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

June 2, 2001

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

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

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON MAY 31, 2001

On May 31, 2001a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss and review the initial implementation of the revised reactor oversight process. An agenda, attendance list, and information exchanged at the meeting are attached. The following dates were established for future meetings: July 12, 2001 and August 15, 2001.

Attachments:

1. List of Participants
2. Agenda
3. Industry Trends Data
4. Frequently Asked Questions, Log. 15, 16, 19, 21
5. IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
6. NRC RISK 2000-21 Pilot PI Experience as of May 31, 2001
7. Fault Exposure Hour Study Charts and Information
8. Summary of the SSU Focus Group Meeting and Key Issues

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NAME:	ASpector AKS		A. Madison			
DATE:	6/2/01		6/ /01			

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NRC Public Meeting
Reactor Oversight Process
List of Participants
May 31, 2001

S. Ferrel, TVA
D. Hickman, NRC.
A. Madison, NRC
M. Johnson, NRC
M. Satorius, NRC
D. Olsen, Dominion
M. Taylor, Exelon
S. Floyd, NEI
Wade Warren, SNC
T. Houghton, NEI
R. Ritzman, PSEG
J. Sumpter, NPPD
P. Loftus, COMED
D. R. Robinson, Nebraska Public Power
C. See, NRR
R. Frahm, NRC
L. Whitney, NRC
D. Anderson, NMC
J. Caves, CP&L
S. Sanders, NRC
C. Seaman, APS
J. McIndine, NEI
A. Halliday, Entergy
B. Smith, NRC
R. Mathews
T. Reis, NRC
P. Baranowsky, NRC
H. Hamzehee
G. Walsh, INPO
J. Weil, McGraw Hill

Attachment 1

May 31, 2001

ROP Public Meeting

Agenda

8:00am	Welcome & Introductions	Alan Madison
8:10am	Fire Protection Handout	Peter Koltay
8:15am	Web Changes	Ron Frahm Conchita See
9:00am	Industry Trends	Tom Boyce
9:45am	Break	
10:00am	Conference Call re IE PI Pilot w/Regions (301)231-5539 Code:6730#	Leon Whitney
12 Noon	Lunch	
1:00pm	Safeguards Update & FAQs	Al Tardif
1:30pm	SSU Working Group Update	Don Hickman
2:00pm	Prairie Island FAQ Conference Call (301)231-5539 Code:8444#	
2:45pm	Break	
3:00pm	FAQs	
4:00pm	Adjourn	

Attachment 2

ATTACHMENT 3

Industry Trends Data

INDUSTRY TRENDS

Status & Schedule

- Information Paper to inform Commission of program development & results to date
- SECY Paper in concurrence
- AARM – 6/26-28 in Region II offices in Atlanta, GA

Background

- Industry trends program helps assess whether nuclear industry is maintaining safety and can enhance public confidence
- Improving industry trends cited as a reason for revised ROP
- Strategic Plan Performance Measure of "No Statistically Significant Adverse Industry Trends in Safety Performance"
  - Reported to Congress annually - input for Green Book in early January
  - Responsibility assigned to NRR from RES in late 2000
  - Used indicators from AEOD and Accident Sequence Precursor (ASP) Program
- AEOD PIs published in various NUREGs; ASP reported in annual SECYs and NUREG/CRs

Objectives of Industry Trends Program

- Collect and monitor industry-wide data to ensure that operating reactor safety performance is maintained by the nuclear industry and to provide feedback for ROP
- Assess the significance and causes for any statistically significant adverse industry trends; determine if they represent an actual degradation in overall industry safety performance, and respond appropriately to any safety issues
- Enhance public confidence by communicating industry-level information to Congress and other stakeholders in an effective and timely manner

Concepts and Approach

- Leveraged existing programs (AEOD indicators, ROP PIs, ASP program, Operating Experience in RES)
- Indicators organized using the ROP regulatory framework of 7 cornerstones; may use additional indicators beyond those monitored by ROP (i.e., initiating events such as SGTRs)
- Trends on quantitative data; long term data vice short term ($\leq$4 years)
- Statistically significant adverse trend must be evaluated for significance; evaluation of contributing factors to determine if a safety issue
- Data review, inspections and event analysis (ASP analysis, significant events, abnormal occurrences) supplement the indicators
- Assess adverse trends by strategic area (Reactor Safety, Radiation Protection, Safeguards)

Development Efforts to Date

- Steering Committee (SES branch chiefs of IIPB, PRAB, REXB, RES/OERAB)
- Working groups for AEOD PIs, ROP PIs, RES Operating Experience

Attachment 3

- Technical Assistance User Need Memorandum signed out to RES
- Transitioned contract for AEOD PIs from RES to NRR
- ASP program results integrated
- Contractor development of statistical methods for adverse trends
- Web page under development
- High level concepts briefed at industry meetings with NEI; additional feedback desired

Statistical Approach and Analyses of Data

- Statistical significant fit of a trendline to each indicator
- Downward or flat trendlines = no adverse trend => done
- Upward trendlines or single point above prediction limit = adverse => initiate evaluation
- Outliers => no industry trend; plant-specific actions possible
- No outliers => expanded review of data and applicable LERs, inspection results
- Enhancements in the future using risk models to establish significance of trends in indicators, experience gained with indicators, and feedback from external stakeholders

Agency Response

- Generic communication process (SECY-99-143); process provides for early engagement with industry; assessment of issues; if appropriate, agency and industry responses could include industry initiatives, requests for information, generic safety inspections
- Results of investigations and actions reviewed at AARM

Communications

- Publish industry indicators on NRC web site as they are developed - quarterly updates
- Annual report to Commission in SECY in February
- Annual report to Congress in NRC Performance and Accountability Report in March
- Report to Congress will use ex-AEOD indicators and ASP results through FY02; Controlled changes to indicators and performance measure possible for FY03.

Results to Date

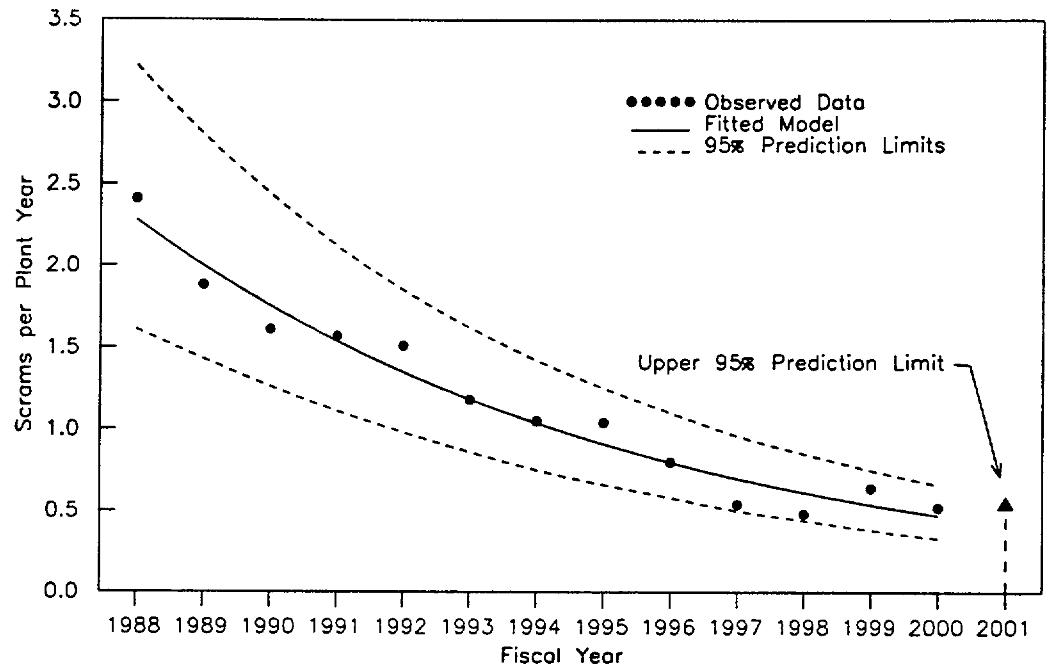
- No statistically significant adverse industry trends in safety performance identified
- Ex-AEOD indicators show flat or downward trendlines
- ASP program shows downward trends (SECY-01-0034)
- Insufficient data (<4 years) on ROP indicators for long term trending (no issues identified by inspection of short term data)

Future Development

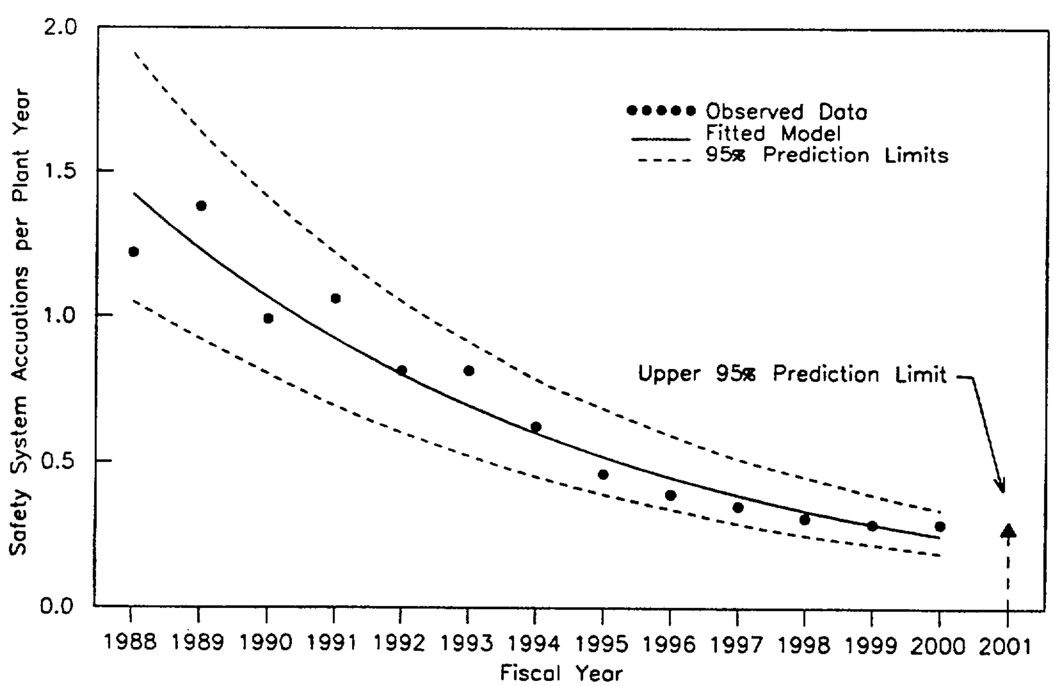
- Commitment to Annual SECY on Industry Trends at time of AARM
- RES update of initiating events data in NUREG-5750 within 1 year; update of data for reliability and special studies within 2-3 years
- Industry indicators will follow ongoing ROP PI improvements (pilot programs, RBPIs)
- Risk-informed method to assess safety significance of trends in individual indicators
- Common reporting of data for NRC and INPO/EPIX

