR system that incorporates four pumps and two heat  
34 exchangers arranged so that each heat exchanger can be supplied by one of two pumps. This is a  
35 two-train RHR system.  
36

37 Some trains have two heat exchangers in series, as shown in Figure 4.3. The system depicted in  
38 Figure 4.3 is also a two-train RHR system.  
39

40 Figure 4.4 shows an arrangement with four parallel sets of a pump and a heat exchanger  
41 combination. This system is a four-train RHR system.  
42  
43

1 Other Systems: For some early BWRs, separate systems are used to remove heat to outside the  
2 containment under low pressure conditions. Depending on the particular design, one or more of  
3 the following systems may be used: shutdown cooling, containment spray, or RHR (torus  
4 cooling function). For example, a unit using a shutdown cooling system (with three heat  
5 exchangers) and a containment spray system (with two heat exchangers) would monitor each  
6 system separately for the safety system unavailability indicators. All components required for  
7 each safety system to perform its heat removal function should be included in the scope. The  
8 number of trains is determined by the number of heat exchangers in the systems that perform the  
9 heat removal function under low pressure conditions (five trains in this example).

10

11 **Clarifying Notes**

12 The low pressure coolant injection (LPCI), steam cooling, and containment spray modes of RHR  
13 operation are not monitored.

14

15 Some components are used to provide more than one function of RHR. If a component cannot  
16 perform as designed, rendering its associated train incapable of meeting one or both of the  
17 monitored functions, then the train is considered to be failed. Unavailable hours (if the train was  
18 required to be available for service) would be reported as a result of the component failure.

19

20

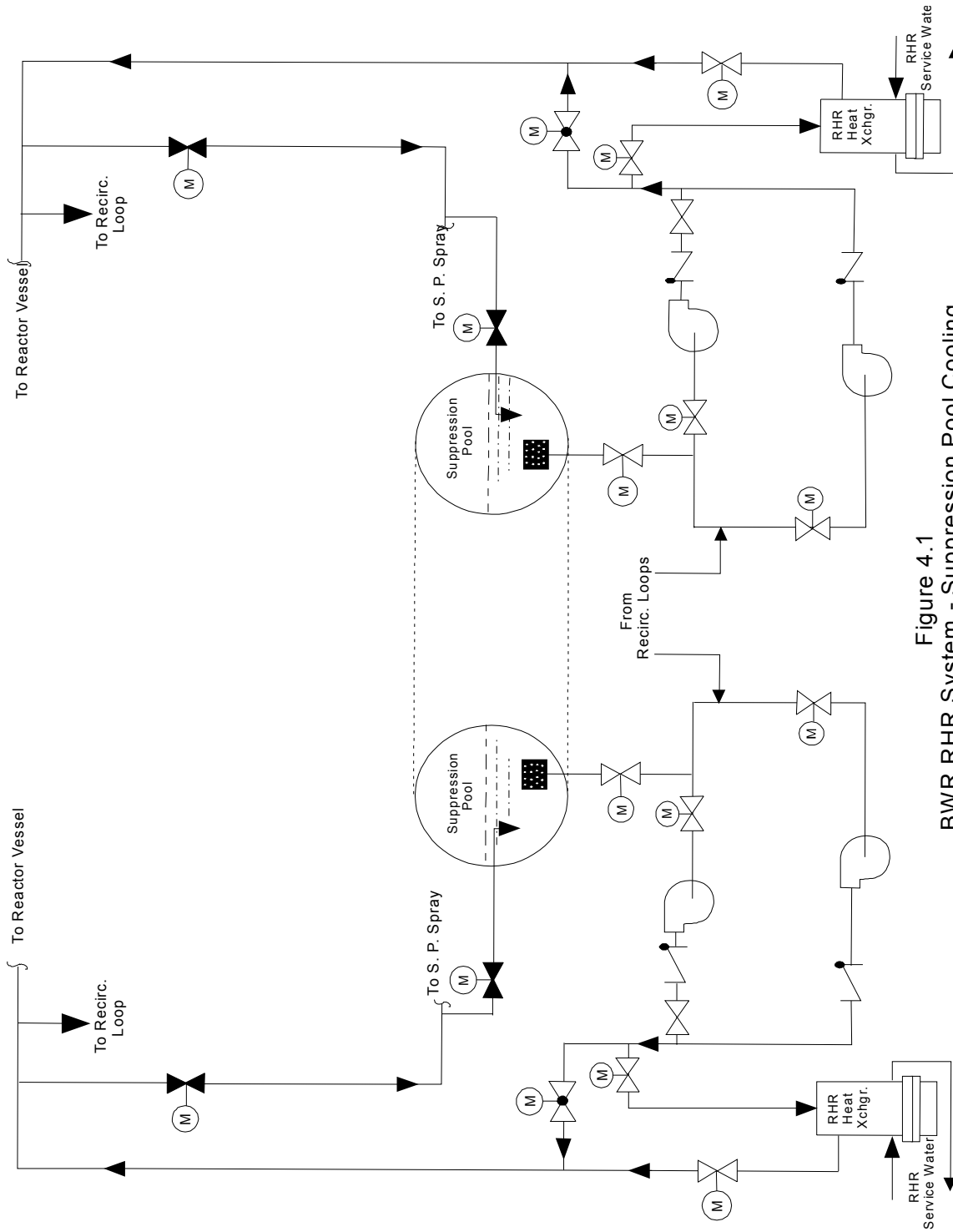


Figure 4.1  
BWR RHR System - Suppression Pool Cooling

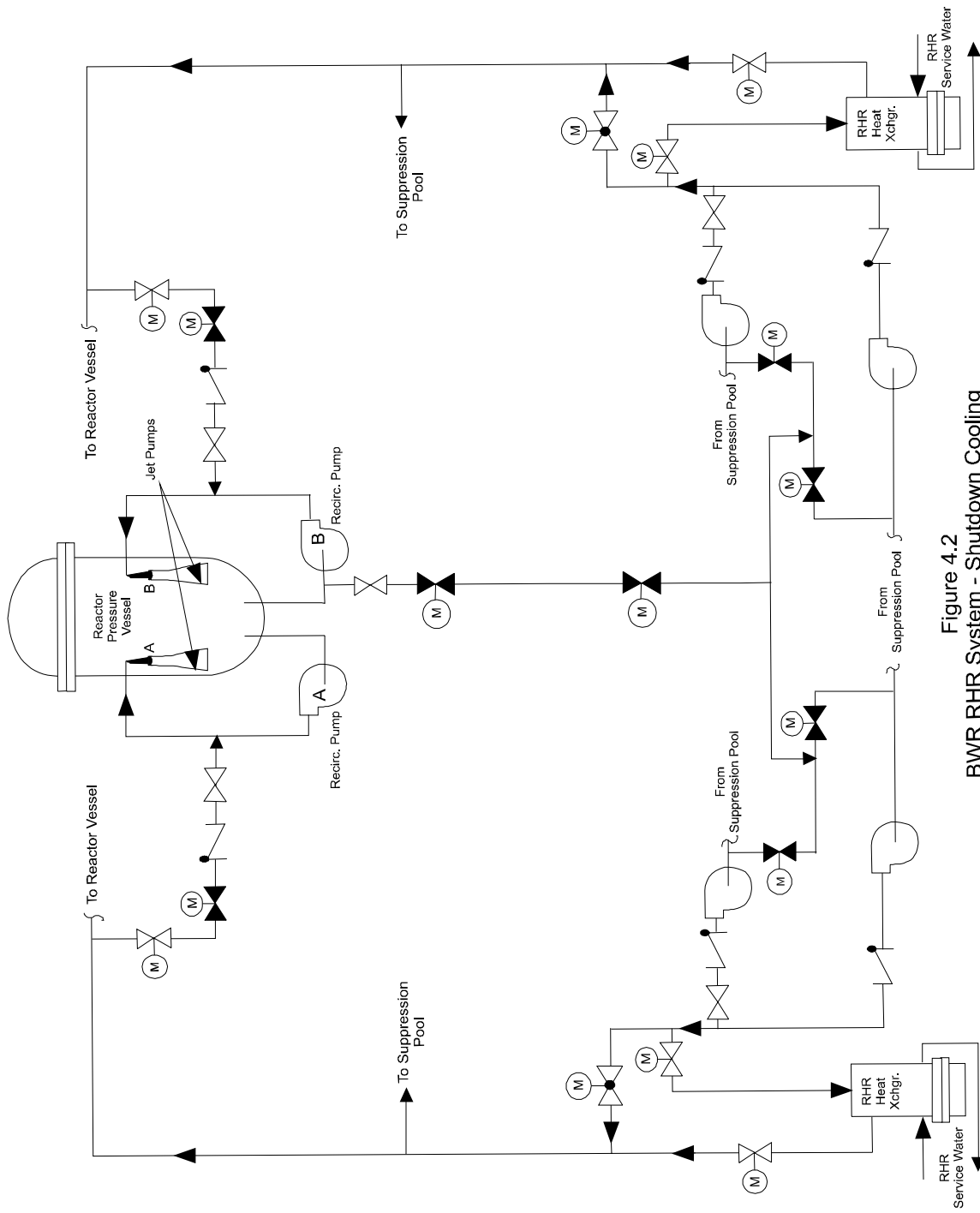


Figure 4.2  
BWR RHR System - Shutdown Cooling

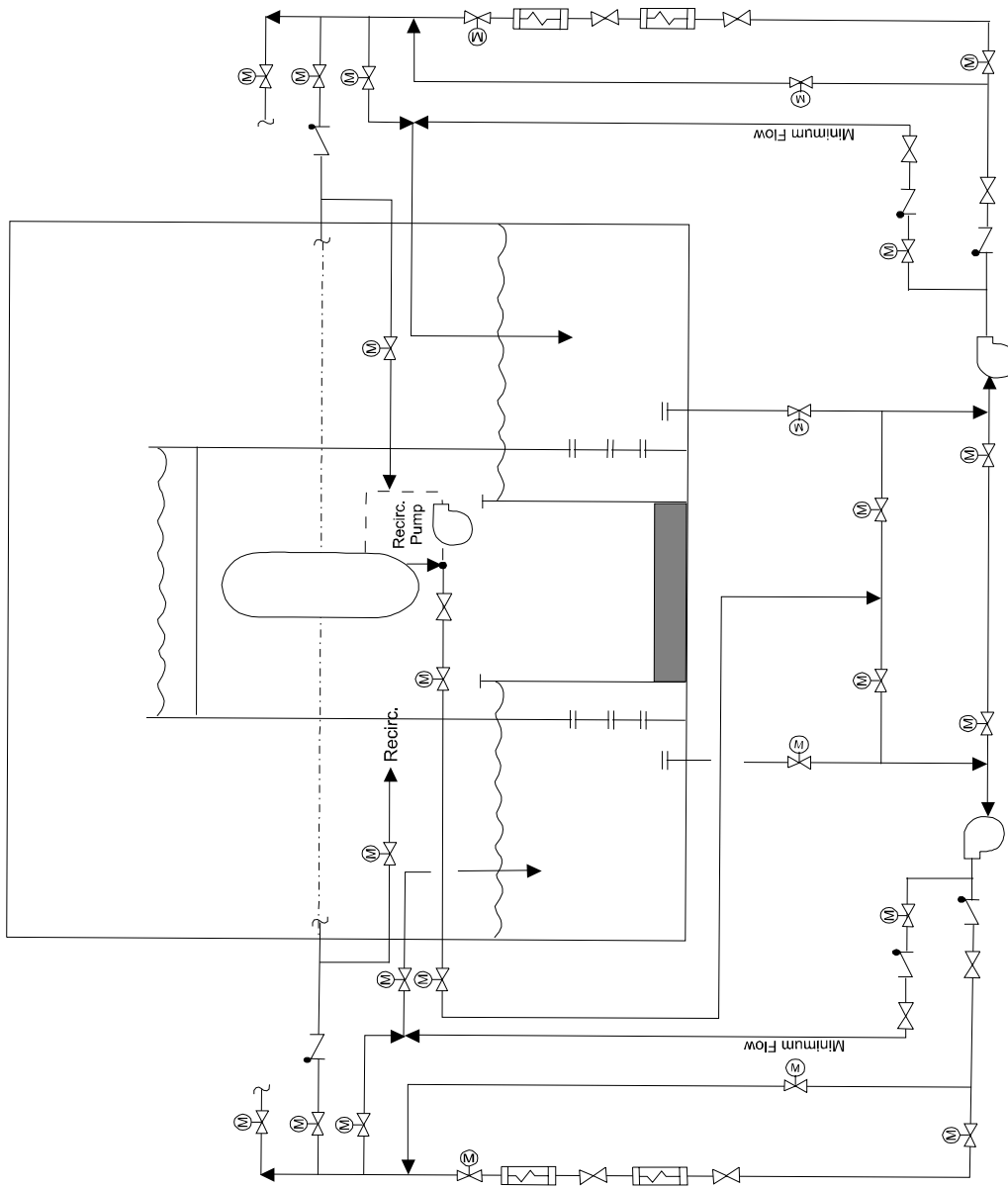
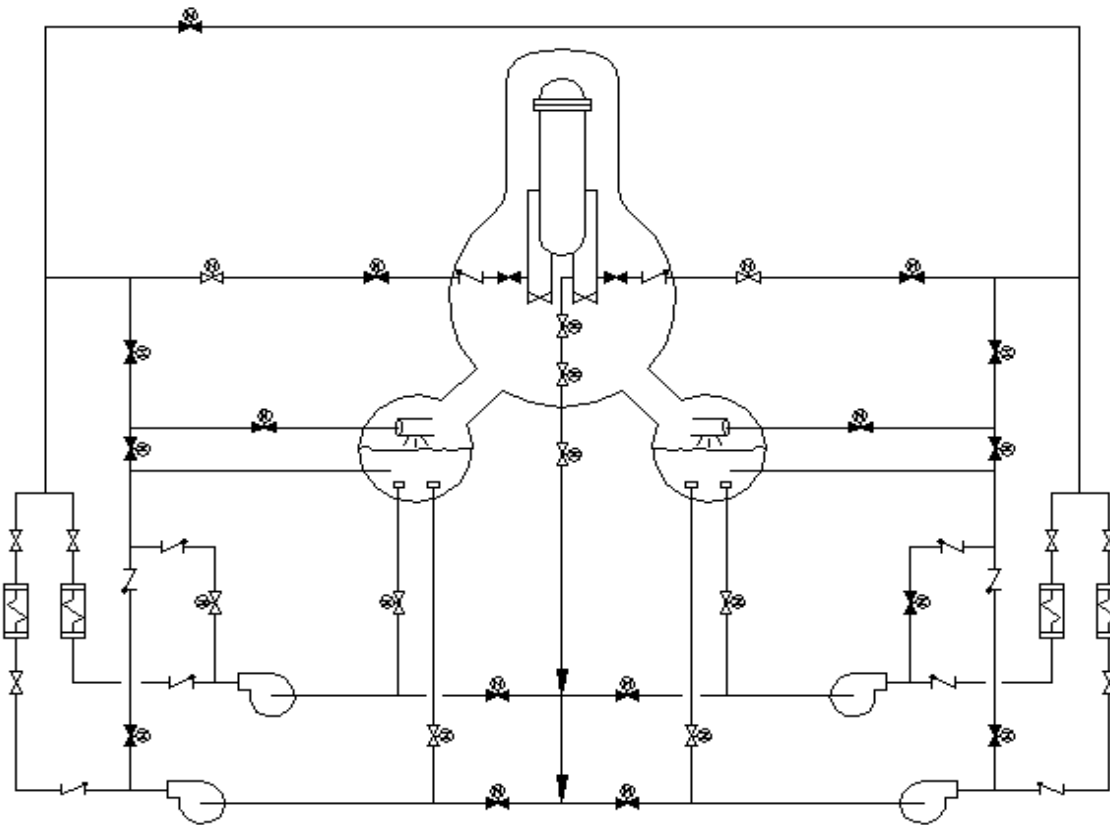


Figure 4.3  
Two-Train BWR RHR System  
(Example of Reporting Scope)



1  
2  
3

Figure 4.4 - 4 Train BWR RHR System



## 1 **PWR High Pressure Safety Injection Systems**

### 2 **Definition and Scope**

3 This section provides additional guidance for reporting the performance of PWR high pressure  
4 safety injection (HPSI) systems. These systems are used primarily to maintain reactor coolant  
5 inventory at high pressures following a loss of reactor coolant. HPSI system operation following  
6 a small-break LOCA involves transferring an initial supply of water from the refueling water  
7 storage tank (RWST) to cold leg piping of the reactor coolant system. Once the RWST inventory  
8 is depleted, recirculation of water from the reactor building emergency sump is required.

9 Components in the flow paths from each of these water sources to the reactor coolant system  
10 piping are included in the scope for the HPSI system. (Because RHR and HPSI are monitored as  
11 separate systems with each having its own performance indicator, there is no need to cascade  
12 RHR system unavailability into HPSI. RHR system unavailability includes the system upstream  
13 of the RHR system to HPSI system isolation valves. Unavailability of the isolation valves  
14 between the RHR system and the HPSI pump suction are only counted against the HPSI system.)

15  
16 There are design differences among HPSI systems that affect the scope of the components to be  
17 included for the HPSI system function. For the purpose of the safety system unavailability  
18 indicator, and where applicable, the HPSI system includes high head pumps (centrifugal  
19 charging pumps/high head safety injection pumps) which discharge at pressures of 2,200-2,500  
20 psig and intermediate head pumps (intermediate head safety injection pumps) which discharge at  
21 pressures of 1200-1700 psig, along with associated components in the suction and discharge  
22 piping to the reactor coolant system cold-legs or hot-legs.

23  
24 The function monitored for HPSI is:

- 25  
26 • the ability of a HPSI train to take a suction from the primary water source (typically,  
27 a borated water tank), or from the containment emergency sump, and inject into the  
28 reactor coolant system at rated flow and pressure.

29  
30 The charging and seal injection functions provided by centrifugal charging pumps in some  
31 system designs are not included within the scope of the safety system unavailability indicator  
32 reports.

33  
34 Figures 5.1 through 5.4 show some typical HPSI system configurations for which train functions  
35 are monitored. The figures contain variations that are somewhat reactor vendor specific. They  
36 also indicate the components for which train unavailability is monitored. Plant-specific design  
37 differences may require other components to be included.

### 38 39 **Train Determination**

40 In general, the number of HPSI system trains is defined by the number of high head injection  
41 paths that provide cold-leg and/or hot-leg injection capability, as applicable. This is necessary to  
42 fully account for system redundancy.

43  
44 Figure 5.1 illustrates a typical HPSI system for Babcock and Wilcox (B&W) reactors. The  
45 design features centrifugal pumps used for high pressure injection (about 2,500 psig) and no hot-  
46 leg injection path. Recirculation from the containment sump requires operation of pumps in the

1 residual heat removal system. The system in Figure 5.1 is a two-train system, with an installed  
2 spare pump (depending on plant-specific design) that can be aligned to either train.  
3

4 HPSI systems in some older, two-loop Westinghouse plants may be similar to the system  
5 represented in Figure 5.1, except that the pumps operate at a lower pressure (about 1600 psig)  
6 and there may be a hot-leg injection path in addition to a cold-leg injection path (both are  
7 included as a part of the train).  
8

9 Figure 5.2 is typical of HPSI designs in Combustion Engineering (CE) plants. The design  
10 features three centrifugal pumps that operate at intermediate pressure (about 1300 psig) and  
11 provide flow to two cold-leg injection paths or two hot-leg injection paths. In most designs, the  
12 HPSI pumps take suction directly from the containment sump for recirculation. In these cases,  
13 the sump suction valves are included within the scope of the HPSI system. This is a two-train  
14 system (two trains of combined cold-leg and hot-leg injection capability). One of the three  
15 pumps is typically an installed spare that can be aligned to either train or only to one of the trains  
16 (depending on plant-specific design).  
17

18 A HPSI system typical of those installed in Westinghouse three-loop plants is shown in Figure  
19 5.3. This design features three centrifugal pumps that operate at high pressure (about 2500 psig),  
20 a cold-leg injection path through the BIT (with two trains of redundant valves), an alternate cold-  
21 leg injection path, and two hot-leg injection paths. One of the pumps is considered an installed  
22 spare. Recirculation is provided by taking suction from the RHR pump discharges. A train  
23 consists of a pump, the pump suction valves and boron injection tank (BIT) injection line valves  
24 electrically associated with the pump, and the associated hot-leg injection path. The alternate  
25 cold-leg injection path is required for recirculation, and should be included in the train with  
26 which its isolation valve is electrically associated. Thus, Figure 5.3 represents a two-train HPSI  
27 system.  
28

29 Four-loop Westinghouse plants may be represented by Figure 5.4. This design features two  
30 centrifugal pumps that operate at high pressure (about 2500 psig), two centrifugal pumps that  
31 operate at an intermediate pressure (about 1600 psig), a BIT injection path (with two trains of  
32 injection valves), a cold-leg safety injection path, and two hot-leg injection paths. Recirculation  
33 is provided by taking suction from the RHR pump discharges. Each of two high pressure trains is  
34 comprised of a high pressure centrifugal pump, the pump suction valves and BIT valves that are  
35 electrically associated with the pump. Each of two intermediate pressure trains is comprised of  
36 the safety injection pump, the suction valves and the hot-leg injection valves electrically  
37 associated with the pump. The cold-leg safety injection path can be fed with either safety  
38 injection pump, thus it should be associated with both intermediate pressure trains. The HPSI  
39 system represented in Figure 5.4 is considered a four-train system for monitoring purposes.  
40  
41

1 **Clarifying Notes**

2 Many plants have charging pumps (typically, positive displacement charging pumps) that are not  
3 safety-related, provide a small volume of flow, and do not automatically start on a safety  
4 injection signal. These pumps should not be included within the scope of HPSI system for this  
5 indicator.

6  
7 Some HPSI components may be included in the scope of more than one train. For example, cold-  
8 leg injection lines may be fed from a common header that is supplied by both HPSI trains. In  
9 these cases, the effects of testing or component failures in an injection line should be reported in  
10 both trains.

11  
12 At many plants, recirculation of water from the reactor building sump requires that the high  
13 pressure injection pump take suction via the low pressure injection/residual heat removal pumps.  
14 For these plants, the low pressure injection/residual heat removal pumps discharge header  
15 isolation valve to the HPSI pump suction is included in the scope of HPSI system.

16  
17

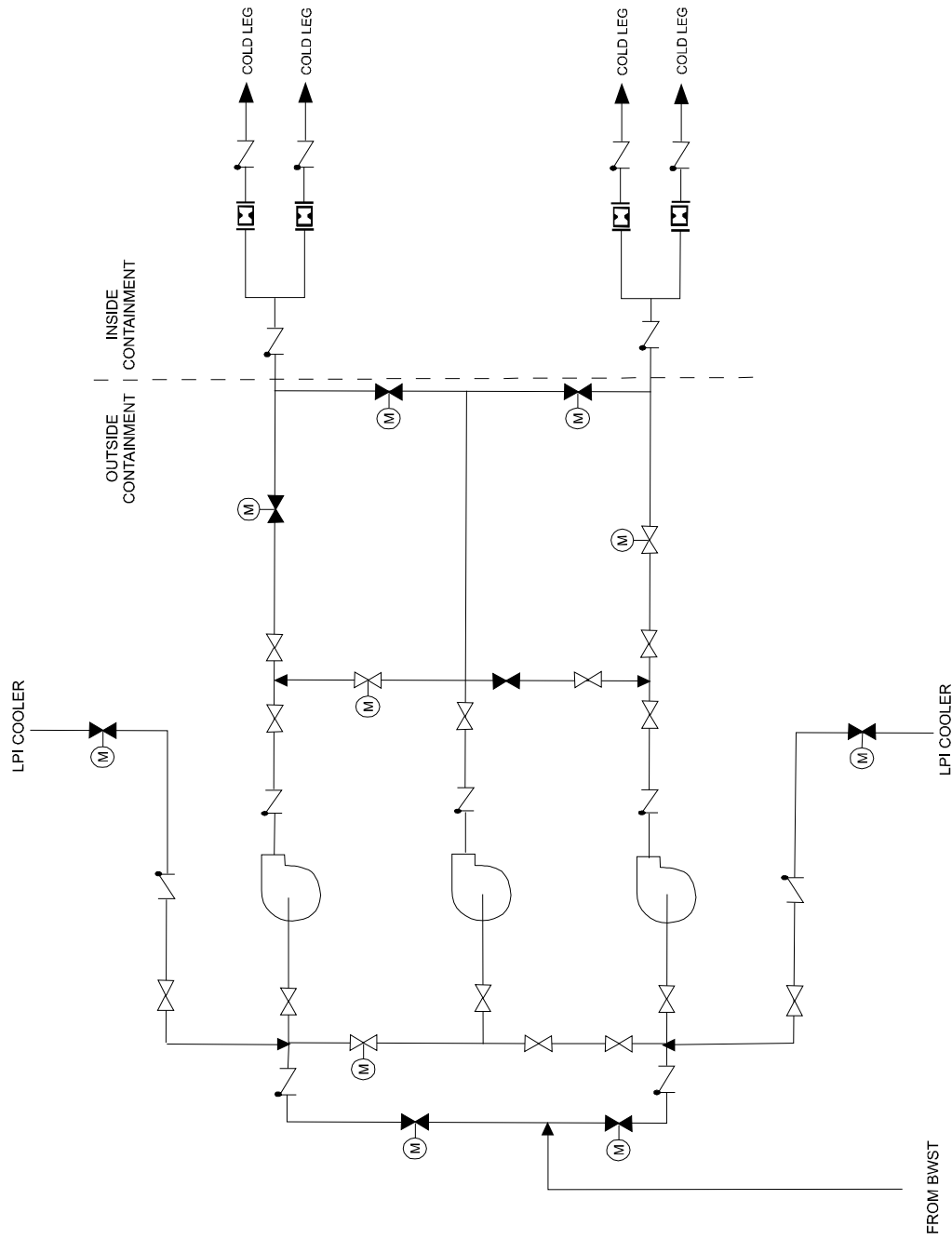


Figure 5.1  
High Pressure Safety Injection System  
(Example of Reporting Scope)

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3  
4  
5

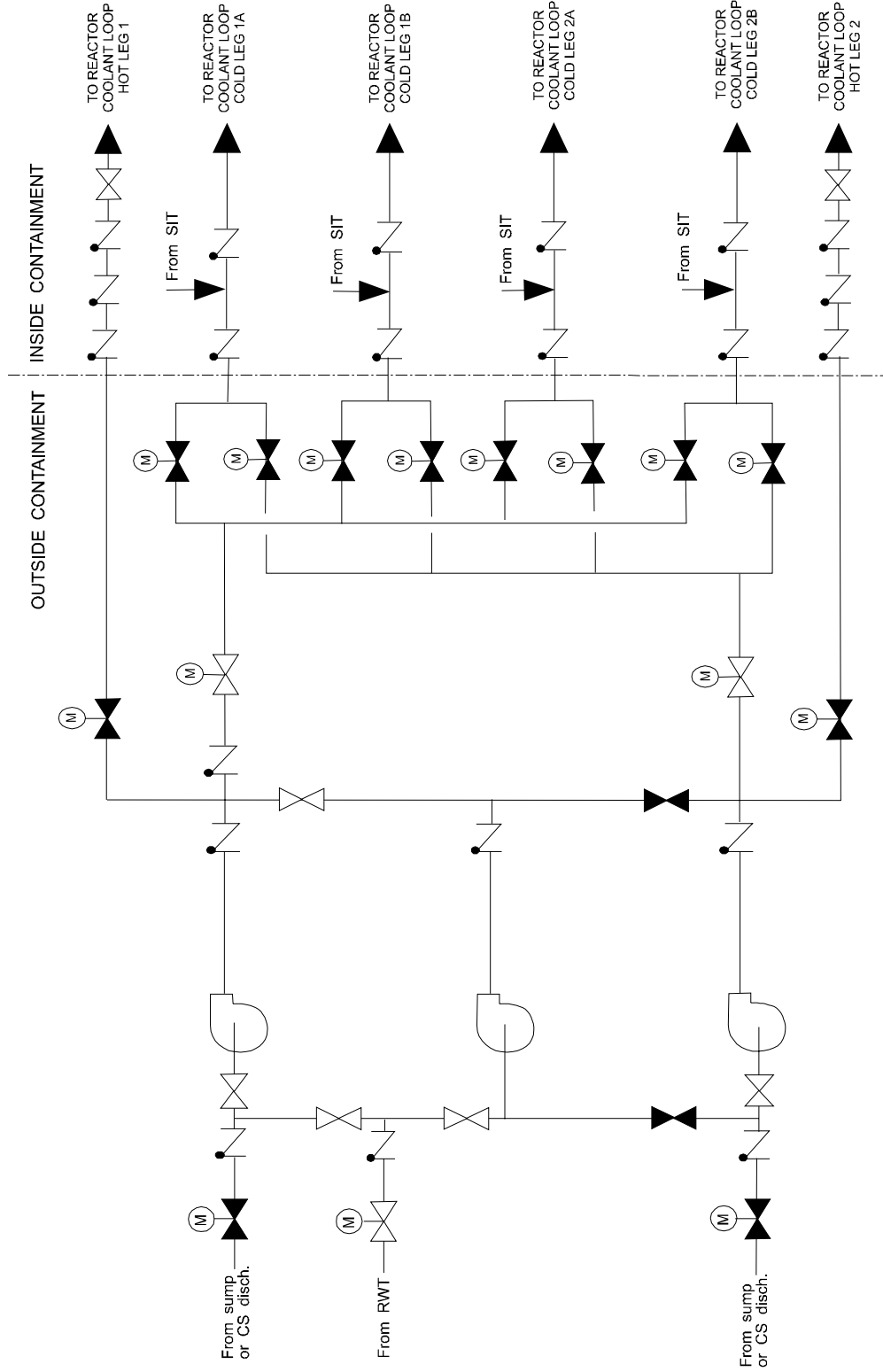


Figure 5.2  
High Pressure Safety Injection System  
(Example of Reporting Scope)

1

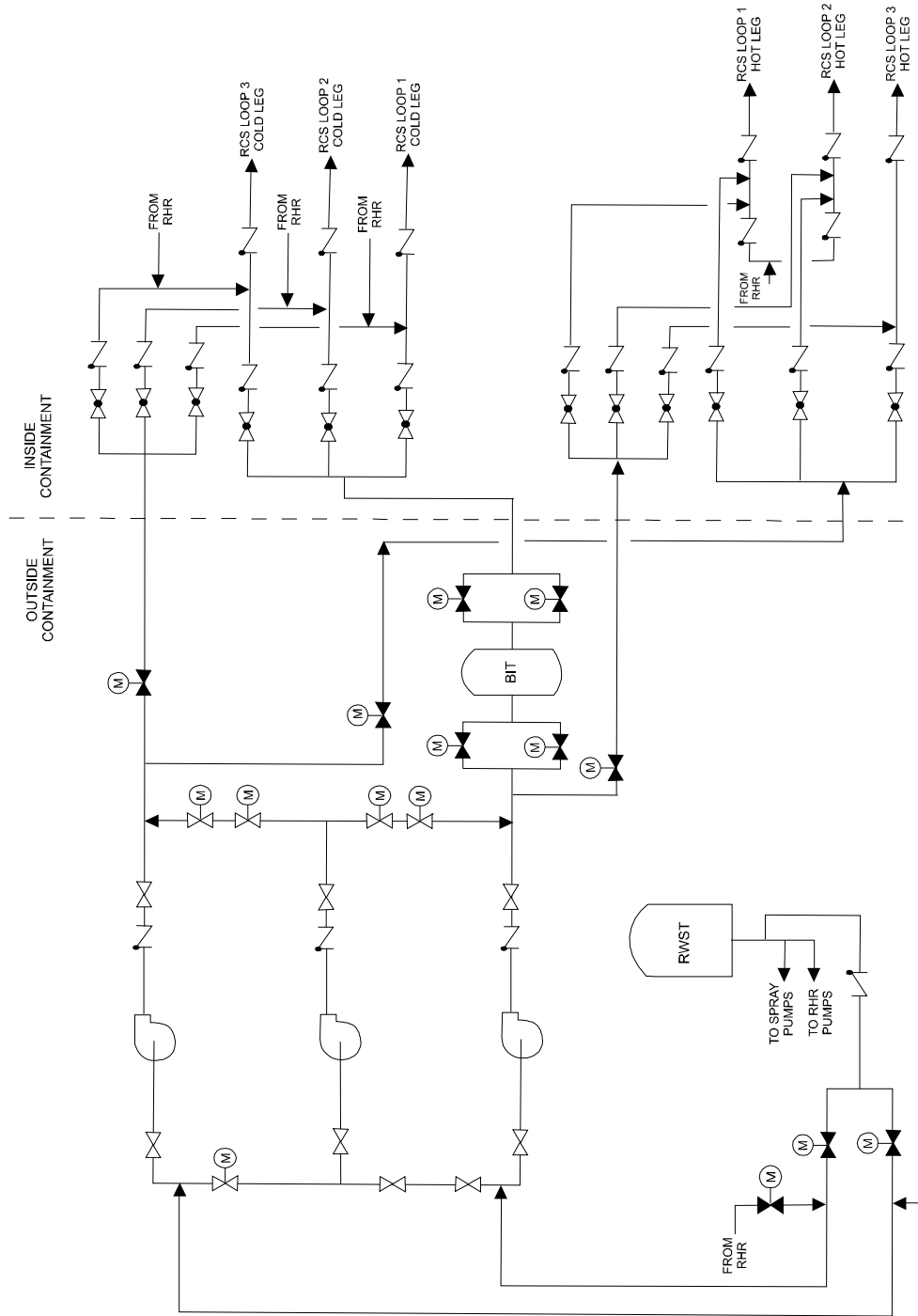
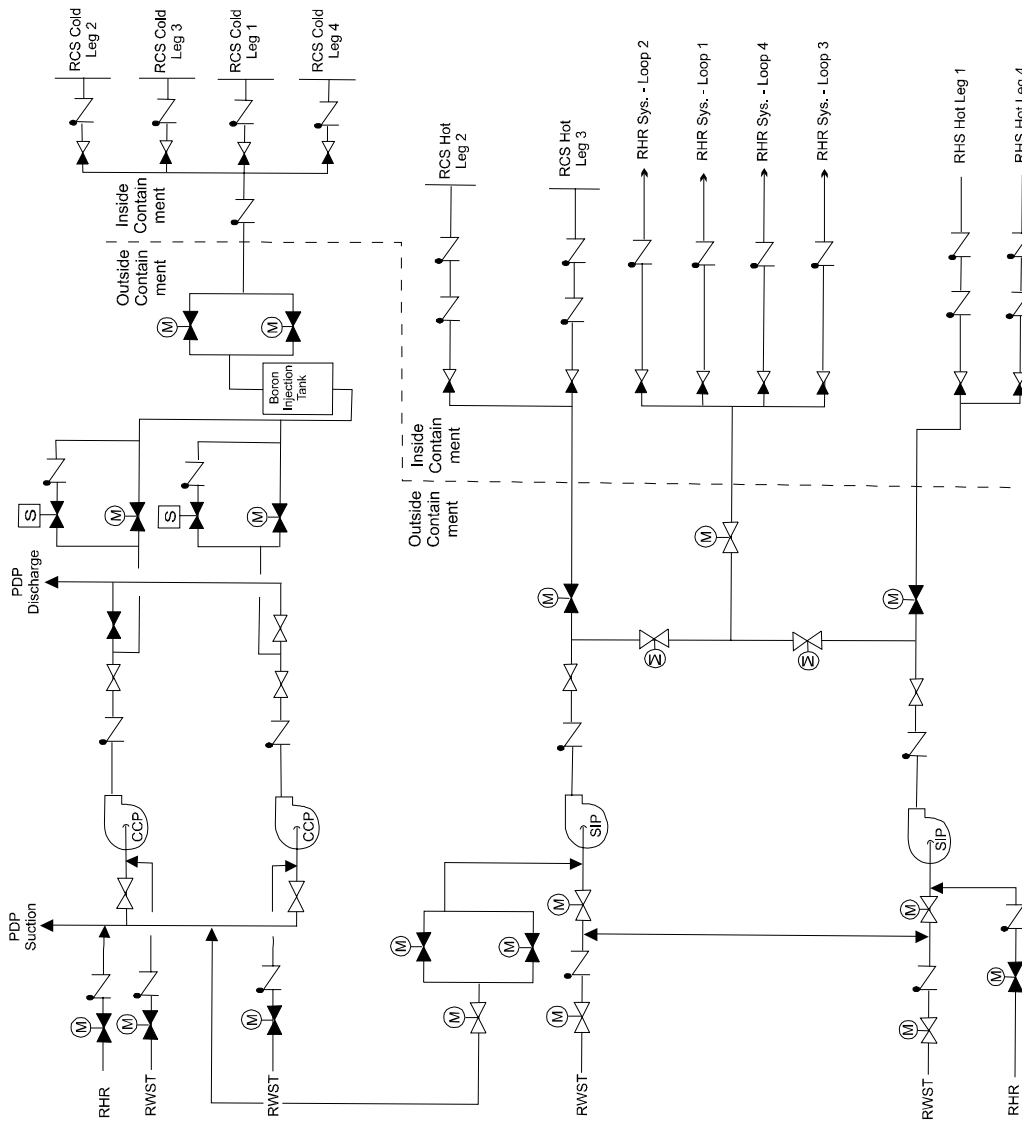


Figure 5.3  
High Pressure Safety Injection System  
(Example of Reporting Scope)

2  
3  
4  
5

1  
2



3  
4

Figure 5.4  
High Pressure Safety Injection System  
(Example of Reporting Scope)

## 1 **PWR Auxiliary Feedwater Systems**

### 2 **Definition and Scope**

3 This section provides additional guidance for reporting the performance of PWR auxiliary  
4 feedwater (AFW) or emergency feedwater (EFW) systems. The AFW system provides decay  
5 heat removal via the steam generators to cool down and depressurize the reactor coolant system  
6 following a reactor trip. The AFW system is assumed to be required for an extended period of  
7 operation during which the initial supply of water from the condensate storage tank is depleted  
8 and water from an alternative water source (e.g., the service water system) is required. Therefore  
9 components in the flow paths from both of these water sources are included; however, the  
10 alternative water source (e.g., service water system) is not included.

11

12 The function monitored for the indicator is:

13

- 14 • the ability of the AFW system to take a suction from the primary water source  
15 (typically, the condensate storage tank) or from an emergency source (typically, a  
16 lake or river via the service water system) and inject into at least one steam generator  
17 at rated flow and pressure.

18

19 Some plants have a startup feedwater pump that requires a manual actuation. Startup feedwater  
20 pumps are not included in the scope of the AFW system for this indicator.

21

22 Figures 6.1 through 6.3 show some typical AFW system configurations, indicating the  
23 components for which train unavailability is monitored. Plant-specific design differences may  
24 require other components to be included.

25

### 26 **Train Determination**

27 The number of trains is determined primarily by the number of parallel pumps in the AFW  
28 system, not by the number of injection lines. For example, a system with three AFW pumps is  
29 defined as three-train system, whether it feeds two, three, or four injection lines, and regardless  
30 of the flow capacity of the pumps.

31

32 Figure 6.1 illustrates a three-pump, two-steam generator plant that features redundant flow paths  
33 to the steam generators. This system is a three-train system. (If the system had only one motor-  
34 driven pump, it would be a two-train system.) The turbine-driven pump train does not share  
35 motor-operated isolation valves with the motor-driven pump trains in this design.

36

37 Another three-pump, two-steam generator design is shown in Figure 6.2. This is also a three-  
38 train system; however, in this design, the isolation and regulating valves in the motor-driven  
39 pump trains are also included in the turbine-driven pump train.

40

41 A three-pump, four-steam generator design is shown in Figure 6.3. In this design, either motor-  
42 driven pump can supply each steam generator through a common header. The turbine-driven  
43 pump can supply each steam generator through a separate header. The turbine-driven and motor-  
44



1 driven pump trains do not share the air-operated regulating valves in this design. This is a three  
2 train system. Three-steam generator designs may be arranged similar to Figure 6.3.  
3

4 **Clarifying Notes**

5 Some AFW components, may be included in the scope of more than one train. For example, one  
6 set of flow regulating valves and isolation valves in a three-pump, two-steam generator system  
7 (as in Figure 6.2) are included in the motor-driven pump train with which they are electrically  
8 associated, but they are also included (along with the redundant set of valves) in the turbine-  
9 driven pump train. In these instances, the effects of testing or failure of the valves should be  
10 reported in both affected trains.

11  
12 Similarly, when two trains provide flow to a common header, such as in Figure 6.3, the effect of  
13 isolation or flow regulating valve failures in paths connected to the header should be considered  
14 in both trains.  
15

1  
2

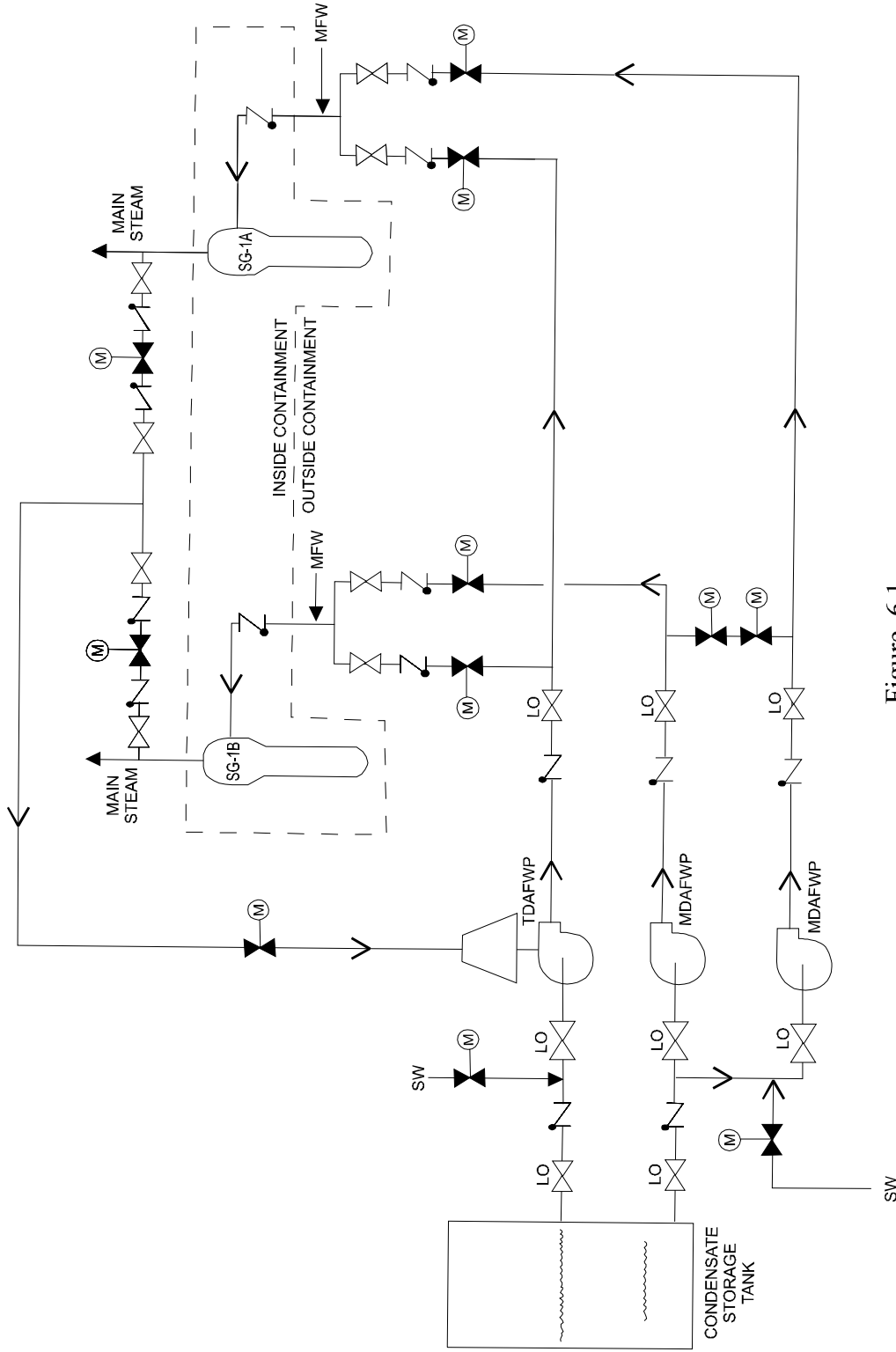


Figure 6.1  
Auxiliary Feedwater System  
(Example of Reporting Scope)

3  
4  
5  
6

1  
2

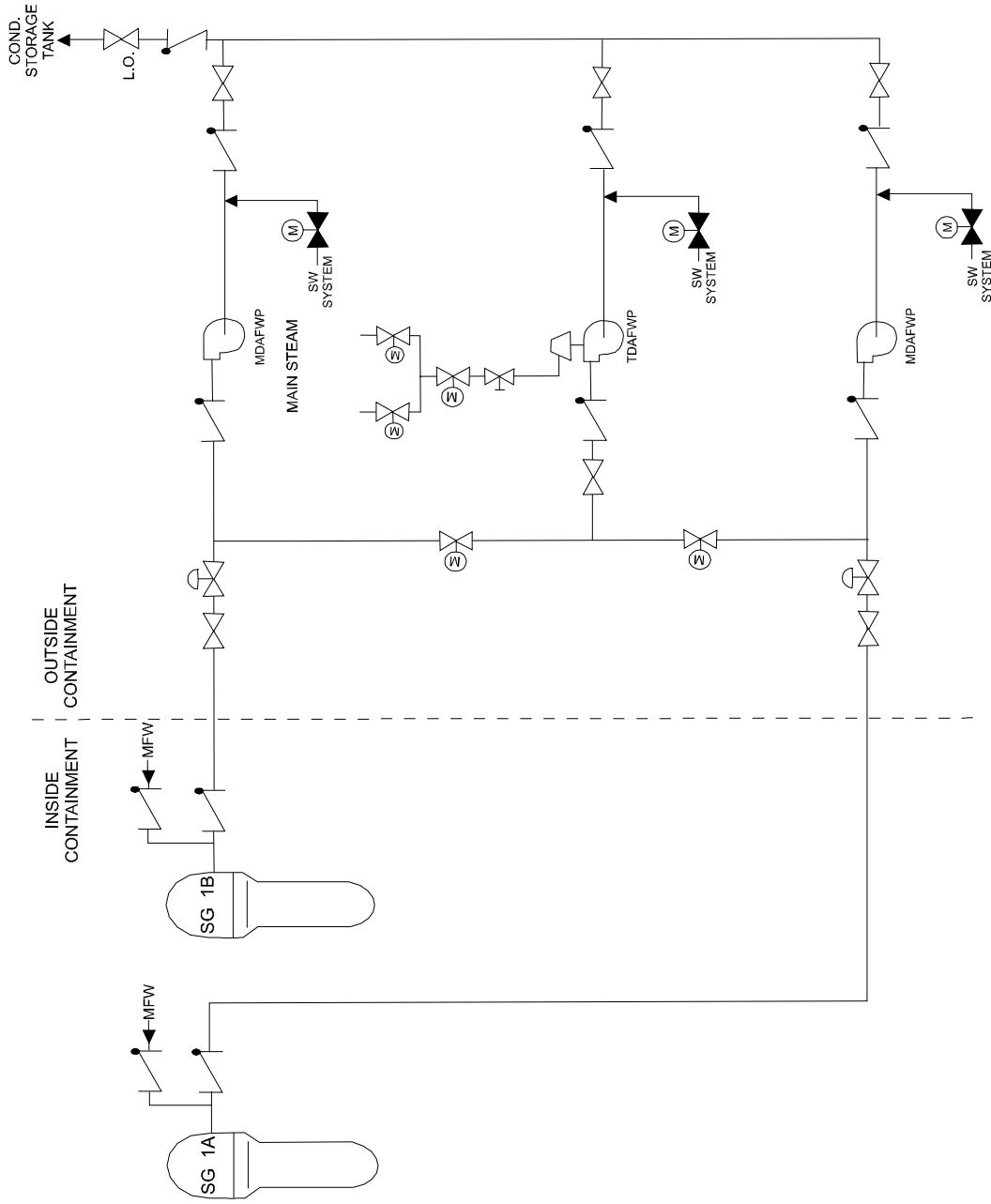


Figure 6.2  
Auxiliary Feedwater System  
(Example of Reporting Scope)

3  
4  
5

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2

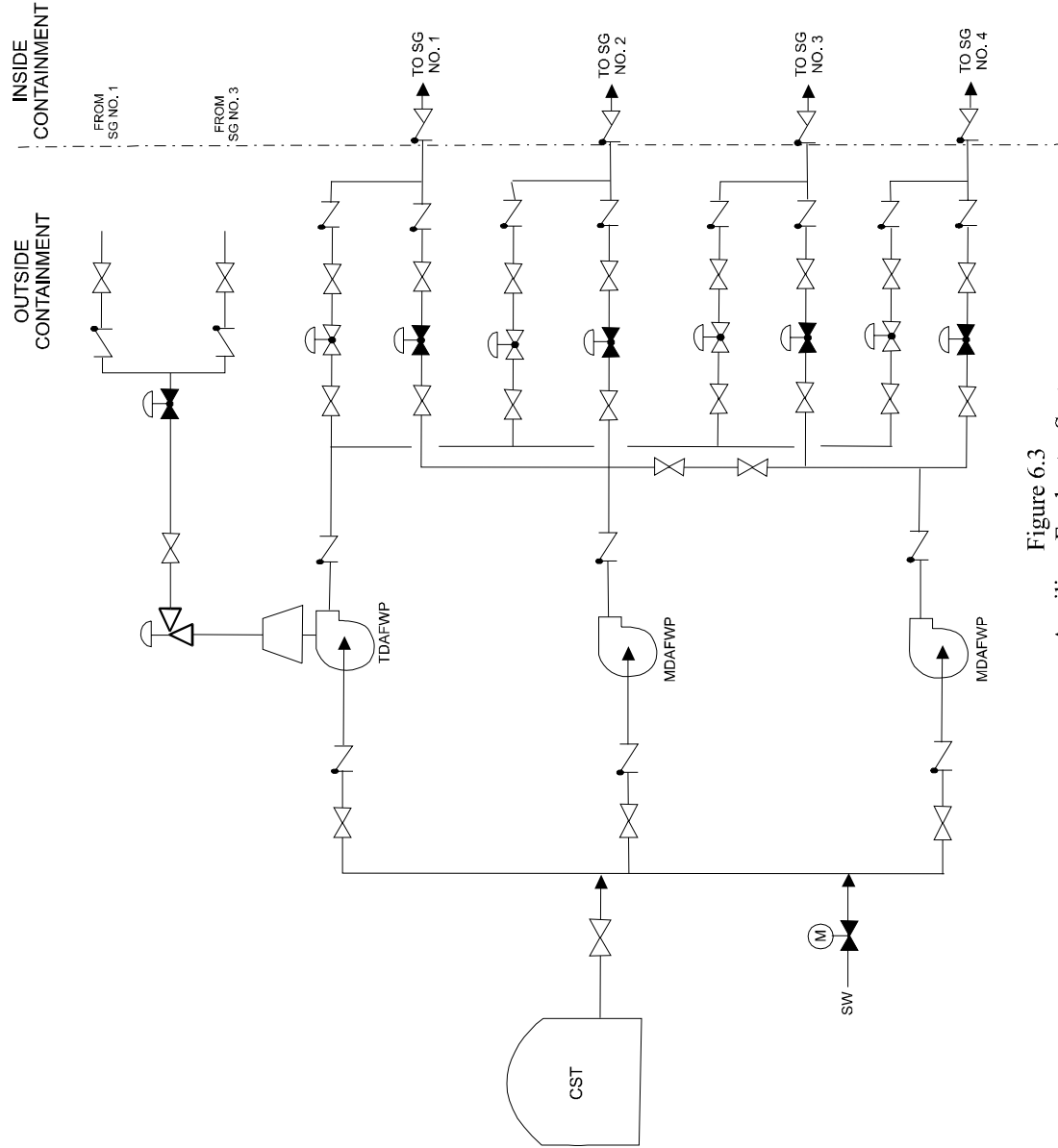


Figure 6.3  
Auxiliary Feedwater System  
(Example of Reporting Scope)

3  
4

## 1 **PWR Residual Heat Removal System**

### 2 **Definition and Scope**

3 This section provides additional guidance for reporting the performance of the PWR residual  
4 heat removal (RHR) system for post-accident recirculation and shutdown cooling modes of  
5 operation. In the event of a loss of reactor coolant inventory, the post-accident recirculation  
6 mode is used to cool and recirculate water from the containment sump following depletion of  
7 RWST inventory. The shutdown cooling function is used to remove decay heat from the primary  
8 system following any transient requiring normal long-term heat removal from the reactor vessel.  
9

10 The functions monitored for this indicator are:

- 11 • the ability of the RHR system to take a suction from the containment sump, cool the fluid,  
12 and inject at low pressure into the RCS, and
- 13
- 14 • the ability of the RHR system to remove decay heat from the reactor during a normal unit  
15 shutdown for refueling or maintenance.  
16

17 Figures 7.1 and 7.2 show generic schematics with the RHR system in the recirculation and  
18 shutdown cooling modes, respectively. The figures indicate the components for which train  
19 unavailability is monitored. Plant-specific design differences may require other components to  
20 be included.  
21

### 22 **Train Determination**

23 The number of trains in the RHR system is determined by the number of parallel RHR heat  
24 exchangers capable of performing post-accident heat removal or shutdown cooling. The  
25 following discussion demonstrates train determination for various generic system designs.  
26

27 Figure 7.1 and 7.2 illustrate a common RHR system (for post-accident recirculation and  
28 shutdown cooling modes) which incorporates two pumps and two heat exchangers arranged so  
29 that each heat exchanger can be supplied by one pump. This is a two-train RHR system.  
30

### 31 **Clarifying Notes**

32 Some components are used to provide more than one function of RHR. If a component cannot  
33 perform as designed, rendering its associated train incapable of meeting one or both of the  
34 monitored functions, then the train is considered to be failed. Unavailable hours (if the train was  
35 required to be available for service) would be reported as a result of the component failure.  
36

37 **RHR system unavailability includes the system upstream of the RHR system to HPSI system**  
38 **isolation valves. Unavailability of the isolation valves between the RHR system and the HPSI**  
39 **pump suction are only counted against the HPSI system.**

1  
2

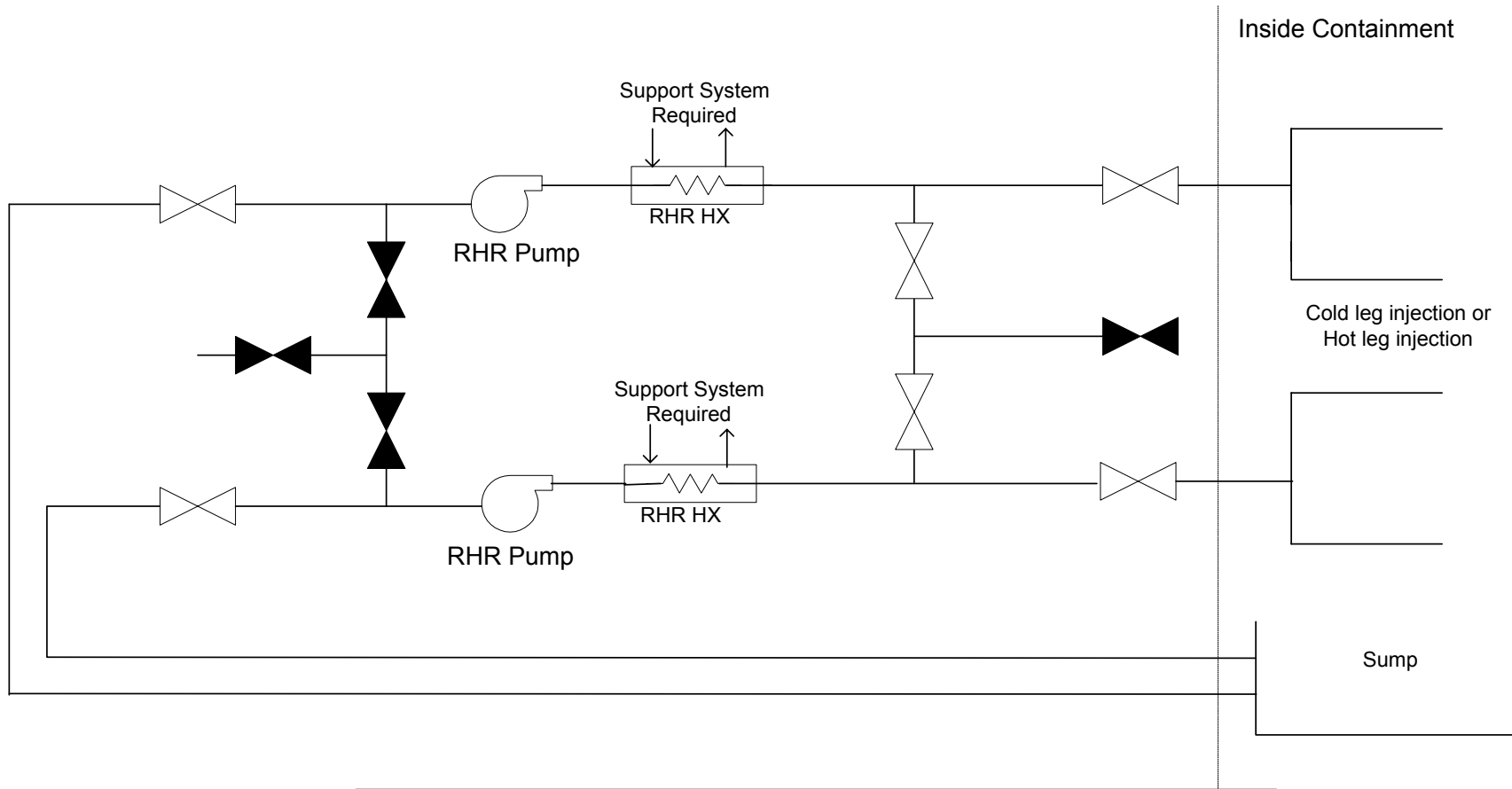


Figure 7.1 – Recirculation Mode – two trains (both source and injection)  
Example of reporting Scope, PWR RHR System

3  
4  
5

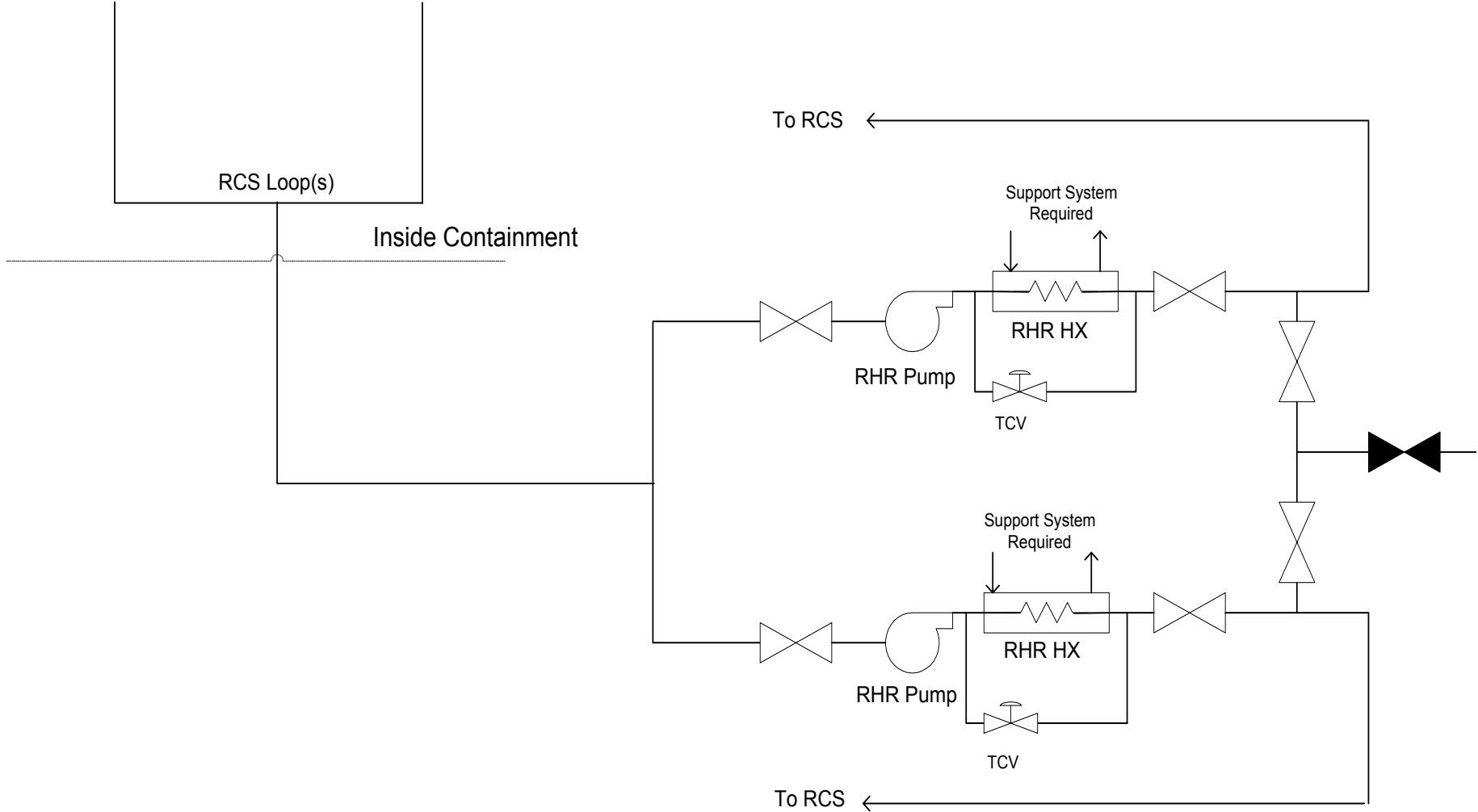


Figure 7.2 Shutdown Cooling Mode  
(Example of Reporting Scope, PWR RHR System)

1  
2  
3





## SAFETY SYSTEM FUNCTIONAL FAILURES

### **Purpose**

This indicator monitors events or conditions that prevented, or could have prevented, the fulfillment of the safety function of structures or systems that are needed to:

- (a) Shut down the reactor and maintain it in a safe shutdown condition;
- (b) Remove residual heat;
- (c) Control the release of radioactive material; or
- (d) Mitigate the consequences of an accident.