1. Ex-AEOD Indicators (long-term graphs only)

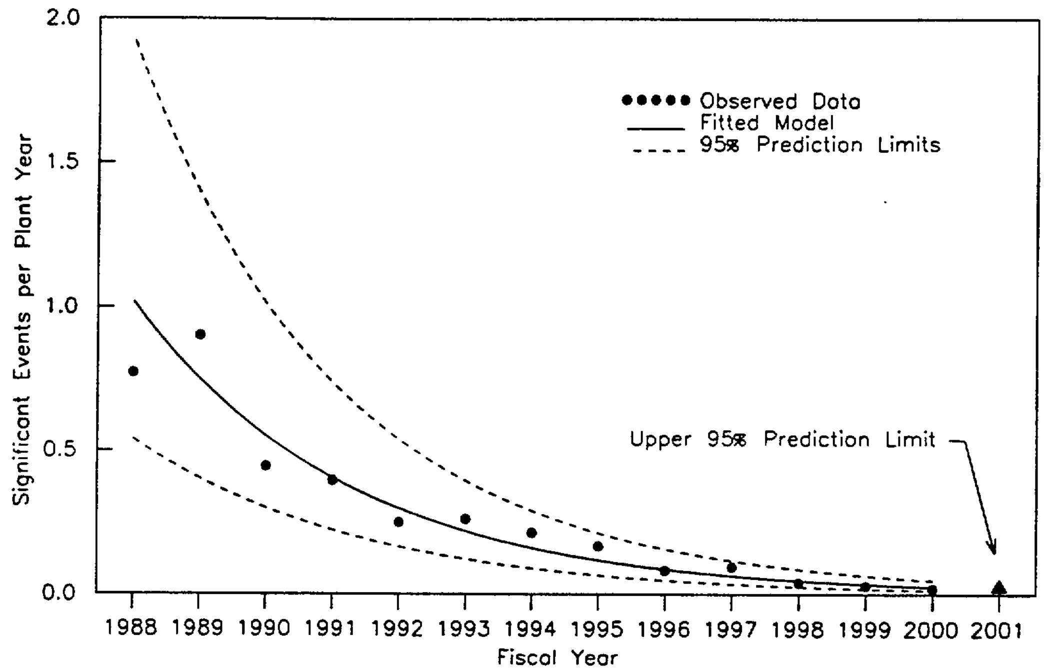
Automatic Scrams While Critical



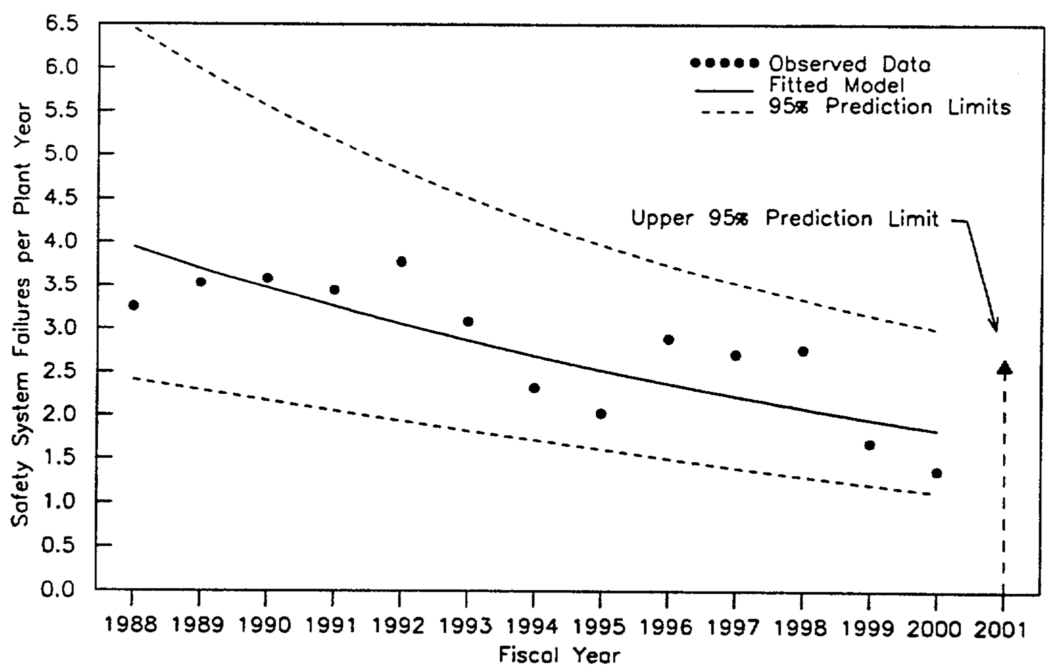
Safety System Actuations



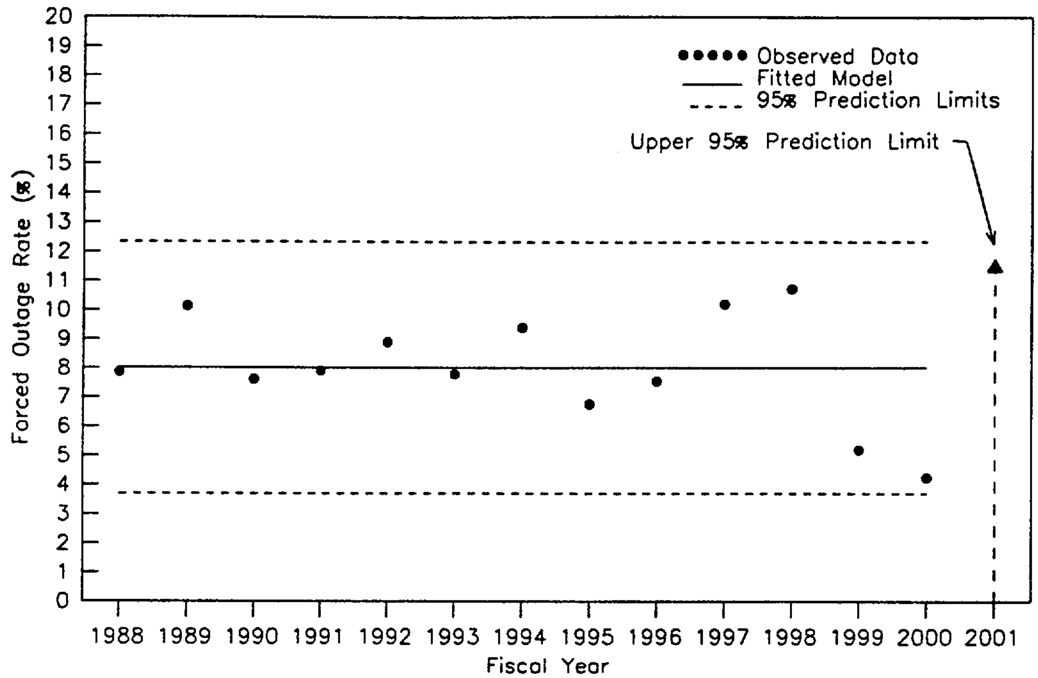
Significant Events



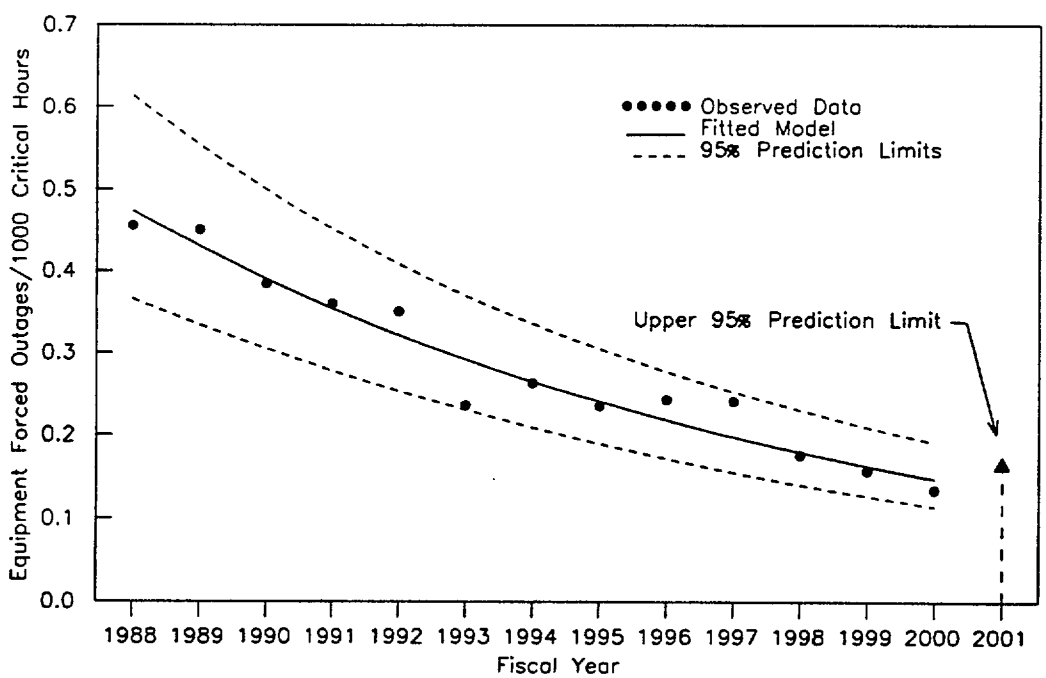
Safety System Failures



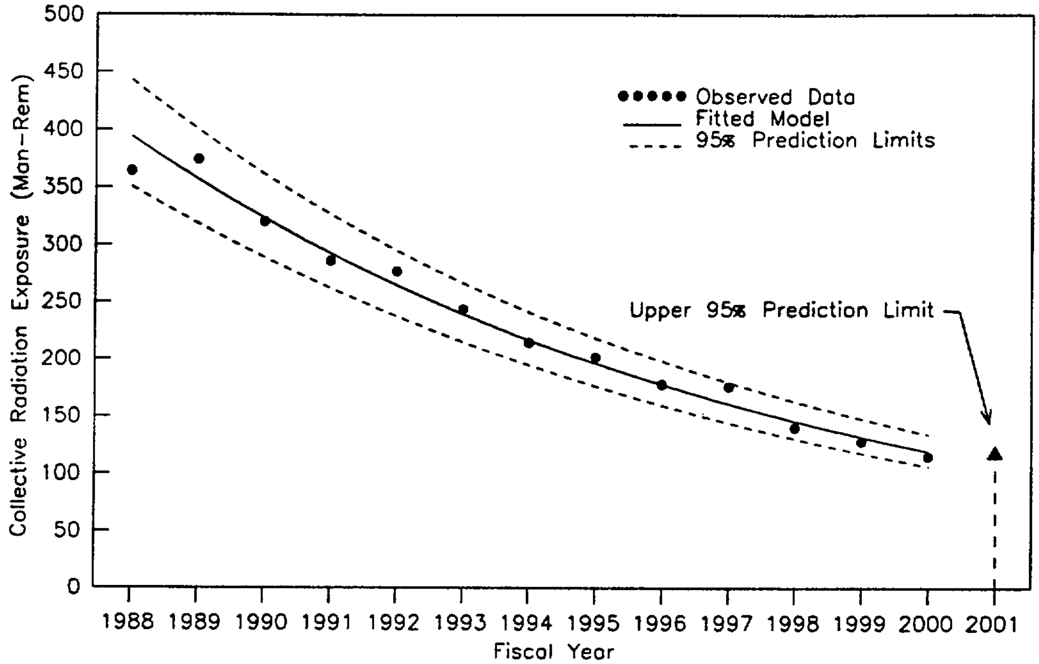
Forced Outage Rate



Equipment Forced Outages



Collective Radiation Exposure

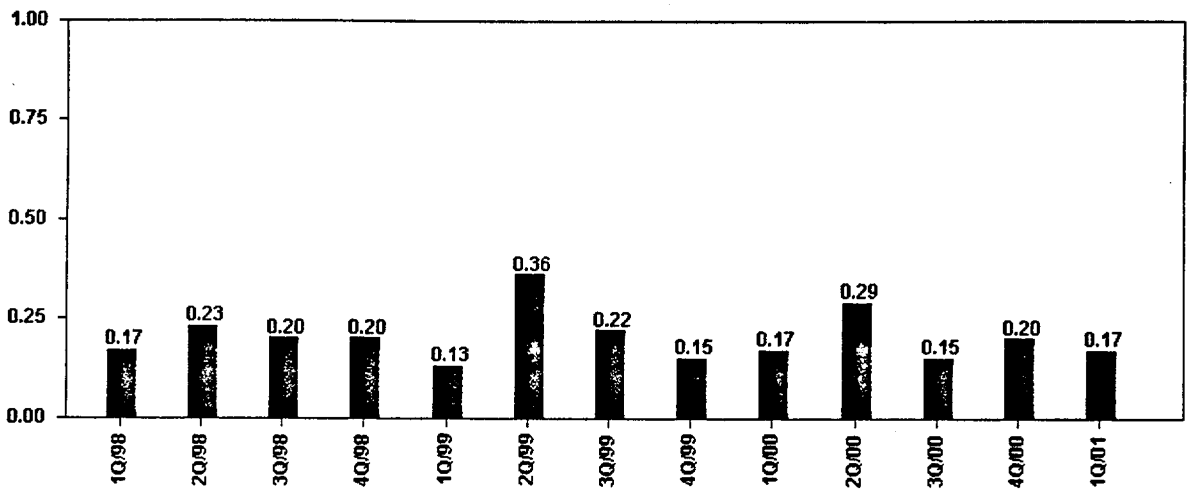


2. ROP Performance Indicators (Short-term graphs only)

Initiating Events Cornerstone - Industry Trends

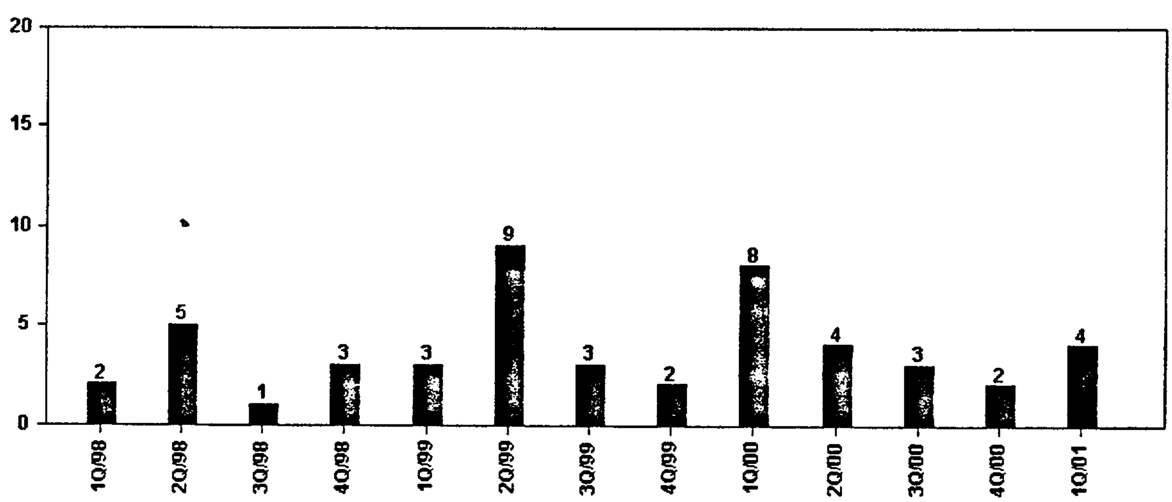
1Q/2001

Unplanned Scrams per 7000 Annual Critical Hrs



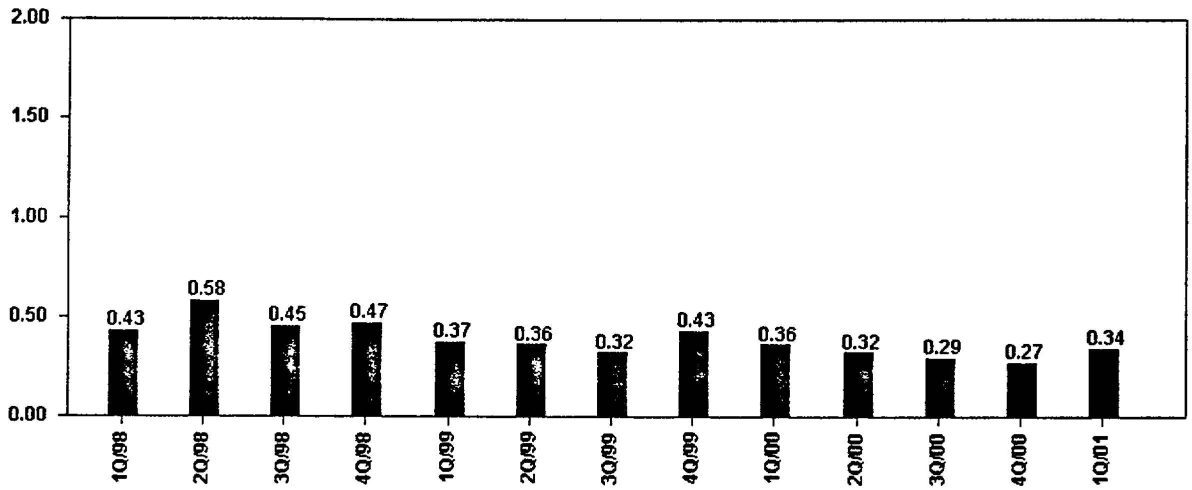
Descriptions

Scrams with Loss of Normal Heat Removal



Descriptions

Unplanned Power Changes per 7000 Annual Critical Hrs



Descriptions

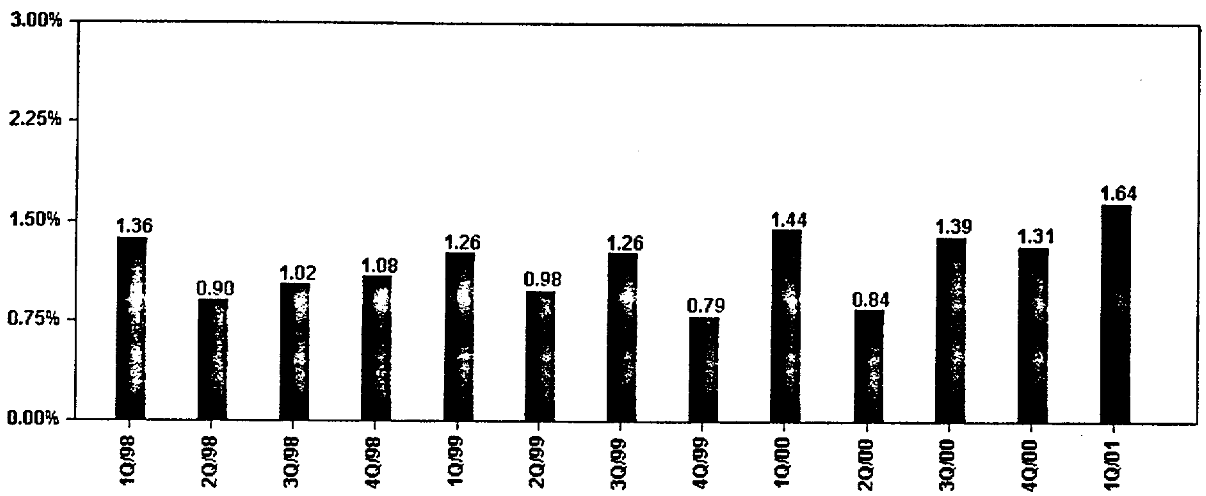
Mitigating Systems Industry Trends

Last Modified: May 20, 2001

Mitigating Systems Cornerstone - Industry Trends

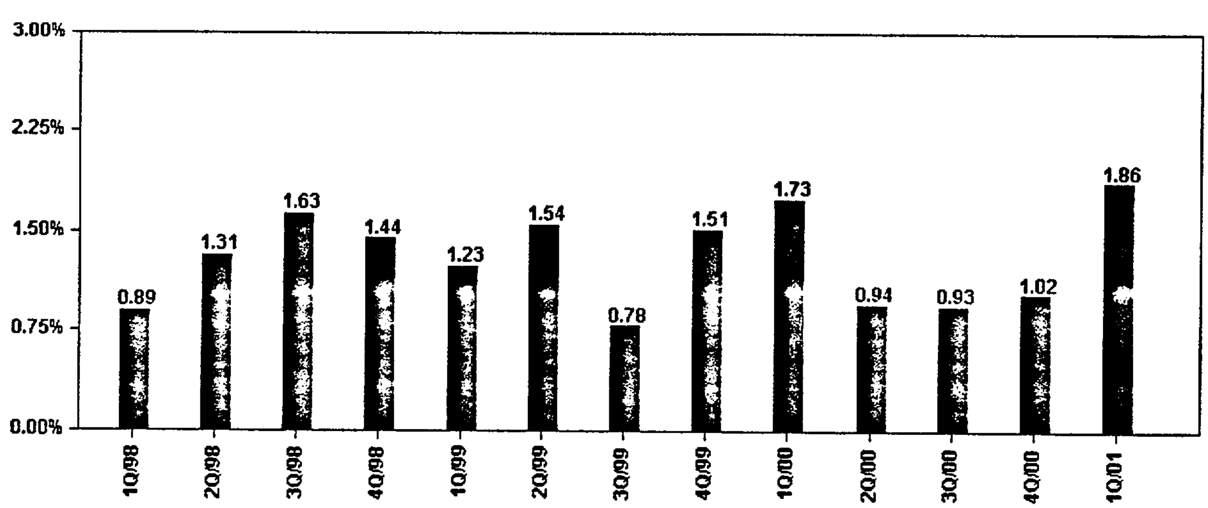
1Q/2001

Safety System Unavailability, Emergency AC Power



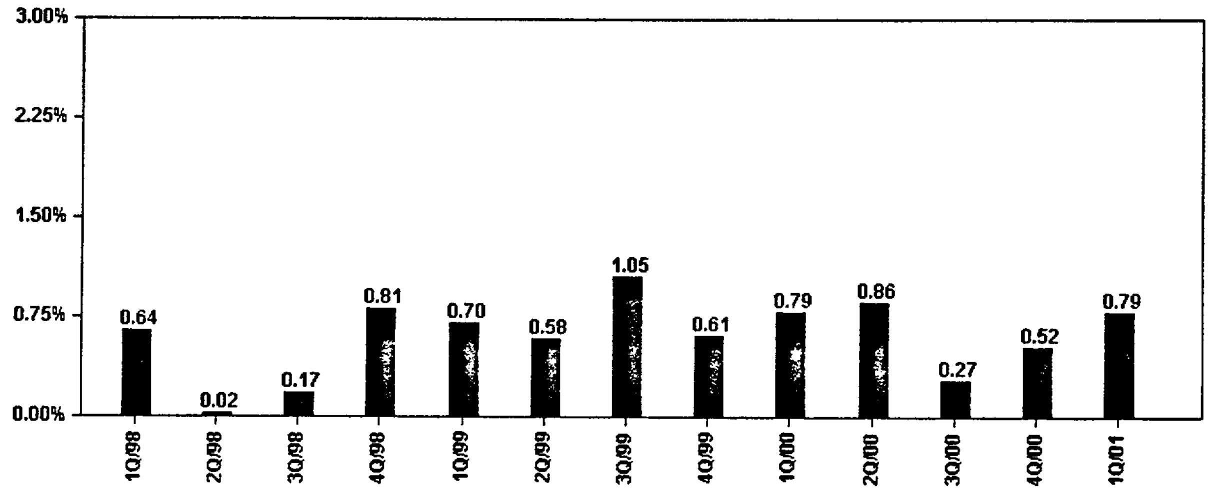
Descriptions

Safety System Unavailability, High Pressure Injection System (HPCI)



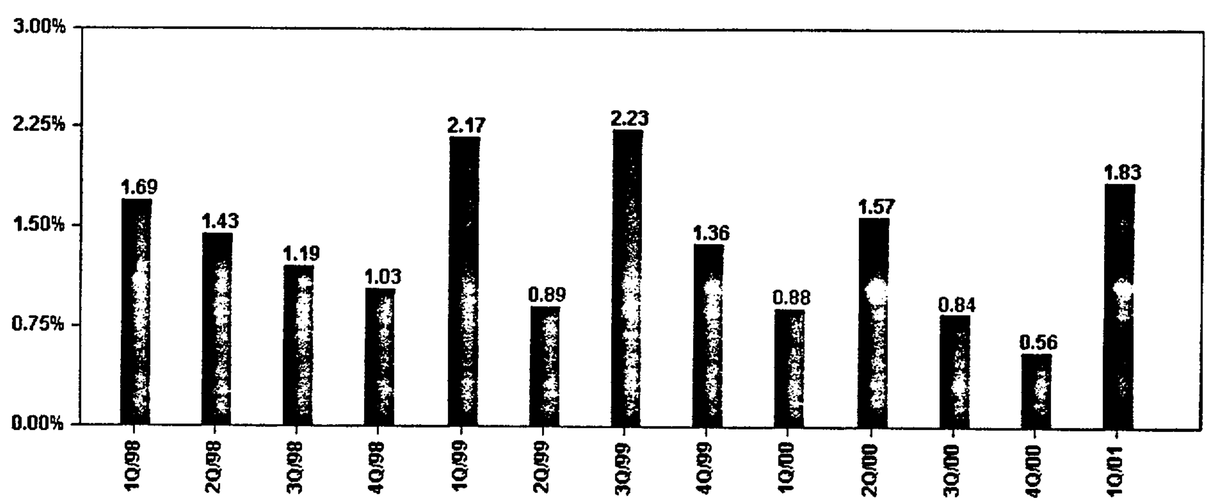
Descriptions

Safety System Unavailability, High Pressure Injection System (HPCS)



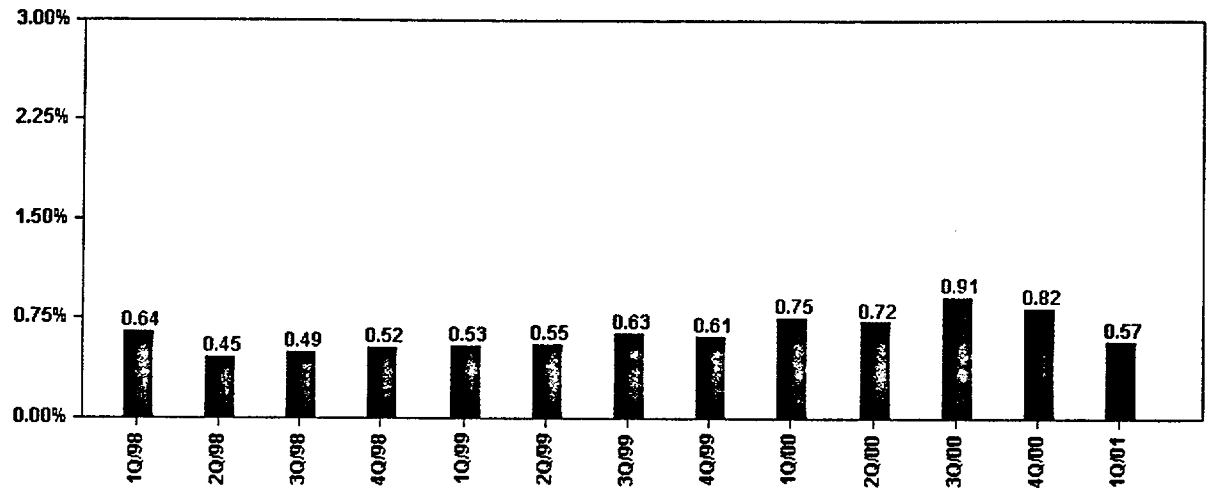
Descriptions

Safety System Unavailability, Heat Removal System (RCIC)



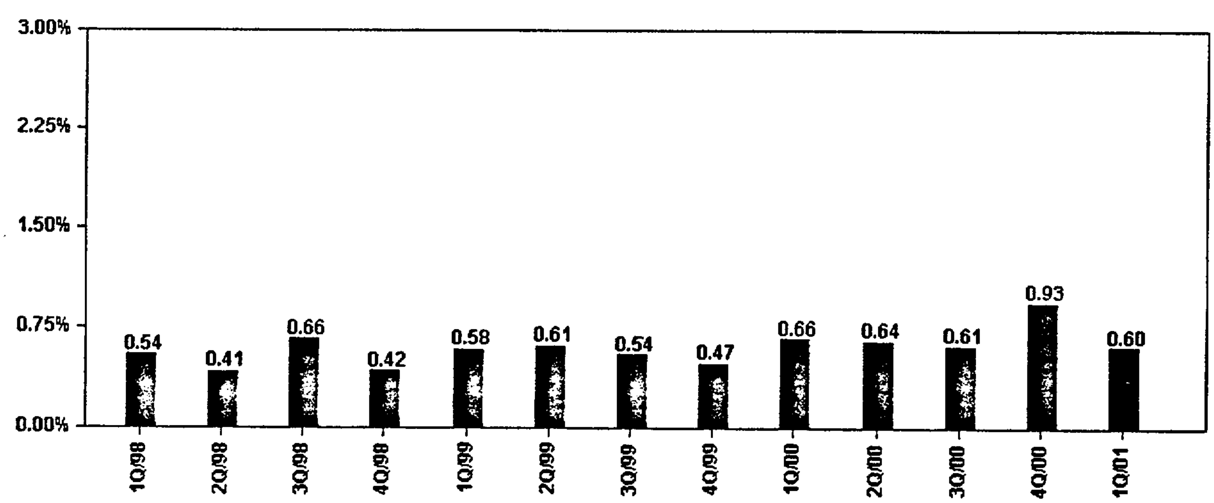
Descriptions

Safety System Unavailability, Heat Removal System (AFW)



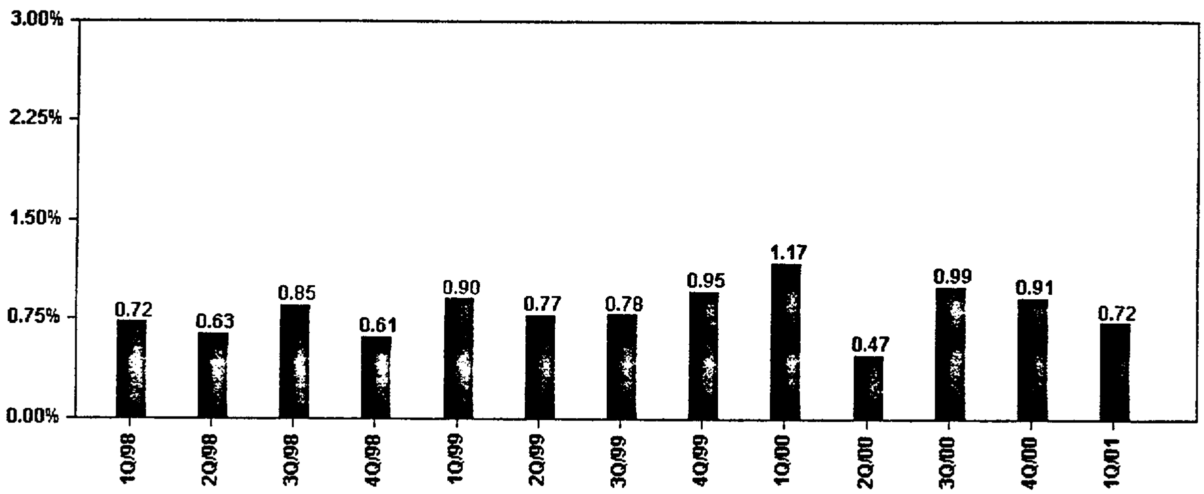
Descriptions

Safety System Unavailability, Residual Heat Removal System (PWR)



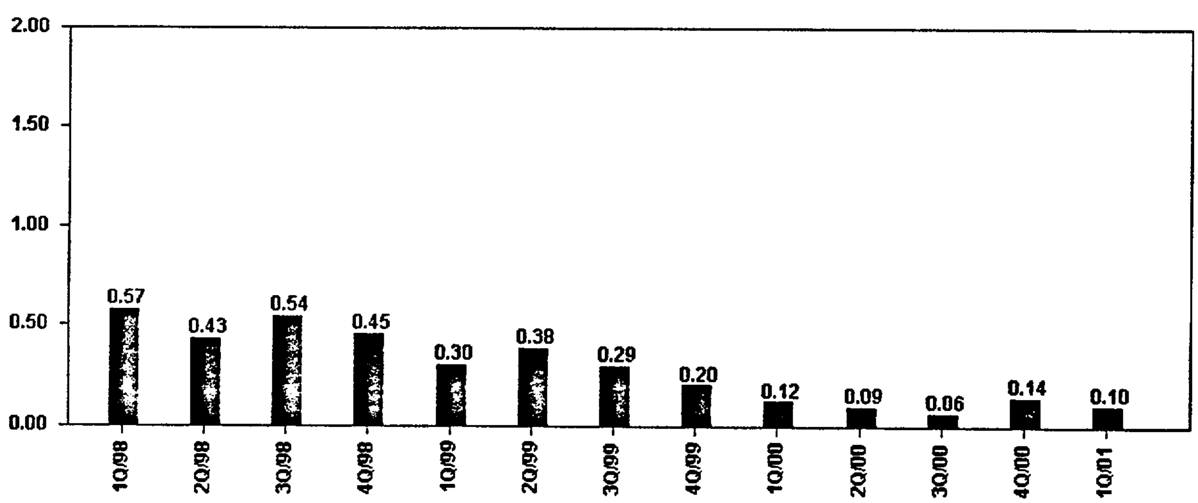
Descriptions

Safety System Unavailability, Residual Heat Removal System (BWR)