### **Indicator Definition**

The number of events or conditions that prevented, or could have prevented, the fulfillment of the safety function of structures or systems in the previous four quarters.

### **Data Reporting Elements**

The following data is reported for each reactor unit:

- the number of safety system functional failures during the previous quarter

### **Calculation**

unit value = number of safety system functional failures in previous four quarters

### **Definition of Terms**

*Safety System Function Failure (SSFF)* is any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to:

- (A) Shut down the reactor and maintain it in a safe shutdown condition;
- (B) Remove residual heat;
- (C) Control the release of radioactive material; or
- (D) Mitigate the consequences of an accident.

The indicator includes a wide variety of events or conditions, ranging from actual failures on demand to potential failures attributable to various causes, including environmental qualification, seismic qualification, human error, design or installation errors, etc. Many SSFFs do not involve actual failures of equipment.

Because the contribution to risk of the structures and systems included in the SSFF varies considerably, and because potential as well as actual failures are included, it is not possible to assign a risk-significance to this indicator. It is intended to be used as a possible precursor to more important equipment problems, until an indicator of safety system performance more directly related to risk can be developed.

1 **Clarifying Notes**

2 *The definition of SSFFs* is identical to the wording of the current revision to 10 CFR  
3 50.73(a)(2)(v). Because of overlap among various reporting requirements in 10 CFR 50.73,  
4 some events or conditions that result in safety system functional failures may be properly  
5 reported in accordance with other paragraphs of 10 CFR 50.73, particularly paragraphs (a)(2)(i),  
6 (a)(2)(ii), and (a)(2)(vii). An event or condition that meets the requirements for reporting under  
7 another paragraph of 10 CFR 50.73 should be evaluated to determine if it also prevented the  
8 fulfillment of a safety function. Should this be the case, the requirements of paragraph (a)(2)(v)  
9 are also met and the event or condition should be included in the quarterly performance indicator  
10 report as an SSFF. The level of judgment for reporting an event or condition under paragraph  
11 (a)(2)(v) as an SSFF is a reasonable expectation of preventing the fulfillment of a safety  
12 function.

13  
14 In the past, LERs may not have explicitly identified whether an event or condition was reportable  
15 under 10 CFR 50.73(a)(2)(v) (i.e., all pertinent boxes may not have been checked). It is  
16 important to ensure that the applicability of 10 CFR 50.73(a)(2)(v) has been explicitly considered  
17 for each LER considered for this performance indicator.

18  
19 *NUREG-1022*: Unless otherwise specified in this guideline, guidance contained in the latest  
20 revision to NUREG-1022, “Event Reporting Guidelines, 10CFR 50.72 and 50.73,” that is  
21 applicable to reporting under 10 CFR 50.73(a)(2)(v), should be used to assess reportability for  
22 this performance indicator.

23  
24 *Planned Evolution for maintenance or surveillance testing*: NUREG-1022, Revision 2, page 56  
25 states, “The following types of events or conditions generally are not reportable under these  
26 criteria:...Removal of a system or part of a system from service as part of a planned evolution  
27 for maintenance or surveillance testing...”

28  
29 The word “planned” is defined as follows:

30  
31 “Planned” means the activity is undertaken voluntarily, at the licensee’s discretion, and is  
32 not required to restore operability or for continued plant operation.

33  
34 *A single event or condition that affects several systems*: counts as only one failure.

35  
36 *Multiple occurrences of a system failure*: the number of failures to be counted depends upon  
37 whether the system was declared operable between occurrences. If the licensee knew that the  
38 problem existed, tried to correct it, and considered the system to be operable, but the system was  
39 subsequently found to have been inoperable the entire time, multiple failures will be counted  
40 whether or not they are reported in the same LER. But if the licensee knew that a potential  
41 problem existed and declared the system inoperable, subsequent failures of the system for the  
42 same problem would not be counted as long as the system was not declared operable in the  
43 interim. Similarly, in situations where the licensee did not realize that a problem existed (and  
44 thus could not have intentionally declared the system inoperable or corrected the problem), only  
45 one failure is counted.

46  
47 *Additional failures*: a failure leading to an evaluation in which additional failures are found is  
48 only counted as one failure; new problems found during the evaluation are not counted, even if

1 the causes or failure modes are different. The intent is to not count additional events when  
2 problems are discovered while resolving the original problem.

3

4 Engineering analyses: events in which the licensee declared a system inoperable but an  
5 engineering analysis later determined that the system was capable of performing its safety  
6 function are not counted, even if the system was removed from service to perform the analysis.

7

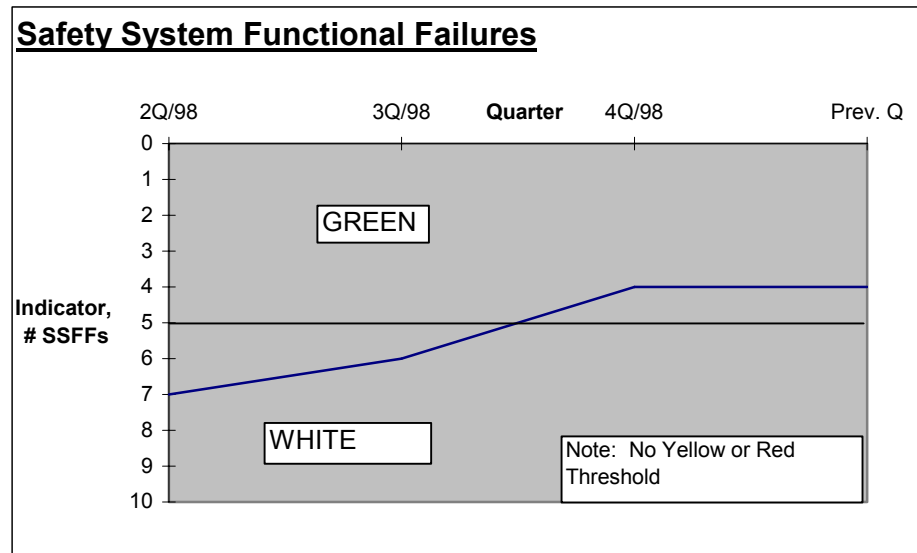
8 Reporting date: the date of the SSFF is the Report Date of the LER.

1 **Data Examples**

**Safety System Functional Failures**

Quarter	2Q/98	3Q/98	4Q/98	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
SSFF in the previous qtr	1	3	2	1	1	2	0	1
					2Q/98	3Q/98	4Q/98	Prev. Q
Indicator: Number of SSFs over 4 Qtrs					7	6	4	4

Threshold for PWRs	
Green	≤5
White	>5
Yellow	N/A
Red	N/A



2  
 3

1   **2.3   BARRIER INTEGRITY CORNERSTONE**

2   The purpose of this cornerstone is to provide reasonable assurance that the physical design  
3   barriers (fuel cladding, reactor coolant system, and containment) protect the public from  
4   radionuclide releases caused by accidents or events. These barriers are an important element in  
5   meeting the NRC mission of assuring adequate protection of public health and safety. The  
6   performance indicators assist in monitoring the functionality of the fuel cladding and the reactor  
7   coolant system. There is currently no performance indicator for the containment barrier. The  
8   performance of this barrier is assured through the inspection program.

9  
10   There are two performance indicators for this cornerstone:

- 11
- 12   •   Reactor Coolant System (RCS) Specific Activity
- 13   •   RCS Identified Leak Rate
- 14

15 <b>REACTOR COOLANT SYSTEM (RCS) SPECIFIC ACTIVITY</b>
--

16   **Purpose**

17   This indicator monitors the integrity of the fuel cladding, the first of the three barriers to prevent  
18   the release of fission products. It measures the radioactivity in the RCS as an indication of  
19   functionality of the cladding.

20

21   **Indicator Definition**

22   The maximum monthly RCS activity in micro-Curies per gram ( $\mu\text{Ci/gm}$ ) dose equivalent Iodine-  
23   131 per the technical specifications, and expressed as a percentage of the technical specification  
24   limit. Those plants whose technical specifications are based on micro-curies per gram ( $\mu\text{Ci/gm}$   
25   total Iodine should use that measurement.

26

27   **Data Reporting Elements**

28   The following data are reported for each reactor unit:

- 29
- 30   •   maximum calculated RCS activity for each unit, in micro-Curies per gram dose  
31   equivalent Iodine-131, as required by technical specifications at steady state power,  
32   for each month during the previous quarter (three values are reported).
- 33
- 34   •   Technical Specification limit
- 35

1 **Calculation**

2 The indicator is calculated as follows:

3

4 
$$\text{unit value} = \frac{\text{the maximum monthly value of calculated activity}}{\text{Technical Specification limit}} \times 100$$

5

6 **Definitions of Terms**

7 (Blank)

8

9 **Clarifying Notes**

10 This indicator is recorded monthly and reported quarterly.

11

12 The indicator is calculated using the same methodology, assumptions and conditions as for the  
13 Technical Specification calculation. **If more than one method can be used to meet Technical**  
14 **Specifications, use the results of the method that was used at the time to satisfy the Technical**  
15 **Specifications.**

16

17 Unless otherwise defined by the licensee, steady state is defined as continuous operation for at  
18 least three days at a power level that does not vary more than  $\pm 5$  percent.

19

20 This indicator monitors the steady state integrity of the fuel-cladding barrier at power. Transient  
21 spikes in RCS Specific Activity following power changes, shutdowns and scrams may not  
22 provide a reliable indication of cladding integrity and should not be included in the monthly  
23 maximum for this indicator.

24

25 Samples taken using technical specification methodology when shutdown are not reported.  
26 However, samples taken using the technical specification methodology at steady state power  
27 more frequently than required are to be reported. If in the entire month, plant conditions do not  
28 require RCS activity to be calculated, the quarterly report is noted as N/A for that month. (A  
29 value of N/A is reported).

30

31 Licensees should use the most restrictive regulatory limit (e.g., technical specifications (TS) or  
32 license condition). However, if the most restrictive regulatory limit is insufficient to assure plant  
33 safety, then NRC Administrative Letter 98-10 applies, which states that imposition of  
34 administrative controls is an acceptable short-term corrective action. When an administrative  
35 control is in place as temporary measure to ensure that TS limits are met and to ensure public  
36 health and safety (**i.e., to ensure 10 CFR Part 100 dose limits are not exceeded**), that  
37 administrative limit should be used for this PI.

38

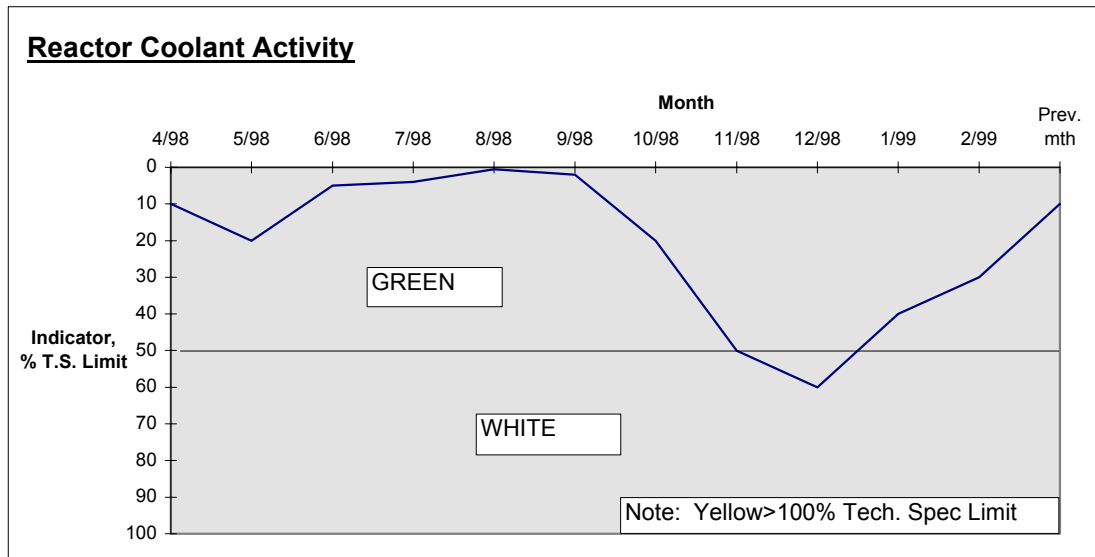
39

40

1 **Data Examples**

**Reactor Coolant System Activity (RCSA)**

	4/98	5/98	6/98	7/98	8/98	9/98	10/98	11/98	12/98	1/99	2/99	Prev. mth
Indicator, % of T.S. Limit	10	20	5	4	0.5	2	20	50	60	40	30	10
Max Activity $\mu\text{Ci/gm I-131 Equivale}$	0.1	0.2	0.05	0.04	0.005	0.02	0.2	0.5	0.6	0.4	0.3	0.1
T.S Limit	1	1	1	1	1	1	1	1	1	1	1	1
Thresholds	Green	$\leq 50\%$ T.S. limit										
	White	$> 50\%$ T.S. limit										
	Yellow	$>100\%$ T.S. limit										



2  
3

## **REACTOR COOLANT SYSTEM LEAKAGE**

### **Purpose**

This indicator monitors the integrity of the RCS pressure boundary, the second of the three barriers to prevent the release of fission products. It measures RCS Identified Leakage as a percentage of the technical specification allowable Identified Leakage to provide an indication of RCS integrity.

### **Indicator Definition**

The maximum RCS Identified Leakage in gallons per minute each month per the technical specifications and expressed as a percentage of the technical specification limit.

### **Data Reporting Elements**

The following data are required to be reported each quarter:

- The maximum RCS Identified Leakage calculation for each month of the previous quarter (three values).
- Technical Specification limit

### **Calculation**

The unit value for this indicator is calculated as follows:

$$\text{unit value} = \frac{\text{the maximum monthly value of identified leakage}}{\text{Technical Specification limiting value}} \times 100$$

### **Definition of Terms**

RCS Identified Leakage as defined in Technical Specifications.

### **Clarifying Notes**

This indicator is recorded monthly and reported quarterly.

Normal steam generator tube leakage is included in the unit value calculation if required by the plant's Technical Specification definition of RCS identified leakage.

For those plants that do not have a Technical Specification limit on Identified Leakage, substitute RCS Total Leakage in the Data Reporting Elements.

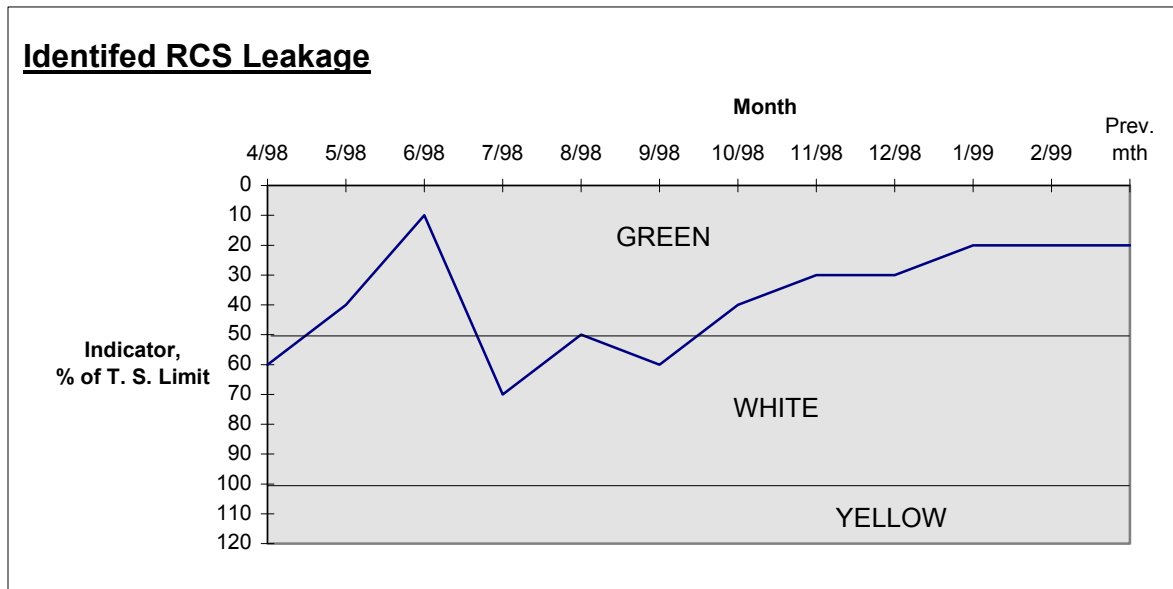
Only calculations of RCS leakage that are computed in accordance with the calculational methodology requirements of the Technical Specifications are counted in this indicator. If in the entire month, plant conditions do not require RCS leakage to be calculated, the quarterly report is noted as N/A for that month. (A value of N/A is reported).



1 **Data Examples**

**Reactor Coolant System Identified Leakage (RCSL)**

	4/98	5/98	6/98	7/98	8/98	9/98	10/98	11/98	12/98	1/99	2/99	Prev. mth
<b>Indicator %T.S. Value</b>	60	40	10	70	50	60	40	30	30	20	20	20
<b>Identified Leakage (gpm)</b>	6	4	1	7	5	6	4	3	3	2	2	2
<b>TS Value (gpm)</b>	10	10	10	10	10	10	10	10	10	10	10	10
<b>Threshold</b>												
Green	≤50% TS limit											
White	>50% TS limit											
Yellow	>100%TS limit											
<b>Data collected monthly, reported quarterly</b>												



2

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1 **2.4 EMERGENCY PREPAREDNESS CORNERSTONE**

2 The objective of this cornerstone is to ensure that the licensee is capable of implementing  
3 adequate measures to protect the public health and safety during a radiological emergency.  
4 Licensees maintain this capability through Emergency Response Organization (ERO)  
5 participation in drills, exercises, actual events, training, and subsequent problem identification  
6 and resolution. The Emergency Preparedness performance indicators provide a quantitative  
7 indication of the licensee's ability to implement adequate measures to protect the public health  
8 and safety. These performance indicators create a licensee response band that allows NRC  
9 oversight of Emergency Preparedness programs through a baseline inspection program. These  
10 performance indicators measure onsite Emergency Preparedness programs. Offsite programs are  
11 evaluated by FEMA.

12  
13 The protection of public health and safety is assured by a defense in depth philosophy that relies  
14 on: safe reactor design and operation, the operation of mitigation features and systems, a multi-  
15 layered barrier system to prevent fission product release, and emergency preparedness.

16  
17 The Emergency Preparedness cornerstone performance indicators are:

- 18  
19
  - Drill/Exercise performance (DEP),
  - Emergency Response Organization Drill Participation (ERO),
  - Alert and Notification System Reliability (ANS)

22  
23 

<b>DRILL/EXERCISE PERFORMANCE</b>
-----------------------------------

24 **Purpose**

25 This indicator monitors timely and accurate licensee performance in drills and exercises when  
26 presented with opportunities for classification of emergencies, notification of offsite authorities,  
27 and development of protective action recommendations (PARs). It is the ratio, in percent, of  
28 timely and accurate performance of those actions to total opportunities.

29  
30 **Indicator Definition**

31 The percentage of all drill, exercise, and actual opportunities that were performed timely and  
32 accurately during the previous eight quarters.

33  
34

1 **Data Reporting Elements**

2 The following data are required to calculate this indicator:

- 3
- 4 • the number of drill, exercise, and actual event opportunities during the previous quarter.
  - 5
  - 6 • the number of drill, exercise, and actual event opportunities performed timely and accurately
  - 7 during the previous quarter.
  - 8

9 The indicator is calculated and reported quarterly. (See clarifying notes)

10

11 **Calculation**

12 The site average values for this indicator are calculated as follows:

13

14 
$$\left[ \frac{\text{\# of timely \& accurate classifications, notifications, \& PARs from DE \& AEs * during the previous 8 quarters}}{\text{The total opportunities to perform classifications, notifications \& PARs during the previous 8 quarters}} \right] \times 100$$

15

16 \*DE & AEs = Drills, Exercises, and Actual Events

17

18 **Definition of Terms**

19 *Opportunities* should include multiple events during a single drill or exercise (if supported by the  
20 scenario) or actual event, as follows:

21

- 22 • each expected classification or upgrade in classification
- 23 • each initial notification of an emergency class declaration
- 24 • each initial notification of PARs or change to PARs
- 25 • each PAR developed

26

27 *Timely* means:

28

- 29 • classifications are made consistent with the goal of 15 minutes once available plant  
30 parameters reach an Emergency Action Level (EAL)
- 31 • PARs are made consistent with the goal of 15 minutes once data is available.
- 32 • offsite notifications are initiated within 15 minutes of event classification and/or PAR  
33 development (see clarifying notes)

34

35

1 *Accurate* means:

- 2
- 3 • Classification and PAR appropriate to the event as specified by the approved plan and
- 4 implementing procedures (see clarifying notes)
- 5 • Initial notification form completed appropriate to the event to include (see clarifying notes):
- 6 - Class of emergency
- 7 - EAL number
- 8 - Description of emergency
- 9 - Wind direction and speed
- 10 - Whether offsite protective measures are necessary
- 11 - Potentially affected population and areas
- 12 - Whether a release is taking place
- 13 - Date and time of declaration of emergency
- 14 - Whether the event is a drill or actual event
- 15 - Plant and/or unit as applicable
- 16

### 17 **Clarifying Notes**

18 While actual event opportunities are included in the performance indicator data , the NRC will  
19 also inspect licensee response to all actual events.

20

21 As a minimum, actual emergency declarations and evaluated exercises are to be included in this  
22 indicator. In addition, other simulated emergency events that the licensee formally assesses for  
23 performance of classification, notification or PAR development may be included in this indicator  
24 (opportunities cannot be removed from the indicator due to poor performance).

25

26 The following information provides additional clarification of the accuracy requirements  
27 described above:

- 28
- 29 • It is understood that initial notification forms are negotiated with offsite authorities. If  
30 the approved form does not include these elements, they need not be added. Alternately,  
31 if the form includes elements in addition to these, those elements need not be assessed for  
32 accuracy when determining the DEP PI. It is, however, expected that errors in such  
33 additional elements would be critiqued and addressed through the corrective action  
34 system.
- 35
- 36 • The description of the event causing the classification may be brief and need not include  
37 all plant conditions. At some sites, the EAL number is the description.
- 38
- 39 • “Release” means a radiological release attributable to the emergency event.
- 40
- 41 • Minor discrepancies in the windspeed and direction provided on the emergency  
42 notification form need not count as a missed notification opportunity provided the  
43 discrepancy would not result in an incorrect PAR being provided.
- 44

45 The licensee shall identify, in advance, drills, exercises and other performance enhancing  
46 experiences in which opportunities will be formally assessed, and shall be available for NRC  
47 review. The licensee has the latitude to include opportunities in the PI statistics as long as the

1 drill (in whatever form) simulates the appropriate level of inter-facility interaction. The criteria  
2 for suitable drills/performance enhancing experiences are provided under the ERO Drill  
3 Participation PI clarifying notes.  
4

5 Performance statistics from operating shift simulator training evaluations may be included in this  
6 indicator only when the scope requires classification. Classification, PAR notifications and  
7 PARs may be included in this indicator if they are performed to the point of filling out the  
8 appropriate forms and demonstrating sufficient knowledge to perform the actual notification.  
9 However, there is no intent to disrupt ongoing operator qualification programs. Appropriate  
10 operator training evolutions should be included in the indicator only when Emergency  
11 Preparedness aspects are consistent with training goals.  
12

13 Some licensees have specific arrangements with their State authorities that provide for different  
14 notification requirements than those prescribed by the performance indicator, e.g., within one  
15 hour, not 15 minutes. In these instances the licensee should determine success against the  
16 specific state requirements.  
17

18 For sites with multiple agencies to notify, the notification is considered to be initiated when  
19 contact is made with the first agency to transmit the initial notification information.  
20

21 Simulation of notification to offsite agencies is allowed. It is not expected that State/local  
22 agencies be available to support all drills conducted by licensees. The drill should reasonably  
23 simulate the contact and the participants should demonstrate their ability to use the equipment.  
24

25 Classification is expected to be made promptly following indication that the conditions have  
26 reached an emergency threshold in accordance with the licensee's EAL scheme. With respect to  
27 classification of emergencies, the 15 minute goal is a reasonable period of time for assessing and  
28 classifying an emergency once indications are available to control room operators that an EAL  
29 has been exceeded. Allowing a delay in classifying an emergency up to 15 minutes will have  
30 minimal impact upon the overall emergency response to protect the public health and safety.  
31 The 15-minute goal should not be interpreted as providing a grace period in which a licensee  
32 may attempt to restore plant conditions and avoid classifying the emergency.  
33

34 If an event has occurred that resulted in an emergency classification where no EAL was  
35 exceeded, the incorrect classification should be considered a missed opportunity. The subsequent  
36 notification should be considered an opportunity and evaluated on its own merits.  
37

38 During drill performance, the ERO may not always classify an event exactly the way that the  
39 scenario specifies. This could be due to conservative decision making, Emergency Director  
40 judgment call, or a simulator driven scenario that has the potential for multiple 'forks'. Situations  
41 can arise in which assessment of classification opportunities is subjective due to deviation from  
42 the expected scenario path. In such cases, evaluators should document the rationale supporting  
43 their decision for eventual NRC inspection. Evaluators must determine if the classification was  
44 appropriate to the event as presented to the participants and in accordance with the approved  
45 emergency plan and implementing procedures.  
46

47 If the expected classification level is missed because an EAL is not recognized within 15 minutes  
48 of availability, but a subsequent EAL for the same classification level is subsequently  
49 recognized, the subsequent classification is not an opportunity for DEP statistics. The reason

1 that the classification is not an opportunity is that the appropriate classification level was not  
2 attained in a timely manner.