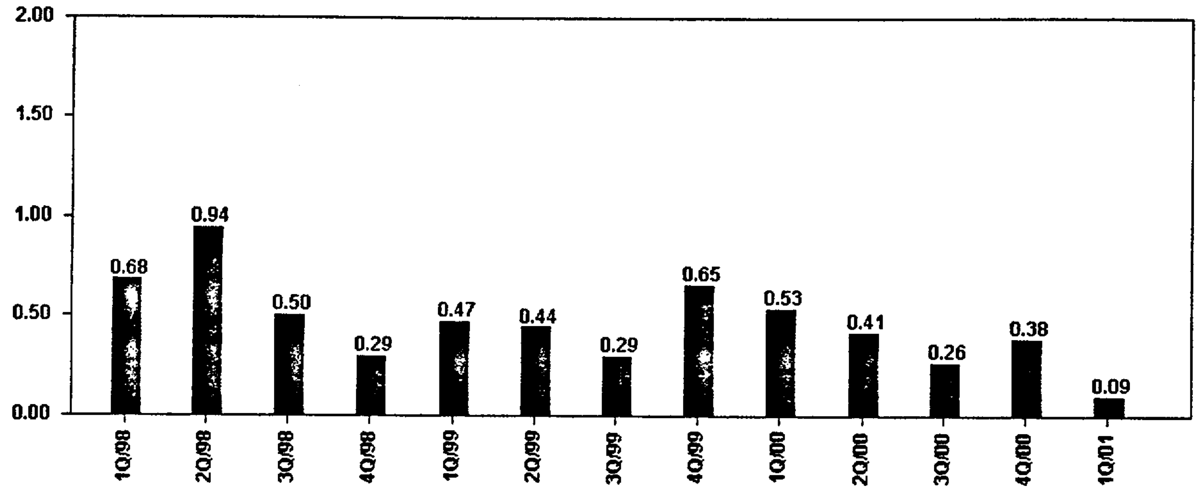
Descriptions

Safety System Functional Failures (PWR)



Descriptions

Safety System Functional Failures (BWR)



Descriptions

Initiating Events Industry Trends

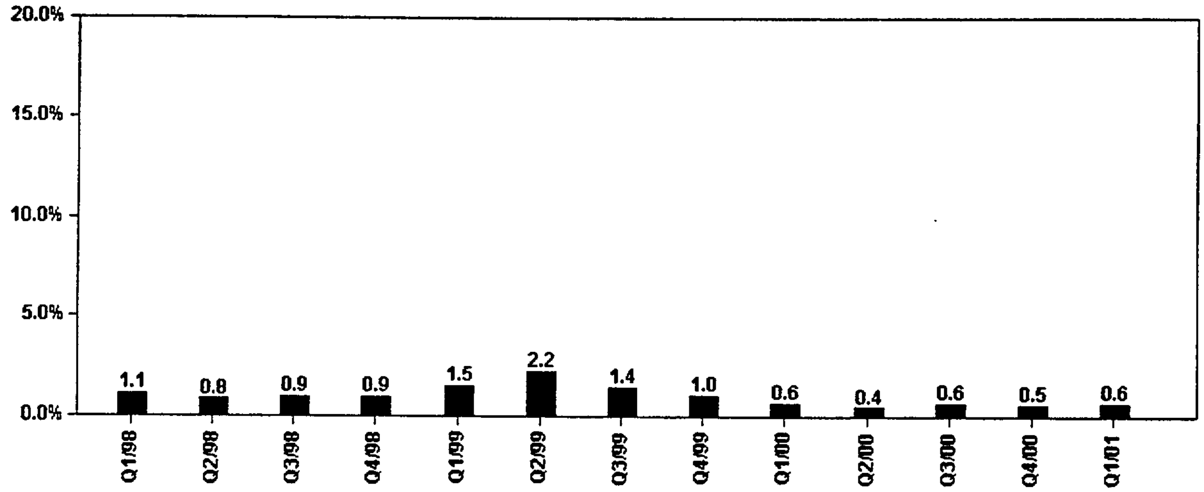
Barrier Integrity Industry Trends

Last Modified: May 20, 2001

Barrier Integrity Cornerstone - Industry Trends

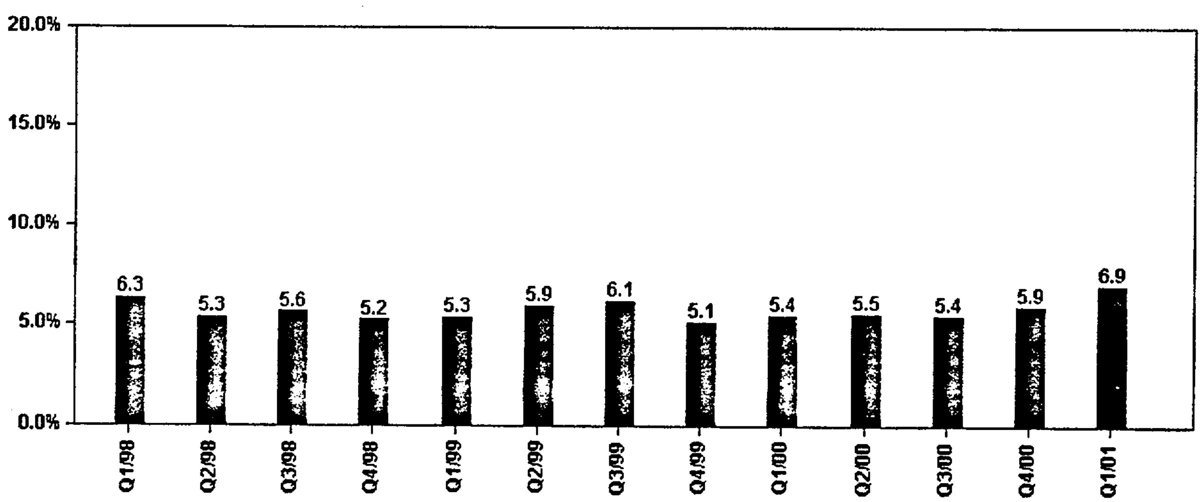
1Q/2001

Reactor Coolant System Activity (Max % of Technical Specification Limits)



Descriptions

Reactor Coolant System Leakage (Max % of Technical Specification Limits)



Comments: Q1/00 - Steam generator tube rupture event at Indian Point 2

Descriptions

Mitigating Systems Industry Trends

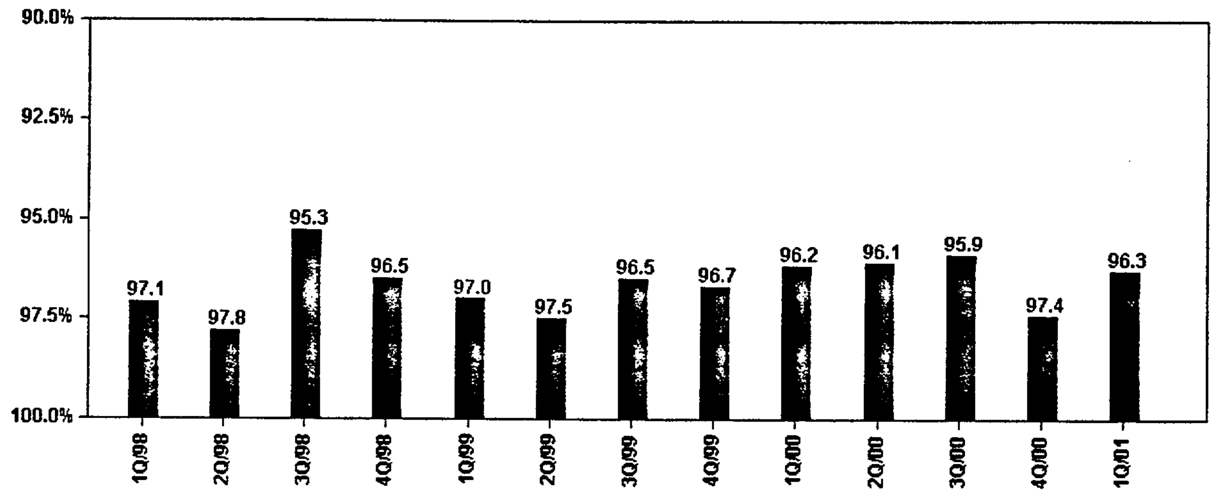
Emergency Preparedness Industry Trends

Last Modified: May 20, 2001

Emergency Preparedness Cornerstone - Industry Trends

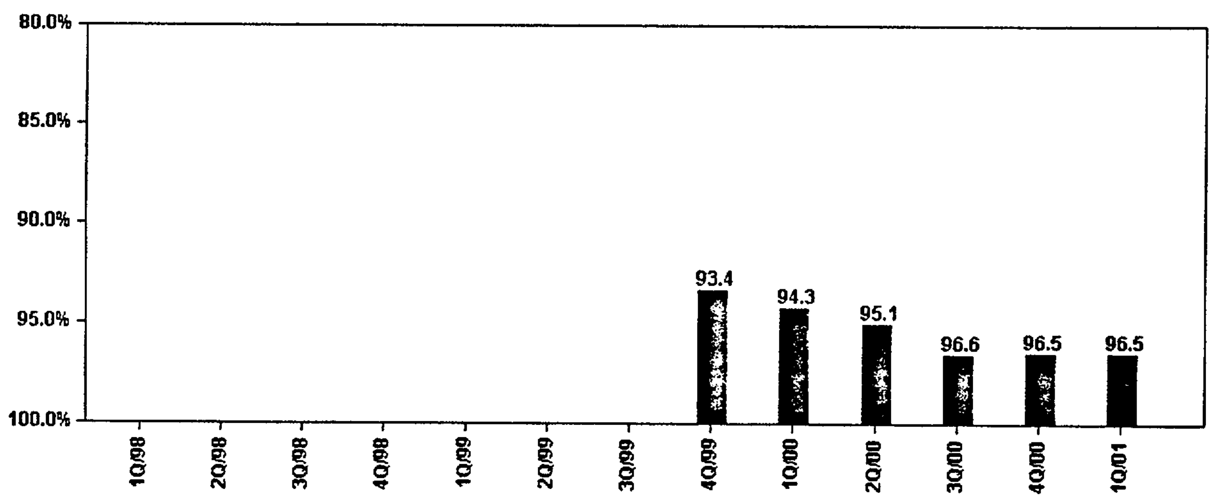
1Q/2001

Drill/Exercise Performance (% Timely and Accurate)

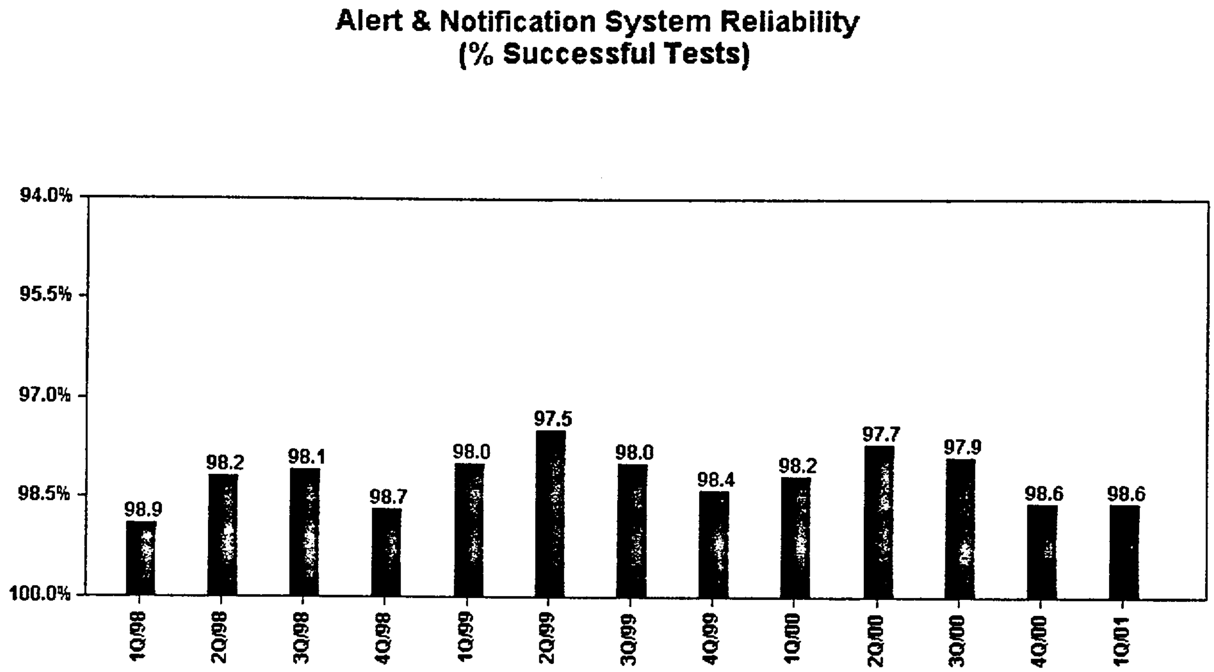


Descriptions

ERO Drill Participation (% Key Personnel)



Descriptions



Descriptions

Barrier Integrity Industry Trends

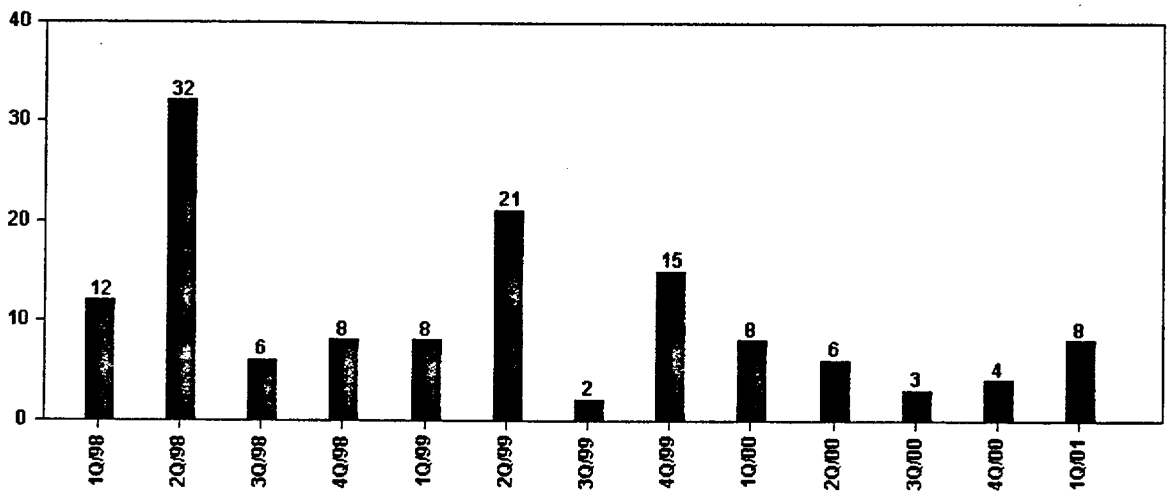
Occupational Radiation Safety Industry Trends

Last Modified: May 20, 2001

Occupational Radiation Safety Cornerstone - Industry Trends

1Q/2001

Occupational Exposure Control Effectiveness



Descriptions

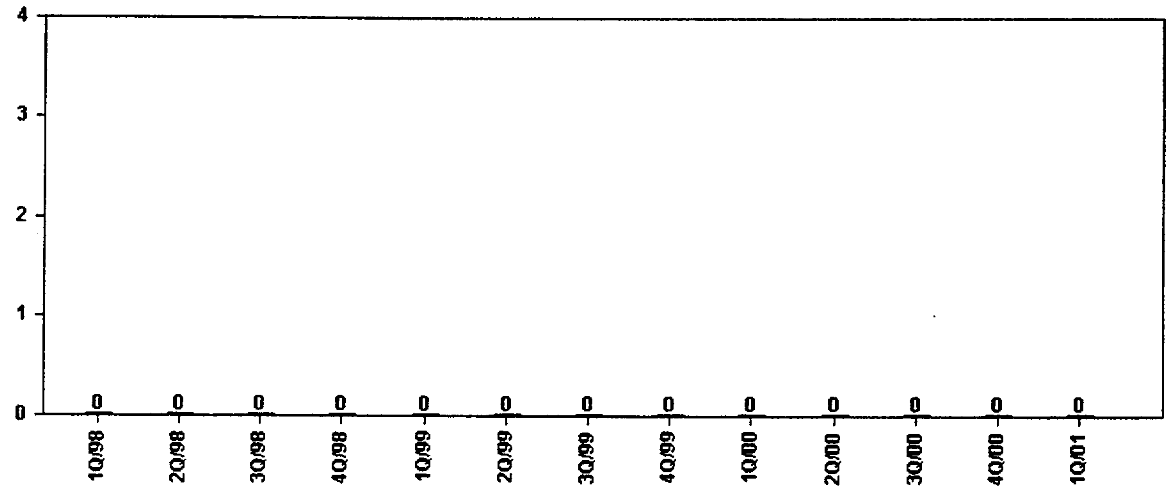
Emergency Preparedness Industry Trends

Public Radiation Safety Industry Trends

Last Modified: May 20, 2001

Public Radiation Safety Cornerstone - Industry Trends 1Q/2001

RETS/ODCM Radiological Effluent Occurrences



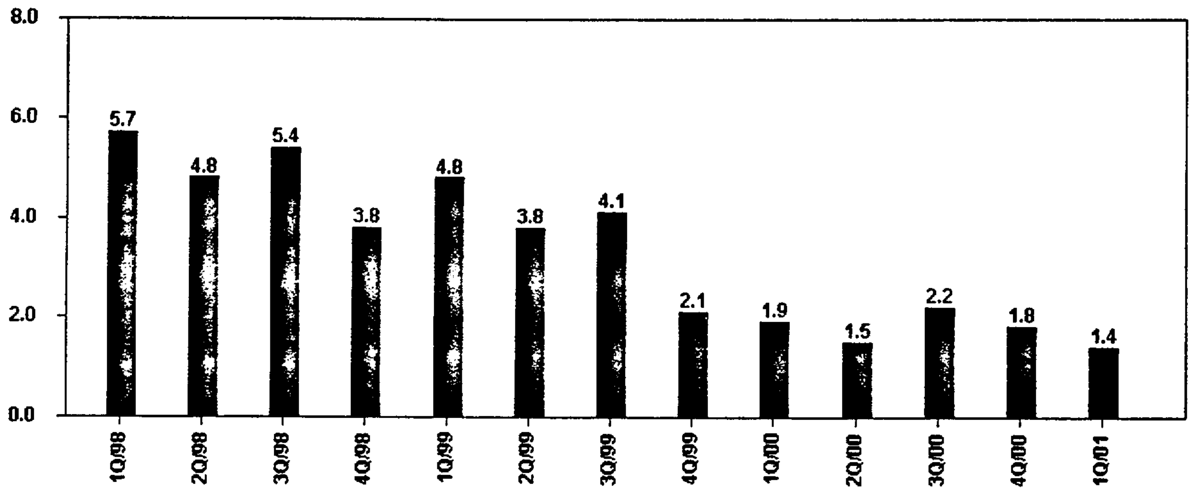
Descriptions

Occupational Radiation Safety Industry Trends *Physical Protection Industry Trends*

Last Modified: May 20, 2001

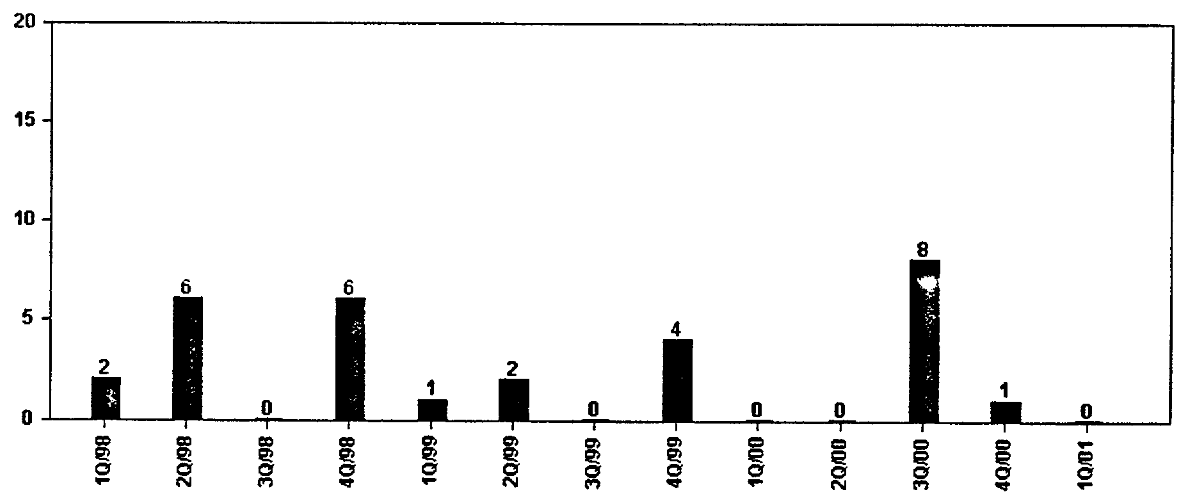
Physical Protection Cornerstone - Industry Trends 1Q/2001

Protected Area Security Equipment Performance Index



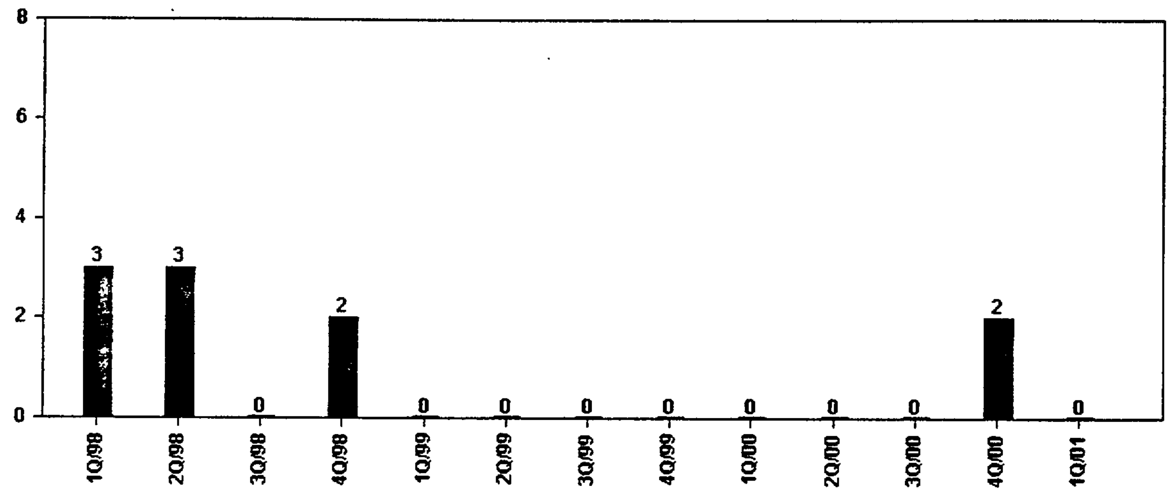
Descriptions

Personnel Screening Program Performance



Descriptions

FFD/Personnel Reliability Program Performance



Descriptions

Public Radiation Safety Industry Trends

Last Modified: May 20, 2001

3. ASP Program Results

The below graphs are provided for illustration only. A detailed explanation is contained in SECY-01-0034, "Status Report on Accident Sequence Precursor Program and Related Initiatives."