3  
4 Failure to appropriately classify an event counts as only one failure: This is because notification  
5 of the classification, development of any PARs and PAR notification are subsequent actions to  
6 classification.

7  
8 The notification associated with a PAR is counted separately: e. g., an event triggering a GE  
9 classification would represent a total of 4 opportunities: 1 for classification of the GE, 1 for  
10 notification of the GE to the State and/or local government authorities, 1 for development of a  
11 PAR and 1 for notification of the PAR.

12  
13 If PARs at the SAE are in the site Emergency Plan they could be counted as opportunities.  
14 However, this would only be appropriate where assessment and decision making is involved in  
15 development of the PAR. Automatic PARs with little or no assessment required would not be an  
16 appropriate contributor to the PI. PARs limited to livestock or crops and no PAR necessary  
17 decisions are also not appropriate.

18  
19 Dose assessment and PAR development are expected to be made promptly following indications  
20 that the conditions have reached a threshold in accordance with the licensee's PAR scheme. The  
21 15 minute goal from data availability is a reasonable period of time to develop or expand a PAR.  
22 Plant conditions, meteorological data, field monitoring data, and/or radiation monitor data should  
23 provide sufficient information to determine the need to change PARs. If radiation monitor  
24 readings provide sufficient data for assessments, it is not appropriate to wait for field monitoring  
25 to become available to confirm the need to expand the PAR. The 15 minute goal should not be  
26 interpreted as providing a grace period in which the licensee may attempt to restore conditions  
27 and avoid making the PAR recommendation.

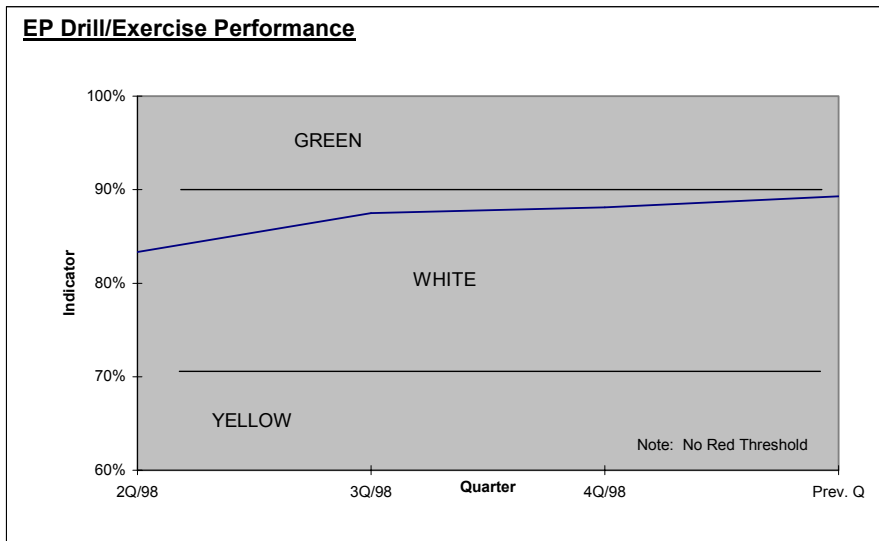
28  
29 If a licensee discovers after the fact (greater than 15 minutes) that an event or condition had  
30 existed which exceeded an EAL, but no emergency had been declared and the EAL is no longer  
31 exceeded at the time of discovery, the following applies:

- 32 • If the indication of the event was not available to the operator, the event should not be  
33 evaluated for PI purposes.
  - 34 • If the indication of the event was available to the operator but not recognized, it should be  
35 considered an unsuccessful classification opportunity.
  - 36 • In either case described above, notification should be performed in accordance with  
37 NUREG-1022 and not be evaluated as a notification opportunity.
- 38

1 **Data Example**

**Emergency Response Organization  
 Drill/Exercise Performance**

	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98
Successful Classifications, Notifications & PARs over qtr	0	0	11	11	0	8	10	0	23
Opportunities to Perform Classifications, Notifications, & PARs in qtr	0	0	12	12	0	12	12	0	24
Total # of succesful Classifications, Notifications, & PARs in 8 qtrs								40	63
Total # of opportunities to perform Classification, Notifications & PARs in 8 qtrs								48	72
								2Q/98	3Q/98
Indicator expressed as a percentage of Opportunities to perform, Classifications, Communications & PARs								83.3%	87.5%



2



## EMERGENCY RESPONSE ORGANIZATION DRILL PARTICIPATION

### Purpose

This indicator tracks the participation of key members of the Emergency Response Organization in performance enhancing experiences, and through linkage to the DEP indicator ensures that the risk significant aspects of classification, notification, and PAR development are evaluated and included in the PI process. This indicator measures the percentage of key ERO members who have participated recently in performance-enhancing experiences such as drills, exercises, or in an actual event.

### Indicator Definition

The percentage of key ERO members that have participated in a drill, exercise, or actual event during the previous eight quarters, **as measured on the last calendar day of the quarter.**

### Data Reporting Elements

The following data are required to calculate this indicator and are reported:

- total number of key ERO members
- total key ERO members that have participated in a drill, exercise, or actual event in the previous eight quarters

The indicator is calculated and reported quarterly, based on participation over the previous eight quarters (see clarifying notes)

### Calculation

The site indicator is calculated as follows:

$$\frac{\text{\# of Key ERO Members that have participated in a drill, exercise or actual event during the previous 8 qrts}}{\text{Total number of Key ERO Members}} \times 100$$

### Definition of Terms

Key ERO members are those who fulfill the following functions:

- Control Room
  - Shift Manager (Emergency Director) - Supervision of reactor operations, responsible for classification, notification, and determination of protective action recommendations
  - Shift Communicator - provides initial offsite (state/local) notification

- 1 • Technical Support Center
- 2
- 3 • Senior Manager - Management of plant operations/corporate resources
- 4 • Key Operations Support
- 5 • Key Radiological Controls - Radiological effluent and environs monitoring,
- 6 assessment, and dose projections
- 7 • Key TSC Communicator- provides offsite (state/local) notification
- 8 • Key Technical Support
- 9
- 10 • Emergency Operations Facility
- 11
- 12 • Senior Manager - Management of corporate resources
- 13 • Key Protective Measures - Radiological effluent and environs monitoring,
- 14 assessment, and dose projections
- 15 • Key EOF Communicator- provides offsite (state/local) notification
- 16
- 17 • Operational Support Center
- 18
- 19 • Key OSC Operations Manager
- 20

## 21 **Clarifying Notes**

22 When the functions of key ERO members include classification, notification, or PAR  
23 development opportunities, the success rate of these opportunities must contribute to  
24 Drill/Exercise Performance (DEP) statistics for participation of those key ERO members to  
25 contribute to ERO Drill Participation.

26  
27 The licensee may designate drills as not contributing to DEP and, if the drill provides a  
28 performance enhancing experience as described herein, those key ERO members whose  
29 functions do not involve classification, notification or PARs may be given credit for ERO Drill  
30 Participation. Additionally, the licensee may designate elements of the drills not contributing to  
31 DEP (e.g., classifications will not contribute but notifications will contribute to DEP.) In this  
32 case, the participation of all key ERO members, except those associated with the non-  
33 contributing elements, may contribute to ERO Drill Participation. The licensee must document  
34 such designations in advance of drill performance and make these records available for NRC  
35 inspection.

36  
37 Evaluated simulator training evolutions that contribute to Drill/Exercise Performance indicator  
38 statistics may be considered as opportunities for key ERO member participation and may be  
39 used for this indicator. The scenarios must at least contain a formally assessed classification and  
40 the results must be included in DEP statistics. However, there is no intent to disrupt ongoing  
41 operator qualification programs. Appropriate operator training evolutions should be included in  
42 this indicator only when Emergency Preparedness aspects are consistent with training goals.

43  
44 If a key ERO member or operating crew member has participated in more than one drill during  
45 the eight quarter evaluation period, the most recent participation should be used in the Indicator  
46 statistics.

47

1 If a change occurs in the number of key ERO members, this change should be reflected in both  
2 the numerator and denominator of the indicator calculation.

3  
4 If a person is assigned to more than one key position, it is expected that the person be counted in  
5 the denominator for each position and in the numerator only for drill participation that addresses  
6 each position. Where the skill set is similar, a single drill might be counted as participation in  
7 both positions.

8  
9 When a key ERO member changes from one key ERO position to a different key ERO position  
10 with a skill set similar to the old one, the last drill/exercise participation may count. If the skill  
11 set for the new position is significantly different from the old position then the previous  
12 participation would not count.

13  
14 Participation may be as a participant, mentor, coach, evaluator, or controller, but not as an  
15 observer. Multiple assignees to a given key ERO position could take credit for the same drill if  
16 their participation is a meaningful opportunity to gain proficiency in the assigned position.

17  
18 The meaning of “drills” in this usage is intended to include performance enhancing experiences  
19 (exercises, functional drills, simulator drills, table top drills, mini drills, etc.) that reasonably  
20 simulate the interactions between appropriate centers and/or individuals that would be expected  
21 to occur during emergencies. For example, control room interaction with offsite agencies could  
22 be simulated by instructors or OSC interaction could be simulated by a control cell simulating  
23 the TSC functions, and damage control teams.

24  
25 In general, a drill does not have to include all ERO facilities to be counted in this indicator. A  
26 drill is of adequate scope if it reasonably simulates the interaction between one or more of the  
27 following facilities, as would be expected to occur during emergencies:

- 28  
29
- the control room,
  - the Technical Support Center (TSC),
  - the Operations Support Center,
  - the Emergency Operations Facility (EOF),
  - field monitoring teams,
  - damage control teams, and
  - offsite governmental authorities.
- 30  
31  
32  
33  
34  
35  
36

37 The licensee need not develop new scenarios for each drill or each team. However, it is expected  
38 that the licensee will maintain a reasonable level of confidentiality so as to ensure the drill is a  
39 performance enhancing experience. A reasonable level of confidentiality means that some  
40 scenario information could be inadvertently revealed and the drill remain a valid performance  
41 enhancing experience. It is expected that the licensee will remove from drill performance  
42 statistics any opportunities considered to be compromised. There are many processes for the  
43 maintenance of scenario confidentiality that are generally successful. Examples may include  
44 confidentiality statements on the signed attendance sheets and spoken admonitions by drill  
45 controllers. Examples of practices that may challenge scenario confidentiality include drill  
46 controllers or evaluators or mentors, who have scenario knowledge becoming participants in  
47 subsequent uses of the same scenarios and use of scenario reviewers as participants.

48

1 All individuals qualified to fill the Control Room Shift Manager/ Emergency Director position  
2 that actually might fill the position should be included in this indicator.

3  
4 The communicator is the key ERO position that fills out the notification form, seeks approval  
5 and usually communicates the information to off site agencies. Performance of these duties is  
6 assessed for accuracy and timeliness and contributes to the DEP PI. Senior managers who do not  
7 perform these duties should not be considered communicators even though they approve the  
8 form and may supervise the work of the communicator. However, there are cases where the  
9 senior manager actually collects the data for the form, fills it out, approves it and then  
10 communicates it or hands it off to a phone talker. Where this is the case, the senior manager is  
11 also the communicator and the phone talker need not be tracked. The communicator is not  
12 expected to be just a phone talker who is not tasked with filling out the form. There is no intent  
13 to track a large number of shift communicators or personnel who are just phone talkers.

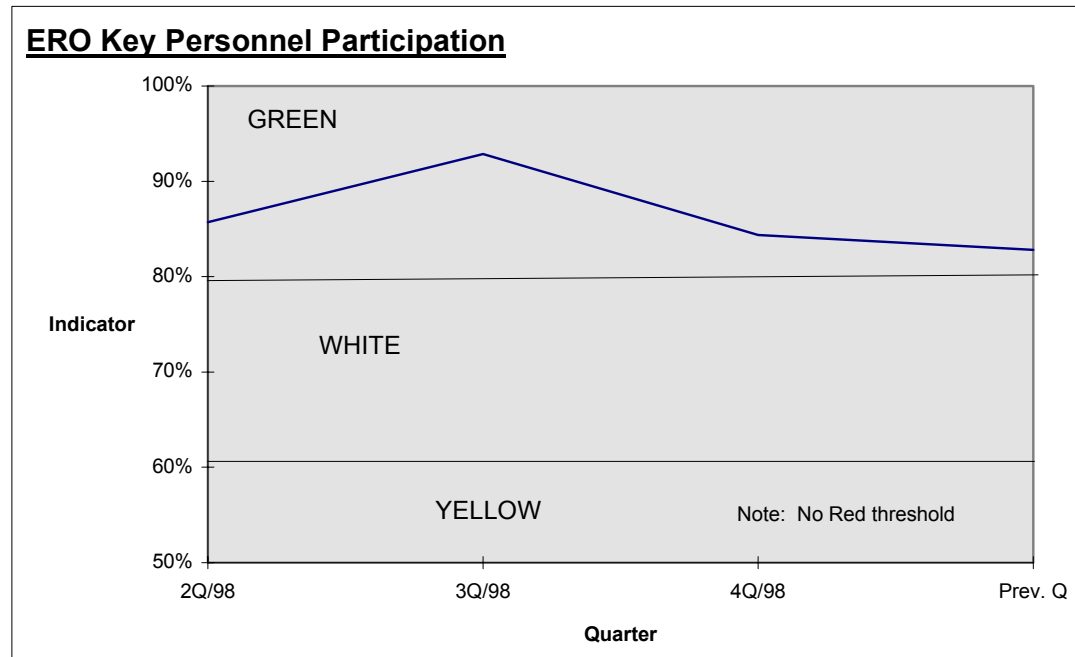
14  
15  
16

1 **Data Example**

**Emergency Response Organization (ERO) Participation**

					2Q/98	3Q/98	4Q/98	Prev. Q
<b>Total number of Key ERO personnel</b>					56	56	64	64
<b>Number of Key personnel participating in drill/event in 8 qtrs</b>					48	52	54	53
					2Q/98	3Q/98	4Q/98	Prev. Q
<b>Indicator percentage of Key ERO personnel participating in a drill in 8 qtrs</b>					86%	93%	84%	83%

<b>Thresholds</b>	
Green	≥80%
White	<80%
Yellow	<60%
No Red Threshold	



2

## ALERT AND NOTIFICATION SYSTEM RELIABILITY

### **Purpose**

This indicator monitors the reliability of the offsite Alert and Notification System (ANS), a critical link for alerting and notifying the public of the need to take protective actions. It provides the percentage of the sirens that are capable of performing their safety function based on regularly scheduled tests.

### **Indicator Definition**

The percentage of ANS sirens that are capable of performing their function, as measured by periodic siren testing in the previous 12 months.

Periodic tests are the regularly scheduled tests (documented in the licensee's test plan or guidelines) that are conducted to actually test the ability of the sirens to perform their function (e.g., silent, growl, siren sound test). Tests performed for maintenance purposes should not be counted in the performance indicator database.

### **Data Reporting Elements**

The following data are reported: (see clarifying notes)

- the total number of ANS siren-tests during the previous quarter
- the number of successful ANS siren-tests during the previous quarter

### **Calculation**

The site value for this indicator is calculated as follows:

$$\frac{\text{\# of succesful siren - tests in the previous 4 qtrs}}{\text{total number of siren - tests in the previous 4 qtrs}} \times 100$$

### **Definition of Terms**

*Siren-Tests*: the number of sirens times the number of times they are tested. For example, if 100 sirens are tested 3 times in the quarter, there are 300 siren-tests.

*Successful siren-tests* are the sum of sirens that performed their function when tested. For example, if 100 sirens are tested three times in the quarter and the results of the three tests are: first test, 90 performed their function; second test, 100 performed their function; third test, 80 performed their function. There were 270 successful siren-tests.

### **Clarifying Notes**

The purpose of the ANS PI is to provide a uniform industry reporting approach and is not intended to replace the FEMA Alert and Notification reporting requirement at this time.

1 For those sites that do not have sirens, the performance of the licensee's alert and notification  
2 system will be evaluated through the NRC baseline inspection program. A site that does not  
3 have sirens does not report data for this indicator.  
4

5 If a siren is out of service for maintenance or is inoperable at the time a regularly scheduled test  
6 is conducted, then it counts as both a siren test and a siren failure.  
7

8 For plants where scheduled siren tests are initiated by local or state governments, if a scheduled  
9 test is not performed either intentionally or accidentally, the missed test is not considered as valid  
10 test opportunities. Missed test occurrences should be entered in the plant's corrective action  
11 program.  
12

13 If a siren failure is determined to be due only to testing equipment, and subsequent testing shows  
14 the siren to be operable (verified by telemetry or simultaneous local verification) without any  
15 corrective action having been performed, the siren test should be considered a success.  
16 Maintenance records should be complete enough to support such determinations and validation  
17 during NRC inspection.  
18

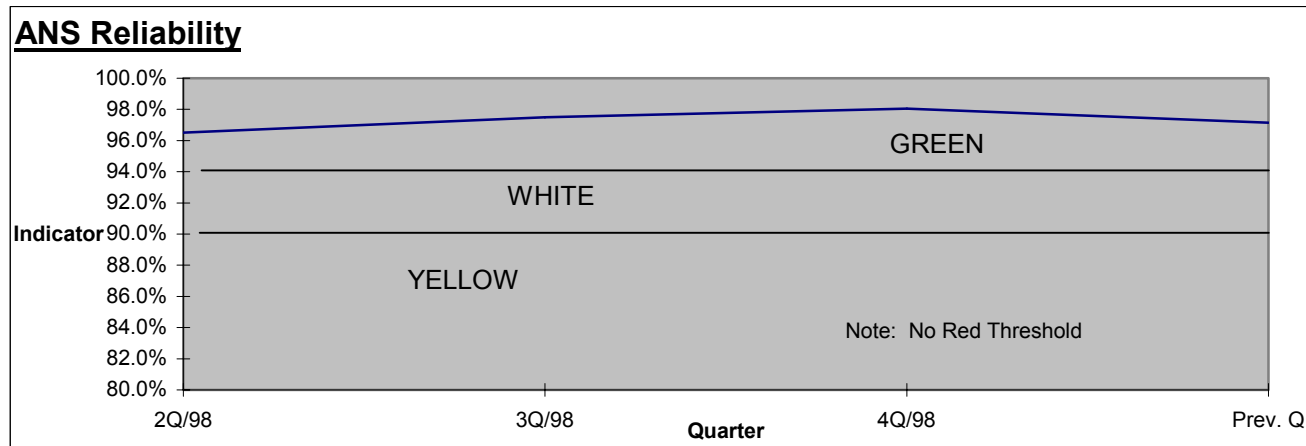
19 Siren systems may be designed with equipment redundancy or feedback capability. It may be  
20 possible for sirens to be activated from multiple control stations. Feedback systems may indicate  
21 siren activation status, allowing additional activation efforts for some sirens. If the use of  
22 redundant control stations is in approved procedures and is part of the actual system activation  
23 process, then activation from either control station should be considered a success. A failure of  
24 both systems would only be considered one failure, whereas the success of either system would  
25 be considered a success. If the redundant control station is not normally attended, requires setup  
26 or initialization, it may not be considered as part of the regularly scheduled test. Specifically, if  
27 the station is only made ready for the purpose of siren tests it should not be considered as part of  
28 the regularly scheduled test.  
29

30 If a siren is out of service for scheduled planned refurbishment or overhaul maintenance  
31 performed in accordance with an established program, or for scheduled equipment upgrades, the  
32 siren need not be counted as a siren test or a siren failure. However, sirens that are out of service  
33 due to unplanned corrective maintenance would continue to be counted as failures. Unplanned  
34 corrective maintenance is a measure of program reliability. The exclusion of a siren due to  
35 temporary unavailability during planned maintenance/upgrade activities is acceptable due to the  
36 level of control placed on scheduled maintenance/upgrade activities. It is not the intent to create  
37 a disincentive to performing maintenance/upgrades to ensure the ANS performs at its peak  
38 reliability.  
39

40 As part of a refurbishment or overhaul plan, it is expected that each utility would communicate  
41 to the appropriate state and/or local agencies the specific sirens to be worked and ensure that a  
42 functioning backup method of public alerting would be in-place. The acceptable time frame for  
43 allowing a siren to remain out of service for system refurbishment or overhaul maintenance  
44 should be coordinated with the state and local agencies. Based on the impact to their  
45 organization, these time frames should be specified in upgrade or system improvement  
46 implementation plans and/or maintenance procedures. Deviations from these plans and/or  
47 procedures would constitute unplanned unavailability and would be included in the PI.

1 **Data Example**

<b>Alert &amp; Notification System Reliability</b>							
Quarter	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
Number of succesful siren-tests in the qtr	47	48	49	49	49	54	52
Total number of sirens tested in the qtr	50	50	50	50	50	55	55
Number of successful siren-tests over 4 qtrs				193	195	201	204
Total number of sirens tested over 4 qtrs				200	200	205	210
Indicator expressed as a percentage of sirens				2Q/98 96.5%	3Q/98 97.5%	4Q/98 98.0%	Prev. Q 97.1%
<b>Thresholds</b>							
Green	≥94%						
White	<94%						
Yellow	<90%						
Red							



2



1 **2.5 OCCUPATIONAL RADIATION SAFETY CORNERSTONE**

2 The objectives of this cornerstone are to:

- 3
- 4 (1) keep occupational dose to individual workers below the limits specified in  
5 10 CFR Part 20 Subpart C; and  
6
- 7 (2) use, to the extent practical, procedures and engineering controls based upon sound  
8 radiation protection principles to achieve occupational doses that are as low as is  
9 reasonably achievable (ALARA) as specified in 10 CFR 20.1101(b).

10

11 There is one indicator for this cornerstone:

- 12
- 13 • Occupational Exposure Control Effectiveness  
14

15 **OCCUPATIONAL EXPOSURE CONTROL EFFECTIVENESS**

16 **Purpose**

17 The purpose of this performance indicator is to address the first objective of the occupational  
18 radiation safety cornerstone. The indicator monitors the control of access to and work activities  
19 within radiologically-significant areas of the plant and occurrences involving degradation or  
20 failure of radiation safety barriers that result in readily-identifiable unintended dose.

21

22 The indicator includes dose-rate and dose criteria that are risk-informed, in that the indicator  
23 encompasses events that might represent a substantial potential for exposure in excess of  
24 regulatory limits. The performance indicator also is considered “leading” because the indicator:

- 25
- 26 • encompasses less-significant occurrences that represent precursors to events that might  
27 represent a substantial potential for exposure in excess of regulatory limits, based on industry  
28 experience; and  
29
- 30 • employs dose criteria that are set at small fractions of applicable dose limits (e.g., the criteria  
31 are generally at or below the levels at which dose monitoring is required in regulation).  
32

33 **Indicator Definition**

34 The performance indicator for this cornerstone is the sum of the following:

- 35
- 36 • Technical specification high radiation area (>1 rem per hour) occurrences  
37 • Very high radiation area occurrences  
38 • Unintended exposure occurrences  
39  
40

## 1 **Data Reporting Elements**

2 The data listed below are reported for each site. For multiple unit sites, an occurrence at one unit  
3 is reported identically as an input for each unit. However, the occurrence is only counted once  
4 against the site-wide threshold value.

- 5
- 6 • The number of technical specification high radiation area (>1 rem per hour)
- 7 occurrences during the previous quarter
- 8 • The number of very high radiation area occurrences during the previous quarter
- 9 • The number of unintended exposure occurrences during the previous quarter

10

## 11 **Calculation**

12 The indicator is determined by summing the reported number of occurrences for each of the  
13 three data elements during the previous 4 quarters.

14

## 15 **Definition of Terms**

16 *Technical Specification High Radiation Area (>1 rem per hour) Occurrence - A*  
17 *nonconformance (or concurrent<sup>15</sup> nonconformances) with technical specifications<sup>16</sup> or*  
18 *comparable requirements in 10 CFR 20<sup>17</sup> applicable to technical specification high radiation*  
19 *areas (>1 rem per hour) that results in the loss of radiological control over access or work*  
20 *activities within the respective high-radiation area (>1 rem per hour). For high radiation areas*  
21 *(>1 rem per hour), this PI does not include nonconformance with licensee-initiated controls that*  
22 *are beyond what is required by technical specifications and the comparable provisions in 10 CFR*  
23 *Part 20.*

24

25 Technical Specification high radiation areas, commonly referred to as locked high radiation  
26 areas, includes any area, accessible to individuals, in which radiation levels from radiation  
27 sources external to the body are in excess of 1 rem (10 mSv) per 1 hour at 30 centimeters from  
28 the radiation source or 30 centimeters from any surface that the radiation penetrates, and  
29 excludes very high radiation areas. Technical specification high radiation areas, in which  
30 radiation levels from radiation sources external to the body are less than or equal to 1 rem (10  
31 mSv) per 1 hour at 30 centimeters from the radiation source or 30 centimeters from any surface  
32 that the radiation penetrates, are excluded from this performance indicator.

33

- 34 • “Radiological control over access to technical specification high radiation areas” refers to
- 35 measures that provide assurance that inadvertent entry into the technical specification high
- 36 radiation areas by unauthorized personnel will be prevented.
- 37 • “Radiological control over work activities” refers to measures that provide assurance that
- 38 dose to workers performing tasks in the area is monitored and controlled.

39

40 Examples of occurrences that would be counted against this indicator include:

- 41 • Failure to post an area as required by technical specifications,

---

<sup>15</sup> “Concurrent” means that the nonconformances occur as a result of the same cause and in a common timeframe.

<sup>16</sup> Or comparable provisions in licensee procedures if the technical specifications do not include provisions for high radiation areas.

<sup>17</sup> Includes 10 CFR 20, §20.1601(a), (b), (c), and (d) and §20.1902(b).

- 1 • Failure to secure an area against unauthorized access,
- 2 • Failure to provide a means of personnel dose monitoring or control required by technical
- 3 specifications,
- 4 • Failure to maintain administrative control over a key to a barrier lock as required by technical
- 5 specifications, or
- 6 • An occurrence involving unauthorized or unmonitored entry into an area.

7  
8 Examples of occurrences that are not counted include the following:

- 9 • Situations involving areas in which dose rates are less than or equal to 1 rem per hour,
- 10 • Occurrences associated with isolated equipment failures. This might include, for example,
- 11 discovery of a burnt-out light, where flashing lights are used as a technical specification
- 12 control for access, or a failure of a lock, hinge, or mounting bolts, when a barrier is checked
- 13 or tested.<sup>18</sup>

14  
15 *Very High Radiation Area Occurrence* - A nonconformance (or concurrent nonconformances)

16 with 10 CFR 20 and licensee procedural requirements that results in the loss of radiological

17 control over access to or work activities within a very high radiation area. “Very high radiation

18 area” is defined as any area accessible to individuals, in which radiation levels from radiation

19 sources external to the body could result in an individual receiving an absorbed dose in excess of

20 500 rads (5 grays) in 1 hour at 1 meter from a radiation source or 1 meter from any surface that

21 the radiation penetrates

- 22
- 23 • “Radiological control over access to very high radiation areas” refers to measures to ensure
- 24 that an individual is not able to gain unauthorized or inadvertent access to very high radiation
- 25 areas.
- 26 • “Radiological control over work activities” refers to measures that provide assurance that
- 27 dose to workers performing tasks in the area is monitored and controlled.

28  
29 *Unintended Exposure Occurrence* - A single occurrence of degradation or failure of one or more

30 radiation safety barriers that results in unintended occupational exposure(s), as defined below.

31  
32 Following are examples of an occurrence of degradation or failure of a radiation safety barrier

33 included within this indicator:

- 34
- 35 • failure to identify and post a radiological area
- 36 • failure to implement required physical controls over access to a radiological area
- 37 • failure to survey and identify radiological conditions
- 38 • failure to train or instruct workers on radiological conditions and radiological work controls
- 39 • failure to implement radiological work controls (e.g., as part of a radiation work permit)

40  
41 An occurrence of the degradation or failure of one or more radiation safety barriers is only

42 counted under this indicator if the occurrence resulted in unintended occupational exposure(s)

43 equal to or exceeding any of the dose criteria specified in the table below. The dose criteria were

44 selected to serve as “screening criteria,” only for the purpose of determining whether an

45 occurrence of degradation or failure of a radiation safety barrier should be counted under this

---

<sup>18</sup> Presuming that the equipment is subject to a routine inspection or preventative maintenance program, that the occurrence was indeed isolated, and that the causal condition was corrected promptly upon identification.

1 indicator. The dose criteria should not be taken to represent levels of dose that are “risk-  
2 significant.” In fact, the dose criteria selected for screening purposes in this indicator are  
3 generally at or below dose levels that are required by regulation to be monitored or to be  
4 routinely reported to the NRC as occupational dose records.

5  
6 **Table: Dose Values Used as Screening Criteria to Identify an Unintended Exposure**  
7 **Occurrence in the Occupational Exposure Control Effectiveness PI**  
8

2% of the stochastic limit in 10 CFR 20.1201 on total effective dose equivalent. The 2% value is 0.1 rem.	
10 % of the non-stochastic limits in 10 CFR 20.1201. The 10% values are as follows:	
5 rem	the sum of the deep-dose equivalent and the committed dose equivalent to any individual organ or tissue
1.5 rem	the lens dose equivalent to the lens of the eye
5 rem	the shallow-dose equivalent to the skin or any extremity, other than dose received from a discrete radioactive particle
20% of the limits in 10 CFR 20.1207 and 20.1208 on dose to minors and declared pregnant women. The 20% value is 0.1 rem.	
100% of the limit on shallow-dose equivalent from a discrete radioactive particle. The current value is 50 rem. <sup>19</sup>	

9  
10 “Unintended exposure” refers to exposure that results in dose in excess of the administrative  
11 guideline(s) set by a licensee as part of their radiological controls for access or entry into a  
12 radiological area. Administrative dose guidelines may be established

- 13  
14 • within radiation work permits, procedures, or other documents,  
15 • via the use of alarm setpoints for personnel dose monitoring devices, or  
16 • by other means, as specified by the licensee.  
17

18 It is incumbent upon the licensee to specify the method(s) being used to administratively control  
19 dose. An administrative dose guideline set by the licensee is not a regulatory limit and does not,  
20 in itself, constitute a regulatory requirement. A revision to an administrative dose guideline(s)  
21 during job performance is acceptable (with regard to this PI) if conducted in accordance with  
22 plant procedures or programs.  
23

24 If a specific type of exposure was not anticipated or specifically included as part of job planning  
25 or controls, the full amount of the dose resulting from that type of exposure should be considered  
26 as “unintended” in making a comparison with the respective criteria in the PI. For example, this

<sup>19</sup> The NRC is currently proceeding with rulemaking that may result in a change to the limit on shallow-dose equivalent from a discrete radioactive particle. At the time a final rule is issued, the performance indicator value will be revised as needed.

1 might include Committed Effective Dose Equivalent (CEDE), Committed Dose Equivalent  
2 (CDE), or Shallow Dose Equivalent (SDE).  
3  
4

5 **Clarifying Notes**

6 An occurrence (or concurrent occurrences) that potentially meet the definition of more than one  
7 element of the performance indicator will only be counted once. In other words, an occurrence  
8 (or concurrent occurrences) will not be double-counted (or triple-counted) against the  
9 performance indicator. If two or more individuals are exposed in a single occurrence, the  
10 occurrence is only counted once.  
11

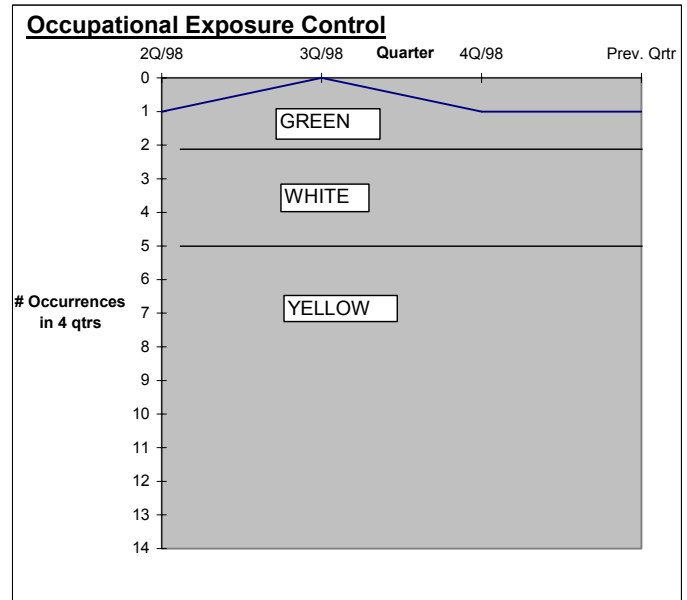
12 Radiography work conducted at a plant under another licensee's 10 CFR Part 34 license is  
13 generally outside the scope of this PI. However, if a Part 50 licensee opts to establish additional  
14 radiological controls under its own program consistent with technical specifications or  
15 comparable provisions in 10 CFR Part 20, then a non-conformance with such additional controls  
16 or unintended dose resulting from the non-conformance shall be evaluated under the criteria in  
17 the PI.  
18  
19

1 **Data Example**

**Occupational Exposure Control Effectiveness**

Quarter	3Q/95	4Q/95	1Q/96	2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
Number of technical specification high radiation occurrences during the quarter	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0
Number of very high radiation area occurrences during the quarter	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0
Number of unintended exposure occurrences during the quarter	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Reporting Quarter				2Q/96	3Q/96	4Q/96	1Q/97	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Qtr
Total # of occurrences in the previous 4 qtrs				4	3	3	1	1	2	2	1	1	0	1	1

Thresholds	
Green	≤2
White	>2
Yellow	>5
No Red Threshold	



2  
3

1 **2.6 PUBLIC RADIATION SAFETY CORNERSTONE**

2 **RETS/ODCM RADIOLOGICAL EFFLUENT OCCURRENCE**

3 **Purpose**

4 To assess the performance of the radiological effluent control program.

5  
6 **Indicator Definition**

7 Radiological effluent release occurrences per site that exceed the values listed below:

8

Radiological effluent releases in excess of the following values:		
Liquid Effluents	Whole Body	1.5 mrem/qtr
	Organ	5 mrem/qtr
Gaseous Effluents	Gamma Dose	5 mrads/qtr
	Beta Dose	10 mrads/qtr
	Organ Doses from I-131, I-133, H-3 & Particulates	7.5 mrems/qtr

9  
10 Note:

- 11 (1) Values are derived from the Radiological Effluent Technical Specifications (RETS) or  
12 similar reporting provisions in the Offsite Dose Calculation Manual (ODCM), if applicable  
13 RETS have been moved to the ODCM in accordance with Generic Letter 89-01.  
14 (2) The dose values are applied on a per reactor unit basis in accordance with the RETS/ODCM.  
15 (3) For multiple unit sites, allocation of dose on a per reactor unit basis from releases made via  
16 common discharge points is to be calculated in accordance with the methodology specified in  
17 the ODCM.  
18

19 **Data Reporting Elements**

20 Number of RETS/ODCM Radiological Effluent Occurrences each quarter involving assessed  
21 dose in excess of the indicator effluent values.  
22

23 **Calculation**

24 Number of RETS/ODCM Radiological Effluent Occurrences per site in the previous four  
25 quarters.  
26

27 **Definition of Terms**

28 A RETS/ODCM Radiological Effluent Occurrence is defined as a release that exceeds any or all  
29 of the five identified values outlined in the above table. These are the whole body and organ  
30 dose values for liquid effluents and the gamma dose, beta dose, and organ dose values for  
31 gaseous effluents.  
32

1 **Clarifying Notes**

2 The following conditions do not count against the RETS/ODCM Radiological Effluent  
3 Occurrence:

- 4
- 5 • Liquid or gaseous monitor operability issues
  - 6
  - 7 • Liquid or gaseous releases in excess of RETS/ODCM concentration or instantaneous  
8 dose-rate values
  - 9
  - 10 • Liquid or gaseous releases without treatment but that do not exceed values in the table

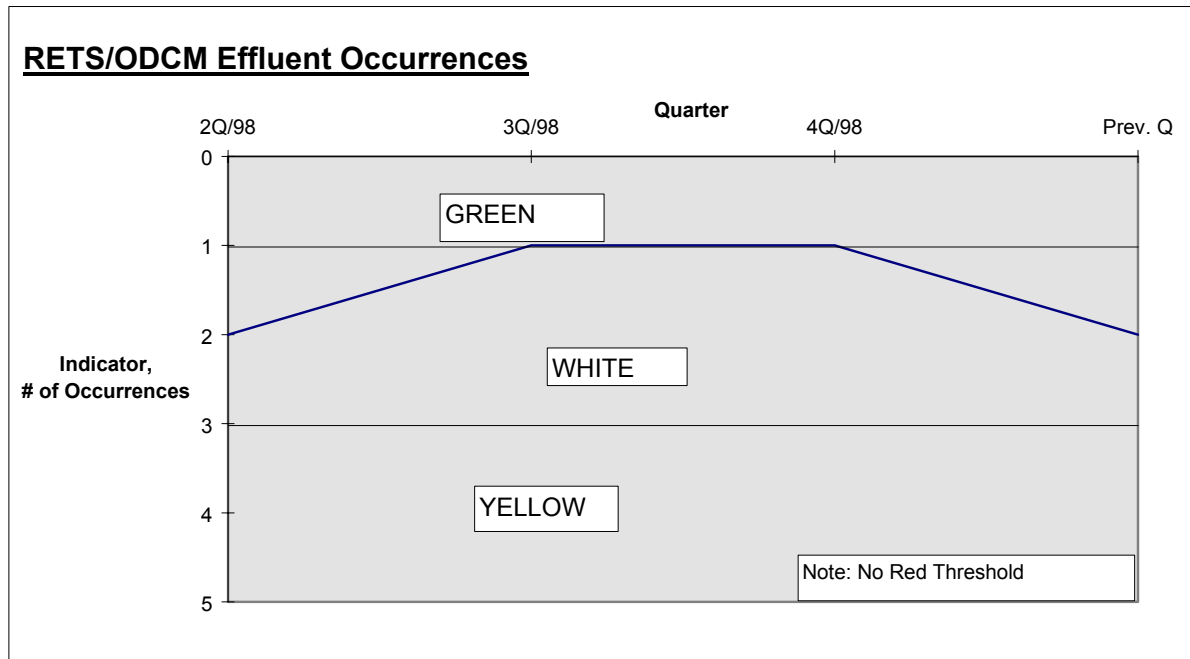
11  
12 Not all effluent sample (e.g., composite sample analysis) results are required to be finalized at  
13 the time of submitting the quarterly PI reports. Therefore, the reports should be based upon the  
14 best-available data. If subsequently available data indicates that the number of occurrences for  
15 this PI is different than that reported, then the report should be revised, along with an explanation  
16 regarding the basis for the revision.

17  
18  
19  
20



1 **Data Example**

RETS/ODCM Radiological Effluent Indicator										
Quarter				3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
Number of RETS/ODCM occurrences in the qtr				1	0	0	1	0	0	1
							2Q/98	3Q/98	4Q/98	Prev. Q
Number of RETS/ODCM occurrences in the previous 4 qtrs							2	1	1	2



2

1  
2  
3  
4

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## 1 2.7 PHYSICAL PROTECTION CORNERSTONE

2 Performance indicators for this cornerstone were selected to provide baseline and trend  
3 information needed to evaluate each licensee's physical protection and access authorization  
4 systems. The regulatory purpose is to provide high assurance that these systems will function to  
5 protect against the design basis threat of radiological sabotage as defined in 10 CFR Part 73. As  
6 a surrogate to any engineered physical security protection system, posted security officers  
7 provide compensation when a portion of the system is unavailable to perform its intended  
8 function. The performance indicator value is not an indication that the protection afforded by the  
9 plant's physical security organization is less than required by the regulatory requirements.

10  
11 An effective access authorization (AA) system minimizes the potential for an internal threat.  
12 Basic elements of this program are the personnel screening program, the fitness-for-duty (FFD)  
13 program and the continual behavior observation program (referred to as CBOP). When there has  
14 been a programmatic failure or significant degradation in the AA system, the licensee is required  
15 to take corrective action and report the event to the regulator. These reportable events are the  
16 basis for the performance indicators (PI) that are used to monitor program effectiveness.

17  
18 There is one performance indicator for the physical protection system, and two indicators for  
19 access authorization. The performance indicators are assessed against established thresholds  
20 using the data and methodology as established in this guideline. The NRC baseline inspections  
21 will validate and verify the testing requirements for each system to assure performance standards  
22 and testing periodicity are appropriate to provide valid data.

### 23 Performance Indicators:

24 The three physical protection performance indicators are:

- 25 1. Protected Area Security Equipment Performance Index,
- 26 2. Personnel Screening Program Performance, and
- 27 3. Fitness-for-Duty (FFD)/Personnel Reliability Program Performance.

28  
29  
30 The first indicator serves as a measure of a plant's ability to maintain equipment—to be available  
31 to perform its intended function. When compensatory measures are employed because a  
32 segment of equipment is unavailable—not adequately performing its intended function, there is  
33 no security vulnerability but there is an indication that something needs to be fixed. The PI  
34 provides trend indications for evaluation of the effectiveness of the maintenance process, and  
35 also provides a method of monitoring equipment degradation as a result of aging that might  
36 adversely impact reliability. Maintenance considerations for protected area and vital area portals  
37 are appropriately and sufficiently covered by the inspection program.

38  
39 The remaining two indicators measure significant programmatic deficiencies in the access and  
40 trustworthiness programs. These programs verify that persons granted unescorted access to the  
41 protected area have satisfactorily completed personal screening and, as a result, are considered to  
42 be trustworthy and reliable. Each indicator is based on the number of reportable events, required  
43 by regulation, that reveal significant problems in the management and operation of the licensee's  
44 access authorization or fitness-for-duty programs.

45

**PROTECTED AREA (PA) SECURITY EQUIPMENT PERFORMANCE INDEX**

**Purpose:**

Operability of the PA security system is necessary to detect and assess safeguards events and to provide the first line of the defense-in-depth physical protection of the plant perimeter. In the event of an attempted encroachment, the intrusion detection system identifies the existence of the threat, the barriers provide a delay to the person(s) posing the threat and the alarm assessment system is used to determine the magnitude of the threat. The PI is used to monitor the unavailability of PA intrusion detection systems and alarm assessment systems to perform their intended function.

**Indicator Definition:**

PA Security equipment performance is measured by an index that compares the amount of the time CCTVs and IDS are unavailable, as measured by compensatory hours, to the total hours in the period. A normalization factor is used to take into account site variability in the size and complexity of the systems.

**Data Reporting Elements:**

Report the following site data for the previous quarter for each unit:

- Compensatory hours, CCTVs: The hours (expressed to the nearest tenth of an hour) expended in posting a security officer as required compensation for camera(s) unavailability because of degradation or defects.
- Compensatory hours, IDS: The hours (expressed to the nearest tenth of an hour) expended in posting a security officer as required compensation for IDS unavailability because of degradation or defects.
- CCTV Normalization factor: The number of CCTVs divided by 30. If there are 30 or fewer CCTVs, a normalization factor of 1 should be used.
- IDS Normalization factor: The number of physical security zones divided by 20. If there are 20 or fewer zones, a normalization factor of 1 should be used.

1 **Calculation**

2  
3 The performance indicator is calculated using values reported for the previous four quarters. The  
4 calculation involves averaging the results of the following two equations.  
5

6 
$$\text{IDS Unavailability Index} = \frac{\text{IDS Compensatory hours in the previous 4 quarters}}{\text{IDS Normalization Factor} \times 8760 \text{ hrs}}$$

7  
8 
$$\text{CCTV Unavailability Index} = \frac{\text{CCTV Compensatory hours in the previous 4 quarters}}{\text{CCTV Normalization Factor} \times 8760 \text{ hrs}}$$

9  
10 
$$\text{Indicator Value} = \frac{\text{IDS Unavailability Index} + \text{CCTV Unavailability Index}}{2}$$

11  
12 **Definition of Terms**

13 *Intrusion detection system (IDS)* - E-fields, microwave fields, etc.

14 *CCTV* - The closed circuit television cameras that support the IDS.

15 *Normalization factors* - Two factors are used to compensate for larger than nominal size sites.

16 – *IDS Normalization Factor*: Using a nominal number of physical security zones across the  
17 industry, the normalization factor for IDS is twenty. If a site has twenty or fewer intrusion  
18 detection zones, the normalization factor will be 1. If a site has more zones than 20, the  
19 factor is the total number of site zones divided by 20 (e.g.,  $50 \div 20 = 2.5$ ).

20 – *CCTV Normalization Factor*: Using a nominal number of perimeter cameras across the  
21 industry, the normalization factor for cameras is 30. If a site has thirty or fewer perimeter  
22 cameras, the normalization factor is 1. If a site has more than 30 perimeter cameras, the  
23 factor is the total number of perimeter cameras divided by 30 (e.g.,  $50 \div 30 = 1.7$ ).

24 

Note: The normalization factors are general approximations and may be modified as 25 experience in the pilot program dictates.
---

26  
27 *Compensatory measures*: Measures used to meet physical security requirements pending the  
28 return of equipment to service. Protected Area protection is not diminished by the use of  
29 compensatory measures for equipment unavailability.  
30

31 *Compensatory man-hours*: The man-hours (expressed to the nearest tenth of an hour) that  
32 compensatory measures are in place (posted) to address a degradation in the IDS and CCTV  
33 systems. When a portion of the system becomes unavailable—incapable of performing its  
34 intended function—and requires posting of compensatory measures, the compensatory man-hour  
35 clock is started. The period of time ends when the cause of the degraded state has been repaired,  
36 tested, and system declared operable.  
37

38 If a zone is posted for a degraded IDS and a CCTV camera goes out in the same posted area, the  
39 hours for the posting of the IDS will not be double counted. However, if the IDS problem is  
40 corrected and no longer requires compensatory posting but the camera requires posting, the hours  
41 will start to count for the CCTV category.

1  
2 *Equipment unavailability:* When the system has been posted because of a degraded condition  
3 (unavailability), the compensatory hours are counted in the PI calculation. If the degradation is  
4 caused by environmental conditions, preventive maintenance or scheduled system upgrade, the  
5 compensatory hours are not counted in the PI calculation. However, if the equipment is  
6 degraded after preventive maintenance or periodic testing, compensatory posting would be  
7 required and the compensatory hours would count. Compensatory hours stop being counted  
8 when the equipment deficiency has been corrected, equipment tested and declared back in  
9 service.

10  
11 **Clarifying Notes**

12 Compensatory posting:

- 13 • The posting for this PI is only for the protected area perimeter, not vital area doors or other  
14 places such posting may be required.
- 15 • Postings for IDS segments for false alarms in excess of security program limits would be  
16 counted in the PI. In the absence of a false alarm limit in the security program, qualified  
17 individuals can disposition the condition and determine whether compensatory posting is  
18 required.
- 19 • Some postings are the result of non-equipment failures, which may be the result of  
20 test/maintenance conditions. For example, in a situation where a part of the IDS is taken out-  
21 of-service to check a condition for false alarms not in excess of security program false alarm  
22 limits, no compensatory hours would be counted. If the equipment is determined to have  
23 malfunctioned, it is not operable and maintenance/repair is required, the hours would count.  
24
- 25 • Compensatory hours expended to address simultaneous equipment problems (IDS & CCTV)  
26 are counted beginning with the initial piece of equipment that required compensatory hours.  
27 When this first piece of equipment is returned to service and no longer requires  
28 compensatory measures, the second covered piece of equipment carries the hours. If one IDS  
29 zone is required to be covered by more than one compensatory post, the total man-hours of  
30 compensatory action are to be counted. If multiple IDS zones are covered by one  
31 compensatory post, the man-hours are only counted once.
- 32 • IDS equipment issues that do not require compensatory hours would not be counted
- 33 • Compensatory man hours for a failed Pan-Tilt-Zoom (PTZ) camera count for the PI only if  
34 the PTZ is either being used as a CCTV or is substituting for a failed CCTV.
- 35 • The PI metric is based on expended compensatory hours and starts when the IDS or CCTV is  
36 actually posted. There are no "fault exposure hours" or other consideration beyond the actual  
37 physical compensatory posting. Also, this indicator only uses compensatory man-hours to  
38 provide an indication of CCTV or IDS unavailability. If a PTZ camera or other non-  
39 personnel (no expended portion of a compensatory man-hour) item is used as the  
40 compensatory measure, it is not counted for this PI.

- 1 • In a situation where security persons are already in place at continuously manned remote  
2 location security booths around the perimeter of the site and there is a need to provide  
3 compensatory coverage for the loss of IDS equipment, security persons already in these  
4 booths can fulfill this function. If they are used to perform the compensatory function, the  
5 hours are included in the PI. The man hours for all persons required to provide compensation  
6 are counted. If more persons are assigned than required, only the required compensatory man  
7 hours would be counted.
- 8 • Compensatory hours for this PI cover hours expended in posting a security officer as required  
9 as compensation for IDS and/or CCTV unavailability because of a degradation or defect. If  
10 other problems (e.g., security computer or multiplexer) result in compensatory postings  
11 because the IDS/CCTV is no longer capable of performing its intended safeguards function,  
12 the hours would count. Equipment malfunctions that do not require compensatory posting  
13 are not included in this PI.
- 14 • If an ancillary system is needed to support proper operability of IDS or CCTV and it fails,  
15 and the supported system does not operate as intended, the hours would count. For example,  
16 a CCTV camera requires sufficient lighting to perform its function so that such a lighting  
17 failure would result in compensatory hours counted for this PI.

18  
19 Data reporting: For this performance indicator, rounding may be performed as desired provided  
20 it is consistent and the reporting hours are expressed to the nearest tenth of an hour. Information  
21 supporting performance indicators is reported on a per unit basis. For performance indicators that  
22 reflect site conditions (IDS or CCTV), this requires that the information be repeated for each unit  
23 on the site. The criterion for data reporting is from the time the failure or deficiency is identified  
24 to the time it is placed back in service.

25  
26 Degradation: Required system/equipment/component is no longer available/capable of  
27 performing its intended safeguards function—manufacturer’s equipment design capability and/or  
28 as covered in the PSP.

29  
30 Extreme environmental conditions:

31 Compensatory hours do not count for extreme environmental conditions beyond the design  
32 specifications of the system, including severe storms, heavy fog, heavy snowfall, and sun glare  
33 that renders the IDS or CCTV temporarily inoperable. If after the environmental condition  
34 clears, the zone remains unavailable, despite reasonable recovery efforts, the compensatory hours  
35 would not begin to be counted until technically feasible corrective action could be completed.  
36 For example, a hurricane decimates a portion of the perimeter IDS and certain necessary  
37 components have to be obtained from the factory. Any restoration delay would be independent of  
38 the licensee’s maintenance capability and therefore would not be counted in the indicator.

39  
40 Other naturally occurring conditions that are beyond the control of the licensee, such as damage  
41 or nuisance alarms from animals are not counted.

42  
43 Independent Spent Fuel Storage Installations (ISFSIs): This indicator does not include protective  
44 measures associated with such installations.

45

1 Intended function: The ability of a component to detect the presence of an individual or display  
2 an image as intended by manufacturer's equipment design capability and/or as covered in the  
3 PSP.  
4

5 Operational support: E-fields or equivalent that are taken out of service to support plant  
6 operations and are not equipment failures but are compensatorily posted do not count for this PI.  
7

8 Scheduled equipment upgrade:

- 9 • In the situation where system degradation results in a condition that cannot be corrected  
10 under the normal maintenance program (*e.g.*, engineering evaluation specifies the need for a  
11 system/component<sup>20</sup> modification or upgrade), and the system requires compensatory  
12 posting, the compensatory hours stop being counted toward the PI for those conditions  
13 addressed within the scope of the modification after such an evaluation has been made and  
14 the station has formally **approved an upgrade** with descriptive information about the upgrade  
15 plan including scope of the project, anticipated schedule, and expected expenditures. This  
16 formally initiated upgrade is the result of established work practices to design, fund, procure,  
17 install and test the project. A note should be made in the comment section of the PI submittal  
18 that the compensatory hours are being excluded under this provision. Compensatory hour  
19 counting resumes when the upgrade is complete and operating as intended as determined by  
20 site requirements for sign-off. Reasonableness should be applied with respect to a justifiable  
21 length of time the compensatory hours are excluded from the PI.  
22
- 23 • For the case where there are a few particularly troubling zones that result in formal initiation  
24 of an entire system upgrade for all zones, counting compensatory hours would stop only for  
25 zones out of service for the upgrade. However, if subsequent failures would have been  
26 prevented by the planned upgrade those would also be excluded from the count. This  
27 exclusion applies regardless of whether the failures are in a zone that precipitated the upgrade  
28 action or not, as long as they are in a zone that will be affected by the upgrade, and the  
29 upgrade would have prevented the failure.  
30

31 Preventive maintenance:

- 32 • Scheduled preventive maintenance (PM) on system/equipment/component to include  
33 probability and/or operability testing. Includes activities necessary to keep the system at the  
34 required functional level. Planned plant support activities are considered PM.
- 35 • If during preventive maintenance or testing, a camera does not function correctly, and can be  
36 compensated for by means other than posting an officer, no compensatory man-hours are  
37 counted.
- 38 • Predictive maintenance is treated as preventive maintenance. Since the equipment has not  
39 failed and remains capable of performing its intended security function, any maintenance  
40 performed in advance of its actual failure is preventive. It is not the intent to create a  
41 disincentive to performing maintenance to ensure the security systems perform at their peak  
42 reliability and capability.

---

<sup>20</sup> A modification to prevent the circumvention of the IDS (or CCTV) (such as the installation of a razor wire barrier) would fall under these provisions because the modification would be acting as an ancillary system of the IDS.

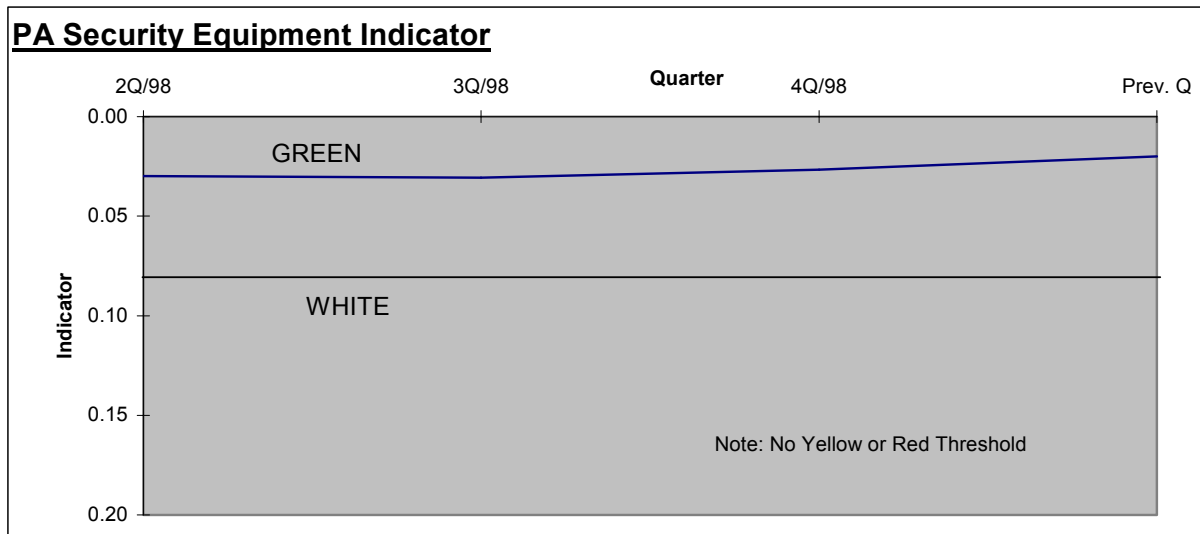


- 1  
2 • Scheduled system upgrade: Activity to improve, upgrade or enhance system performance, as  
3 appropriate, in order to be more effective in its reliability or capability.

1 **Data Example**

**Protected Area Security Equipment Performance Indicator**

Quarter	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
IDS Compensatory Hours in the qtr	36	48	96	126	65	45	60	55
CCTV Compensatory Hours in the qtr	24	36	100	100	48	56	53	31
IDS Compensatory Hrs in previous 4 qtrs				306	335	332	296	225
CCTV Compensatory Hrs in the previous 4 qtrs				260	284	304	257	188
IDS Normalization Factor	1.05	1.05	1.05	1.05	1.1	1.1	1.1	1.1
CCTV normalization Factor	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3
IDS Unavailability Index				0.033268	0.034765	0.034454	0.030718	0.02335
CCTV Unavailability Index				0.024734	0.024939	0.026695	0.022568	0.016509
					<b>2Q/98</b>	<b>3Q/98</b>	<b>4Q/98</b>	<b>Prev. Q</b>
Indicator Value				0.03	0.03	0.03	0.03	0.02



2

1 **PERSONNEL SCREENING PROGRAM PERFORMANCE**

2 **Purpose:**

3 The screening program performance indicator is used to verify that the unescorted access  
4 authorization program has been implemented pursuant to 10 CFR §§ 73.56 & 73.57 to evaluate  
5 trustworthiness of personnel prior to granting unescorted access to the protected area. The  
6 screening program includes psychological evaluation, an FBI criminal history check, a  
7 background check and reference check. The program should be able to verify that persons  
8 granted unescorted access to the protected area have satisfactorily completed personal screening  
9 and, as a result, are considered to be trustworthy and reliable.

10  
11 **Indicator Definition**

12 The number of reportable failures to properly implement the regulatory requirements.

13  
14 **Data Reporting Elements**

15 The number of failures to implement requirement(s) of 10 CFR Part 73.56 and 73.57 that were  
16 reportable during the previous quarter under 10 CFR Part 73 Appendix G.

17  
18 **Calculation:**

19 The indicator is a summation of the values reported for the previous four quarters.

20  
21 **Definition of Terms:**

22 *Reportable event:* - a failure in the licensee's program that requires prompt regulatory  
23 notification. This is in contrast to a loggable event, which is not considered significant.

24  
25 **Clarifying Notes:**

26 The only reportable event is that defined in the PI - "a failure in the licensee's program that  
27 requires prompt regulatory notification." If you are not required to make a one-hour report  
28 concerning a significant failure to meet regulation it is not included for PI purposes. This  
29 indicator provides a measure of the effectiveness of programmatic efforts to implement  
30 regulatory requirements outlined in 10 CFR §§ 73.56 and 73.57 only and does not apply to the  
31 rest of Part 73. It does not include any reportable events that result from the program operating  
32 as intended. For example, if a background investigation reveals a significant event concerning a  
33 contract worker but unescorted access had not been granted and proper action was taken, this  
34 does not count as a data reporting element. It is not a failure to implement the requirements  
35 because the program functioned as implemented in compliance with the requirements.