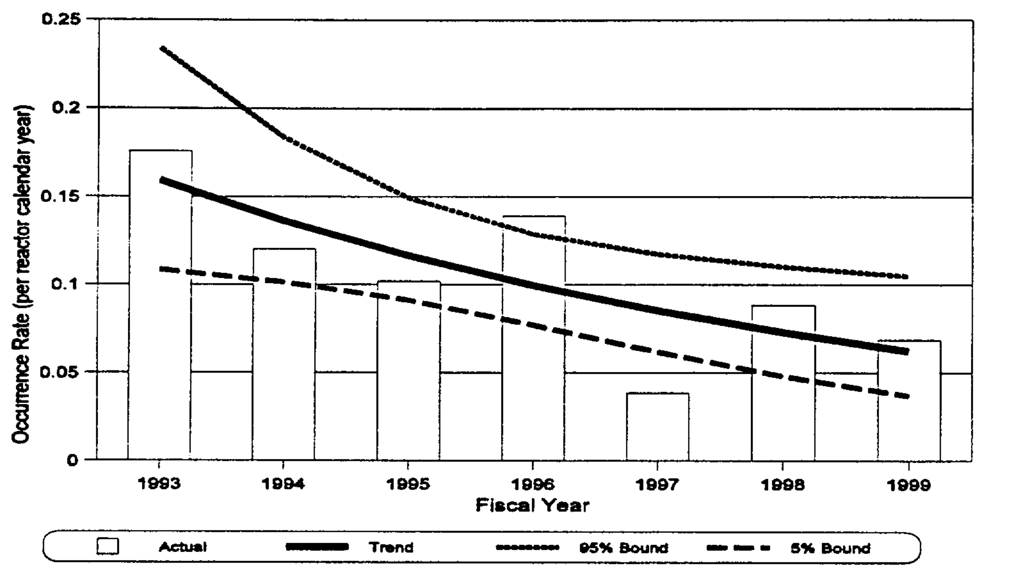


Figure 1. Precursor occurrence rate for 1993-1999 plotted against fiscal year. The trend is statistically significant (p-value = 0.0068). The result for 1999 is preliminary.

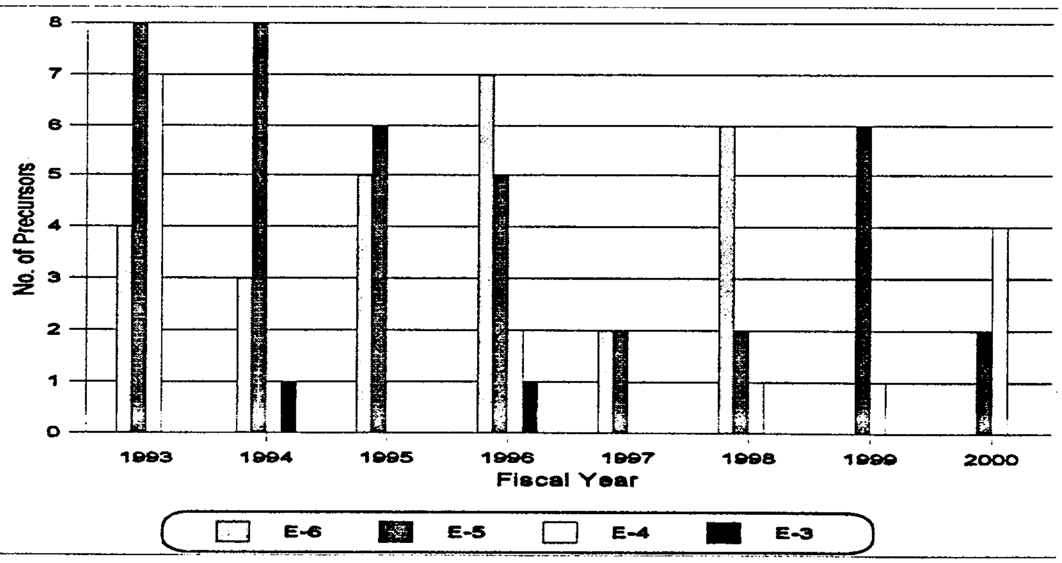
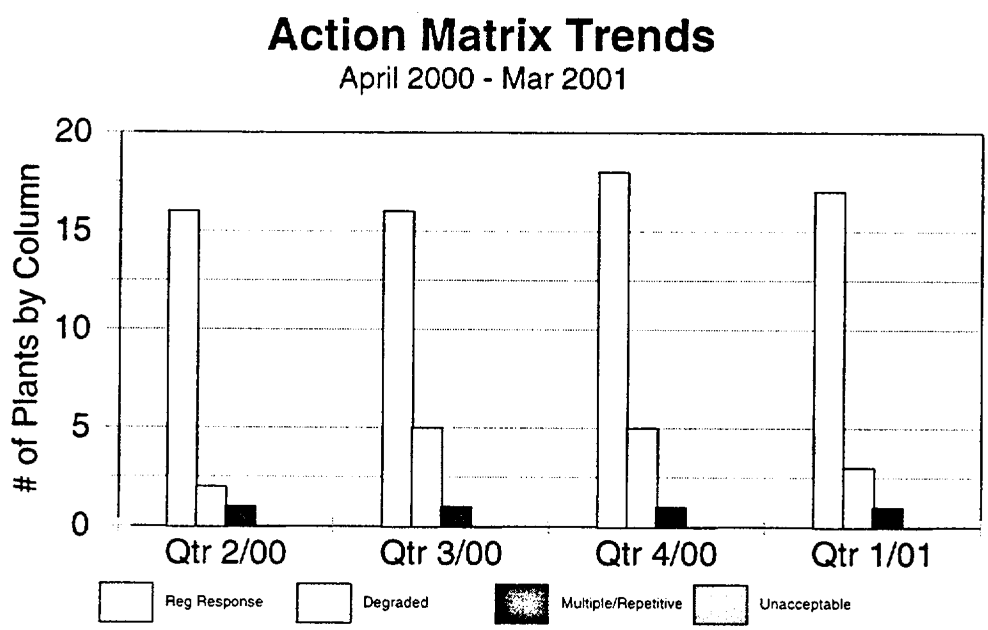


Figure 2. Conditional core damage probability results from ASP Program (1993-2000) for each of the CCDP bins (*E-3*: $\geq 1 \times 10^{-3}$; *E-4*: 9.9 $\times 10^{-4}$ to 1.0 $\times 10^{-4}$; *E-5*: 9.9 $\times 10^{-5}$ to 1.0 $\times 10^{-5}$; *E-6*: 9.9 $\times 10^{-6}$ to 1.0 $\times 10^{-6}$). Results for FYs 1999 and 2000 are preliminary.

4. ROP Program Trends

The staff examines summary information for feedback on the effectiveness of the ROP. The results are provided for the first year of ROP implementation.

A. Action Matrix trends. The below chart shows trends of plants between the columns of the Action Matrix. A trend of degrading performance would be one that showed a migration of plants from the licensee response column to one of the other columns in the Action Matrix. For the first year of ROP implementation, this chart does not show any trends.



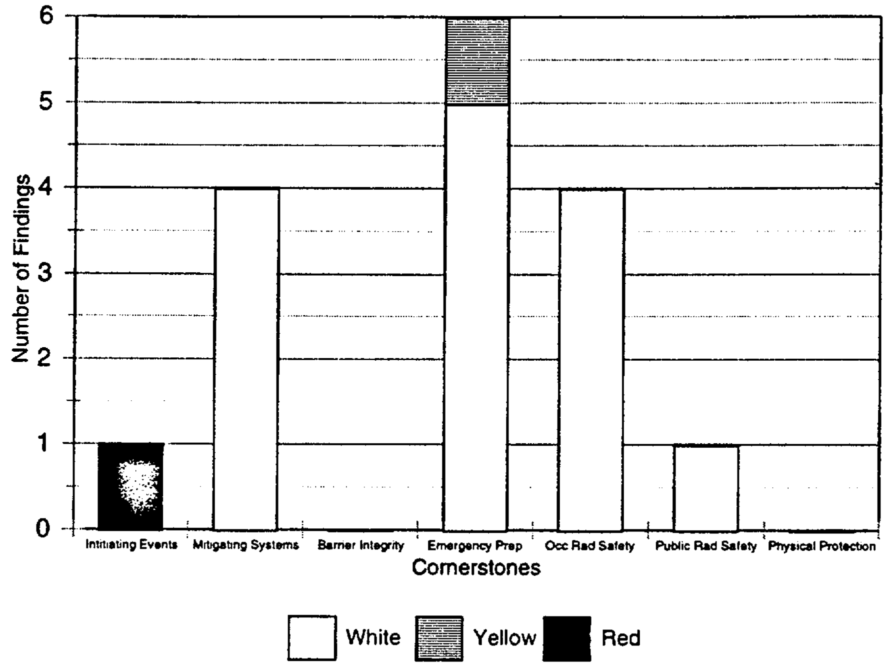
* This chart does not include DC Cook units 1 and 2.

B. ROP Inspection Findings. IIPB performed an audit of significant (other-than-green) inspection findings in inspection reports during the first year of implementation of the ROP (April 2, 2000 - March 31, 2001). The findings, summarized below, covered issues that were too varied in nature to identify any trends or generic issues. IIPB intends to continue to audit ROP inspection findings in the future.

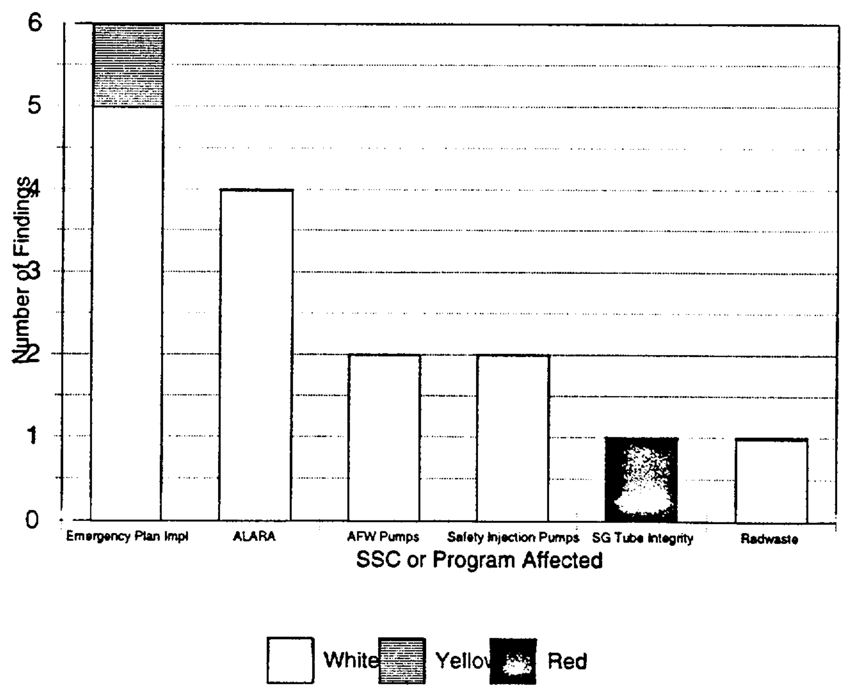
Plant	Cornerstone	Color	SSC/Program Affected	Apparent Cause
INITIATING EVENTS CORNERSTONE				
Indian Point 2	Initiating Events	Red	Steam Generator Tubes - February 2000 SGTF	Failure to take adequate corrective actions regarding 1997 SG tube inspection results
MITIGATING SYSTEMS CORNERSTONE				
Oconee 1	Mitigating Systems	White	High Pressure Injection Pump - HPI may not be able to draw suction from SFP following tornado	Pressure, temperature or hydraulic requirements not adequately considered and SFP as a suction source for HPI was not assured following tornados
Millstone 2	Mitigating Systems	White	AFW - Speed control for TDAFW pump was unresponsive and erratic	Inadequate evaluation of degraded condition and untimely corrective actions.
Summer	Mitigating Systems	White	AFW - Discharge isolation valve for TDEFW pump shut for 48 days.	Failure to follow procedures
Harris	Mitigating Systems	White	Safety Injection Pump - Failed thrust bearing on C CSIP	
BARRIER INTEGRITY CORNERSTONE (NO FINDINGS)				
EMERGENCY PREPAREDNESS CORNERSTONE				
Indian Point 2	Emergency Preparedness	White	Emergency Plan Implementation - Failure of ERO to respond in 60 minutes	Program structure or design problems contributed to the failure to meet emergency planning standards
Indian Point 2	Emergency Preparedness	White	Emergency Plan Implementation - Failure to establish accountability in 30 minutes	Program structure or design problems contributed to the failure to meet emergency planning standards
Indian Point 2	Emergency Preparedness	White	Emergency Plan Implementation - Inadequate communications to the public	Program structure or design problems contributed to the failure to meet emergency planning standards

Plant	Cornerstone	Color	SSC/Program Affected	Apparent Cause
Kewaunee	Emergency Preparedness	White	Emergency Plan Implementation - Deficiencies identified with staffing ERO during off-hours staff augmentation drills	Inadequate corrective actions taken for previous deficiencies
Cooper	Emergency Preparedness	White	Emergency Plan Implementation - Failure to identify incorrect PARs in a post EP drill critique.	Failure of licensees EP critique process to identify deficiency with PARs
Kewaunee	Emergency Preparedness	Yellow	Emergency Plan Implementation - Alert and notification siren availability	Root cause evaluation was not performed at the depth necessary to identify the causes of the siren performance problems
		OCCUPATIONAL RADIATION SAFETY CORNERSTONE		
Callaway	Occupational Radiation Safety	White	ALARA - Scaffolding activities which accrued actual doses greater than 25 person-rem	Poor planning and preparation, failure to properly train workers in dose reduction, failure to ensure good communications
Callaway	Occupational Radiation Safety	White	ALARA - SG eddy current/robotic plugging/stabilizing/electrosleeving activities accrued actual doses greater than 25 person-rem.	Poor planning and preparation, failure to properly train workers in dose reduction, failure to ensure good communications
Callaway	Occupational Radiation Safety	White	ALARA - Each of four jobs (SG manway cover and inserts removal and installation, foreign object search and retrieval, RCP seal replacement) accrued actual doses greater than 5 person-rem.	Poor planning and preparation, failure to properly train workers in dose reduction, failure to ensure good communications
Quad Cities 1& 2	Occupational Radiation Safety	White	ALARA - Increased dose for SRV replacement job	Poor planning and preparation, higher than expected source term, and high heat stress environment
		PUBLIC RADIATION SAFETY CORNERSTONE		
Peach Bottom Units 2 & 3	Public Radiation Safety	White	Radwaste Shipping - Misclassification of radwaste shipment	Licensee did not collect representative resin samples for the purpose of analysis and classification of the waste
		PHYSICAL PROTECTION CORNERSTONE (NO FINDINGS)		

Inspection Findings by Cornerstone



Insp Findings By SSC/Program Affected



ATTACHMENT 4
Frequently Asked Questions, Log. 15, 16, 19, 21

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

Attachment 4

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.5	MS03	**Question:** **Appendix D** NEI 99-02 states (p 26) that Planned Unavailable Hours include "…testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "…an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator within 10 minutes. Should this be counted as unavailable time? **Licensee Proposed Response:** No. The PI should not count them since this is an NRC approved design.	Introduced 12/6 Discussed. This question applies to the 2 standby AFWP, not the 3 auto start AFW pumps. The pumps are provided for HELB; An AO is required by procedure to manually start the standby AFW pumps in ten minutes. **5/2 Tentative Approval**	Ginna
16.11	MS02 MS04	**Question:** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. This process is carried out over a six hour period in which the temperature is raised slowly in order to chase fish toward the fish elevator so they can be removed from the intake and thus minimize the consequential fish kill. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. The ability of the safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Licensee Proposed Response:** No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis	San Onofre

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.14	MS03	**Question:** **Appendix D Question** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of 100% capacity turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated? (Note: this FAQ is similar to Appendix D questions for Palo Verde and Crystal River regarding the auxiliary feedwater system) **Response:** Based on the information provided, this pump should be considered a third train of auxiliary feedwater for NEI 99-02 monitoring purposes. See the Palo Verde Appendix D question.	Introduced 12/6 5/2 Discussed	Davis-Besse

FAQ Log 17				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
17.2	PP01	**Question:** For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated? Response: Continue ~~calulating~~**calculating** the indicator in accordance with NEI 99-02. This issue will be resolved in a future revision to NEI 99-02.	Introduced 1/10 1/10/2001 – Tentative Approval – NRC action to confirm acceptability 2/7/01 – NEI proposed alternate responses. 3/2/01 – Discussed. **5/2 Tentative Approval**	NRC

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

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.6	IE03	**Question:** On January 6th and 7th, the FitzPatrick Nuclear Power Plant performed unscheduled power reductions in excess of 20% due to environmental conditions. Lake temperature, wind speed and wind direction combined to create conditions resulting in the main condenser water box fouling which required the power reductions to correct. These power reductions have not been included in the "Unplanned Power Change per 7,000 Critical Hours" Performance Indicator based on previous FAQ's concerning unscheduled power reductions arising from external conditions. On 01/06/01 power was reduced to 60% to allow the A2 waterbox to be cleaned & inspected. The "C" traveling screen was removed from service and the remaining waterboxes were de-fished. A recommendation to clean the forebay when divers became available was made to the Shift. Because the availability of divers was expected to be 24 to 96 hours, normal power level was restored. Divers arrived on site 01/07/01, and preparations for forebay cleaning were ongoing. After "C" traveling screen was returned to service condenser delta T and delta P rose slightly. Subsequent lowering of a stop-log (to isolate "A" traveling screen for forebay cleaning) caused condenser delta T and delta P to rise and condenser vacuum dropped. The Shift responded by raising the stop-log, reducing power to 60 percent and de-fishing the waterboxes. Previously, these stop-logs have been lowered without significant effect on condenser performance. Divers confirmed that a large amount of silt and zebra mussel shells had collected in the forebays, which had been cleaned during RO-14. As outlined above, power was reduced on these two successive occasions 01/06/01 (for ~15 hours) and 01/07/01 due to waterbox fouling caused by external environmental conditions. The 01/07/01 down power was an unexpected evolution to be implemented based on when divers were available to perform the cleaning operation. –Therefore, both power reductions were the result of the same environmentally caused influx of debris into the forebay. The initial mitigating action (de-fishing) was known to be a temporary measure to allow full power operation until long-term corrective action could be implemented. Since the second power reduction was **also** caused by ~~additional~~ zebra mussels and **environmental conditions, and** prior intake cleaning evolutions were done at full power, should this count as an unplanned power change? **Response:** No. When external conditions are the fundamental cause of the power reduction it should not count in the Performance Indicator regardless of the period of time between power reductions	Introduced 2/8 Need more information 4/23 Question revised 5/2 Discussed	FitzPatrick

TempNo.	PI	Question/Response	Status	Plant/ Co.
19.1	IE03	**Question:** If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is <u>not</u> required by the license bases would this reduction be counted?	Introduced 3/1 **5/2 Tentative Approval**	River Bend

TempNo.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: If the ALARA program determines that a power reduction of >20% is appropriate to conduct the maintenance/ repair, and the downpower is conducted in less than 72 hours from discovery, the downpower would count.		
19.2	MS01 MS02 MS03 MS04	**Question:** Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis…", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements? **Response:** If the conditions have been met to reset fault exposure hours, in accordance with NEI 99-02, for fault exposure hours experienced during the historical data period, the hours can be reset without having to revise the remaining historical data to conform with all 99-02 requirements. However, because the green/white threshold was not crossed, the fault exposure hours cannot be removed.	Introduced 3/1 **5/2 Tentative Approval**	Susquehanna
19.3	MS04	**Question:** **(Potential Appendix D question –** Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because, as stated in the FSAR, the system's response to design basis LOCA/LOOP events while in SPC configuration determined that a usage factor of 10% is acceptable. The probability of the event of concern is 6.4 E-10. If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing? **Response:** No, because the plant is being operated in accordance with technical specifications.	Introduced 3/1 5/2 Discussed	Susquehanna

TempNo.	PI	Question/Response	Status	Plant/ Co.
19.4	IE03	**Question:** In February 2000, a leak was identified in main generator hydrogen cooler No. 34. At that time the leak rate was considered low enough for continued plant operation in accordance with Main Generator Gas System Operating Procedure (SOP-TG-001). Development of an Action Plan and outage schedule was initiated, daily trending of the hydrogen leakage rate was initiated, and plans for repair formulated. By the end of February 2000, an outage schedule was developed, Work Requests planned, material identified and orders placed. The schedule and work package was set aside for use if it became necessary to effect repairs prior to Refueling Outage 11 (scheduled for April 2001). In October 2000, the hydrogen leak rate increased (exceeded approximately 500 cu ft per day) and in accordance with the procedure additional monitoring via a special log was initiated. The approved Action Plan recommended that hydrogen coolers No. 33 and 34 be replaced with available spares. The leak continued to increase and after a maintenance shutdown October 25, the leakage increased to 843 cu ft per day by November 1. By the beginning of December the leak had increased to approximately 1200 cu ft per day and on December 18, the hydrogen leak rate increased to 2054 cu-ft per day. After assessing the condition, plant management decided to shut down the plant and perform the repairs as detailed in the outage schedule based on holiday resource scheduling. On December 19, the plant was shut down **prior to reaching the procedural limitation of 4000 cu-ft per day which would have required an operability determination. This limitation is also less than the leakage specification specified by the vendor for continued operation. The 4000 cu-ft per day was considered a threshold for re-evaluation of the condition as required by the procedure.** ~~, repairs~~**Repairs** made and the unit returned to service close to the original outage schedule. This forced outage was evaluated for determining if it was applicable under the classification rules for an unplanned outage. In accordance with the guidelines of NEI-99-02, if the outage was planned more than 72 hours in advance, the outage could be classified as planned. Since the off-normal condition (leak) was identified in February and planning developed, although not all details completed, the shutdown met the criteria of identifying and planning 72 hours prior to the shutdown, and it was classified as a "planned" shutdown. The additional clarification in NEI-99-02, under FAQ No. 6 reinforced that determination. The shutdown was planned and per the examples in NEI-99-02, the time period between discovery of the off-normal condition exceeded 72 hours allowing assessment of plant conditions, preparation and review in anticipation of an orderly power reduction and shutdown. ~~The NRC Resident Inspector questioned the date identified for when the leak started and considered the appropriate date was December 18, when the leak rate was considered to have exhibited a "step" increase. This date was less than 72 hours prior to the actual shutdown, and included consideration of factors not previously considered in the action plan (such as availability of people due to the approaching holiday.~~ Does this event qualify as a unplanned shutdown?	Introduced 3/1 5/2 Discussed	IP3
		Response: No, the degraded condition was identified in February 2000, and an Action Plan was developed to address the condition, including a outage schedule, Work Request, material identification and procurement. Therefore, the degraded condition was identified and planning had been performed more than 72 hours prior to the initiation of plant shutdown. The increased leak rate in December 2000 was not a different condition, only a continuing degradation of the off-normal condition discovered in February 2000. The December leak rate did not exceed procedural limits requiring assessment of operability and plant shutdown **and did not require a rapid response.**		

TempNo.	PI	Question/Response	Status	Plant/ Co.
19.5	MS01	**Question:** NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states: "When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria: ☐ a load run of any duration that resulted from a real (e.g., not a test) manual or automatic start signal ☐ a load-run test that successfully satisfied the plant's load and duration test specifications ☐ other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above." The following sentence states: "For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault." If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test. **Licensee Proposed Response:** The key to interpreting this section of the guideline is determining the cause of the surveillance failure. If the cause is known (and the time of failure cannot be ascertained) the fault exposure time would be calculated as half the time since the last test which could have revealed the failure. This could be any of the load run tests described in the section.	Introduced 3/1 3/2/01 – Discussed. NEI action to revise to clarify question and proposed response. **5/2 Tentative Approval**	APSC

TempNo.	PI	Question/Response	Status	Plant/ Co.
19.6	MS01 MS02 MS03 MS04	**Question** **(Potential Appendix D Question)** **At Prairie Island, the three safeguards Cooling Water (service water) pumps were declared inoperable for lack of qualified source of lineshaft bearing water. This required entry into Technical Specifications 3.0.c (motherhood). The plant requested and received a Notice of Enforcement Discretion (NOED) that allowed continued operation of both units until installation of a temporary modification to provide a qualified bearing water supply to two of the three pumps was complete (14 days). Compensatory measures were implemented to ensure continued availability of water to the lineshaft bearings.** **The Cooling Water System is required to mitigate design basis transients and accidents, maintain safe shutdown after external events (e.g. seismic event), and maintain safe shutdown after a fire (Appendix R).The only events for which the Cooling Water System function could have been compromised are the loss of off-site power (LOOP) and a design basis earthquake (DBE). These two events are limiting because they both involve the loss of off-site power. If off-site power continues to power the non-safeguards buses, then the Cooling Water System function is not lost.** **Our Risk Assessment determined that the initiating event frequency for a DBE during the 14 day NOED period was so low that it was not a concern. Therefore, this discussion will focus on the LOOP event. The bearing water supply was not fully qualified for LOOP because the power to the automatic backwash for strainers in the system was not safeguards. The concern was that system strainers would plug eventually. However, for this initiating event, function is not lost immediately – it takes time for the strainers to plug. The time it takes is a function of river water quality. Based on an estimate of worst-case river water quality, there are 4 to 7 hours before function would be lost (strainers plug). In fact, testing around the period of the event, showed river water quality was such that the strainers did not plug after 48 hours. Given the time available there is high probability that operators could complete recovery actions before function was lost. A specific probabilistic risk assessment of the local operator actions determined that the probability of failure was less than 1%.** **The NOED was requested to preclude a two unit shutdown. As part of the request for the NOED, compensatory measures to assure that the Cooling Water System function is maintained were proposed. In summary, the compensatory measures were to:** • **use a hose (pressure-rated) to connect a safety related source of Cooling Water to the lineshaft bearing supply piping for a Cooling Water Pump** • **post a dedicated operator locally in the screenhouse near the Cooling Water Pumps** • **pre-stage equipment and tools in the screenhouse** • **place identification tags at the connection locations** • **train the dedicated operator(s) on the procedure for connecting the hose**	Introduced 3/1 ~~QUESTION BEING REVISED~~ **5/23/01 Question and Response revised.**	Prairie Island

TempNo.	PI	Question/Response	Status	Plant/ Co.
		The need to implement the compensatory measures would have been identified to the Control Room operator by a loss of bearing flow alarm. As stated earlier, this condition is not expected to occur until a filter becomes plugged 4 to 7 hours after the loss of off site power. The Control Room operator would notify the dedicated operator to perform the procedure. The walkdown of the procedure determined that bearing flow could be established in less than 10 minutes. The pump is capable of operating for approximately one hour without bearing flow. When bearing flow is established, the Control Room alarm will clear, thereby giving the Control Room operator confirmation that the procedure has been performed. The procedure also required an independent verification of the bearing flow restoration within one hour of receiving the loss of bearing water flow alarm. The Cooling Water System is a support system and it's unavailability affects: High Pressure Safety Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2 Emergency AC is cooled independent of Cooling Water). Using NEI 99-02 criteria, Prairie Island included the time that the Cooling Water Pumps were declared inoperable, approximately 300 hours, as unplanned unavailability in our PI data report. This resulted in two White Indicators (one on each unit), two other systems (one per unit) on the Green/White threshold, and two systems (again, one per unit) close to the Green/White threshold. However, the cause for these Performance Indicators changing from Green to White is a direct result of the lack of qualified bearing water to the Cooling Water pumps. The lack of qualified bearing water was evaluated through the SDP and resulted in a White finding. A root cause evaluation was performed and corrective actions identified. Since the change in the performance Indicators from Green to White was a direct result of the unqualified bearing water, no additional corrective action is planned. This event does not fit into the guidance given in NEI 99-02. In Rev. 0, page 26, the Clarifying Notes address testing and Control Room operator actions. In Rev. 1, page 28, the Clarifying Notes only allow operator actions taken in the Control Room. We have also reviewed Catawba's FAQ 254. However, their situation addressed maintenance activity results not operator action. Initially, unavailable hours were recorded from the time of discovery until completion of a Temporary Modification that provided a qualified bearing water supply. This resulted in counting approximately 300 unavailable hours per pump. Since the compensatory actions would have maintained the Cooling Water System function, should the unavailable hours be counted only from the time of discovery until the compensatory measures were in place?		

TempNo.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes, the unavailable hours should be counted only from the time of discovery until the time that the compensatory measures were in place. The actions required to restore the Cooling Water System function were simple and had a high probability of success. This is based upon the following factors: • A probabilistic risk assessment of the local operator actions calculated less than a 1% probability of failure. • There is control room alarm to alert the Control Room operator of the need for the compensatory measures. • There are at least two means of communication between the Control Room and the local operator. • Recovery action for each pump was simple - connect a hose to two fittings and position two valves. • Time to complete the recovery action was estimated to be about 10 minutes, based on walk-throughs. Failure to successfully complete the recovery action was not expected to preclude the ability to make additional attempts at recovery. • A dedicated operator was stationed in the area to complete the recovery action. • The operator had a procedure and training for accomplishing the recovery action. • All necessary equipment for recovery action was pre-staged and the fittings and valves were readily accessible. Indication of successful recovery actions was available locally and in the Control Room.		

Temp No.	PI	Question/Response	Status	Plant/ Co.
20.3	MS04	**Question:** FAQ for Mitigating System MS04 concerning CE Designed NSSS systems, "Alternative historical data correction method to convert 2 trains to 4 trains." Calvert Cliffs, Fort Calhoun, Millstone 2, Pallisades, Palo Verde, San Onofre, St. Lucie, and Waterford 3 In FAQ # 172, approved on May 2, 2000 for use by CE plants, two methods for changing historical data from an initial 2 train report to a revised 4 train report were outlined. Specifically, the change report methodology was to perform one of the following changes to historical data: **1. Maintain Train 1 and Train 2 historical data as is. For Train 3 and 4, repeat Train 1 and Train 2 data.** **2. Recalculate and revise all historical data using this guidance.** For CE plants incorporating method 1, a non-performance related degradation in the PI calculation for Trains 3 and 4 (and the overall PI) was subsequently observed. This degradation occurred due to a decrease in the required hours in the denominator as the historical data was replaced by typically zero (0) or low required hours reported in the revised data (post Jan, 2000) in combination with artificially high unavailability hours in the numerator (due to the doubling of non-shutdown cooling related unavailability hours from the historical data). As a result, PI values would generally degrade over time regardless of performance until the historical data drops from the PI calculation. In some cases, plants projected a fall below the GREEN/WHITE threshold in 2002, even if perfect performance was used in the projection. **Licensee Proposed Response:** To address the calculation anomaly in the determination of the RHR PI, a third alternative is suggested for the estimation of Train 3 and Train 4 data: **3) Maintain Train 1 and Train 2 historical data as is. For Train 3 and Train 4, estimate the number of unavailable hours and required hours for the historical data period.** If changes to historical data are made, then provide comments with the change report to identify the manner in which the historical data has been revised.	4/4 – Discussed. Need CE owners to provide additional input. 5/2 Discussed	CE Plants
20.4	PP01	**Question:** Scheduled Equipment Upgrade During a recent NRC Security Inspection (IP 71130.03), NRC Contractors were able to defeat the Intrusion Detection System (IDS) in several areas, by using assisted jumps. An engineering evaluation was issued and formal Modification/ upgrade action was initiated that directed the installation of additional razor wire to prohibit attempts to circumvent the IDS system without being detected. Is a physical modification to a protected area boundary, that is designed to prohibit the defeat of a Intrusion Detection System (IDS) component considered to be a system/ component modification or upgrade as stated in the Clarifying Notes to NEI 99-02 under Scheduled Equipment Upgrade (and as augmented by FAQ 259)?	4/4 - Introduced and discussed. **5/2 Tentative Approval**	Turkey Point

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: Yes. A physical modification to a protected area boundary is considered to be a system/ component modification or upgrade that deters or prohibits the defeat of the IDS system components. The conditions of the clarifying notes must be met to stop counting compensatory hours.		
21.1	MS02	Question: Appendix D Page 62 of NEI 99-02, Rev 0, states in part: "…the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system." Ginna Station's system design has three MOV's meeting this definition: 857A and 857C (two valves in series from the A RHR train) and 857B from the B RHR train. Each RHR train is a 100% train. MOVs 857 A and 857C are in parallel with 857B. If Ginna Station was to have a fault exposure to one of these three valves, it would not prevent any of the three HPSI pumps from performing its function of taking a suction from the containment emergency sump. Rather, a fault exposure to one of these three valves would prevent its associated RHR train from supplying a suction from the containment emergency sump to any of the three HPSI pumps. Thus, the boundary between the RHR and HPSI systems needs to be adjusted for Ginna Station. Licensee Proposed Response: The down-stream side of the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system for Ginna Station. The isolation valve(s) themselves will be in the RHR system and be associated with their respective RHR train.	**5/2 Tentative Approval**	Ginna
21.2	MS01 -04	Question: Removing (Resetting) Fault Exposure Hours Question being reviewed Licensee Proposed Response:		Ginna

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

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

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

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

Response:
Anticipatory power reductions, from 100% to 50% and from 50% to less than 25%, that result from high swells and ocean debris are proceduralized and cannot be predicted 72 hours in advance. Neither of these anticipatory power reductions would count under the Unplanned Power Changes PI. However, a power shutdown from less than 25% that is initiated on loss of the main condenser (i.e., shutdown of the only running CWP) would count as an unplanned power change since such a reduction is forced and can therefore not be considered anticipatory.</td><td>5/2 Tentative Approval</td><td>Diablo Canyon</td></tr>
<tr><td>21.4</td><td>MS01 -04</td><td>Question:
By the NEI guidance, fault exposure hours can only be removed for "a single item" when the fault exposure hours associated with the item are greater than or equal to 336 hours. How are multiple failures of the same component handled when some of the failures have fault exposure hours less than 336 hours, yet the total of all the failures attributed to the same failed component are greater than 336 hours.</td><td>5/2 Discussed . Response to be revised</td><td>Southern Co.</td></tr>
</table>

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Proposed Response: The intent is that the removal of fault exposure hours is associated with the identification of cause to preclude recurrence of the condition. A failure to adequately identify cause (such as intermittent failures) which leads to additional failures are considered the same condition and may be grouped for removing of fault exposure hours. However, it is also the intent that the NRC supplemental inspection considered all failures associated with this condition. Under these restrictions, multiple items may be considered as a single item since they represent a single condition. Therefore, the fault exposure hours may be removed for the applicable failures. However, situations involving multiple failures due to different components or causes can not be grouped. For example, a valve failure and a subsequent pump controller failure can not be grouped for fault exposure hour removal even if they are considered in the supplemental inspection.		
21.5	IE01	Question A plant is reducing power for a planned refueling outage, and is planning to insert a manual scram at 25 percent power in accordance with the plant shutdown procedure. At 28 percent power, as a result of a report from the field, operators believe they are about to have an equipment failure that would lead to an automatic scram. The operators immediately insert a manual scram. Afterwards, the operators determine that the actual field condition was minor, and the suspected equipment failure would not have occurred. Therefore, there would not have been an automatic scram. Should the manual scram be counted as an unplanned scram? Response Yes, the manual scram should be counted because the scram was inserted above the 25% level specified in the plant shutdown procedure.	**5/2 Tentative Approval**	Nine Mile
21.6	IE02	Question: Some plants are designed to have a residual transfer of the non-safety electrical buses from the generator to an off-site power source when the turbine trip is caused by a generator protective feature. The residual transfer automatically trips large electrical loads to prevent damaging plant equipment during reenergization of the switchgear. These large loads include the reactor feedwater pumps, reactor recirculation pumps, and condensate booster pumps. After the residual transfer is completed the operators can manually restart the pumps. The turbine trip will result in a reactor scram. Should the trip of the reactor feedwater pumps be counted as a scram with a loss of normal heat removal? Response In this instance, the electrical transfer scheme performed as designed following a scram and a residual transfer; therefore, this would not count as a scram with a loss of normal heat removal	5/2 Introduced	Nine Mile

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.7	MS02 MS04	Question NEI 99-02, Rev. 0 states in the Definition and Scope section for PWR High Pressure Safety Injection Systems that: "Because the residual heat removal system has been added to the PWR scope, the isolation valve(s) between the RHR system and the HPSI pump suction is the boundary of the HPSI system. The RHR pumps used for piggyback operation are no longer in HPSI scope." It is further stated later in the same section that the function monitored for HPSI is: "the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure." These two statements appear to conflict. For our plant design the RHR / HPSI piggyback mode is the only path available for HPSI to get water from the containment sump and inject it into the RCS. Therefore, we have been counting unavailability of the RHR system upstream of the isolation valves between the RHR system and the HPSI pump suction as unavailability for RHR and HPSI. This would include component unavailability for containment sump isolation valves, RHR heat exchangers and the isolation valves between the RHR and HPSI systems. Should the RHR and HPSI systems be treated independently such that RHR system unavailability should not count against HPSI even though the RHR system is required for the HPSI system to fulfill the function of taking a suction from the containment sump? If so, should unavailability of the isolation valves between the RHR and HPSI pumps' suction be only counted against HPSI?	5/2 Introduced	Kewaunee
		Response Because RHR and HPSI are monitored as separate systems with each having its own performance indicator, there is no need to cascade RHR system unavailability into HPSI. RHR system unavailability includes the system upstream of the RHR system to HPSI system isolation valves. Unavailability of the isolation valves between the RHR system and the HPSI pump suction are only counted against the HPSI system.		

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

Temp No.	PI	Question/Response	Status	Plant/ Co.
21.9	MS01	Question: NEI 99-02 Revision 0, Page 1, INTRODUCTION, line 22 states: "Performance indicators are used to assess licensee performance in each cornerstone." Consider the situation where a certified vendor supplied a safety related sub-component for a standby diesel generator. This sub-component was refurbished, tested and certified by the Vendor with missing parts. The missing parts eventually manifested themselves as a sub-component failure that lead to a main component operability test failure. The Vendor issued a Part 21 Notification for the condition after notified by the Licensee of the test failure. (The licensee conducted a successful post maintenance surveillance and two subsequent successful monthly surveillances before the test failure. Thus there was fault exposure and unplanned maintenance unavailability incurred.) If a licensee is required to take a component out of service for evaluation and corrective actions related to a Part 21 Notification or if a Part 21 Notification is issued in response to a licensee identified condition (i.e. Report # 10CFR21-0081), should the licensee have to count the fault exposure and unplanned unavailability hours incurred? Response:	5/2 Introduced	FitzPatrick
22.1	IE02	**Question** **Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" A loud noise was heard in the Control Room from the Unit 2 Turbine Building. Operators noted a steam leak, but could not determine the source of the steam because of the volume of steam in the area. It was suspected that the leak was coming from the No. 21 or 22 Moisture Separator Reheater (MSR). The steam prevented operators from accessing the MSR manual isolation valves. Due to the difficulty in determining the exact source of the leak, the potential for personnel safety concerns, and the potential for equipment damage due to the volume of steam being emitted into the Turbine Building, operators manually tripped the Unit. After the manual trip, a large volume of steam was still being emitted, and the shift manager had the main steam isolation valves (MSIVs) shut. Once the MSIVs where shut, the operators identified a ruptured 2-inch diameter vent line from No. 21 MSR second stage to No. 25A Feedwater Heater. The operators shut the second stage steam supplies and isolated the leak. Once the leak was isolated, the MSIVs were opened and normal heat removal was restored. The majority of the steam that was emitted following the trip was due to all the fluid in the MSR and feedwater heater escaping from the pipe.** **Response** **No. Complete closure of the MSIVs was easily recoverable from the Control Room without the need for diagnosis or repair to restore the normal heat removal path. The normal heat removal path was easily recoverable from the Control Room by reopening the MSIVs. The leak, by itself, did not affect the normal heat removal function. The shift manager could have alternatively had the Turbine Building cleared and had the MSIVs reopened if the heat removal safety function was threatened. For this event, the secondary heat sink was not lost.**		**Calvert Cliffs**
22.2	**IE02**	**Question** **Should the following reactor trip described in the scenario below be reported as a "Scram with Loss of Normal Heat Removal?" Following a reactor trip, No. 11 Moisture Separator/Reheater second-stage steam source isolation valve (1-MS-4025) did not close. The open valve increased the cooldown rate of the Reactor Coolant System. Control Room Operators closed the main steam isolation valves and used the atmospheric dump valves to control Reactor Coolant System temperature. Within three hours, 1-MS-4025 was shut manually. Control Room Operators opened the main steam isolation valves, and Reactor Coolant System temperature control using turbine bypass valves was resumed.**		**Calvert Cliffs**

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response No. Operators intentionally took actions to control the reactor cooldown rate by closing the main steam isolation valves. The normal heat removal path was easily recoverable from the Control Room without the need for diagnosis or repair to restore the normal heat removal path.		

ATTACHMENT 5

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
PV 3	1	1	2	Unplanned shutdown to repair leak in steam generator downcomer sample line Average daily power on 9/26/00 was 30,400 / 24 = 1267 Average daily power on 9/27/00 was 23,600 / 24 = 983 Average daily power on 9/28/00 was 0 / 24 = 0 9/27/00 Power reduction = 284 9/28/00 Power reduction = 983 "Maximum Dependable Capacity" for Unit 3 as used to determine capacity factor = 1247 .20 X 1247 = 249 **Current ROP:** Count as unplanned power reduction **NEI Proposal:** Count as non-elective power reduction **NRC Proposal:** Count as 2 power reduction >20% (284 is greater than 249 ; 983 is greater than 249)
ComPeak1	1	1	2	Rx Power: 30% Gen Power: 30% approx 287 MWe. (242 MWe NET) 70% power reduction. High sodium in waterbox power to 30% to investigate. Leak isolated ramped to 722 MWe (677 MWe NET) 60% Rx power for repairs. Returned to 100% 7/26/00 NEI 99-02: Counted due to it being a Unplanned Power Change > 20%. NEI Proposed: Counted due to it being a unanticipated Rx power reduction NRC Proposed: Counted due to exceeding net Average Daily Power change > 20% *The *NRC Proposed PI is not specific to events and as a result this event caused the ADP to change by >33% on the first day and by an additional 22% on the second day (total 55%). The wording of the PI does not exclude this counting as 2 for "the number of reductions in average daily power (ADP) level > 20% of full power".*
PB2	1	1	1	Unplanned - Decreased power in order to troubleshoot feedwater heater water hammer and pressurization events. Action was not immediately required to avoid an automatic trip or reactor shutdown, but was taken <72 hours after the condition was identified. Average daily power change >20% (56% decrease).
PB2	1	1	1	Unplanned - Decreased power due to the trip of the 2A recirc pump. Event occurred because of the incorrect installation of a capacitor. Action with <72 hours notice, and was required to avoid an automatic trip. Average daily power change >20% (39% decrease).
PB2	1	1	1	Unplanned - Decreased power following the test failure of drywell vacuum relief valve. Action taken <72 hours after failure of test, and was required. Average daily power change >20% (80% decrease).
PB3	1	1	1	Decreased power due to a low lube oil level alarm in the 3B recirc pump motor. Action was taken <72 hours after the condition was discovered, and was required. Average daily power change >20% (65% reduction).
PB3	1	1	1	Decreased power due to a low lube oil level alarm in the 3B recirc pump motor. Action was taken <72 hours after the condition was discovered, and was required. Average daily power change >20% (65% reduction).