36  
37 Where a programmatic failure affected multiple sites, the instance is reported for each affected  
38 unit at each affected site.

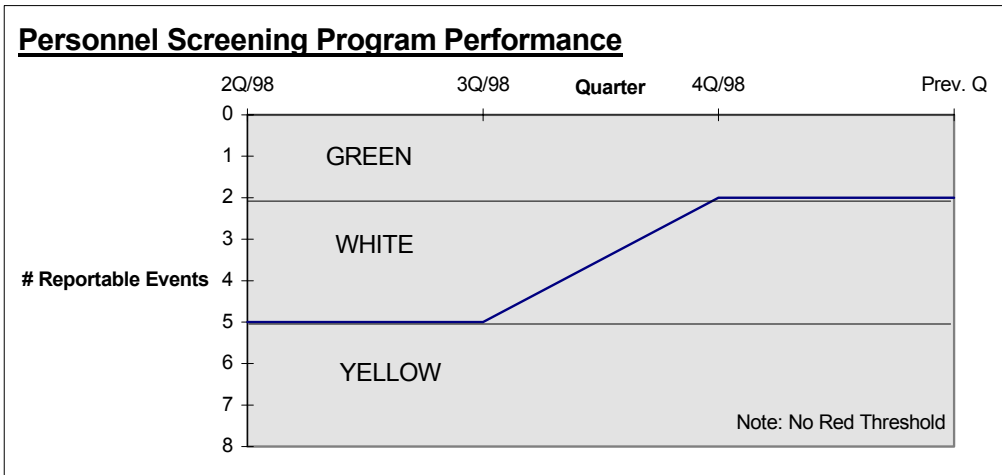
39  
40 The criterion for reporting of performance indicators is based on the time the failure or  
41 deficiency is identified.

1 **Data Examples**

**Personnel Screening Program Indicator**

Quarter	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
10 CFR §73.56 One Hr Reports	0	1	3	0	1	1	0	0
Reportable Events in previous 4 qtrs					2Q/98	3Q/98	4Q/98	Prev. Q
					5	5	2	2

Thresholds	
Green	≤2
White	>2
Yellow	>5



2  
3

**FITNESS-FOR-DUTY (FFD)/PERSONNEL RELIABILITY PROGRAM PERFORMANCE**

**Purpose:**

The fitness-for-duty/personnel reliability program performance indicator is used to assess the implemented program for reasonable assurance that personnel are in compliance with associated requirements, 10 CFR Part 26 and § 73.56, to include: suitable inquiry, testing for substance abuse and behavior observation. This trustworthiness and reliability program is designed to minimize the potential for a person's performance or behavior to adversely affect his or her ability to safely and competently perform required duties.

**Indicator Definition**

The number of reportable failures to properly implement the requirements of 10 CFR Part 26 and 10 CFR 73.56.

**Data Reporting Elements:**

The number of failures to implement fitness-for-duty and behavior observation requirements, reportable during the previous quarter.

**Calculation:**

The indicator is a summation of the values reported for the previous four quarters.

**Definition of Terms:**

*Reportable event:* a failure in the licensee's program that requires prompt regulatory notification. This is in contrast to a loggable event, which is not considered significant.

**Clarifying Notes:**

This indicator provides a measure of the effectiveness of programmatic efforts to implement regulatory requirements outlined in 10 CFR Part 26 and Part 73.56 and does not include any reportable events that result from the program operating as intended. For example, if a contract supervisor is selected for a random drug test, tests positive, and proper action is taken, this does not count as a data reporting element. It is not a failure to implement the requirements because the program functioned as implemented in compliance with the requirements of 10 CFR Part 26.

Only reports of significant programmatic failures of the implemented regulatory requirements are included in the PIs for access authorization or fitness-for-duty.

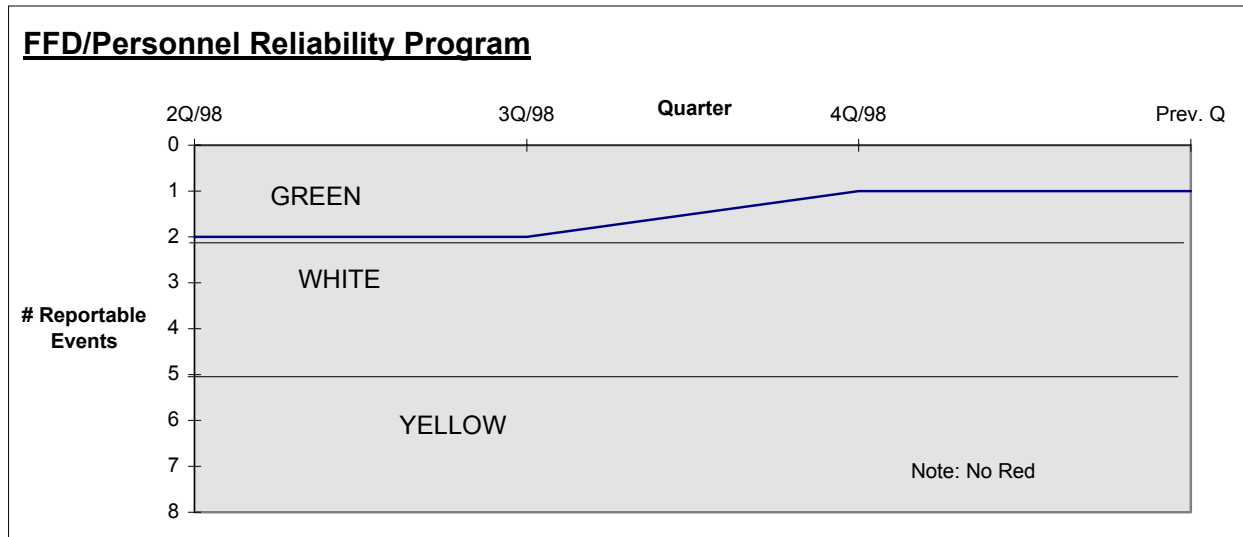
Where a programmatic failure affected multiple sites, the instance is reported for each affected unit at each affected site.

The criterion for reporting of performance indicators is based on the time the failure or deficiency is identified.

1 **Data Example**

**FFD/Personnel Reliability**

Quarter	2Q/97	3Q/97	4Q/97	1Q/98	2Q/98	3Q/98	4Q/98	Prev. Q
10 CFR Part 26 Prompt Reports	0	1	1	0	0	1	0	0
					2Q/98	3Q/98	4Q/98	Prev. Q
Reportable Events in previous 4 qtrs					2	2	1	1
<b>Thresholds</b>								
Green	≤2							
White	>2							
Yellow	>5							
Red	N/A							



2

## **APPENDIX A**

### **Acronyms & Abbreviations**

1		
2		
3		
4	AA	Access Authorization
5	AC	Alternating (Electrical) Current
6	AFW	Auxiliary Feedwater System
7	ALARA	As Low As Reasonably Achievable
8	ANS	Alert & Notification System
9	BWR	Boiling Water Reactor
10	CBOP	Continual Behavior Observation Program
11	CFR	Code of Federal Regulations
12	CCTV	Closed Circuit Television
13	DC	Direct (Electrical) Current
14	DE & AEs	Drills, Exercises and Actual Events
15	EAL	Emergency Action Levels
16	EDG	Emergency Diesel Generator
17	EOF	Emergency Operations Facility
18	EFW	Emergency Feedwater
19	ERO	Emergency Response Organization
20	ESF	Engineered Safety Features
21	FBI	Federal Bureau of Investigations
22	FEMA	Federal Emergency Management Agency
23	FFD	Fitness for Duty
24	FSAR	Final Safety Analysis Report
25	FWCI	Feedwater Coolant Injection
26	IDS	Intrusion Detection System
27	ISFSI	Independent Spent Fuel Storage Installation
28	HPCI	High Pressure Coolant Injection
29	HPCS	High Pressure Core Spray
30	HPSI	High Pressure Safety Injection
31	HVAC	Heating, Ventilation and Air Conditioning
32	LER	Licensee Event Report
33	LPCI	Low Pressure Coolant Injection
34	LPSI	Low Pressure Safety Injection
35	LOCA	Loss of Coolant Accident
36	MSIV	Main Steam Isolation Valve
37	N/A	Not Applicable
38	NEI	Nuclear Energy Institute
39	NRC	Nuclear Regulatory Commission
40	ODCM	Offsite Dose Calculation Manual
41	OSC	Operations Support Center
42	PA	Protected Area
43	PARs	Protective Action Recommendations
44	PI	Performance Indicator
45	PRA	Probabilistic Risk Analysis
46		

1	PORV	Power Operated Relief Valve
2	PWR	Pressurized Water Reactor
3	RETS	Radiological Effluent Technical Specifications
4	RCIC	Reactor Core Isolation Cooling
5	RCS	Reactor Coolant System
6	RHR	Residual Heat Removal
7	SSFF	Safety System Functional Failure
8	SSU	Safety System Unavailability
9	TSC	Technical Support Center



## **APPENDIX B**

### **STRUCTURE AND FORMAT OF NRC PERFORMANCE INDICATOR DATA FILES**

Performance indicator data files submitted to the NRC as part of the Regulatory Oversight Process should conform to structure and format identified below. The NEI performance indicator Website (PIWeb) automatically produces files with structure and format outlined below.

#### **File Naming Convention**

Each NRC PI data file should be named according to the following convention. The name should contain the unit docket number, underscore, the date and time of creation and (if a change file) a “C” to indicate that the file is a change report. A file extension of .txt is used to indicate a text file.

Example: 05000399\_20000103151710.txt

In the above example, the report file is for a plant with a docket number of 05000399 and the file was created on January 3, 2000 at 10 seconds after 3:17 p.m. The absence of a C at the end of the file name indicates that the file is a quarterly data report.

#### **General Structure**

Each line of the report begins with a left bracket (e.g., “[”) and ends with a right bracket (e.g., “]”). Individual items of information on a line (elements) are separated by a vertical “pipe” (e.g., “|”).

Each file begins with [BOF] as the first line and [EOF] as the last line. These indicate the beginning and end of the data file. The file may also contain one or more “buffer” lines at the end of the file to minimize the potential for file corruption. The second line of the file contains the unit docket number and the date and time of file creation (e.g., [05000399|1/2/2000 14:20:32]). Performance indicator information is contained beginning with line 3 through the next to last line (last line is [EOF]). The information contained on each line of performance indicator information consists of the performance indicator ID, applicable quarter/year (month/year for Barrier Integrity indicators), comments, and each performance indicator data element. Table B-1 provides a description of the data elements and order for each line of performance indicator data in a report file.

Example:

[IE01|3Q1998|Comments here|2|2400]

In the above example, the line contains performance indicator data for Unplanned Scrams per 7000 Critical Hours (IE01), during the 3<sup>rd</sup> quarter of 1998. The applicable comment text is “Comments here”. The data elements identify that (see Table B-1) there were 2 unplanned automatic and manual scrams while critical and there were 2400 hours of critical operation during the quarter.

**TABLE B-1 – PI DATA ELEMENTS IN NRC DATA REPORT**

<b>Performance Indicator</b>	<b>Data Element Number</b>	<b>Description</b>
<b>General Comment</b>	1	Performance Indicator Flag (i.e., GEN)
	2	Report quarter and year (e.g., 1Q2000)
	3	Comment text
<b>Unplanned Scrams per 7,000 Critical Hours</b>	1	Performance Indicator Flag (i.e., IE01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of unplanned automatic and manual scrams while critical in the reporting quarter
	5	Number of hours of critical operation in the reporting quarter
<b>Unplanned Scrams with Loss of Normal Heat Removal</b>	1	Performance Indicator Flag (i.e., IE02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	The number of <b>unplanned</b> automatic and manual scrams while critical in the reporting quarter <b>that were either caused by or involved a loss of</b> the normal heat removal path <b>prior to establishing reactor conditions that allow use of the plant's normal long term heat removal system</b>
<b>Unplanned Power Changes per 7,000 Critical Hours</b>	1	Performance Indicator Flag (i.e., IE03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of unplanned power changes, excluding scrams, during the reporting quarter
	5	Number of hours of critical operation in the reporting quarter
<b>Safety System Unavailability (SSU), Emergency AC Power System</b>	1	Performance Indicator Flag (i.e., MS01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Planned Unavailable Hours
	5	Unplanned Unavailable Hours
	6	Fault Exposure Hours
	7	Hours Train Required for Service
	*	Items 4 to 7 are repeated for each train
<b>Safety System Unavailability (SSU), High Pressure Injection System</b>	1	Performance Indicator Flag (i.e., MS02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Planned Unavailable Hours
	5	Unplanned Unavailable Hours
	6	Fault Exposure Hours
	7	Hours Train Required for Service
	*	Items 4 to 7 are repeated for each train

<b>Performance Indicator</b>	<b>Data Element Number</b>	<b>Description</b>
<b>Safety System Unavailability (SSU), Heat Removal System</b>	1	Performance Indicator Flag (i.e., MS03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Planned Unavailable Hours
	5	Unplanned Unavailable Hours
	6	Fault Exposure Hours
	7	Hours Train Required for Service
	*	Items 4 to 7 are repeated for each train
<b>Safety System Unavailability (SSU), Residual Heat Removal System</b>	1	Performance Indicator Flag (i.e., MS04)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Planned Unavailable Hours
	5	Unplanned Unavailable Hours
	6	Fault Exposure Hours
	7	Hours Train Required for Service
	*	Items 4 to 7 are repeated for each train
<b>Safety System Functional Failures</b>	1	Performance Indicator Flag (i.e., MS05)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of safety system functional failures during the reporting quarter
<b>Reactor Coolant System Activity (RCSA)</b>	1	Performance Indicator Flag (i.e., BI01)
	2	Month and year (e.g., 3/2000)
	3	Comment text
	4	Maximum calculated RCS activity, in micro curies per gram dose equivalent Iodine 131, as required by technical specifications, for reporting month
	5	Technical Specification limit for RCS activity in micro curies per gram dose equivalent Iodine 131
<b>Reactor Coolant System Identified Leakage (RCSL)</b>	1	Performance Indicator Flag (i.e., BI02)
	2	Month and year (e.g., 3/2000)
	3	Comment text
	4	Maximum RCS Identified Leakage calculation for reporting month in gpm
	5	Technical Specification limit for RCS Identified Leakage in gpm
<b>Emergency Response Organization Drill/Exercise Performance</b>	1	Performance Indicator Flag (i.e., EP01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of drill, exercise and actual event opportunities performed timely and accurately during the reporting quarter
	5	Number of drill, exercise and actual event opportunities during the reporting quarter
<b>Emergency Response Organization (ERO) Participation</b>	1	Performance Indicator Flag (i.e., EP02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Total Key ERO members that have participated in a drill, exercise, or actual event in the previous 8 qtrs

<b>Performance Indicator</b>	<b>Data Element Number</b>	<b>Description</b>
	5	Total number of Key ERO personnel at end of reporting quarter
<b>Alert &amp; Notification System Reliability</b>	1	Performance Indicator Flag (i.e., EP03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Total number of successful ANS siren-tests during the reporting quarter
	5	Total number of ANS sirens tested during the reporting quarter
<b>Occupational Exposure Control Effectiveness</b>	1	Performance Indicator Flag (i.e., OR01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of technical specification high radiation area occurrences during the reporting quarter
	5	Number of very high radiation area occurrences during the reporting quarter
	6	The number of unintended exposure occurrences during the reporting quarter
<b>RETS/ODCM Radiological Effluent Indicator</b>	1	Performance Indicator Flag (i.e., PR01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of RETS/ODCM occurrences in the quarter
<b>Protected Area Security Equipment Performance Indicator</b>	1	Performance Indicator Flag (i.e., PP01)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	IDS Compensatory Hours in the quarter
	5	CCTV Compensatory Hours in the quarter
	6	IDS Normalization Factor
	7	CCTV Normalization Factor
<b>Personnel Screening Program Indicator</b>	1	Performance Indicator Flag (i.e., PP02)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	10 CFR §73.56 One Hr Reports
<b>FFD/Personnel Reliability</b>	1	Performance Indicator Flag (i.e., PP03)
	2	Quarter and year (e.g., 1Q2000)
	3	Comment text
	4	Number of failures to implement fitness-for-duty and behavior observation requirements, reportable during the reporting quarter.
<b>Reset of Fault Exposure Hours</b>	1	Target Performance Indicator (Performance Indicator Flag preceded by "FR", e.g., (FRMS01, FRMS02, FRMS03 or FRMS04)
	2	Target Quarter (Quarter and year of data to be reset, e.g., 1Q2000)
	3	Effective Quarter (Quarter and year that reset data becomes effective, e.g., 1Q2001)
	4	Comment text

Performance Indicator	Data Element Number	Description
	5	Delta Planned Unavailable Hours (Delta change to planned unavailable hours reported for train 1 for Target Quarter. Hours are added to reported hours beginning with Effective Quarter.)
	6	Delta Unplanned Unavailable Hours (Delta change to unplanned unavailable hours reported for train 1 for Target Quarter. Hours are added to reported hours beginning with Effective Quarter.)
	7	Delta Fault Exposure Hours (Delta change to fault exposure hours reported for train 1 for Target Quarter. Hours are subtracted from reported hours beginning with Effective Quarter.)
	*	Items 5 to 7 are repeated for each train

1



1  
2 **APPENDIX C**

3  
4 **Background Information and Cornerstone Development**  
5

6 **INTRODUCTION**

7 This section discusses the overall objectives and basis for the performance indicators used for  
8 each of the seven cornerstone areas. A more in-depth discussion of the background behind each  
9 of the performance indicators identified in the main report may be found in SECY 99-07.

10 **INITIATING EVENTS CORNERSTONE**

11 **GENERAL DESCRIPTION**

12 The objective of this cornerstone is to limit the frequency of those events that upset plant stability  
13 and challenge critical safety functions, during shutdown as well as power operations. When such  
14 an event occurs in conjunction with equipment and human failures, a reactor accident may occur.  
15 Licensees can therefore reduce the likelihood of a reactor accident by maintaining a low  
16 frequency of these initiating events. Such events include reactor trips due to turbine trip, loss of  
17 feedwater, loss of offsite power, and other reactor transients. There are a few key attributes of  
18 licensee performance that determine the frequency of initiating events at a plant.

19 **PERFORMANCE INDICATORS**

20 PRAs have shown that risk is often determined by initiating events of low frequency, rather than  
21 those that occur with a relatively higher frequency. Such low-frequency, high-risk events have  
22 been considered in selecting the PIs for this cornerstone. All of the PIs used in this cornerstone  
23 are counts of either initiating events, or transients that could lead to initiating events (see Table 1).  
24 They have face validity for their intended use because they are quantifiable, have a logical  
25 relationship to safety performance expectations, are meaningful, and the data are readily  
26 available. The PIs by themselves are not necessarily related to risk. They are however, the first  
27 step in a sequence which could, in conjunction with equipment failures, human errors, and off-  
28 normal plant configurations, result in a nuclear reactor accident. They also provide indication of  
29 problems that, if uncorrected, increase the risk of an accident. In most cases, where PIs are  
30 suitable for identifying problems, they are sufficient as well, since problems that are not severe  
31 enough to cause an initiating event (and therefore result in a PI count) are of low risk significance.  
32 In those cases, no baseline inspection is required (the exception is shutdown configuration  
33 control, for which supplemental baseline inspections is necessary).

## 1 **MITIGATING SYSTEMS CORNERSTONE**

### 2 **GENERAL DESCRIPTION**

3 The objective of this cornerstone is to ensure the availability, reliability, and capability of systems  
4 that respond to initiating events to prevent undesirable consequences (i.e., core damage). When  
5 such an event occurs in conjunction with equipment and human failures, a reactor accident may  
6 result. Licensees therefore reduce the likelihood of reactor accidents by enhancing the availability  
7 and reliability of mitigating systems. Mitigating systems include those systems associated with  
8 safety injection, residual heat removal, and emergency AC power. This cornerstone includes  
9 mitigating systems that respond to both operating and shutdown events.

### 10 **PERFORMANCE INDICATORS**

11 While safety systems and components are generally thought of as those that are designed for  
12 design-basis accidents, not all mitigating systems have the same risk importance. PRAs have  
13 shown that risk is often influenced not only by front-line mitigating systems, but also by support  
14 systems and equipment. Such systems and equipment, both safety- and nonsafety-related, have  
15 been considered in selecting the PIs for this cornerstone. The PIs are all direct counts of either  
16 mitigating system availability or reliability or surrogates of mitigating system performance. They  
17 have face validity for their intended use because they are quantifiable, have a logical relationship  
18 to safety performance expectations, are meaningful, and the data are readily available. Not all  
19 aspects of licensee performance can be monitored by PIs. Risk-significant areas not covered by  
20 PIs will be assessed through inspection.

## 21 **BARRIER INTEGRITY CORNERSTONE**

### 22 **GENERAL DESCRIPTION**

23 The purpose of this cornerstone is to provide reasonable assurance that the physical design  
24 barriers (fuel cladding, reactor coolant system, and containment) protect the public from  
25 radionuclide releases caused by accidents or events. These barriers play an important role in  
26 supporting the NRC Strategic Plan goal for nuclear reactor safety, "Prevent radiation-related  
27 deaths or illnesses due to civilian nuclear reactors." The defense in depth provided by the  
28 physical design barriers which comprise this cornerstone allow achievement of the reactor safety  
29 goal.

### 30 **PERFORMANCE INDICATORS**

31 The performance indicators for this cornerstone cover two of the three physical design barriers.  
32 The first barrier is the fuel cladding. Maintaining the integrity of this barrier prevents the release  
33 of radioactive fission products to the reactor coolant system, the second barrier. Maintaining the  
34 integrity of the reactor coolant system reduces the likelihood of loss of coolant accident initiating  
35 events and prevents the release of radioactive fission products to the containment atmosphere in  
36 transients and other events. Performance indicators for reactor coolant system activity and reactor  
37 coolant system leakage monitor the integrity of the first two physical design barriers. Even if  
38 significant quantities of radionuclides are released into the containment atmosphere, maintaining  
39 the integrity of the third barrier, the containment, will limit radioactive releases to the



1 environment and limit the threat to the public health and safety. The integrity of the containment  
2 barrier is ensured through the inspection process.

3  
4 Therefore, there are three desired results associated with the barrier integrity cornerstone. These  
5 are to maintain the functionality of the fuel cladding, the reactor coolant system, and the  
6 containment.

## 7 **EMERGENCY PREPAREDNESS CORNERSTONE**

### 8 **GENERAL DESCRIPTION**

9 Emergency Preparedness (EP) is the final barrier in the *defense in depth* approach to safety that  
10 NRC regulations provide for ensuring the adequate protection of the public health and safety.  
11 Emergency Preparedness is a fundamental cornerstone of the Reactor Safety Strategic  
12 Performance Area. 10 CFR Part 50.47 and Appendix E to Part 50, define the requirements of an  
13 EP program and a licensee commits to implementation of these requirements through an  
14 Emergency Plan (the Plan). The performance indicators for this cornerstone are designed to  
15 ensure that the licensee is capable of implementing adequate measures to protect the public health  
16 and safety in the event of a radiological emergency.

### 17 **PERFORMANCE INDICATORS**

18 Compliance of EP programs with regulation is assessed through observation of response to  
19 simulated emergencies and through routine inspection of onsite programs. Demonstration  
20 exercises involving onsite and offsite programs, form the key observational tool used to support,  
21 on a continuing basis, the reasonable assurance finding that *adequate protective measures can*  
22 *and will be taken in the event of a radiological emergency*. This is especially true for the most  
23 risk significant facets of the EP program. This being the case, the PIs for onsite EP draw  
24 significantly from performance during simulated emergencies and actual declared emergencies,  
25 but are supplemented by direct NRC inspection and inspection of licensee self assessment. NRC  
26 assessment of the adequacy of offsite EP will rely (as it does currently) on regular FEMA  
27 evaluations.

## 28 **OCCUPATIONAL EXPOSURE CORNERSTONE**

### 29 **GENERAL DESCRIPTION**

30 This cornerstone includes the attributes and the bases for adequately protecting the health and  
31 safety of workers involved with exposure to radiation from licensed and unlicensed radioactive  
32 material during routine operations at civilian nuclear reactors. The desired result is the adequate  
33 protection of worker health and safety from this exposure. The cornerstone uses as its bases the  
34 occupational dose limits specified in 10 CFR 20 Subpart C and the operating principle of  
35 maintaining worker exposure “as low as reasonably achievable (ALARA)” in accordance with  
36 10 CFR 20.1101. These radiation protection criteria are based upon the assumptions that a linear  
37 relationship, without threshold, exists between dose and the probability of stochastic health  
38 effects (radiological risk); the severity of each type of stochastic health effect is independent of  
39 dose; and nonstochastic radiation-induced health effects can be prevented by limiting exposures

1 below thresholds for their induction. Thus, 10 CFR Part 20 requires occupational doses to be  
2 maintained ALARA with the exposure limits defined in 10 CFR 20 Subpart C constituting the  
3 maximum allowable radiological risk. Industry experience has shown that the occurrences of  
4 uncontrolled occupational exposure that potentially could result in an individual exceeding a dose  
5 limit have been low frequency events. These potential overexposure incidents are associated with  
6 radiation fields exceeding 1000 millirem per hour (mrem/hr) and have involved the loss of one or  
7 more radiation protection controls (barriers) established to manage and control worker exposure.  
8 The probability of undesirable health effects to workers can be maintained within acceptable  
9 levels by controlling occupational exposures to radiation and radioactive materials to prevent  
10 regulatory overexposures and by implementing an aggressive and effective ALARA program to  
11 monitor, control and minimize worker dose.

## 12 **PERFORMANCE INDICATORS**

13 A combined performance indicator is used to assess licensee performance in controlling worker  
14 doses during work activities associated with high radiation fields or elevated airborne  
15 radioactivity areas. The PI was selected based upon its ability to provide an objective measure of  
16 an uncontrolled measurable worker exposure or a loss of access controls for areas having  
17 radiation fields exceeding 1000 millirem per hour (mrem/hr). The data for the PI are currently  
18 being collected by most licensees in their corrective action programs. The PI either directly  
19 measures the occurrence of unanticipated and uncontrolled dose exceeding a percentage of the  
20 regulatory limits or identifies the failure of barriers established to prevent unauthorized entry into  
21 those areas having dose rates exceeding 1000 mrem/hr. The indicator may identify declining  
22 performance in procedural guidance, training, radiological monitoring, and in exposure and  
23 contamination control prior to exceeding a regulatory dose limit. The effectiveness of the  
24 licensee's assessment and corrective action program is considered a cross-cutting issue and is  
25 addressed elsewhere.

## 26 **PUBLIC EXPOSURE CORNERSTONE**

### 27 **GENERAL DESCRIPTION**

28 This cornerstone includes the attributes and the bases for adequately protecting public health and  
29 safety from exposure to radioactive material released into the public domain as a result of routine  
30 civilian nuclear reactor operations. The desired result is the adequate protection of public health  
31 and safety from this exposure. These releases include routine gaseous and liquid radioactive  
32 effluent discharges, the inadvertent release of solid contaminated materials, and the offsite  
33 transport of radioactive materials and wastes. The cornerstone uses as its bases, the dose limits  
34 for individual members of the public specified in 10 CFR 20, Subpart D; design objectives  
35 detailed in Appendix I to 10 CFR Part 50 which defines what doses to members of the public  
36 from effluent releases are "as low as reasonably achievable" (ALARA); and the exposure and  
37 contamination limits for transportation activities detailed in 10 CFR Part 71 and associated  
38 Department of Transportation (DOT) regulations. These radiation protection standards require  
39 doses to the public be maintained ALARA with the regulatory limits constituting the maximum  
40 allowable radiological risk based on the linear relationship between dose received and the  
41 probability of adverse health effects.

1 **PERFORMANCE INDICATORS**

2 One PI for the radioactive effluent release program has been initially developed to monitor for  
3 inaccurate or increasing projected offsite doses. The effluent radiological occurrence (ERO) PI  
4 does not evaluate performance of the radiological environmental monitoring program (REMP)  
5 which will be assessed through the routine baseline inspection. For transportation activities, the  
6 infrequent occurrences of elevated radiation or contamination limits in the public domain from  
7 this measurement area precluded identification of a corresponding indicator. A second PI has been  
8 proposed for future use to monitor the inadvertent release of potentially contaminated materials  
9 which could result in a measurable dose to a member of the public. These indicators will provide  
10 partial assessments of licensee radioactive effluent monitoring and offsite material release  
11 activities and were selected to identify decreasing performance prior to exceeding public  
12 regulatory dose limits.

13 **PHYSICAL SECURITY CORNERSTONE**

14 **GENERAL DESCRIPTION**

15 This cornerstone addresses the attributes and establishes the basis to provide assurance that the  
16 physical protection system can protect against the design basis threat of radiological sabotage as  
17 defined in 10 CFR 73.1(a). The key attributes in this cornerstone are based on the defense in  
18 depth concept and are intended to provide protection against both external and internal threats.  
19 To date, there have been no attempted assaults with the intent to commit radiological sabotage  
20 and, although there has been no PRA work done in the area of safeguards, it is assumed that there  
21 exists a small probability of an attempt to commit radiological sabotage. Although radiological  
22 sabotage is assumed to be a small probability, it is also assumed to be risk significant since a  
23 successful sabotage attempt could result in initiating an event with the potential for disabling of  
24 the safety systems necessary to mitigate the consequences of the event with substantial  
25 consequence to public health and safety. An effective security program decreases the risk to  
26 public health and safety associated with an attempt to commit radiological sabotage.