Attachment 5

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
TMI	1	1	1	Unplanned power reduction to 65% power due to Feedwater Pump trip during surveillance testing .NEI 99-02 : Counted due to it being an unplanned power reduction of > 20% NEI Proposed: Counted due to it being an unplanned power reduction >20%.NRC Proposed: Counted due to it being an unplanned power reduction >20%. (35% ADP)
OC	1	1	1	Power reduction to indentify and suppress fuel leaks
LIM2	1	1	1	#4 Main Turbine Control Vlv Failed Closed due to Failed Servo, the load drop was unplanned and caused ADP to be 43%. The load drop was not required by Tech Specs to be taken but to be certain to avoid an auto scram, administratively we took a load drop so this is counted towards NEI because we took immediate action to avoid a scram
LIM2	1	1	1	Recirc pump trip . Unplanned load drop, ADP 75%, automatic operator action required.
Farley 1	1	1	1	Power reduction to 60% due to cooling tower structural failure. The average daily power level change was 20.6% therefore this counts in the NRC proposed PI. This also is considered a count in the NEI proposed PI since a ramp was commenced 9 minutes after receiving information locally of the damaged cooling tower. The ramp was completed in 48 minutes which is faster than a normal ramp.
Brunswick 1	1	1	1	Rx power reduced to < 60% due to trip of the 1A RFP turbine on low suction pressure. <u>NEI 99-02:</u> Unplanned power change > 20%. <u>NEI Proposed:</u> Power reduction occurs automatically or immediately with no operator action. <u>NRC Proposed:</u> Average daily power change > 20%.
Brunswick 1	1	1	1	Rx power reduced to ~ 60% - 1A RFP turbine tripped due to problems with the main oil pump. <u>NEI 99-02:</u> Unplanned power change > 20%. <u>NEI Proposed:</u> Power reduction occurs automatically or immediately with no operator action. <u>NRC Proposed:</u> Average daily power change > 20% (6/19/00).
Brunswick 2	1	1	1	2B Recirc pump tripped due to problems with the MG set exciter collector ring. NEI 99-02: Power change initiated < 72 hours following the discovery of an off-normal event. <u>NEI Proposed:</u> Power reduction occurs automatically or immediately with no operator action. <u>NRC Proposed:</u> Average daily power change > 20%.
Cooper	1	1	1	Discovered a hot wiring connection through thermography on the "A" Recirc MG-Set. Reduced power to enter Single Loop Operation and repair. Meets NRC PI criteria.
Cooper	1	1	1	Human error during performance of a surveillance resulted in a critical bus load shed and tripping of a recirc pump. This would count under both proposed criteria as well as the current criteria.
Millstone 2	1	1	1	A forced downpower to 55% power due to a failure of the "A" Steam Generator Feed Pump trip test relay to reset.Current ROP: Counted, unplanned change greater than 20% power NEI Proposal: Counted, operator action to preclude an automatic reactor shutdown.NRC Proposal: Counted, greater than 20% ADPL reduction
N Anna 2	1	1	1	Reactor shutdown due to RCS leakage from the "C" reactor coolant loop bypass valve leaking past the valve stem packing material. <u>Current ROP:</u> Counted, unplanned power change less than 72 hours from discovery of RCS leak.<u>NEI Proposal</u>: Counted, power reduction in response to TS action statement.<u>NRC Proposal</u>: Counted, greater than 20% ADPL reduction

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Surry 2	1	1	1	Unit Shutdown from 100 % power in response to Technical Specification action statement to Replace Snubber 2-RC-HSS-116. Current ROP: Counted as unplanned change in power greater than 20 %-NEI Proposal: Counted as unanticipated power reduction in response to TS Action Statement NRC Proposal: Counted as ADPL reduction greater than 20%
PV 1	1	1	1	Rx Cutback due to turbine generator excitation system diode failure - Rx power reduced to 10% Average daily power on 5/20/00 was 30,100 / 24 = 1254; Average daily power on 5/21/00 was 15,300 / 24 = 638; Power reduction = 616; "Maximum Dependable Capacity" for Unit 1 as used to determine capacity factor = 1243; .20 X 1243 = 249; **Current ROP:** Count as unplanned power reduction; **NEI Proposal:** Count as non-elective power reduction; **NRC Proposal:** Count as power reduction >20% (616 is greater than 249)
PV 2	1	1	1	MSIV closed due to a faulty solenoid valve on 5/8/00 - downpowered to 65% Average daily power on 5/07/00 was 30,500 / 24 = 1271 Average daily power on 5/08/00 was 29,000 / 24 = 1208 Average daily power on 5/09/00 was 15,900 / 24 = 663 5/8/00 Power reduction = 63 5/9/00 Power reduction = 545 "Maximum Dependable Capacity" for Unit 2 as used to determine capacity factor = 1243 .20 X 1243 = 249 **Current ROP:** Count as unplanned power reduction **NEI Proposal:** Count as non-elective power reduction **NRC Proposal:** Count as 1 power reduction >20% (63 is less than 249 ; 545 is greater than 249)
PV 2	1	1	1	Rx Cutback during WSCC VAR test followed by Rx trip on DNBR Average daily power on 11/17/00 was 30,700 / 24 = 1279 Average daily power on 11/18/00 was 14,000 / 24 = 583 Power reduction = 696 "Maximum Dependable Capacity" for Unit 2 as used to determine capacity factor = 1243 .20 X 1243 = 249 **Current ROP:** Count as unplanned power reduction **NEI Proposal:** Count as non-elective power reduction **NRC Proposal:** Count as power reduction >20% (696 is greater than 249)
ComPeak1	1	1	1	Rx Power: 65% Gen Power: 65% approx 748 MWe (703 MWe NET). 34% power reduction. Heater Drain Pump 1-02 Expansion Joint leak. Returned to 100% power on 9/25/2000. NEI 99-02: Counted due to it being a Unplanned Power Change > 20%. NEI Proposed: Counted due to it being a unanticipated Rx power reduction.- NRC Proposed: Counted - Exceeded net Average Daily Power change > 20% (ADP 28.4%)

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
ComPeak2	1	1	1	Rx Power: 65% Gen Power: 65% approx 762 MWe (717 MWe NET). 34% power reduction. Heater Drain Pump 2-01 Expansion Joint leak. Returned to 100% power on 11/15/2000. NEI 99-02: Counted due to it being a Unplanned Power Change > 20% NEI Proposed: Counted due to it being a unanticipated Rx power reduction. NRC Proposed: Counted - exceeded net Average Daily Power change > 20%- (ADP 31.1%)
Quad 2	1	1	1	47%RCTP = 53% power reduction;Condenser vacuum transient NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (22% based on ADPL = 610)
Quad 2	1	1	1	33%RCTP = 67% power reduction; Unplanned SBM switch replacement NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (48% based on ADPL = 375)
Quad 2	1	1	1	30%RCTP = 70% power reduction;Unplanned for troubleshooting #3 TCV NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (22% based on ADPL = 611)
Quad 1	1	1	1	31%RCTP = 69% power reduction;Unplanned due to recirc pump trip NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (53% based on ADPL = 367)
Quad 1	1	1	1	27%RCTP = 73% power reduction;Unplanned due to recirc pump trip NEI 99-02; counted due unplanned NEI Proposal; counted due unanticipated NRC Proposal; counted due load reduction > 20% of full power (32% based on ADPL = 528)
Dresden 2	1	1	1	Unplanned Inadvertent trip of "B" RR M/G set 820 MWE to 210 MWE loss of 5596 MWH 28% ADPL reduction
Dresden 2	1	1	1	Rx Power: 25% Gen Power: 20% approx 150 MWe.75% power reduction. Reactor Recirculation pump tripped manually due to brush arcing.--NEI 99-02: Counted due to it being unplanned >20% power change. --- NEI Proposed: Counted due to it being an unplanned >20% power change. NRC Proposed: Counted due to being >20% ADPL decrease (75% decrease)
LaSalle2	1	1	1	EHC malfunction 21 % power drop
LaSalle2	1	1	1	TCV failed closed 23 % power drop
LaSalle2	1	1	1	Feedwater pump repairs 22 % power drop
LaSalle2	1	1	1	Transient after Unit 1 scram

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Braidwood2	1	1	1	Unit 2 turbine-generator was rampled off-line to repair a hydraulic oil leak. Reactor power change was aproximately 80%.
FitzPatrick	1	1	1	Decreased power from 94 % to approximately 60%. A short circuit within RWCU hold pump resulted in a voltage perturbation on L-13 bus, causing 02A-K46A relay to drop out causing an "A" RWR pump run back to 44%. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power reduction. **NRC Proposed**: Counted – exceeded net Average Daily Power change > 20% (25.2% ADP)
FitzPatrick	1	1	1	Decreased power from 100% to approximately 50% due to an outboard seal failure on the "B" Rx. Feedwater pump. **Current ROP**: Counted due to being an Unplanned Power change >20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power changed > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 30.8%)
FitzPatrick	1	1	1	Decreased power from 100% to approximate 50% due to an oil leak from the "B" Rx. Feedwater pump bearing oil seal. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 44.2%).
FitzPatrick	1	1	1	Decreased power from 50% to 0% due to EHC fluid leak on Turbine Stop Valve #1. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 100%).
FitzPatrick	1	1	1	Decreased power from 100% to approximately 12% due to a Main Turbine EHC fluid leak. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Counted – exceeded net ADP change > 20% (ADP 45.3%).
Salem 1	1	1	1	Traveling screen failure. This was counted in all three PI's. Power reduction commenced approximately 2 hours after the condition was discovered and resulted in an average daily power change of greater than 20%. Although the plant was not in danger of a plant trip, under other environmental conditions, this condition could have resulted in a plant trip; therefore, this is being counted toward the NEI proposal.
LIM1	1	1	0	Reactor feed pump sleeve crack, ADP not below 80%,
LIM1	1	1	0	1C reactor feed pump turbine lube oil reservoir low level, immediate action required, ADP not below 80%
LIM2	1	1	0	Reactor recirc pump runback, automatic action required, ADP not below 80%
Hatch 1	1	1	0	Reduced load due to #4 turbine control valve closed and #1 and #2 turbine bypass valves opened. This equipment failure required prompt operator action. This does not count in the NRC proposed PI since the average daily power level reduction was not >20% from the 22nd to the 23rd. However, see the next power reduction.
Hatch 2	1	1	0	Power reduction due to the loss of an electrical bus (due to personnel error) resulted in a recirculation pump runback. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
Cooper	1	1	0	During performance of a surveillance, it was discovered that two sump pumps required for secondary containment were outside the surveillance acceptance criteria. This required them to be declared inoperable and thus initiated a technical specification entry into LCO 3.0.3. The power reduction was initiated and exceeded 20%. This met the criteria for the current NRC PI and the proposed NEI PI. It did not meet the proposed NRC criteria as the daily average power level did not drop below 80%.
Dresden 3	1	1	0	Unplanned 820mwe to 600mwe to repair stm seal relief, loss of 1150mwh 6% ADPL recduction

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
FitzPatrick	1	1	0	Decreased power from 95% to approximately 30% due to loss of "A" Rx. Feedwater pump due to power interruption to 10100 bus. **Current ROP**: Counted due to being an Unplanned Power change >20%. **NEI Proposed**: Counted due to being an unanticipated Rx. Power change > 20%. **NRC Proposed**: Not counted – did not exceed net ADP change > 20% (13.1%).
FitzPatrick	1	1	0	Decreased power from 100% to approximately 70% to complete repairs on outboard MSIV limit switch. **Current ROP**: Counted due to being an Unplanned Power change > 20%. **NEI Proposed:** Counted due to being an unanticipated Rx. Power reduction. **NRC Proposed:** Not counted due to not exceeding ned ADP . 20% (ADP 3.4%)
Brunswick 1	0	1	0	Derated to 620 MWe due to loss of Weatherspoon transmission line. <u>NEI 99-02:</u> Power change requested by the system load dispatchers are excluded. <u>NEI Proposed:</u> Unanticipated power reduction/ prompt operator action required to preclude an automatic reactor shutdown or turbine trip. <u>NRC Proposed:</u> Average daily power change < 20% and reductions directed by the load dispatcher for grid stability concerns arising from external events outside the control of the nuclear unit are excluded.
PB2	1	0	1	Unplanned - Decreased power in order to isolate the "B" feedwater heater string. Action was taken <72 hours after identification of the problem. Action was not immediately required to avoid an automatic trip or turbine reactor shutdown (leaking tubes in the 2B feedwater heater). Average daily power change >20% (33% decrease).
PB2	1	0	1	Unplanned - Decreased power to repair leaks in the A2 condenser waterbox. Action was not required to avoid a turbine trip or reactor shutdown, but was taken <72 hours after discovery of the condition. Average daily power change >20% (33% decrease).
PB2	1	0	1	Unplanned - Decreased power following intrusion of neutrally bouyant log into 2C circ water travelling screen. Action taken <72 hours after discovery of condition, but was not required. Average daily power change >20% (21% decrease).
OC	1	0	1	Main Generator taken offline to perform maintenance on the main transformer (M1A). Less than 72 hours planning, but was perfomed as a controlled maintenance activity.
OC	1	0	1	Power reduction to repair Cooling Water system leak. Less than 72 hours planning, but was performed as a controlled maintenance activity.
OC	1	0	1	Power reductino to replace turbine vacuum trip device. Less than 72 hours planning, but was performed as a controlled maintenance activity.
LIM1	1	0	1	Rod Pattern adjustment after a scram, the load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement), NRC proposal because ADP 79%
LIM1	1	0	1	Load drop for condenser waterbox tube repairs, unplanned and ADP was 78%, the load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement)
LIM2	1	0	1	Planned and unplanned maintenance on reactor feed pump and MSIV solenoid, ADP 79%, load drop was anticipated (in other words not a prompt or automatic action and not a Tech Spec requirement)

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Hatch 1	1	0	1	Unit shutdown to repair condensate demineralizer valve internals. Condensate low pressure occurred during ramp up following outage. Unit was shutdown to disassemble and inspect valve internals. No prompt operator actions resulted in >20% power change. Therefore this does not count in the NEI proposed PI. Average change in daily power level was greater than 20%.
Millstone 2	1	0	1	During Combine Intermediate Valve testing a secondary plant transient occurred due to feedwater heater drain level control problems. Operators reduced power to 80% and restored feedwater heater to normal configuration.Current ROP: Counted, however was not greater than 20% power reduction and is being reevaluated for reporting.NEI Proposal: Not counted, not greater than 20% power reduction NRC Proposal: Counted, ADPL reduction slightly greater than 20%.-*Note: Counted or not counted for this power reduction appears to be a function of measuring gross output (reactor power) versus net output (ADPL)
BF 3	1	0	1	Downpower to work on 3A recirc pump MG set
FitzPatrick	1	0	1	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP:** Counted but an FAQ has been submitted to the NRC with justification as to why this downpower should be considered an event created from marine and biological debris contamination. **NEI Proposed:** Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed:** Counted but is contingent on results of the FAQ submittal.
Salem 1	1	0	1	Voltage Regulator Replacement followed by heater drain valve maintenance. This counts under the current rules because although the voltage regulator replacement was planned and scheduled more than 72 hours in advance, the heater drain valve maintenance was not. It would count under the NRC proposal because the average daily power changed by greater than 20% from the previous day. It would not count under the NEI proposal because it was voluntary maintenance.
Salem 1	1	0	1	EHC O-ring leakage. This counts under the current rules because the power reduction began 17 hours after discovery of the issue. It would count under the NRC proposal because the average daily power changed by greater than 20% from the previous day. It would not count under the NEI proposal because there was no impact on operability at the time that the power reduction commenced.
Ft. Calhoun	1	0	1	Rx Power: 0% Gen Power: 0% approx 502 MWe.(483 MWe NET) 100% power reduction. Plant shutdown to replace degraded reactor coolant pump seals on pump A.
Ft. Calhoun	1	0	1	Rx Power: 0% Gen Power: 0% approx 502 MWe.(483 MWe NET) 30% power reduction. Reduced power due to feedwater chemistry problem.
PB2	0	0	1	Power reduced to remove "B" feedwater heater string from service, due to suspected leaks. Action >72 hours after discovery of condition, not required. Power reduced to 68%.
PB3	0	0	1	Planned - Power reduction for planned evolution - lube oil system repairs on 3B recirc pump motor. Power reduced to 18%.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
TMI	0	0	1	Decreased power to 50% to fix minor condenser leak. Evolution conducted > 72 hrs after identification of problem. Downpower was electively initiated and not required to avoid turbine trip or reactor shutdown. Average daily power decrease was >20% NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being an anticipated power reduction. NRC Proposed: Counted due to it being a reduction <20% power level that does not meet any of the exceptions. (50% ADP)
OC	0	0	1	Power reduction to repair the 1-2 tank reheater. Planned maintenance 72 hours prior to power reduction.
LIM1	0	0	1	Rod Pattern adjustment and reactor feed pump repair, Planned, ADP 79%. (Other maintenance was performed, but the original LD was planned, doesn't count for NEI per the third example given)
LIM1	0	0	1	Planned LD for scram time testing, condensate pump repair, rod pattern adjustment, and MSIV testing. ADP 67%.
LIM2	0	0	1	Planned Rod pattern adjustment, scram time testing, condenser tube trial cleaning, ADP 75%
BF2	0	0	1	downpower to 75% for control rod pattern adjustments and SCRAM testing
BF2	0	0	1	Planned manual downpower w/shutdown to repair drywell leakage **within** of TS allowable
BF2	0	0	1	Repair 2A Condensate pump, SCRAM testing, Rod adjustments, RPS testing and misc scheduled maintenance
BF2	0	0	1	SCRAM Testing
Farley 1	0	0	1	Planned power reduction to remove a cooling tower from service for repairs. The change in average daily power level was 25.3 %. Therefore, this event would be included in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 1	0	0	1	Power reduction from 100% to 67% to repair feed water pump lube oil temperature control problems. The change in the average daily power level was 36 %. Therefore, this event would be included in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 2	0	0	1	Planned power reduction to remove a cooling tower from service for repairs. The change in the average daily power level was 26%. Therefore, this counts in the proposed NRC PI. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Hatch 1	0	0	1	Additional power reductions to replace servo-strainer on turbine control valve. These additional power reductions do not count under the current ROP PI and the proposed NEI PI. The additional power change was part of the planned power step change to repair the turbine control valve after stablizing the unit earlier. However, this power reduction in combination with the power reduction on Nov 23 did result in the average daily power reduction being greater than >20% from Nov 23 to the 24th. The unit power was subsequently raised and stablized until the following power reduction was commenced as part of a planned power reduction.
Hatch 1	0	0	1	Additional planned power reduction to repair steam leak on MSR manway resulted in average daily power reduction being greater than 20% from Nov 24 to 25th. This is not counted as part of the current ROP PI or NEI proposed PI because it was part of the planned power change.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Hatch 1	0	0	1	Additional power reduction from the 26th to repair steam leak on MSR manway, replace EHC system servo strainers and EHC system filters. This does not count in the current ROP PI since it was planned. Change in average daily power level was greater than 20%.
Hatch 2	0	0	1	Replace diode function generator card in the EHC system control loop and repair steam leaks on feedwater heaters. This did not count under the current ROP PI or NEI proposed PI since the work was planned greater than 72 hours in advance. However, the average daily power level change was greater than 20%
Hatch 2	0	0	1	Additional power reduction for planned maintenance activities which included feedwater valve maintenance, repair leak on feedwater heater level control valve, change EHC system filters, replace servo-strainers on turbine control valves and repair MSIV limit switch. These activities had been preplanned therefore they would not count in the NEI proposed PI or the current ROP PI. However, the average daily power level change was greater than 20%.
Hatch 2	0	0	1	Additional power reduction for turbine valve testing and planned maintenance activities which included feedwater valve maintenance, change EHC system filters, replace servo-strainers on turbine control valves. These activities had been preplanned therefore they would not count in the NEI proposed PI or the current ROP PI. However, the average daily power level change was greater than 20%.
Brunswick 1	0	0	1	Rx power reduced to 55% for Rod Improvement, valve and scram time testing. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20% (6/24/00).
Brunswick 1	0	0	1	Rx power reduced to 55% for Rod Improvement, valve and scram time testing. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20%.
Brunswick 2	0	0	1	Rx power reduced to 25% to add oil to the Recirc pump motor. NEI 99-02: Planned power reduction. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change > 20% (5/6/00).
Brunswick 2	0	0	1	Rx power reduced to 55% for valve and scram time testing. NEI 99-02: Planned > 72 hours before power reduction. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change > 20%.
Cooper	0	0	1	Inidications of a fuel pin leak are observed. Reduced power to find and suppress the leaking pin. This meets the new NRC criteria but did not meet the previous criteria since this was a planned power reduction that occurred greater than 72 hours after the first indication of a leak.
Cooper	0	0	1	Normal downpower for a control rod pattern adjustment. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Cooper	0	0	1	Normal downpower for a control rod sequence exchange. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Cooper	0	0	1	Planned downpower to investigate and troubleshoot a problem with one of the Main Turbine Govenor valve positioin limit switches. The problem had been identified two weeks prior to the downpower so it does not meet either the current criteria or the proposed NEI criteria. It does meet the new NRC criteria.
Cooper	0	0	1	Normal downpower for a control rod pattern adjustment. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
Cooper	0	0	1	Normal downpower for required surveillances. This did not count under the current criteria as it was scheduled greater than 72 hours in advnace and does not represent a degraded condition. This would count under the new NRC criteria based on a daily power average.
N Anna 2	0	0	1	Ramped down to 27% power to isolate 2-RC-49 ("B" loop hot leg sample isolation valve) due to suspected leakage from 2-SS-TV-208B ("B" loop hot leg sample trip valve).Current ROP: Not counted. Transient initiated greater than 72 hours after discovery of leaking valve.NEI Proposal: Not counted, doesn't meet any of the three criteria.NRC Proposal: Counted. Greater than 20% ADPL reduction.
N Anna 2	0	0	1	There was no event on this date. The reactor was fully shutdown.-----------NRC Proposal: This meets the criteria because ADPL goes from 558 Mwe on 1/19 to 0 Mwe on 1/20.
PV 3	0	0	1	Planned shutdown to repair RCP high vibration Average daily power on 2/16/01 was 30,200 / 24 = 1258 Average daily power on 2/17/01 was 200 / 24 = 8 2/17/01 Power reduction = 1250 "Maximum Dependable Capacity" for Unit 3 as used to determine capacity factor = 1247 .20 X 1247 = 249 **Current ROP:** No count - planned power reduction **NEI Proposal:** No count - elective power reduction **NRC Proposal:** Count as 1 power reduction >20% (1250 is greater than 249)
Sequoyah2	0	0	1	Planned power reduction for maintenance on Mn Feed pumps.
BF 3	0	0	1	Work on Heater Drain system flow element
ComPeak1	0	0	1	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing, and planned feedwater heater 1A steam leak repair. NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being planned work that plant management elected to completed during a routine downpower for testing. NRC Proposed: Counted - testing and repairs exceeded net ADP change > 20% (ADP 26.2%)
Quad 2	0	0	1	30% RCTP = 70% power reduction; Planned scram timing, rod pattern adjustment, & TCV #3 repairs. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; counted due >20% power [465 ADPL; 41% load reduction based on ADPL and RNWMe]