27 **PERFORMANCE INDICATORS**

28 Three performance indicators are used to assess licensee performance in the Physical Protection  
29 and Access Authorization Systems. The PIs were selected based on their ability to provide  
30 objective measures of performance.

31  
32 The performance of the physical protection system will be measured by the percent of the time all  
33 components (barriers, alarms and assessment aids) in the systems are available and capable of  
34 performing their intended function. When systems are not available and capable of performing  
35 their intended function, compensatory measures must be implemented. Compensatory measures  
36 are considered acceptable pending equipment being returned to service, but historically have  
37 been found to degrade over time. The degradation of compensatory measures over time, along  
38 with the additional costs associated with implementation of compensatory measures provides the  
39 incentive for timely maintenance/I&C support to return equipment to service. The percent of time  
40 equipment is available and capable of performing its intended function will provide data on the  
41 effectiveness of the maintenance process and also provide a method of monitoring equipment  
42 degradation as a result of aging that could adversely impact on reliability.

1  
2 Two performance indicators are used to measure the Access Authorization System. The  
3 performance indicators for this system will count the number of reportable events that reflect  
4 program degradations. This data is currently available and there are regulatory requirements to  
5 report significant events in the areas of Personnel Screening and FFD. The Behavior Observation  
6 significant events are captured in the FFD reporting requirements.  
7  
8  
9

## **APPENDIX D**

### **Plant Specific Design Issues**

This appendix provides additional guidance on plant specific Frequently Asked Questions and identifies resolutions to performance indicator reporting issues that are specific to individual plant designs. FAQs should be submitted as soon as possible once the Licensee and resident inspector or region have identified an issue on which there is not agreement. If the Licensee is not sure how to interpret a situation and the quarterly report is due, an FAQ should be submitted and a comment in the PI comment field would be appropriate. It is incumbent on NRC and the Licensee to work expeditiously and cooperatively, sharing concerns, questions and data in order that the issue can be resolved quickly.

#### **Plant-specific Issues**

The NEI 99-02 guidance was written to accommodate situations anticipated to arise at a typical nuclear power plant. However, uncommon plant designs or unique conditions may exist that have not been anticipated. In these cases, licensees should first apply the guidance as written to determine the impact on the indicators. Then, if the licensee believes that there are unique circumstances sufficient to warrant an exception to the guidance as written, the licensee should submit a Frequently Asked Question to NEI for consideration at a public meeting with the NRC. If the FAQ is approved, the issue will be included in Appendix D of this document as a plant-specific issue.

Some provisions in NEI 99-02 may differ from the design, programs, or procedures of a particular plant. Examples include (1) the lack of a high pressure injection system at Oyster Creek, and (2) the overlapping Emergency Planning Zones at Kewaunee and Point Beach. There are also a number of plants that perform the containment heat removal and shutdown cooling functions with multiple systems rather than with a Residual Heat Removal system. For these types of situations, licensees should submit an FAQ describing the way a particular function is performed and recommending a method for monitoring that function.

There are some provisions in NEI 99-02 that are intentionally restrictive to ensure that the NRC is informed of the condition of the plant. Such provisions include (1) no exemption of overhaul hours for support systems, (2) limited credit for operator actions to recover unavailable support systems, and (3) limited credit for actions taken to mitigate the effects of unavailability of monitored systems. A risk-informed process would apply a consistent standard of judgment to each situation to determine the appropriate unavailable hours. This provision for plant-specific exceptions will risk-inform the performance indicators using the NRC/Industry public meeting forum to apply that consistent standard of judgment.

In evaluating each request for a plant-specific exception, this forum will take into consideration factors related to the particular issue. Examples of the factors to be considered for various types of exceptions are listed below:

For exceptions to allow exclusion of unavailable hours for overhaul of support systems, the following issues may be addressed, along with any other pertinent information:

- 1
- 2 1. NRC approval through an NOED, Technical Specification change, or other means
- 3 2. results of a quantitative risk-assessment of the overhaul activity
- 4 3. the expected improvement in plant performance as a result of the overhaul
- 5 4. the net change in risk as a result of the overhaul
- 6

7 For exceptions to allow credit for operator actions to recover unavailable support systems, the  
8 following issues may be addressed, along with any other pertinent information:

- 9
- 10 1. NRC approval through an NOED, Technical Specification change, or other means
- 11 2. risk-significance of the support function(s)
- 12 3. capability to recognize the support system unavailability
- 13 4. availability of personnel to perform the recovery actions
- 14 5. means of communications between the control room and the local operators
- 15 6. frequency with which the recovery actions are performed
- 16 7. probability of successful completion of recovery actions
- 17 8. soundness of engineering analysis
- 18

19 For exceptions to allow credit for operator compensatory actions to mitigate the effects of  
20 unavailability of monitored systems, the following issues may be addressed, along with any  
21 other pertinent information:

- 22
- 23 1. NRC approval through an NOED, Technical Specification change, or other means
- 24 2. risk-significance of the monitored function(s)
- 25 3. capability to recognize the need for compensatory actions
- 26 4. availability of trained personnel to perform the compensatory actions
- 27 5. means of communications between the control room and the local operators
- 28 6. availability of compensatory equipment
- 29 7. availability of a procedure for compensatory actions
- 30 8. frequency with which the compensatory actions are performed
- 31 9. probability of successful completion of compensatory actions within the required time
- 32

## 33 Oyster Creek

34  
35 Issue: Oyster Creek does not have a high pressure coolant injection system. The function  
36 performed by the HPCI system is accomplished at the Oyster Creek station by a combination of  
37 pressure reduction using the Automatic Depressurization System (ADS) and injecting coolant into  
38 the vessel using the Core Spray System (low pressure coolant injection). The core spray system  
39 consists of two redundant trains each having redundant active components (pumps and valves).

40  
41 Resolution: For the HPCS indicator, Oyster Creek will report system availability of the Core Spray  
42 System and consider ADS as a support function required for system operability. Note: Technical  
43 Specifications for Oyster Creek require plant shutdown if ADS is inoperable.

44  
45 At this point, Oyster Creek will consider core spray as a two train system and consider similar  
46 configurations at other plants, the WANO definition, and how unavailability is reported to WANO.

## 47 Dresden Station

1  
2 Issue: At Dresden Station, the RHR function as defined in NEI 99-02 is accomplished using both  
3 the Low Pressure Coolant Injection (LPCI) and the Shutdown Cooling (SDC) Systems. LPCI  
4 performs the suppression pool heat removal function while SDC performs the reactor core decay  
5 heat removal function.

6  
7 The LPCI System has two parallel heat exchangers and the SDC System consists of three 100%  
8 capacity parallel trains. The configuration of the SDC system can be treated as two trains with one  
9 installed spare train as described in Section 2.2 of NEI 99-02.

10  
11 Resolution: Dresden is utilizing two trains of LPCI and two trains of SDC to meet the reporting  
12 requirements of NEI 99-02. The third train of SDC should be treated as an installed spare and is  
13 subject to the reporting requirements in NEI 99-02.

### 14 15 **Kewaunee and Point Beach**

16  
17 Issue: The Kewaunee and Point Beach sites have overlapping Emergency Planning Zones (EPZ).  
18 We report siren data to the Federal Emergency Management Agency (FEMA) grouped by criterion  
19 other than entire EPZs (such as along county lines). May we report siren data for the PIs in the  
20 same fashion to eliminate confusion and prevent 'double reporting' of sirens that exist in both  
21 EPZs? Kewaunee and Point Beach share a portion of EPZs and responsibility for the sirens has  
22 been divided along the county line that runs between the two sites. FEMA has accepted this, and  
23 so far the NRC has accepted this informally.

24  
25 Resolution: The purpose of the Alert and Notification System Reliability PI is to indicate the  
26 licensee's ability to maintain risk-significant EP equipment. In this unique case, each neighboring  
27 plant maintains sirens in a different county. Although the EPZ is shared, the plants do not share  
28 the same site. In this case, it is appropriate for the licensees to report the sirens they are  
29 responsible for. The NRC Web site display of information for each site will contain a footnote  
30 recognizing this shared EPZ responsibility.

### 31 32 33 **Surry, North Anna and Beaver Valley Unit 1**

34  
35 Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:

- 36  
37
- The ability of the RHR system to take a suction from the containment sump, cool the fluid,  
38 and inject at low pressure to the RCS, and
  - The ability of the RHR system to remove decay heat from the reactor during normal  
39 shutdown for refueling and maintenance.
- 40  
41  
42

43 The RHR system for Surry Units 1 & 2, North Anna Units 1& 2 and Beaver Valley Unit 1  
44 provides function 2, shutdown cooling, and does not provide for function 1, post accident  
45 recirculation cooling. Function 1, is provided by two 100% low head safety injection pumps  
46 taking suction from the containment sump and injecting to the RCS at low pressure and with the  
47 heat exchanger function (containment sump water cooling) provided by four 50% capacity

1 containment recirculation spray system pumps and heat exchangers. How should the Safety system  
2 unavailability for these units be calculated?

3  
4 Resolution: The RHR Performance Indicator should be calculated as follows. The RHR system  
5 should be counted as two trains of RHR providing decay heat removal, function 2. The low head  
6 safety injection and recirculation spray pumps and associated coolers should be counted as an  
7 additional two trains of RHR providing the post accident recirculation cooling, function 1  
8 | .Four trains should be monitored as follows:

9  
10 Train 1 (recirculation mode)

11 “A” train consisting of the “A” LHSI pump, associated MOVS and the required “A” train  
12 recirculation spray pumps heat exchangers, and MOVS.

13  
14 Train 2 (recirculation mode)

15 “B” train consisting of the “B” LHSI pump, associated MOVS and the required “B” train  
16 recirculation spray pumps, heat exchangers, and MOVS.

17  
18 Train 3 (shutdown cooling mode)

19 “A” train consisting of the “A” RHR pump, associated MOVS and heat exchanger.

20  
21 Train 4 (shutdown cooling mode)

22 “B” train consisting of the “B” RHR pump, associated MOVS and heat exchanger.

23  
24  
25 **Beaver Valley Unit 2**

26  
27 Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:

- 28
- 29 • The ability of the RHR system to take a suction from the containment sump, cool the fluid,  
30 and inject at low pressure to the RCS, and
  - 31
  - 32 • The ability of the RHR system to remove decay heat from the reactor during normal  
33 shutdown for refueling and maintenance.

34  
35 The RHR system for Beaver Valley Unit 2 provides function 2, shutdown cooling, and does not  
36 provide for function 1, post accident recirculation cooling.

37  
38 Function 1, is provided by two 100% containment recirculation spray pumps taking suction from  
39 the containment sump, and injecting to the RCS at low pressure. The heat exchanger function is  
40 provided by two 100% capacity containment recirculation spray system heat exchangers, one per  
41 train.

42  
43 How should the safety system unavailability for BVPS Unit 2 be calculated?

44  
45 Resolution: The RHR Performance Indicator should be calculated as follows. The two  
46 containment recirculation spray pumps and associated coolers should be counted as two trains of  
47 RHR providing the post accident recirculation cooling, function 1. The RHR system should be  
48 counted as two additional trains of RHR providing decay heat removal, function 2.



1 Four trains should be monitored as follows:  
2

3 Train 1 (recirculation mode)

4 Consisting of the containment recirculation spray pump associated MOVS and the required  
5 recirculation spray pump heat exchanger and MOVS.  
6

7 Train 2 (recirculation mode)

8 Consisting of containment recirculation spray pump associated MOVS and the required  
9 recirculation spray pump heat exchanger, and MOVS.  
10

11 Train 3 (shutdown cooling mode)

12 Consisting of the "A" RHR pump, associated MOVS and heat exchanger.  
13

14 Train 4 (shutdown cooling mode)

15 Consisting of the "B" RHR pump, associated MOVS and heat exchanger.  
16  
17

18 **ANO-2, Calvert Cliffs, Fort Calhoun, Millstone 2, Palisades, Palo Verde, San**  
19 **Onofre, St. Lucie, and Waterford 3**  
20

21 For CE designed NSSS systems, the functions reported under the RHR SSU performance indicator  
22 are accomplished by multiple systems. How should CE plants collect and report data for this  
23 indicator?  
24

25 Issue: The Safety System Unavailability Performance Indicator for PWR RHR monitors:  
26

27 The ability of the RHR system to take a suction from the containment sump, cool the fluid, and  
28 inject at low pressure into the RCS, and  
29

30 The ability of the RHR system to remove decay heat from the reactor during normal shutdown for  
31 refueling and maintenance.  
32

33 CE ECCS designs differ from the RHR description and typical figures in NEI 99-02. CE designs  
34 run all ECCS pumps during the injection phase (Containment Spray (CS), High Pressure Safety  
35 Injection (HPSI), and Low Pressure Safety Injection (LPSI)), and on Recirculation Actuation  
36 Signal (RAS), the LPSI pumps are automatically shutdown, and the suction of the HPSI and CS  
37 pumps is shifted to the containment sump. The HPSI pumps then provide the recirculation phase  
38 core injection, and the CS pumps by drawing inventory out of the sump, cooling it in heat  
39 exchangers, and spraying the cooled water into containment, support the core injection inventory  
40 cooling. How should CE designs report the RHR SSU Performance Indicator?  
41

42 Resolution: For the first function: "The ability of the RHR system to take a suction from the  
43 containment sump, cool the fluid, and inject at low pressure into the RCS."  
44

45 The CE plant design uses HPSI to "take a suction from the sump", CS to "cool the fluid", and  
46 HPSI to "inject at low pressure into the RCS". Due to these design differences, CE plants with this  
47 design should monitor this function in the following manner. The HPSI pumps and their suction  
48 valves are already monitored under the HPSI function, and no monitoring under the RHR PI is

1 necessary or required. The two containment spray pumps and associated coolers should be counted  
2 as two trains of RHR providing the post accident recirculation cooling.

3  
4 For the second function: "The ability of the RHR system to remove decay heat from the reactor  
5 during normal shutdown for refueling and maintenance."

6  
7 The CE plant design uses LPSI pumps to pump the water from the RCS, through the SDC heat  
8 exchangers, and back to the RCS. Due to this CE design difference, the SDC system should be  
9 counted as two trains of RHR providing the decay heat removal function.

10  
11 Therefore, for the CE designed plants four trains should be monitored, when the particular affected  
12 function is required by Technical Specifications, as follows:

13  
14 Train 1 (recirculation mode) Consisting of the "A" containment spray pump, the required spray  
15 pump heat exchanger and associated flow path valves.

16  
17 Train 2 (recirculation mode) Consisting of the "B" containment spray pump, the required spray  
18 pump heat exchanger and associated flow path valves.

19  
20 Train 3 (shutdown cooling mode) Consisting of the "A" SDC pump, associated flow path valves  
21 and heat exchanger.

22  
23 Train 4 (shutdown cooling mode) Consisting of the "B" SDC pump, associated flow path valves  
24 and heat exchanger.

25  
26 Note that required hours and unavailable hours will be determined by technical specification  
27 requirements, not "default hours."

28  
29 Reporting of RHR data should follow this guidance beginning with the second quarter 2000 data  
30 submittal. Historical data was originally reported as two trains. A change report must be submitted  
31 to provide historical data for four trains. This can be accomplished in either of two ways:

32  
33 1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2  
34 data.

35  
36 2. Recalculate and revise all historical data using this guidance.

37  
38 Provide comments with the change report to identify the manner in which the historical data has  
39 been revised.

40  
41  
42

1 **Palo Verde**

2  
3 Issue: NEI 99-02, revision 0 states "Some plants have a startup feedwater pump that requires  
4 manual actuation. Startup feedwater pumps are not included in the scope of the AFW system for  
5 this indicator." Our plants have startup feedwater pumps that require manual actuation. They are  
6 not safety related, but they are credited in the safety analysis report as providing additional  
7 reliability/availability to the AFW system and are required by Technical Specifications to be  
8 operable in modes 1, 2 and 3. They are also included in the plant PRA and are classified as high  
9 risk significant. Should these pumps be treated as third train of auxiliary feedwater for NEI 99-02  
10 monitoring purposes or does the startup feedwater pump exemption apply?  
11

12 Resolution: Based on the information provided, these particular SSCs should be considered a third  
13 train of auxiliary feedwater for NEI 99-02 monitoring purposes.  
14  
15

16 **North Anna and Surry**

17 **Continue to report PP01 in accordance with the current guidance in NEI 99-02.**  
18

19 **Indian Point 3**

20  
21 Issue: Regarding the HPSI indicator, our plant has a unique flow path for high head recirculation.  
22 If this flow path was found isolated by a manual valve, would fault exposure hours necessarily be  
23 counted, even if the main flow path was available?  
24

25 Our plant has three trains of HPSI with three intermediate pressure pumps fed by separate safety  
26 related power supplies. Our three trains share common suction supplies. For the recirculation phase  
27 of an accident, two HPSI pumps are required in the short term if the event was a small break  
28 LOCA. For a large break LOCA, the HPSI pumps are not required until we transfer to hot leg  
29 recirculation, which is required to occur between 14 and 23.4 hours after the LOCA. During high  
30 head recirculation (hot or cold leg), the HPSI suction is supplied by the output of low head pumps.  
31 We have two internal SI Recirculation pumps located in the containment that provide the primary  
32 choice for low head recirculation and for supplying the suction of the HPSI pumps. The external  
33 RHR pumps provide a backup to the internal SI Recirculation pumps for both functions. Both sets  
34 of pumps deliver flow through the RHR HXs that can then be routed to a common header for the  
35 suction of the HPSI pumps.  
36

37 In the case of a passive failure requiring the isolation of the flow path to the common HPSI suction  
38 piping, we have a unique design in that a separate flow path is installed to deliver a suction supply  
39 to just one of our three SI pumps (specifically, the 32 SI pump). This flowpath bypasses the RHR  
40 HXs and would deliver sump fluid directly from the RHR pump discharge to the suction of the 32  
41 SI pump. The internal recirculation pumps can not support this flowpath, but they can still be run  
42 for containment heat removal via recirculation spray if required. This alternate low to high head  
43 flowpath does not fit into the typical "train" design common in the industry because it is not used  
44 in the event of any active failure, and it relies on powering pumps and valves from all 3 of our  
45 EDGs. Our system is also unique in that loss of the alternate flow path is not a failure that equates  
46 to the NEI guidance. It appears that the mispositioning of a valve in the designs of the NEI  
47 guidance would cause the loss of one of two trains used for high head injection considering either

1 and active or passive failure.  
2

3 The mispositioning of the valve was reported in LER 2000-001. The LER reported a bounding risk  
4 assessment since the IPE does not model the passive failure flow path to the HHSI pumps header.  
5 The risk assessment determined that the core damage frequency (CDF) would be approximately  
6  $3E-8$  per year with a conditional CDF of approximately  $7.5E-9$  for a period of three months  
7 (approximate time of valve misposition). This is not risk significant.  
8

9 Resolution: The fault exposure hours do not have to be counted. Except as specifically stated in the  
10 indicator definition and reporting guidance, no attempt is made to monitor or give credit in the  
11 indicator results for the presence of other systems (or sets of components) that add diversity to the  
12 mitigation or prevention of accidents. The passive failure mitigation features described as  
13 supporting the high head recirculation function, while serving a system diversity function, are not  
14 included as part of the high head safety injection system components monitored for this indicator.  
15

## 16 **Grand Gulf**

17  
18  
19 Issue: Of the 43 sirens associated with our Alert Notification System, two of the sirens are located  
20 in flood plain areas. During periods of high river water, the areas associated with these sirens are  
21 inaccessible to personnel and are uninhabitable. During periods of high water, the electrical power  
22 to the entire area and the sirens is turned off. The frequency and duration of this occurrence varies  
23 based upon river conditions but has occurred every year for the past five years and lasts an average  
24 of two months on each occasion.  
25

26 Assuming the sirens located in the flood plain areas are operable prior to the flooded and  
27 uninhabitable conditions, would these sirens be required to be included in the performance  
28 indicator during flooded conditions?  
29

30 Resolution: If sirens are not available for operation due to high flood water conditions and the area  
31 is deemed inaccessible and uninhabitable by State and/or Local agencies, the siren(s) in question  
32 will not be counted in the numerator or denominator of the Performance Indicator for that testing  
33 period.  
34  
35

## 36 **Crystal River Unit 3 (CR-3)**

37  
38 Issue: CR-3 has two EF System pumps and associated piping systems that are credited for Design  
39 Basis Accidents of Loss of Main Feedwater, Main Feedwater Line Break, Main Steam Line Break,  
40 and Small Break LOCA. A design criterion for the EF System is that a maximum time limit of 60  
41 seconds from initiation signal to full flow shall not be exceeded for automatic initiation. Pumps  
42 EFP-2 (steam turbine driven) and EFP-3 (independent diesel driven) are auto-start pumps and are  
43 tested for the 60-second time criteria. EFP-3 was installed in 1999 to replace a third pump, the  
44 electric motor driven (EFP-1) pump, due to emergency diesel generator electrical loading concerns  
45 in certain accident scenarios.  
46

1 Per FSAR Section 10.5.2, "MAR [modification approval record] 98-03-01-02 installed a diesel  
2 driven Emergency Feedwater Pump (EFP-3) to functionally replace the motor driven Emergency  
3 Feedwater Pump (EFP-1) as the "A" EF Train."  
4

5 The motor driven pump does not receive an automatic start signal. The motor driven pump is  
6 interlocked with the diesel driven pump so that if the diesel driven pump is operating, EFP-1 will  
7 be tripped or its start inhibited. The motor driven pump is maintained for defense-in-depth. EFP-1  
8 can be used to transfer water from the condenser hotwell into the steam generators during a  
9 seismic event, if long term cooling is necessary. EFP-1 can be used as a backup to EFP-2 to supply  
10 EFW to the steam generators for fires in the Main Control Room, Cable Spreading Room, and  
11 Control Complex HVAC Room.  
12

13 CR-3 is reporting RROP safety system unavailability performance indicator data on the basis of  
14 two EF pumps and trains. CR-3 is not reporting on EFP-1. CR-3 design and usage of EFP-1 does  
15 not fit the NEI definition of either an "installed spare" or a "redundant extra train."  
16

17 EFP-1 is safety-related and tested. However, EFP-1 is not required to be OPERABLE in any  
18 MODE in accordance with the Improved Technical Specifications (ITS). EFP-1 cannot replace  
19 EFP-3 to meet two train EFW ITS requirements. EFP-1 is included in the PRA but is not a "risk  
20 significant" component. EFP-1 is credited in the FSAR as noted above for providing defense-in  
21 depth and maintained for potential use in certain seismic and Appendix R conditions.  
22

23 Should this be reported as a third train of AFW?  
24

25 Resolution: No, since the pump has no operability requirements in the Technical Specifications.  
26  
27

### 28 **Crystal River Unit 3 (CR-3)** 29

30 Issue: CR-3 has an independent motor driven pump and independent piping system for the  
31 Auxiliary Feedwater (AFW) System that is separate from the EF System. The AFW pump (FWP-  
32 7) and associated components are designed to provide an additional non-safety grade source of  
33 secondary cooling water to the steam generators should a loss of all main and EF occur. This  
34 reduces reliance on the High Pressure Injection/Power Operated Relief Valve (HPI/PORV) mode  
35 of long term cooling. This AFW source was added to CR-3 in 1988 in response to NRC concerns  
36 on the issue of EF reliability (Generic Issue 124).  
37

38 Per the FSAR, "The AFW source is non-safety grade and is not Class 1E powered or electrically  
39 connected to the emergency diesel generators. As such, it is not relied upon during design basis  
40 events and is intended for use on an "as available" basis only. AFW performs no safety function  
41 and there is no impact on nuclear safety if it fails to operate.....It is not environmentally qualified  
42 nor Appendix R protected.....Although the AFW source is non-safety grade it is credited by the  
43 NRC as a compensating feature in enhancing the reliability of secondary decay heat removal.  
44 Auxiliary feedwater may be used, as defense-in depth, during emergency situation when steam  
45 generator pressure has been reduced to the point where EFP-2 is no longer available or to avoid  
46 EFP-2 cyclic operation."  
47

1 FWP-7 is powered by an independent, non-safety related, diesel. FWP-7 is a manually started  
2 pump and the associated control valves are manually controlled from the Main Control Room.

3  
4 FWP-7 is not safety related.

5  
6 FWP-7 is not required by ITS to be OPERABLE in any MODE.

7  
8 FWP-7 cannot replace either EFP-2 or EFP-3 to meet two train EFW ITS requirements. CR-3  
9 design and usage of FWP-7 does not fit the NEI definition of either an "installed spare" or a  
10 "redundant extra train."

11  
12 FWP-7 is credited in the FSAR for providing defense-in depth and as an additional source non-  
13 safety grade source of secondary cooling water to steam generators.

14  
15 Should this be reported as a third train of AFW?

16  
17 Resolution: No, since the pump has no operability requirements in the Technical Specifications.  
18

## 19 20 **Indian Point 2, Indian Point 3**

21  
22 Issue: The ECCS designs for Indian Point 2 and Indian Point 3 include two safety injection  
23 recirculation pumps, the recirculation sump inside containment, piping and associated valves  
24 located inside containment, and two RHR/LHSI pumps, piping, containment sump (dedicated to  
25 RHR pumps), two RHR heat exchangers and associated valves. These two subsystems are  
26 identified in the Technical Specifications and FSAR. The RHR/LHSI system is automatically  
27 started on an SI, takes suction from the RWST as do the high head SI pumps (3), provides water in  
28 the injection phase of an accident, and is secured during the transfer to the recirculation phase of  
29 the accident. The recirculation pumps remain in standby in the injection phase and are started by  
30 operator action during switchover for the recirculation phase. The recirculation pumps (2) take  
31 suction from their dedicated sump and have the capability to feed the low head injection lines, the  
32 containment spray headers, and the suction of the high head SI pumps for high head injection. The  
33 RHR head exchangers can provide cooling for both the RHR and recirculation flowpaths. The  
34 recirculation pumps are inside containment and can not be tested during operation  
35

36 The RHR pumps perform the normal decay heat removal function during shutdown operations,  
37 and can also be aligned for post accident recirculation. However, the two redundant recirculation  
38 pumps represent the primary providers of the low head recirculation function. If a single active  
39 failure were to occur, then one recirculation pump would remain available and provides sufficient  
40 capacity to meet the core and containment cooling requirements. Only in the event of a passive  
41 failure or multiple active failures would it be necessary to align the RHR pumps for recirculation.  
42 Use of the RHR pumps for recirculation requires opening two motor operated valves aligned in  
43 series to allow suction from the containment sump.  
44

45 How should the recirculation subsystem unavailability be reported under the mitigating system PI  
46 for RHR?

47  
48 Resolution: The Safety System Unavailability Performance Indicator for RHR monitors two  
49 functions:

1  
2 The ability of the RHR system to draw suction from the containment sump, cool the fluid, inject at  
3 low pressure to the RCS, and  
4 The ability of the RHR System to remove decay heat from the reactor during normal shutdown for  
5 refueling and maintenance.  
6

7 At Indian Point Units 2 & 3, the two SI Recirculation Pumps and associated valves and  
8 components should be counted as two trains of RHR providing post accident recirculation cooling,  
9 function 1. The two RHR pumps and associated valves and components should be counted as two  
10 trains of RHR providing decay heat removal, function 2. The RHR Heat Exchangers and  
11 associated components and valves which serve both RHR and recirculation functions should be  
12 shared by an RHR and an SI Recirculation Pump train, functions 1 and 2.  
13

14 The two RHR pumps are also capable of providing backup to function 1. Except as specifically  
15 stated in the indicator definition and reporting guidance, no attempt is made to monitor or give  
16 credit in the indicator results for the presence of other systems (or sets of components) that add  
17 diversity to the mitigation or prevention of accidents. The RHR pump suction flowpath from the  
18 Containment Sump provides passive failure mitigation features which, while supporting a system  
19 diversity function, are not included as part of the RHR system components monitored for this  
20 indicator.  
21

22 Four (4) trains should be monitored as follows:  
23

24 **Train 1 (shutdown cooling mode)**

25 "A" train consisting of the "A" RHR pump, "A" RHR heat exchanger, and associated valves.  
26

27 **Train 2 (shutdown cooling mode)**

28 "B" train consisting of the "B" RHR pump, "B" RHR heat exchanger, and associated valves.  
29

30 **Train 3 (recirculation mode)**

31 "A" train consisting of the "A" SI Recirculation pump, "A" RHR heat exchanger, and  
32 associated valves.  
33

34 **Train 4 (recirculation mode)**

35 "B" train consisting of the "B" SI Recirculation pump, "B" RHR heat exchanger, and  
36 associated valves.  
37

38 The required hours for trains 1 & 2 differ from trains 3 & 4, and will be determined using existing  
39 guidelines. Reporting of RHR data should follow this guidance beginning with the first quarter  
40 2001 data submittal.  
41  
42  
43  
44

## 1 **Catawba Site**

2  
3 Issue: A recently issued FAQ for the NRC Performance Indicators Program revised the positions  
4 taken for unavailability associated with planned overhaul hours. FAQ 178 was withdrawn from  
5 NEI 99-02 and replaced with FAQ 219. The new FAQ, effective for fourth quarter reporting, adds  
6 two clarifying questions and answers to the previous FAQ 178. These two additional items are:  
7

8 Q. What is considered to be a major component for overhaul purposes?  
9

10 A. A major component is a prime mover - a diesel engine or, for fluid systems, the pump or its  
11 motor or turbine driver or heat exchangers.  
12

13 Q. Does the limitation on exemption of planned unavailable hours due to overhaul maintenance of  
14 "once per train per operating cycle" extend to support systems for a monitored system?  
15

16 A. For this indicator, only planned overhaul maintenance of the four monitored systems (not to  
17 include support systems) may be considered for the exemption of planned unavailable hours.  
18

19 At Catawba Nuclear Station, periodic testing indicated that crud and rust accumulation in the  
20 Nuclear Service Water System (NSWS) headers and piping was reducing water flow. To restore  
21 the water flow and the prevent further deterioration of the headers and piping, a refurbishment  
22 project was planned to clean the system, replace part of the piping, and rearrange certain piping  
23 access to the headers to avoid water stagnation. Since the NSWS is a shared system between both  
24 Catawba units, it was decided that the optimum time to perform this work would be while Unit 1  
25 was in a refueling outage and Unit 2 was at power. This project included both "A" and "B"  
26 redundant trains of the system and was sequenced independently during the recent Catawba  
27 Nuclear Station Unit 1 End of Cycle 12 (1EOC12) refueling outage. Approximately 8,000 feet of  
28 piping was cleaned that included 4,260 feet of 42 inch, 760 feet of 30 inch, 330 feet of 24 inch,  
29 660 feet of 18 inch, 1,935 feet of 10 inch, and 100 feet of 8 inch. Due to the extensive nature of the  
30 work performed, each train of NSWS was unavailable for approximately ten days.  
31

32 Applicable technical specifications were revised through the standard NRC approval process  
33 (reference Amendment No. 189 to FOL NPF-35 and Amendment No. 182 to FOL NPF-52  
34 approved October 4, 2000) to allow this project to be performed. These amendments allowed  
35 specific systems, including mitigating systems monitored under the NRC performance indicator  
36 program, to be inoperable beyond the normal technical specification allowable outage times (AOT)  
37 of 72 hours for up to a total of 288 hours on a one-time basis. A significant part of the justification  
38 for the license amendment request was a discussion of the risk assessment of the proposed change  
39 and the NRC concluded in the SER that the results and insights of the risk analysis supported the  
40 proposed temporary AOT extensions.  
41

42 The NSWS itself is not a monitored system under the performance indicators; however, its  
43 unavailability does affect various systems and components, many of which are considered major  
44 components by the definition contained in FAQ 219 (diesel engines, heat exchangers, and pumps).  
45 The specific performance indicators affected by unavailability of the NSWS are contained in the  
46 Mitigating Systems Cornerstone and include: Emergency AC Power System Unavailability, High  
47 Pressure Safety Injection System Unavailability, Auxiliary Feedwater System Unavailability, and  
48 Residual Heat Removal System Unavailability. If the hours that this overhaul of the NSWS made  
49 its supported systems unavailable cannot be excluded from reporting under the performance



1 indicators, it will result in Catawba Unit 2 reporting two white indicators for the 4Q2000 data.  
2 These two white indicators for Emergency AC Power System Unavailability and Residual Heat  
3 Removal System Unavailability would result in a degraded cornerstone situation as defined in the  
4 NRC Action Matrix. Additionally, since these indicators are twelve quarter averages, carrying  
5 these hours for the next three years would result in decreased margin to the white/yellow threshold  
6 and greatly increase the consequences of additional unavailable hours that might occur during that  
7 period of time.