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Quad 2	0	0	1	0% RCTP = 100% power reduction; TCV #3 Repairs. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; counted due >20% power [267 ADPL; 66% load reduction based on ADPL and RNWMe]
Quad 1	0	0	1	No power reduction, just the ramp back up to full power from the drop on the night of the 15th. However, the ADPL = 600 which corresponds to a 23% delta with respect to rated net power. Does this count?
Dresden 3	0	0	1	Unit taken off line for generator ring repair 820mwe to 0mwe, loss of 38000mwh
Dresden 3	0	0	1	Rx Power: 37% Gen Power: approx 300 MWe. 63% power reduction. Planned power drop to repair a feedwater heater. NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. NRC Proposed: Counted since ADPL was >20% (63% decrease)
Dresden 2	0	0	1	Planned 820MWE drop to 700mwe for 3D3 heater leak loss of 4183mwh 21% ADPL reduction
Dresden 2	0	0	1	Rx Power: 30% Gen Power: 23% approx 200 MWe. 70% power reduction. Planned to repair condensor tube leaks.----NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. - NRC Proposed: Counted due to being >20% ADPL decrease (70% decrease)
LaSalle 1	0	0	1	Planned > 72 hours - Repair work on TCV solenoid valve 82 % power drop
LaSalle 1	0	0	1	Planned > 72 hours repair work on 12 A Feedwater heater 50 % power drop
LaSalle2	0	0	1	Planned > 72 hours repair EHC Accumulator 50 % power drop
LaSalle2	0	0	1	Planned > 72 hours repair #2 CIV servo valve 50 % power drop
LaSalle2	0	0	1	Planned > 72 hours Feedwater pump swap from TDRFP to MDRFP to allow Repairs to TDRFP25 % power drop
LaSalle2	0	0	1	Planned > 72 hours Feedwater pump swap from MDRFP to TDRFP after repairs, 25 % power drop
LaSalle2	0	0	1	Planned > 72 hours Repair work on 2A TDRFP 22 % power drop
Braidwood2	0	0	1	Unit 2 was ramped down > 20% to allow repairs to 2FW090A which had a packing leak in containment. Planning had been in progress for longer than a month prior to the downpower when repairs were made. This was preplanned > 72 hours in advance.
FitzPatrick	0	0	1	Decreased power from 100% to approximately 50% for scheduled maintenance activities. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed:** Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Counted - downpower was not scheduled prior to startup from a refuel outage and exceeded net ADP > 20% (ADP 46.8%).
FitzPatrick	0	0	1	Power was decreased from 90% to 0% in support of a planned maintenance outage. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed:** Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Counted – downpower was not scheduled prior to startup from a refuel outage and exceeded net ADP > 20%.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Salem 1	0	0	1	This power reduction was for maintenance on the generator backup voltage regulator. It counts under the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current indicator or the NEI proposal because it was preplanned (greater than 72 hours in advance).
Salem 2	0	0	1	Turbine control valve testing and feedwater heater maintenance. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing.
Salem 2	0	0	1	Turbine control valve testing. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing.
Salem 2	0	0	1	Turbine control valve testing and scheduled equipment repairs. This counts toward the NRC proposal because it resulted in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing.
Hope Creek	0	0	1	Control valve testing and rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
Hope Creek	0	0	1	Main transformer maintenance. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
Hope Creek	0	0	1	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does count under the NRC proposal because it resulted in an average daily power change of greater than 20%.
Ft. Calhoun	0	0	1	Rx Power: 30% Gen Power: 30% approx 502 MWe.(483 MWe NET) 40% power reduction. Reduced power to reduce coolant activity before the refueling outage.
Farley 1	1	0	0	A leaking cooling tower header gasket was reported and 57 minutes later a ramp was commenced. I did not consider this "prompt" for the NEI proposal. The unit was ramped to 62% power in 1 hour and 53 minutes from the start of the ramp. It appears the decision to ramp was based on a conservative decision due to the concern of a potential failure similar to the July 5, 2000 structural failure. This is a faster ramp rate than normal operating procedures, however, exceeding the normal ramp rate is not a criteria in the NEI proposal. The average daily power level change from the previous day was 9.3%. Therefore, this does not meet the criteria of the proposed NRC PI.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Farley 1	1	0	0	A leaking rubber seal on a cooling tower header was identified at approximately 1800. At 2000 a power reduction was commenced and stopped at 2140 at 62 % power. This is a faster ramp rate than normal operating procedures in that the ramp rate exceeded 15 % per hour. This is not considered prompt under the NEI proposal. Also, the change in average daily power level due to this event was approximately 11%. Therefore, this does not meet the criteria of the proposed NRC PI.
Farley 1	1	0	0	After ramping to 100 % following the above power reduction, a leak was noted on another cooling tower. This leak was identified at approximately 2030. A power reduction was commenced at 2146 to approximately 60 % power at 2308. This was not considered prompt under the NEI proposal. The change in average daily power level due to this event was approximately 7.2 %. Therefore, this does not meet the criteria of the proposed NRC PI. However, over the three day period of these two power reductions the total change in average daily power level was 21.0%. However, this change of 21 % does not meet the criteria of the proposed NRC PI.
Hatch 2	1	0	0	Subsequent unexpected power increase (bus re-energized and controlled returned pump to normal speed) of greater than 20% power when power restored to the electrical bus and recirculation pump speed increased. Power change was unplanned. NEI proposed PI does not consider unexpected power increases. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
Hatch 2	1	0	0	Power reduction to repair leak on feedwater heater level control valve. The leak had occurred the previous day. Therefore, it counts under the current ROP PI, but not under the NEI proposed PI. Average daily power level change was less than 20% from the previous day, therefore it would not count in the NRC proposed PI.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 75%.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 67%.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 60%.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 69%.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 75%.
PB2	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 57%.
PB3	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 67%.
PB3	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 59%.
PB3	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment, and other planned maintenance activities. Power reduced to 21%.
PB3	0	0	0	Planned - Power reduced for planned evolution - control rod pattern adjustment. Power reduced to 74%.
BF2	0	0	0	Commenced Refueling Outage
Vogtle1	0	0	0	Manual Scram when main steam isolation valve closed. This does not count in the current PI nor either of the proposed PIs since this was a scram.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Vogtle1	0	0	0	Automatic scram during solid state protection system and reactor trip breaker testing. This does not count in the current PI nor either of the proposed PIs since this was a scram.
Vogtle2	0	0	0	None
Farley 1	0	0	0	Ramp from 94 % to 55 % power due to noise indicated on the steam generator metal impact monitoring system. Since this was planned it did not count in the current PI nor the proposed NEI PI. The change in average daily power level was 3.4%.
Farley 1	0	0	0	Planned power reduction to remove a cooling tower from service for repairs.The change in the average daily power level was 5.5 %. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Farley 2	0	0	0	Planned power reduction for mid-cycle steam generator chemical flushing. The change in average daily power level was 87 %. However, since this was a planned mid-cycle activity this activity does not count in the NRC proposed PI as well as the current and NEI proposed PIs.
Farley 2	0	0	0	Reactor scram
Farley 2	0	0	0	Planned power reduction to remove a cooling tower from service for repairs. The change in the average daily power level was 10%. Since this was planned it did not count in the current PI nor the proposed NEI PI.
Hatch 1	0	0	0	Planned control rod sequence exchange, scram time testing and turbine control valve testing. The average daily power level change was not greater than 20%.
Hatch 1	0	0	0	Planned control rod sequence exchange, scram time testing and turbine control valve testing. The average daily power level change was not greater than 20%.
Hatch 1	0	0	0	Automatic reactor scram due to turbine stop valve fast closure. Does not count in any of the PIs due to being a scram.
Hatch 1	0	0	0	During shutdown for refueling outage manual reactor scram at 55% power due to low suction pressure. Does not count in any of the PIs due to being a scram.
Hatch 1	0	0	0	Planned load reduction for control rod pattern adjustment
Hatch 1	0	0	0	Planned control rod sequence exchange and scram time testing. Average daily power change was less than 20%.
Hatch 1	0	0	0	Automatic reactor scram due to turbine trip. Does not count in any of the PIs due to being a scram.
Hatch 2	0	0	0	Control rod sequence exchange. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	Further power reduction for inspection and maintenance activities in condenser bay and too conduct turbine valve testing during power ascension. Note change in average daily power from pervious day was 19.83%.
Hatch 2	0	0	0	Control rod sequence exchange, scram time testing and turbine control valve testing. Also replaced EHC servo-strainers and EHC system filters. The average daily power level change was not greater than 20%.

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Hatch 2	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Hatch 2	0	0	0	Control rod sequence exchange and scram time testing. The average daily power level change was not greater than 20%.
Brunswick 1	0	0	0	Rx power reduced to 55% for special backwashing of A-N and A-S debris filters. NEI 99-02: Planned power change initiated > 72 hours following discovery of an off-normal event. NEI Proposed: See clarifying notes under "*Unanticipated power reductions that are not counted*". NRC Proposed: Average daily power change > 20%, however, reductions in response to expected problems, such as accumulation of marine debris or biological contaminants in certain seasons are not counted.
Brunswick 1	0	0	0	Rx power reduced to 55% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	Rx power reduced to 55% for Rod improvement and scram time testing. NEI 99-02: Planned power change. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	Rx power reduced to 56% to perform special backwashing of the 2B-N debris filter. NEI 99-02: Planned power change initiated > 72 hours following the discovery of an off-normal event. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20% and reductions in response to expected problems, such as accumulation of marine debris or biological contaminants in certain seasons are not counted.
Brunswick 2	0	0	0	Rx power reduced to 70% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: Not unanticipated. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	All Rods Out (final rod improvement for cycle 15). NEI 99-02: Planned power change. NEI Proposed: Not an unanticipated power reduction. NRC Proposed: Average daily power change < 20%.
Brunswick 2	0	0	0	Rx power reduced to ~ 60% for Rod Improvement. NEI 99-02: Planned power change. NEI Proposed: An anticipated power reduction. NRC Proposed: Average daily power change < 20%.
Millstone 2	0	0	0	Reactor shutdown for scheduled refueling outage
Millstone 2	0	0	0	Reactor Trip from 65% power caused by a component failure related to the turbine-generator Power Load Unbalance test pushbutton Current ROP: Not counted, reactor trips excluded.NEI Proposal: Not counted, this is counted in the unplanned reactor shutdown indicator.NRC Proposal: Not counted, this is counted in the unplanned scram indicator.
N Anna 1	0	0	0	Automatic reactor trip due to generator output breaker failure. Current ROP: Not counted, automatic reactor trips excluded-NEI Proposal: Not counted since it is counted in unplanned reactor shutdown indicator-NRC Proposal: Not counted as it is included in the unplanned scram indicator
N Anna 1	0	0	0	There was no event on this date. The reactor was fully shutdown.-----------NRC Proposal: This meets the criteria because ADPL goes from 309 Mwe on 5/7 to 0 Mwe on 5/8.
Surry 1	0	0	0	Reactor shutdown for scheduled refueling outage.
Surry 1	0	0	0	Unit 1 Reactor Trip due to Unit 2 Outage Work being performed on wrong unit.

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
N Anna 2	0	0	0	Ramped down from 72% power for scheduled refueling outage.
N Anna 2	0	0	0	There was no transient on this date. There was a greater than 20 % ADPL change.<u>NRC Proposal</u>: Not counted, unit shutdown for a scheduled refueling outage
Surry 2	0	0	0	Reactor shutdown for scheduled refueling outage.
WattsBar 1	0	0	0	Coastdown for refueling; no single days reduction exceeded 20% power
Sequoyah 1	0	0	0	none
ComPeak1	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing-<u>NEI 99-02:</u> Not counted due to it being a planned evolution. <u>NEI Proposed:</u> Not counted due to it being a anticipated Rx power reduction. <u>NRC Proposed:</u> Not counted due to not exceeding net ADP change > 20% (ADP 7.3%)
ComPeak1	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. (830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing. <u>NEI 99-02:</u> Not counted due to it being a planned evolution <u>NEI Proposed:</u> Not counted due to it being a anticipated Rx power reduction. <u>NRC Proposed:</u> Not counted due to not exceeding net ADP change > 20% (ADP 8.5%)
ComPeak1	0	0	0	Rx Power: 83% Gen Power: 83% approx 957 MWe (914 MWe NET). Feedwater Heater 1B tube leak. Returned to 100% power on 1/28/2001. Approximate 17% power reduction. NEI 99-02: Not counted due to reactor power change not greater than 20%. NEI Proposed: Not counted due to reactor power change not greater than 20%.NRC Proposed: Counted due to potentially exceeding net ADP change > 20% *The NRC Proposed PI is not specific to what value is considered NET full power. Comanche Peak Unit 1 is designed rated at 1150 MWe. Using this criteria the change in ADP is 20.5%. If we use the 100% power level before the event or a 30 day average for full power (1111 MWe NET), the reduction was 17.8%. This would not have met the criteria for an event. The actual performance during the hottest summer months when high lake temperatures make the MWe NET performance about 1090 MWe NET, demonstrates the potential fluctuations in value for NET FULL POWER.*
ComPeak1	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction.- While down for the unplanned derate for the feedwater heater 1B tube leak repairs, the decision was made to take advantage of the downpower and perform the OPT-217 Turbine stop and control valve testing in the derate window. NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. NRC Proposed: Possibly counted with the above event due to exceeding net ADP change > 20%. Power change did not exceed 20% until the performance of the OPT-217.

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
ComPeak1	0	0	0	Rx Power: 79% Gen Power: 79% approx 906 MWe. (861 MWe NET). Approx 21% reduction. EHC Pressure switch failure. Returned to 93% Full Power 3/18/2001 (Unit in End of Cycle Coastdown for start of 1RF08) .- NEI 99-02: Not counted due to it being a less than 20% reduction in Rx Power NEI Proposed: Not counted due to it not exceeding 20% of full power. NRC Proposed: Possibly counted event due to exceeding design net ADP change > 20%. However, the unit full power (Reactor and Turbine) was only 93% due to the coastdown. The reduction from 93% to 79% would only be 14% reduction. The NRC proposed does not clearly address how this would be counted.
ComPeak1	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. Ramp down to begin 1RF08. This would not be counted due to being a planned evolution. NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction.NRC Proposed: Not counted due to it being a scheduled pre-outage activity.-
ComPeak2	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. - NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 5.7%)
ComPeak2	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.--NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 4.5%)
ComPeak2	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. Ramp down to begin 2RF05. Returned from outage 11/05 sync and 11/10 100% NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction. NRC Proposed: Not counted due to it being a scheduled pre-outage activity.-(ADP 61.9%)--
ComPeak2	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe.(830 MWe NET) 24% power reduction. Planned Routine OPT-217 Turbine stop and control valve testing.--NEI 99-02: Not counted due to it being a planned evolution. - NEI Proposed: Not counted due to it being a anticipated Rx power reduction. NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 4.9%)
ComPeak2	0	0	0	Rx Power: 85% Gen Power: 74% approx 851 MWe. 26% power reduction-- EHC pressure switch failure. --NEI 99-02: Not counted due N16 Rx power not exceeding >20%.(see below)-- NEI Proposed: Not counted due to n16 Rx power not exceeding >20% (see below) - NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 16.0%)

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
ComPeak2	0	0	0	Rx Power: 76% Gen Power: 76% approx 875 MWe. 24% power reduction.While down for the unplanned derate for EHC pressure switch failure repairs (See Above), the decision was made to take advantage of the downpower and perform the OPT-217 Turbine stop and control valve testing in the derate window. This adjustment staggered the unit testing . --- NEI 99-02: Not counted due to it being a planned evolution. NEI Proposed: Not counted due to it being a anticipated Rx power reduction NRC Proposed: Not counted due to not exceeding net ADP change > 20% (ADP 16.0%)
Quad 2	0	0	0	57% RCTP = 43% power reduction; Scram Timing, rod pattern adjustment, 1C1 FW Heater work. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [688 ADPL; 13% load reduction based on ADPL and RNWMe]
Quad 2	0	0	0	0% RCTP = 100% power reduction; Shutdown for Q2M16. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [690 ADPL; 12% load reduction based on ADPL and RNWMe] Note - for the next several days with the unnit offlione, the ADPL = -192/24hrs = -8 or 108% reduction from rated net electrical power. Would this be reported each day?
Quad 1	0	0	0	79%RCTP = 21% power reduction; Planned load reduction for CRD return to service & PMTs, and turbine testing. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due load reduction < 20% of full power based on rated NET electrical power (ADPL = 16730MWE/day / 24hrs = 697.08MWE/hr / 775 RNMWe = 90% = 10% power reduction).
Quad 1	0	0	0	57% RCTP = 43% power reduction; Planned reduction for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [692 ADPL; 11% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	66% RCTP = 34% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [749 ADPL; 3% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	68% RCTP= 32% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [731 ADPL; 6% load reduction based on ADPL and RNWMe]

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Quad 1	0	0	0	75% RCTP= 25% power reduction; Planned for scram timing & rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [729 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	67% RCTP= 33% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [733 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	65% RCTP= 35% power reduction; Planned for rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [731 ADPL; 6% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	0% RCTP= 100% power reduction; Planned shutdown for refuel outage Q1R16 NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due planned refueling outage
Quad 1	0	0	0	48% RCTP= 52% power reduction; Planned for startup testing and rod pattern adjustment NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due scheduled as post refuel startup testing. The reduction is however >20% power [607 ADPL; 22% load reduction based on ADPL and RNWMe].
Quad 1	0	0	0	52% RCTP = 48% power reduction; Planned to support corrective actions from prior recirc trip. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [645 ADPL; 17% load reduction based on ADPL and RNWMe] * Note: on the next day (11/16/00, the ADPL of 619 = 20.1% which would then be counted under the NRC Proposal although, technically, there wasn't a reduction on the 16th so would it get counted or not?. Load reduction began on 11/15/00 at 2000hrs and load was returned to full power at 0845 on 11/16/00. Had the load drop been longer over the 2 days, would the NRC Proposal require in the same event being reported twice?

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Quad 1	0	0	0	42% RCTP = 58% power reduction; Planned to support corrective actions from prior recirc trip. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [634 ADPL; 18% load reduction based on ADPL and RNWMe] ** On the next day, 11/18/00, the ADPL is reduced to 269 which is a 65% reduction from rated but since the reduction was actually on the 17th, would the 18th be counted?
Quad 1	0	0	0	75% RCTP = 25% power reduction; Planned rod pattern adjustment as part of scram recovery. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [760 ADPL; 2% load reduction based on ADPL and RNWMe]
Quad 1	0	0	0	60% RCTP = 40% power reduction; Planned scram timing & rod pattern adjustment. NEI 99-02; not counted due planned NEI Proposal; not counted due anticipated NRC Proposal; not counted due <20% power [780 ADPL; 0% load reduction based on ADPL and RNWMe]. Note that on the next day, 02/25/01, where the recovery takes place, the ADPL = 686 corresponding to a delta from rated net generation of 11%.
Dresden 3	0	0	0	Load Drop per Load Dispatchers request 750mwe to 520mwe, loss of 1745mwh 9% ADPL reduction
Dresden 3	0	0	0	Planned 820 to 580mwe for rod swap. Loss of 1767mwh 9% ADPL reduction
Dresden 3	0	0	0	Planned 820 to 540mwe for FWRV, loss of 3360mwh 17% ADPL reduction
Dresden 3	0	0	0	Rx Power: 70% Gen Power: approx 550MWe. 30% power reduction. Planned power change for control rod pattern swap.-----------------------------------NEI 99-02: Not counted due to it being a planned evolution. ------------------------------------- NEI Proposed: Not counted due to it being a anticipated Rx power reduction. --------------- NRC Proposed: Not counted since ADLP was <20% (5.0% decrease).
Dresden 3	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe. 100% power reduction. Reactor scram caused by reactor low level- NEI 99-02: does not count due being counted as a reactor scram . NEI Proposed: Doesn't count since counted as an unplanned reactor scram.- NRC Proposed: Doesn't count since counted as an unplanned reactor scram.
Dresden 2	0	0	0	Planned drop for steam leak in feedwater heater 817mwe drop to 650mwe, loss of 3432mwh 17% ADPL reduction
Dresden 2	0	0	0	Planned Control Rod Swap 820mwe to 648mwe, loss of 715mwh 4% ADPL reduction
Dresden 2	0	0	0	Planned CRD testing 820 to 648mwe. Loss of 1503mwh 8% ADPL recduction

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Dresden 2	0	0	0	Rx Power: 0% Gen Power: 0% approx 0 MWe.100% power reduction. Reactor Recirculation pump trip that led to a subsequent manual scram when they other recirculation pump tripped.--NEI 99-02: Not counted due to it being part of an event that culminated with a scram. - NEI Proposed: Not counted due to being counted in the unplanned scram indicator. -- NRC Proposed: Not counted due it being counted in the unplanned scram indicator.
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle 1	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
LaSalle2	0	0	0	Planned > 72 hours for Tech Spec. surveillance
Braidwood2	0	0	0	Unit 2 load was reduced from 100% to 0% for refueling outage A2R08. This was a planned shutdown.
Braidwood1	0	0	0	Unit 1 load was reduced from 65% in preparation for A1R08.
FitzPatrick	0	0	0	Decreased power from 100% to approximately 60% to perform repairs on Off-gas Recombiner Inlet valve. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx power reduction. **NRC Proposed**: Not counted due to not exceeding net ADP >20% (ADP 19%)
FitzPatrick	0	0	0	Decreased power from 100% to approximately 70% to complete control rod adjustments. **Current ROP**: Not counted due to being a planned evolution. **NEI Proposed**: Not counted due to being a anticipated Rx. Power reduction. **NRC Proposed**: Not counted due to not exceeding net ADP > 20% (ADP 5.4%)
FitzPatrick	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.
FitzPatrick	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination. **NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01
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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
FitzPatrick	0	0	0	Decreased power from 100% to approximately 60% due to Condenser fouling as a result of marine and biological debris contamination. **Current ROP**: Not counted due to being a result of conditions created from marine and biological debris contamination.**NEI Proposed**: Not counted due to being a result of a seasonal environmental condition (biological and marine contamination). **NRC Proposed**: Not counted due to being a result of conditions created from marine and biological debris contamination.
Salem 1	0	0	0	Manual trip - counted in scram PI
Salem 1	0	0	0	This power reduction was anticipatory due to a severe storm with the potential to impact a transmission line and does not count in any of the three indicators.
Salem 1	0	0	0	This power reduction was anticipatory due to solar magnetic disturbances and does not count in any of the three indicators.
Salem 1	0	0	0	Plant trip - counted in scram PI
Salem 1	0	0	0	Inspect and fill Reactor Coolant Pump Oil. This does not count under the current PI because it was planned greater than 72 hours in advance. It does not count toward the NRC proposal because it did not result in an average daily power change of greater than 20% (change was 98mw <10%). It does not count toward the NEI proposal because it is voluntary maintenance.
Salem 1	0	0	0	Plant trip - counted in scram PI
Salem 2	0	0	0	This power reduction does not count for any of the proposals because it was due to a load dispatcher request associated with abnormal grid situation and solar magnetic disturbances.
Salem 2	0	0	0	This power reduction does not count for any of the proposals because it was for the beginning of 2R11.
Salem 2	0	0	0	Turbine control valve testing. This does not count toward the NRC proposal because it did not result in an average daily power change of greater than 20%. It does not count toward the current PI because it was planned greater than 72 hours in advance. It does not count toward the NEI proposal because it is limited to planned maintenance and surveillance testing.
Hope Creek	0	0	0	Shutdown for RF09
Hope Creek	0	0	0	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20%.
Hope Creek	0	0	0	Rod adjustments. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20% (approximately 17%).
Hope Creek	0	0	0	Control valve and scram time testing. This does not count under the current PI because it is pre-planned (greater than 72 hours in advance). It does not count under the NEI proposal because it was a planned evolution. It does not count under the NRC proposal because it did not result in an average daily power change of greater than 20%.