8  
9 Based on input from NRC and NEI individuals who participated in discussions related to FAQ  
10 219, Duke Energy understands that there was a desire to eliminate exclusion of monitored systems  
11 unavailable hours caused by minor "overhaul" type activities on supporting systems. However, it  
12 seems unreasonable to require reporting of unavailable hours for situations such as this when the  
13 overhaul activities are extensive enough to have required NRC review and approval of a change in  
14 technical specifications to allow the increased AOT.

15  
16 Should this situation be counted?

17  
18 Resolution: For this plant specific situation, the planned overhaul hours for the nuclear service  
19 water support system may be excluded from the computation of monitored system unavailabilities.

20  
21 Such exemptions may be granted on a case-by-case basis. Factors considered for this approval  
22 include (1) the results of a quantitative risk assessment of the overhaul activity, (2) the expected  
23 improvement in plant performance as a result of the overhaul, and (3) the net change in risk as a  
24 result of the overhaul.

## 25 26 27 **Diablo Canyon Units 1 and 2**

28  
29 Issue: At Diablo Canyon (DC), intrusion of marine debris (kelp and other marine vegetation) at the  
30 circulating water intake structures can occur and, under extreme storm conditions result in high  
31 differential pressure across the circulating water traveling screens, loss of circulating water pumps  
32 and loss of condenser. Over the past several years, DC has taken significant steps, including  
33 changes in operating strategy as well as equipment enhancements, to reduce the vulnerability of  
34 the plant to this phenomenon. DC has also taken efforts to minimize kelp, however environmental  
35 restrictions on kelp removal and the infeasibility of removing (and maintaining removal of)  
36 extensive marine growth for several miles around the plant prevent them from eliminating the  
37 source if the storm-driven debris. To minimize the challenge to the plant under storm conditions  
38 which could likely result in loss of both circulating water pumps, DC procedurally reduces power  
39 to 25% power or less. From this power level, the plant can be safely shut down by control rod  
40 motion and use of atmospheric dump valves without the need for a reactor trip.

41  
42 Is this anticipatory plant shutdown in response to an external event, where DC has taken all  
43 reasonable actions within environmental constraints to minimize debris quantity and impact, able  
44 to be excluded from being counted under IE01 and IE02?

45  
46 Resolution: In consideration of the intent of the performance indicators and the extensive actions  
47 taken by PG&E to reduce the plant challenge associated with shutdowns in response to severe  
48 storm-initiated debris loading, the following interpretation will be applied to Diablo Canyon. A

1 controlled shutdown from reduced power (less than 25%), which is performed in conjunction with  
2 securing of the circulating water pumps to protect the associated traveling screens from damage  
3 due to excessive debris loading under severe storm conditions, will not be considered a "scram." If,  
4 however, the actions taken in response to excessive debris loading result in the initiation of a  
5 reactor trip (manual or automatic), the event would require counting under both the Unplanned  
6 Scrams (IE01) and Scrams with a Loss of Normal Heat Removal (IE02) indicators.

## 9 **South Texas Project Units 1 and 2**

11 Issue: NEI 99-02 requires the Residual Heat Removal (RHR) system to satisfy two separate  
12 functions:

- 13 • The ability to take a suction from the containment sump, cool the fluid, and inject at low  
14 pressure into the RCS
- 15 • The ability of the RHR system to remove decay heat from the reactor during a normal unit  
16 shutdown for refueling or maintenance

17  
18 These functions are completed by the Emergency Core Cooling System on most Westinghouse  
19 PWR designs. South Texas Project has a unique design for these functions completed by two  
20 separate systems with a shared common heat exchanger. How should unavailability be counted for  
21 South Texas Project?

22  
23 Resolution: Due to the unique design South Texas project, unavailability will be determined as  
24 follows:

- 25  
26 • In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low  
27 Head Safety Injection Pump and the flowpath through it's associated RHR Heat Exchanger as  
28 the hours to count for the RHR performance indicator. This equipment and flowpath satisfies  
29 the requirement to "take a suction from the containment sump, cool the fluid, and inject at low  
30 pressure into the RCS". The RHR pump does not contribute to the performance of this safety  
31 function since it can not take suction on the containment sump.
- 32 • In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR  
33 Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for  
34 the RHR performance indicator. This equipment and flowpath satisfies the requirement to  
35 "remove decay heat from the reactor during a normal unit shutdown for refueling or  
36 maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in  
37 Modes 1, 2, and 3 due to the system design. This requirement prevents the system from  
38 performing its intended cooling function until plant pressure and temperature are lowered to a  
39 value consistent with the system design.

40  
41 Overlap times when both functions/systems are required will be adjusted to eliminate double  
42 counting the same time periods.

## 43 **San Onofre**

44  
45 Issue: At our ocean plant we periodically recirculate the water in our intake structure causing the  
46 temperature to rise in order to control marine growth. Marine mollusks, if allowed to grow larger  
47 than ¾" in size, can clog the condenser and component cooling water heat exchangers. This  
48 process is carried out over a six hour period in which the temperature is raised slowly in order to  
49 encourage fish to move toward the fish elevator so they can be removed from the intake.

1 Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with  
2 warm water in the intake is less than half of the evolution. A dedicated operator is stationed for  
3 the evolution, and by procedure at any point, can back out and restore normal intake temperatures  
4 by pushing a single button to reposition a single circulating water gate. The gate is large and may  
5 take several minutes to reposition and clear the intake of the warm water, but a single button with  
6 a dedicated operator, in close communication with the control room initiates the gate closure.  
7 During this evolution, one train of service water, a support system for HPSI and RHR, is aligned  
8 to the opposite unit intake and remains fully Operable in accordance with the Technical  
9 Specifications. The second train is aligned to participate in the heat treat, and while functional,  
10 has water beyond the temperature required to perform its design function. This design function of  
11 the support system is restored with normal intake temperatures by the dedicated operator  
12 realigning the gate with a single button if needed. Gate operation is tested before the start of the  
13 evolution and restoration actions are virtually certain. Does the time required to perform these  
14 evolutions on a support system need to be counted as unavailability for HPSI and RHR?  
15  
16

17 Resolution: No. The period of heat treatment will not be considered as “unavailable” for the HPSI  
18 and RHR systems because of the utility’s actions to limit the environmental impact of heat  
19 treatments. As described in the question, the ability of safety systems HPSI and RHR to actuate  
20 and start is not impaired by these evolutions There are no unavailable hours.  
21

## 22 **Susquehanna**

23  
24 Issue: Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC)  
25 Mode, the potential for a waterhammer in the RHR piping exists for design basis accident  
26 conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to  
27 control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec  
28 surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool  
29 temperature control or surveillance testing because, as stated in the FSAR, the system’s response  
30 to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of  
31 10% is acceptable. The probability of the event of concern is 6.4 E-10.If the specified design basis  
32 accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral  
33 equipment damage that could subsequently affect the ability of the system to perform the safety  
34 function. If the time RHR is run in SPC mode must be counted as unavailability, then our station  
35 RHR system indicator will be forever white due to the number of hours of normal SPC run time  
36 (approximately 300 hours per year). This would tend to mask any other problems, which would not  
37 be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the  
38 time when RHR is operated in SPC mode for temperature control or surveillance testing?  
39

40 Resolution: No, as long as the plant is being operated in accordance with technical specifications  
41 and the updated FSAR.  
42  
43

1 **Davis Besse**  
2

3 Issue: Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate  
4 from the two trains of 100% capacity turbine-driven auxiliary feedwater pumps. The piping for  
5 the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system  
6 up to the steam generator containment isolation valves. The MDFP is not part of the original plant  
7 design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means  
8 of supplying auxiliary feedwater to the steam generators, thus improving the reliability and  
9 availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis  
10 Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for  
11 their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not  
12 been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI  
13 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered  
14 or automatically connected to the emergency diesel generators. The DB MDFP is required by the  
15 Technical Specifications to be operable in modes 1-3. However, the Tech Specs do not require the  
16 MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP  
17 is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The  
18 DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in  
19 the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP  
20 from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high  
21 risk-significant for Davis-Besse. Per the DB Tech Specs, the MDFP and both trains of turbine-  
22 driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI  
23 definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages  
24 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even  
25 though it is manually initiated? (Note: this FAQ is similar to Appendix D questions for Palo Verde  
26 and Crystal River regarding the auxiliary feedwater system)  
27

28 Resolution: Based on the information provided, this pump should be considered a third train of  
29 auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.  
30

31 **Prairie Island**  
32

33 Issue: At Prairie Island, the three safeguards Cooling Water (service water) pumps were declared  
34 inoperable for lack of qualified source of lineshaft bearing water. This required entry into  
35 Technical Specifications 3.0.c (motherhood). The plant requested and received a Notice of  
36 Enforcement Discretion (NOED) that allowed continued operation of both units until installation  
37 of a temporary modification to provide a qualified bearing water supply to two of the three pumps  
38 was complete (14 days). Compensatory measures were implemented to ensure continued  
39 availability of water to the lineshaft bearings.  
40

41 The Cooling Water System is required to mitigate design basis transients and accidents, maintain  
42 safe shutdown after external events (e.g. seismic event), and maintain safe shutdown after a fire  
43 (Appendix R). The only events for which the Cooling Water System function could have been  
44 compromised are the loss of off-site power (LOOP) and a design basis earthquake (DBE). These  
45 two events are limiting because they both involve the loss of off-site power. If off-site power  
46 continues to power the non-safeguards buses, then the Cooling Water System function is not lost.  
47

48 Our Risk Assessment determined that the initiating event frequency for a DBE during the 14 day  
49 NOED period was so low that it was not a concern. Therefore, this discussion will focus on the

1 LOOP event. The bearing water supply was not fully qualified for LOOP because the power to the  
2 automatic backwash for strainers in the system was not safeguards. The concern was that system  
3 strainers would plug eventually. However, for this initiating event, function is not lost  
4 immediately – it takes time for the strainers to plug. The time it takes is a function of river water  
5 quality. Based on an estimate of worst-case river water quality, there are 4 to 7 hours before  
6 function would be lost (strainers plug). In fact, testing around the period of the event, showed  
7 river water quality was such that the strainers did not plug after 48 hours. Given the time available  
8 there is high probability that operators could complete recovery actions before function was lost. A  
9 specific probabilistic risk assessment of the local operator actions determined that the probability  
10 of failure was less than 1%.

11  
12 The NOED was requested to preclude a two unit shutdown. As part of the request for the NOED,  
13 compensatory measures to assure that the Cooling Water System function is maintained were  
14 proposed. In summary, the compensatory measures were to:

- 15  
16 • use a hose (pressure-rated) to connect a safety related source of Cooling Water to the lineshaft  
17 bearing supply piping for a Cooling Water Pump  
18 • post a dedicated operator locally in the screenhouse near the Cooling Water Pumps  
19 • pre-stage equipment and tools in the screenhouse  
20 • place identification tags at the connection locations  
21 • train the dedicated operator(s) on the procedure for connecting the hose  
22

23 The need to implement the compensatory measures would have been identified to the Control  
24 Room operator by a loss of bearing flow alarm. As stated earlier, this condition is not expected to  
25 occur until a filter becomes plugged 4 to 7 hours after the loss of off site power. The Control Room  
26 operator would notify the dedicated operator to perform the procedure. The walkdown of the  
27 procedure determined that bearing flow could be established in less than 10 minutes. The pump is  
28 capable of operating for approximately one hour without bearing flow. When bearing flow is  
29 established, the Control Room alarm will clear, thereby giving the Control Room operator  
30 confirmation that the procedure has been performed. The procedure also required an independent  
31 verification of the bearing flow restoration within one hour of receiving the loss of bearing water  
32 flow alarm.  
33

34 The Cooling Water System is a support system and it's unavailability affects: High Pressure Safety  
35 Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2  
36 Emergency AC is cooled independent of Cooling Water). Using NEI 99-02 criteria, Prairie Island  
37 included the time that the Cooling Water Pumps were declared inoperable, approximately 300  
38 hours, as unplanned unavailability in our PI data report. This resulted in two White Indicators (one  
39 on each unit), two other systems (one per unit) on the Green/White threshold, and two systems  
40 (again, one per unit) close to the Green/White threshold. However, the cause for these Performance  
41 Indicators changing from Green to White is a direct result of the lack of qualified bearing water to  
42 the Cooling Water pumps. The lack of qualified bearing water was evaluated through the SDP and  
43 resulted in a White finding. A root cause evaluation was performed and corrective actions  
44 identified. Since the change in the performance Indicators from Green to White was a direct result  
45 of the unqualified bearing water, no additional corrective action is planned.  
46

1 This event does not fit into the guidance given in NEI 99-02. In Rev. 0, page 26, the Clarifying  
2 Notes address testing and Control Room operator actions. In Rev. 1, page 28, the Clarifying Notes  
3 only allow operator actions taken in the Control Room. We have also reviewed Catawba's FAQ  
4 254. However, their situation addressed maintenance activity results not operator action.

5  
6 Initially, unavailable hours were recorded from the time of discovery until completion of a  
7 Temporary Modification that provided a qualified bearing water supply. This resulted in counting  
8 approximately 300 unavailable hours per pump. Since the compensatory actions would have  
9 maintained the Cooling Water System function, should the unavailable hours be counted only from  
10 the time of discovery until the compensatory measures were in place?

11  
12 Resolution: Yes, the unavailable hours should be counted only from the time of discovery until the  
13 time that the compensatory measures were in place and remained in place. The actions required to  
14 restore the Cooling Water System function were simple and had a high probability of success. This  
15 is based upon the following factors:

- 16
- 17 • A probabilistic risk assessment of the local operator actions calculated less than a 1%  
18 probability of failure.
- 19 • There is control room alarm to alert the Control Room operator of the need for the  
20 compensatory measures.
- 21 • There are at least two means of communication between the Control Room and the local  
22 operator.
- 23 • Recovery action for each pump was simple - connect a hose to two fittings and position two  
24 valves.
- 25 • Time to complete the recovery action was estimated to be about 10 minutes, based on walk-  
26 throughs. Failure to successfully complete the recovery action was not expected to preclude the  
27 ability to make additional attempts at recovery.
- 28 • A dedicated operator was stationed in the area to complete the recovery action.
- 29 • The operator had a procedure and training for accomplishing the recovery action.
- 30 • All necessary equipment for recovery action was pre-staged and the fittings and valves were  
31 readily accessible.
- 32 • Indication of successful recovery actions was available locally and in the Control Room.

33  
34 Note: This FAQ is specific to the plant and the circumstances, which included NRC approval of  
35 compensatory measures and an SDP review. Other licensees should not unilaterally apply this  
36 FAQ result, but should submit a plant specific FAQ.

## 37 38 **Ginna**

39  
40 Issue: NEI 99-02 states (p 26) that Planned Unavailable Hours include "...testing, unless the test  
41 configuration is automatically overridden by a valid starting signal, or the function can be  
42 promptly restored either by an operator in the control room or by a dedicated operator stationed  
43 locally for that purpose." Also,(p 40) The control room operator must be "...an operator  
44 independent of other control room operator immediate actions that may also be required.  
45 Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do  
46 not have an auto-start signal; they are required to be manually started by an operator within 10  
47 minutes. Should this be counted as unavailable time?  
48

1 Resolution: No. The PI should not count them since this is an NRC approved design.  
2  
3

## 4 **Ginna**

5

6 Issue: Page 62 of NEI 99-02, Rev 0, states in part: "...the isolation valve(s) between the RHR  
7 system and the HPSI pump suction is the boundary of the HPSI system." Ginna Station's system  
8 design has three MOV's meeting this definition: 857A and 857C (two valves in series from the A  
9 RHR train) and 857B from the B RHR train. Each RHR train is a 100% train. MOVs 857 A and  
10 857C are in parallel with 857B. If Ginna Station was to have a fault exposure to one of these three  
11 valves, it would not prevent any of the three HPSI pumps from performing its function of taking a  
12 suction from the containment emergency sump. Rather, a fault exposure to one of these three  
13 valves would prevent its associated RHR train from supplying a suction from the containment  
14 emergency sump to any of the three HPSI pumps. Thus, the boundary between the RHR and HPSI  
15 systems needs to be adjusted for Ginna Station.  
16

17 Resolution: The down-stream side of the isolation valve(s) between the RHR system and the HPSI  
18 pump suction is the boundary of the HPSI system for Ginna Station. The isolation valve(s)  
19 themselves will be in the RHR system and be associated with their respective RHR train.  
20

## 21 **Diablo Canyon**

22

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

28 Due to its location on the Pacific coast, Diablo Canyon is subject to kelp/debris intrusion at the  
29 circulating water intake structure under extreme storm conditions. If the rate of debris intrusion is  
30 sufficiently high, the traveling screens at the intake of the main condenser circulating water pumps  
31 (CWP's) become overwhelmed. This results in high differential pressure across the screens and  
32 necessitates a shutdown of the affected CWP(s) to prevent damage to the screens.

33 To minimize the challenge to the plant should a shutdown of the CWP(s) be necessary in order to  
34 protect the circulating water screens, the following operating strategy has been adopted:

- 35 • If a storm of sufficient intensity is predicted, reactor power is procedurally curtailed to 50% in  
36 anticipation of the potential need to shut down one of the two operating CWP's. Although the  
37 plant could remain at 100% power, this anticipatory action is taken to avoid a reactor trip in the  
38 event that intake conditions necessitate securing a CWP. One CWP is fully capable of  
39 supporting plant operation at 50% power.
- 40 • If one CWP must be secured based on adverse traveling screen/condenser differential pressure,  
41 the procedure directs operators to immediately reduce power to less than 25% in anticipation of  
42 the potential need to secure the remaining CWP. Although plant operation at 50% power could  
43 continue indefinitely with one CWP, this anticipatory action is taken to avoid a reactor trip in  
44 the event that intake conditions necessitate securing the remaining CWP. Reactor shutdown  
45 below 25% power is within the capability of the control rods, being driven in at the maximum  
46 rate, in conjunction with operation of the atmospheric dump valves.

1 • Should traveling screen differential pressure remain high and cavitation of the remaining CWP  
2 is imminent/occurring, the CWP is shutdown and a controlled reactor shutdown is initiated.  
3 Based on anticipatory actions taken as described above, it is expected that a reactor trip would  
4 be avoided under these circumstances.

5 How should each of the above power reductions (i.e., 100% to 50%, 50% to 25%, and 25% to  
6 reactor shutdown) count under the Unplanned Power Changes PI?

7  
8 Resolution: Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%,  
9 that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours  
10 in advance. Neither of these anticipatory power reductions would count under the Unplanned  
11 Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the  
12 main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power  
13 change since such a reduction is forced and can therefore not be considered anticipatory.

## 14 **D.C. Cook**

15  
16  
17 Issue: The definition for the Reactor Coolant System (RCS) Leakage performance indicator is  
18 "The maximum RCS Identified Leakage in gallons per minute each month per the technical  
19 specification limit and expressed as a percentage of the technical specification limit."

20  
21 Cook Nuclear Plant Unit 1 and 2 report Identified Leakage since the Technical Specifications have  
22 a limit for Identified Leakage with no limit for Total Leakage. Plant procedures for RCS leakage  
23 calculation requires RCS leakage into collection tanks to be counted as Unidentified Leakage due  
24 to non-RCS sources directed to the collection tanks. All calculated

25 leakage is considered Unidentified until the leakage reaches an administrative limit at which point  
26 an evaluation is performed to identify the leakage and calculate the leak rate. Consequently,  
27 Identified Leakage is unchanged until the administrative limit is reached. This does not allow for  
28 trending allowed RCS Leakage. The procedural requirements will remain in place until plant  
29 modifications can be made to remove the non-RCS sources from the drain collection tanks. What  
30 alternative method should be used to trend allowed RCS leakage for the Barrier Integrity  
31 Cornerstone?

32  
33 Resolution: Report the maximum RCS Total Leakage calculated in gallons per minute each month  
34 per the plant procedures instead of the calculated Identified Leakage. This value will be compared  
35 to and expressed as a percentage of the combined Technical Specification Limits for Identified and  
36 Unidentified Leakage. This reporting is considered acceptable to provide consistency in reporting  
37 for plants with the described plant configuration.

## 38 **Calvert Cliffs**

39  
40  
41 Issue: Calvert Cliffs monitors the Safety System Unavailability Performance Indicator for PWR  
42 RHR using the guidance in NEI 99-02 provided for Combustion Engineering (CE) designed plants.



1 When a unit is in Mode 6 and with water level in the Refueling Pool, at 23 feet or more above the  
2 top of the irradiated fuel assemblies seated in the reactor vessel, the Technical Specifications only  
3 require one Shutdown Cooling (SDC) loop to be operable and in operation. Unlike most of the  
4 other CE designed plants, at Calvert Cliffs, the two SDC loops on each unit have a common  
5 suction piping line. As a result, to permit required local leak rate testing and other maintenance  
6 activities on this common suction line, both trains of SDC would be taken out-of-service.  
7 Recognizing this plant specific design feature, the Technical Specifications specifically allow this  
8 required testing and maintenance to be performed without entering the action statements while the  
9 plant is in this particular condition. While the SDC trains are unavailable, decay heat is removed  
10 by natural convection to the volume of water in the Refueling Pool. Calvert Cliffs Technical  
11 Specifications Bases indicates that “a minimum refueling water level of 23 feet above the  
12 irradiated fuel assemblies seated in the reactor vessel provides an adequate available heat sink.” In  
13 this situation, should unavailable hours be counted against the SDC loop given the plant design at  
14 Calvert Cliffs?

15  
16 Resolution: It is appropriate to not count unavailable hours for the above-described situation at  
17 Calvert Cliffs. Removing the SDC suction headers from service for the circumstances specifically  
18 allowed by the applicable Technical Specification is a reflection of plant design rather than an  
19 indication of adequate component or train maintenance practices. Unavailable hours would be  
20 counted while operating in accordance with this applicable Technical Specification if a situation  
21 occurred that required entering the action statement.

## 22 **Nine Mile Point**

23  
24 Issue: Some plants are designed to have a residual transfer of the non-safety electrical buses from  
25 the generator to an off-site power source when the turbine trip is caused by a generator protective  
26 feature. The residual transfer automatically trips large electrical loads to prevent damaging plant  
27 equipment during reenergization of the switchgear. These large loads include the reactor  
28 feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual  
29 transfer is completed the operators can manually restart the pumps from the control room. The  
30 turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be  
31 counted as a scram with a loss of normal heat removal?  
32

33 Resolution: No. In this instance, the electrical transfer scheme performed as designed following a  
34 scram and the residual transfer. In addition the pumps can be started from the control room.  
35 Therefore, this would not count as a scram with a loss of normal heat removal.  
36  
37

## 38 **Turkey Point**

39  
40 Issue: Turkey Point's Unit 3 Emergency Diesel Generators (EDGs) are air-cooled, using very large  
41 radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG  
42 building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant  
43 decided to replace them. Replacing all eight radiator assemblies is a labor-intensive  
44 activity, that requires that sections of the missile shield grating be removed, heat deflecting  
45 cowling be cut away, and support structures be built above and around the existing radiators to  
46 facilitate the fitup process. This activity could not have been completed within the standard 72

1 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license  
2 amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02  
3 allows for the exclusion of planned overhaul maintenance hours from the EAC performance  
4 indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the  
5 majority of the cooling system, for which an extended AOT was granted, qualify as overhaul  
6 maintenance?  
7

8 Resolution: In this specific case, yes, for three reasons: (1) that activity involves disassembly and  
9 reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the  
10 activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine  
11 alone (every 12 years); and (3) the NRC specifically granted an AOT extension for this activity  
12 supported by a quantitative analysis  
13

### 14 **D.C. Cook**

15

16 Issue: Safety System Unavailability (SSU) indicators for Cook Units 1 and 2 are not calculated due  
17 to insufficient reported data. The SSU indicators and performance thresholds require 12 quarters  
18 of operational data to calculate unavailability and determine safety system performance. Cook Unit  
19 1 returned to service December 18, 2000, after a 39-month forced outage and Unit 2 on June 25,  
20 2000, after a 33-month forced outage. SSU indicator data has been reported for both units since  
21 the second quarter of the year 2000. Historical data was not reported since unavailability was not  
22 monitored during the extended outages. Cook Nuclear Plant (CNP) wants the SSU indicators to  
23 reflect actual safety system performance and have the indicators calculated with submitted data  
24 vice waiting until April 2003 for 12 quarters of data to be collected. What actions can be taken to  
25 have calculated SSU indicators and appropriately account for the effects of a T/2 fault exposure?  
26

27 Resolution: Submit a change report "zero-summing" the time prior to the 2Q2000 to provide for an  
28 indicator calculation. If a T/2 fault exposure occurs prior to obtaining 12 quarters of operational  
29 data, then the time would be reported in the comment field but not calculated for the SSU  
30 indicator. The inspection and SDP process would then evaluate the T/2 fault exposure.

**APPENDIX E**

**Frequently Asked Questions**

1  
2  
3  
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6  
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8

The following table identifies where NRC approved FAQs were incorporated in the text. Not all FAQs have been directly included in the text. (For example, some FAQs were withdrawn; others asked questions whose answer was already in the text; and some asked questions not directly related to the PI Guideline.)

Section	FAQs
Introduction	
Unplanned Scrams per 7,000 Critical Hours	275(no change needed)
<b>Unplanned</b> Scrams with Loss of Normal Heat Removal	264,286,287
Unplanned Power Changes per 7,000 Critical Hours	270, 277(no change needed)
Safety System Unavailability	257, 260(no change needed), 261, 265, 271, 272, 280, 285
Safety System Functional Failure	
Reactor Coolant System Specific Activity	262, 288(no change needed)
Reactor Coolant System Leakage	
EP Drill/Exercise Performance	
ERO Drill Participation	
Alert and Notification System Reliability	
Occupational Exposure Control Effectiveness	
RETS/ODCM Radiological Effluent Occurrence	
Protected Area Security Equipment Performance Index	269(no change needed), 279
Personnel Screening Program Performance	
Fitness-For-Duty/Personnel Reliability Program Performance	
Appendix D	258, 266, 267, 268, 273, 274, 278, 281, 282, 283, 284
Withdrawn	276

9