IE03 Power Change Performance Indicator Comparison 4/1/00 through 3/31/01

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Plant	Counts as:			
	ROP	NEI	NRC	Cause/Explanation
Hope Creek	0	0	0	This power reduction was anticipatory due to solar magnetic disturbances and does not count in any of the three indicators.
Ft. Calhoun	0	0	0	Rx Power: 70% Gen Power: 70% approx 502 MWe.(483 MWe NET) 19.14% power reduction. Reduced power to reduce coolant activity before the refueling outage.
	74	53	123	

ATTACHMENT 6
NRC RISK 2000-21 Pilot PI Experience as of May 31, 2001

NRC RIS 2000-21 PILOT PI EXPERIENCE AS OF MAY 31, 2001

- Over the six month trial, no differences were noted between the data reported under the current program's "unplanned scrams per 7000 critical hours" and the pilot program's "unplanned reactor shutdowns per 7000 critical hours" performance indicators.

- Over the six month trial, three differences were noted between the data reported under the current program's "unplanned scrams with loss of normal heat removal" performance indicator and the pilot program's "unplanned reactor shutdowns with loss of normal heat removal" performance indicator (Salem Unit 1 and Farley Unit 2 had pilot program reactor shutdowns not meeting the current program's scram definition, and, conversely, Dresden Unit 2 had a current program scram not meeting the pilot program's reactor shutdown definition. This would indicate no significant divergence in the two data sets.

  From the data collected in NUREG/CR-5750, the expectation value for scrams with loss of normal heat removal for the pilot program PWR and BWR plant population is 2.42 events per six months. The current program experience was one such event, and the pilot program experience was two such events. This again indicates no significant divergence in the two data sets.

- The NRC staff believes that clarifications would be needed (possibly in the form of FAQs) to explain which insertions of negative reactivity start the "15 minute clocks" within the pilot performance indicators (do insertions of negative reactivity conducted in response to events unrelated to the same cause as the eventual scram count, and do simple PWR steam demand or BWR recirculation pump controlled downpower maneuvers qualify? [The staff's review of CY2000 LERs identified 10 potential non-counted scrams involving power reductions which were initiated for reason's unrelated to the event which >15 minutes later drove the operators to manually scram, and 2 other events where downpower maneuvers related to the destabilizing event preceded a scram by > 15 minutes.]

- Further clarification would be needed to explain that, for certain reactor designs and types, certain scenarios of loss of normal heat removal may be more probable than is true at other reactor designs and types, but they nevertheless are not to be considered as "planned" even if "expected" by virtue of the design.

- Although the staff has no data suggesting a problem currently exists, it can be argued that perceived potential exists for licensees to be influenced to take less than conservative action to avoid "taking a PI hit" on the proposed replacement performance indicators (not unlike existing concerns raised with respect to the current performance indicators). For example, in order to ensure exceeding 15 minutes, licensee management may influence operators who are considering scramming the reactor. Another scenario could be, at reactor designs and types more susceptible to loss of normal heat removal, for licensees to change their procedures to establish a purposeful initiation of a loss of normal heat removal (so that the loss could be considered as "planned" and therefore not be counted under the PI).

- With respect to licensee burden, industry reports seeing no difference in reporting burden between the current and pilot performance indicators.

Attachment 6

ATTACHMENT 7
Fault Exposure Hour Study Charts and Information

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
1	ANO 2	MS03	1			45.3	Yes	?	Contact: Steve Coffman Hours are T/2. No known SDP performed. No LER written on event. Event was "breaker failed to close on SDEFW pump".
2	Beaver Valley 1	MS01	2	62			No	Yellow	Contact: John Maracek Hours are total. Time of failure known. SDP Yellow? LER 2000-002. One train of River Water System inoperable. Event affected multiple safety systems.
3	Beaver Valley 1	MS02	2	62					
4	Beaver Valley 1	MS04	2	62					
5	Braidwood 1	MS01	1	7.4			Yes	?	Contact: Randy Mika Hours are T/2. Time of failure not known. SDP? No LER. EDG load oscillations caused by loose wire in the governor.
6	Callaway	MS03	1			231.3	No	Green	Contact: Kevin Schoolcraft Hours are Total. Time of failure was known. SDP performed and characterized preliminarily as "Green". LER 2000-006. Reported fault exposure hours are for an Aux. Feed Pump room cooler below minimum flow requirements.
7	Catawba 2	MS01	1		8.1		No	?	Contact: Kay Nicholson Hours are total. Time of failure known. SDP not known. No LER. EDG sequencer reset actuator failure.
8	Catawba 2	MS01	2	527.97			No	?	Contact: Kay Nicholson Hours are total. Time of failure known. SDP not known. LER 2000-001.Failure of EDG output breaker.
9	Cook 2	MS03	3		78.06		No	?	Contact: Toby Woods Hours are Total. Time of failure known. SDP not known. LER 2000-005. Feedwater pump inoperable due to incorrect flow retention valve setting.

Attachment 7

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
10	Davis-Besse	MS03	1		168		No	Green	Contact: Gerald Wolf Hours are Total. Time of failure known. SDP performed and characterized as "Green". LER 2000-005. Event was discovery of open drain valve on TDEFW system.
11	Farley 1	MS01	3	1228.5			No	?	Contact: Jack Kale Hours are total. Time of failure known. SDP? No LER. EDG breaker alignment problem.
12	Farley 2	MS01	1	1038.4			Yes	?	Contact: Jack Kale Hours are T/2. Time of failure not known. SDP? No LER. Feeder breaker for fuel oil transfer pumps inoperable.
13	Farley 2	MS03	1	668.9			Yes	?	Contact: Jack Kale Two events. Hours are T/2 for both events. SDP? No LER. Failure of MDAFWP room cooler to start due to aux contact on breaker (572.6 hours). Second event (96.1 hours).
14	Farley 2	MS03	3	234.5	515		Yes	Green	Contact: Jack Kale Two events. Hours are T/2 for both events. SDP Green. No LER. First event (234.5 in 1Q, 126.1 in 2Q). Second event was TDAFWP trip on start attempt (317.6 hours in 2Q).
15	Fermi 2	MS01	1	667.88	32.88		No	Green	Contact: Kevin Burke Hours are spread between 1Q & 2Q. Time of failure known. SDP Green. LER 2000-009. Low viscosity oil discovered in alternator bearing of EDG.
16	Hatch 2	MS04	1	1.367			Yes	?	Contact: Eddie Perkins Hours are T/2. Time of failure is not known. SDP? No LER. Primary DHR pump found tripped during system walk down.

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
17	Hope Creek	MS01	2		336		Yes	?	Contact: John Nagle Hours are T/2. Time of failure is not known. SDP? No LER. Diode failure in power supply to EDG voltage regulator.
18	Hope Creek	MS02	1		1.3		No	?	Contact: John Nagle Hours are total. Time of failure is known. SDP? No LER. 200 psig HPCI clock for discharge check valve maintenance.
19	Hope Creek	MS03	1		2.8		No	?	Contact: John Nagle Hours are total. Time of failure is known. SDP? No LER. RCIC demand failure.
20	Indian Point 3	MS01	3			4	Yes	?	Contact: Brian Rokes Hours are T/2. No known SDP performed. No LER written since Tech Spec LCO not exceeded. Inoperable pre-lube oil pump discovered during scheduled rounds; cause was blown fuse for heating element.
21	LaSalle County 1	MS03	1		5.4		No	?	Contact: Randy Mika Hours are total. Time of failure known. SDP? No LER. RCIC leakage resulting in potential for water hammer.
22	Millstone 2	MS02	2			654.2	No	Green	Contact: Michael Strout Hours are total. Time of failure known. SDP performed resulting in "GREEN" finding. LER 2000-014. Discovery, during routine surveillance, of low oil in bearing housing of HPSI pump.
23	Millstone 2	MS03	3			335	Yes	White	Contact: Michael Strout Hours are T/2. Time of failure not known. SDP performed resulting in WHITE finding. No LER. Inoperable speed control on Turbine driven AFW pump.

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
24	Nine Mile Point 1	MS04	4			558.07	No	?	Contact: Chris Skinner Hours are total. Time of failure known. SDP not performed. No LER. A containment spray pump motor tripped during a surveillance test due to a breaker lubrication problem.
25	North Anna 1	MS01	1	95.52			No	?	Contact: John Peyton Hours are total. Time of failure known. SDP? LER 2000-002. EDG cylinder hydraulically locked due to being full of oil.
26	North Anna 1	MS01	1		3.92		No	?	Contact: John Peyton Hours are total. Time of failure known. SDP? No LER. EDG placed in Local Manual for UV PT and later proved to be inoperable.
27	Oconee 1	MS04	1	34.88			Yes	No	Contact: Judy Smith Hours are T/2. Time of failure not known. No SDP. No LER. The LPI cross connect valve failed to open from the control room. The thermal overload for the valve was found in a tripped condition.
28	Palo Verde 3	MS02	2	984.1			Yes	?	Contact: Duane Kanitz Hours are T/2. Time of failure not known. SDP? No LER. Valve failed to open on HPI pump due to MCC failure.
29	Pilgrim	MS02	1			11.79	No	?	Contact: Doug Ellis Hours are total. Time of failure known. SDP? No LER. Flow controller problem during HPCI surveillance test.
30	Point Beach 1	MS01	1			604.1	No	?	Contact: Chuck Krause Hours are total. Time of failure known. SDP? No LER. Wrist pin bearing failed on EDG.
31	Prairie Island 2	MS01	1	340.05			Yes	?	Contact: Rod Stenroos Hours are T/2. Time of failure not known. SDP? No LER. EDG voltage regulator failed.

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
32	Quad Cities 1	MS02	1	1889.4			Yes	Green	Contact: Randy Mika Total hours spread over 3 quarters (5439.8 hours). Hours are T/2. Time of failure not known. SDP Green. LER 2000-003. HPCI Auxiliary oil pump cycle during logic testing, rather than starting and staying on to develop necessary oil pressure to allow HPCI start.
33	Quad Cities 2	MS02	1	1.67			No	Green	Contact: Randy Mika Hours are total. Time of failure known. SDP Green. LER 2000-005. Maintenance not completed on HPCI prior to reactor startup. HPCI did not start during low pressure testing.
34	Quad Cities 2	MS04	1	161.87			Yes	?	Contact: Randy Mika Hours are T/2. Time of failure not known. SDP? No LER. Motor operated valve on RHR failed to close during surveillance testing due to breaker issue.
35	River Bend	MS01	1			327.5	Yes	?	Contact: Tom Bolke Hours are T/2. Time of failure not known. SDP? LER 2000-014. Failed indicating light on EDG.
36	River Bend	MS01	2			419.5	Yes	?	Contact: Tom Bolke Hours are T/2. Time of failure no known. SDP? LER 2000-014. Crack in EDG turbocharger lube oil piping.
37	Summer	MS03	3			1157	No	?	Contact: Susan Reese Hours are total. Time of failure known. SDP being performed. LER 2000-006. Valve mispositioned on Terry Turbine EFW pump.
38	Susquehanna 2	MS04	2			104.8	No	?	Contact: Duane Filchner Hours are total. Time of failure known. No known SDP performed. No LER. Event was relay failure in shutdown cooling circuitry for RHR.
39	Turkey Point 3	MS01	2			268.7	Yes	?	Contact: Craig Mowrey Hours are T/2. Time of failure not known. Phase 1 SDP, unknown result. No LER. Failled speed control on EDG.

No.	Reactor Unit	PI	Train	1Q 2000	2Q 2000	3Q 2000	T/2	SDP	Info
40	Turkey Point 3	MS03	1			82	Yes	?	Contact: Craig Mowrey Hours are T/2. Time of failure not known. Phase 1 SDP, unknown result. No LER. Governor failure on AFW pump. Affects unit 4; AFW pump common to both units.
41	Turkey Point 3	MS03	2	0.25			No	?	Contact: Craig Mowrey Hours are total. Time of failure known. No SDP. No LER. AFW flow transmitter failed high.
42	Turkey Point 4	MS02	2			23	Yes	Green	Contact: Craig Mowrey Hours are T/2. Time of failure not known. SDP performed with GREEN finding. No LER. Gas binding of HHSI pump due to venting problem.
43	Turkey Point 4	MS03	1			82	Yes	?	Contact: Craig Mowrey Hours are T/2. Time of failure not known. Phase 1 SDP, unknown result. No LER. Governor failure on AFW pump. Affects unit 4; AFW pump common to both units.
44	Watts Bar 1	MS01	2		25.08		No	?	Contact: David Flournoy Hours are total. Time of failure known. SDP Green. No LER. Event was failure to reset interlock relay on CO2 system in Diesel building.

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

PROBLEM/ GOAL

To reset/ remove fault exposure hours for the mitigating systems unavailability performance indicators without overwriting historical data and changing the previous quarters' PI presentation on the web. Currently, if fault exposure hours are removed for a given plant in a given quarter, the previous quarters on the PI chart would be overwritten and it would appear as though the fault exposure hours never existed. The normal quarterly PI data submittals would be unaffected; instead, change reports would be submitted by those plants that are removing fault exposure hours.

MILESTONES

1.	Brief NEI/ industry on concept	05/02/01
2.	NEI to discuss their proposed revisions	05/31/01
3.	NEI/IT work closely with NRC to develop data file specifics	06/30/01
4.	Create an FAQ to document process change	06/30/01
5.	Revise NEI's and NRC's databases and algorithms	07/31/01
6.	Run test on selected plants/ scenarios	08/15/01
7.	Publish Regulatory Issue Summary to announce the change	08/31/01
8.	Begin to implement for ALL plants for historical data changes	08/31/01
9.	Implement for ALL plants historically and going forward	10/21/01
10.	Incorporate FAQ into NEI 99-02	05/31/01

Fault exposure hours may be removed on a case by case basis provided the following ~~conditions~~ criteria are met

- The applicable failures are associated with the same specific component
- Portions of the ~~failure~~ FEHs are associated with ~~managements conservative decision to~~ managements conservative decision to increase the surveillance testing frequency in an attempt to verify effective corrective action and a failure occurred during the increased surveillance frequency
- The NRC supplemental inspection considered all failures associated with the condition
- All the FEH reset criteria of NEI 99-02 have been satisfied

- The removal receive concurrence from the ~~Senior Resident~~ NRC

- A comment is placed in the comment field of the data submittal indicating more than one failure ~~a~~ was considered in resetting the FEDs

ATTACHMENT 8
Summary of the SSU Focus Group Meeting and Key Issues

SUMMARY OF THE SSU FOCUS GROUP MEETING

On May 16, 2001, Mike Johnson, Chief of IIPB, and Don Hickman of IIPB hosted an all-day public meeting of the Safety System Unavailability (SSU) Task Force (SSUTF) held at NRC headquarters. Steve Alexander, IQPB, represented maintenance rule (MR) interests. Hossein Hamazehee and Pat Baranowski represented RES/DRAA/OERAB. Tony Petrangelo and Tom Houghton represented the Nuclear Energy Institute (NEI). Other principal participants included representatives from INPO, Exelon, Southern Nuclear, Duke Power, and the industry group that is working on the consolidated data collection project. Reporters from McGraw-Hill and Scientech observed. The main topic was finding a common definition (including data to be collected and method of calculation) of SSU that would remain meaningful for the ROP (the SSU PIs), the MR, the PRA, and for INPO/WANO reporting. The group reviewed and discussed a "strawman" proposal by NEI in detail and several associated issues as delineated on the attached agenda.

The following comprise the principal results of the meeting:

1. The group agreed to the work towards development of a standard definition for unavailability (UA).

2. The group proposed that the risk/safety-significant functions to be tracked for unavailability be defined as:

> "those functions needed to be performed to satisfy the PRA success criteria, as defined for high-safety-significant (HSS) structures, systems and components (SSCs), per the industry guidance for 10 CFR 50.65, the Maintenance Rule, NUMARC 93-01, Revision 3."

All participants/interested parties were to present this definition to their respective organizations and report back at the July 12th meeting of the SSUTF.

2. The group discussed whether the UA definition should include UA while critical and UA while shutdown. As a result of concerns regarding differences in risk significance associated with shutdown and critical states, the group proposed to include only UA while critical. As an action, all participants will consider the ramifications of not counting HSS UA during shutdown, as one possible measure in normalizing the UA calculation. for all users, including MR, PRA, ROP, and INPO/ WANO. Representatives are to report their organizations' positions on this proposition at the July 12 meeting.

3. The group considered the following question: If T/2 (default estimate of unknown fault exposure time) were not to be included among unavailable hours (i.e., the numerator of the SSU fraction), what other tools might be available and usable to meet PRA, ROP, and INPO/WANO needs (note that MR does not use T/2)?

The group proposed two principal candidates for replacement of T/2:

3.a Reliability ROP performance indicators (PIs) for monitored systems in terms of numbers of functional failures per so many valid demands during a specified period. OERAB was to present a conceptual description of such PIs at the July 12th meeting. (Longterm fix)

Attachment 8

3.b Some sort of significance determination process (SDP) for SSU to supplement planned and unplanned unavailable hours and provide some alternative reliability insight. (possible near-term measure).

3.c To validate this measure, OERAB was to review significant T/2 events (i.e., T/2 longer than 336 hours) and compare results with SDP results of the same events. Status report due at May 31 mtg.

4. Handling of support system unavailability and its impact on SSU was discussed. The group proposed that unavailability PIs be developed for the two most HSS support systems, i.e., component cooling water (CCW) and service water (SW) systems or their equivalents (in addition to standby/ emergency electric power systems). One or two other HSS support systems may be added to the list if any should be identified. (Longterm)

4.a Until Action No. 4 above is completed, licensees should continue to cascade unavailability of proximate support systems onto SSU of their supported, front-line monitored systems.

4.b (Longterm) When CCW and SW PIs are implemented, cascading would be discontinued entirely for purposes of ROP and INPO/ WANO reporting. MR does not typically cascade (except possibly for ROP PI systems) and PRA must cascade interdependencies.

4.c NRC to consider, for the near term, cascading unavailability of CCW and SW only. Status by the July 13 meeting.

5. The group considered crediting operator recovery actions (ORAs) in reducing SSU charged in various situations.

5.a For testing, the group proposed to adopt (reaffirm) the treatment proposed by NEI in its strawman and as expressed in NEI 99-02, Page 28, and also NUMARC 93-01 language.

5.b For maintenance activities other than testing, specifically maintenance that may disable an automatic function (e.g.,standby/ auto-start), certain ORAs may be credited when manual operation is available *(and/or in use)*.

5.c ORAs may be credited in such situations provided that the manual operation and the ORAs meet all the criteria for ORAs creditable for testing.

6. The group discussed the treatment of design deficiencies. As a preliminary step, it was resolved to have the equipment reliability staff provide input based on industry operating experience. They are to evaluate counting certain design deficiencies against SSU and SS reliability versus use of an SDP. Cognizant parties are to have a strawman proposal on this issue reviewed by their organizations to present to the July 13 meeting.

7. Conceptual proposals on thresholds and implementation/phase-in are to be developed by all stakeholders and discussed at the July 13 meeting.

KEY ISSUES IN STANDARD SSU PI DEFINITION

1. **What is the scope of functions to be monitored in the SSU PI?**

   The confusion in the NRC PI came about over FAQs that treat design basis functions equally. The NRC PIs and thresholds were initially based on a risk-based scope that addressed the dominant functions. The standard definition should be based on the dominant risk-based functions modeled in the PSA and monitored in the maintenance rule. Counting the impact of design basis functions associated with low-risk scenarios compromises the effectiveness of the PI by overstating the risk impacts for that unavailability.

2. **What is the scope of support system functions monitored in the SSU PI?**

   The confusion in NRC PI has come about over FAQs that treat all support system functions equally. The NRC PIs and thresholds were initially based on a risk-based scope that addressed the dominant functions. NRC representatives believe that the dominant support function considered were ERCW (EECW) and CCS (RBCCW). The risk-based PI proposal includes a recommendation to add these 2 systems to the NRC PI mix. In the interim, the NRC SSU PI definition should limit support system impacts to these two systems. NRC needs to confirm this approach based on earlier work performed. Counting the impact of less risk-important support functions compromises the effectiveness of the PIs by overstating the risk impacts for the support system unavailability. In addition, the proposed change would align the current PI system with the RB PI proposal, which minimizes the impact of future changes.

3. **What unavailability should be included/evaluated from the indicator?**

   All unavailability should be counted with the following exceptions:

   a. Time for system maintenance, testing, or surveillances that can be quickly recovered with certainty (apply the standard definition for credit for operator action to these cases. A specific example for maintenance would be work on an auto-start timer where the manual start function was available and the criteria for operator action is met. (See additional discussion on "Credit for Operator Action.")

b. Estimated fault exposure time (T/2 time) that exceeds a threshold time limit for a single event. These items would be included in the comment field and NRC would assess through the SDP as a finding. The NEI benchmarking for this proposal needs to be reviewed and accepted. The time limit threshold (e.g. > 336 hours) needs to be established to minimize the impact on NRC inspection resources. NRC can inspect the corrective action documents for these issues as part of the baseline maintenance rule inspections, safety system design inspections, or the problem identification and resolution inspections, since they all sample corrective action documents. The WANO indicator will still include this unavailability; whereas, the NRC process will use it as a flag for a potential finding. This change would improve the PIs by eliminating the masking effect that a large T/2 event can have on the PI.

c. Unavailability during shutdown conditions. The NRC SSU PIs would focus on standby conditions during power operation. For two indicators, this change would have no impact. It is a change for the DG PI; however, the power operation data is a reasonable estimate of overall system performance during all modes since the system functional demands are not significantly different. It improves the validity of the indicator because it eliminates the confusion created by different TS requirements during shutdown that create differences in what shutdown unavailability is counted. (See additional discussion on "Default Hours.") This change will also impact the RHR PI; however it recognizes that unavailability is not a good measure for shutdown conditions. Unavailability is a good indicator for standby operation. In shutdown conditions, the RHR system is in service. Reliability is a better measure for this mode of operation. The NRC Maintenance Rule team will reassess their guidance for RHR unavailability during shutdown. This change can be made to the RHR PI now independent of the RB-PI efforts to establish either a shutdown risk PI or system reliability indicator, since unavailability not an effective measure for shutdown risk cases.

NOTE: These changes will eliminate the current exclusion for overhaul hours. (See additional discussion on "Threshold Basis.")

NOTE: We need to decide if we need to keep the separate reporting of planned and unplanned unavailability.

4. What operator actions should be credited when assessing unavailability impacts?

The current criteria used in the maintenance rule and NRC PIs ensures virtual certainty of success for allowed operator actions. It should be adopted by INPO/WANO. This credit for operator action should be applied equally to maintenance, testing, and surveillances. The specific maintenance example of work on auto-start controls discussed above should be included in the guidance.

5. **Should "Default Hours" be used instead of counting actual required hours?**

   The confusion on this point comes from the potential large non-conservative impact that can occur for extended shutdown periods. The problem is compounded when one is both trains of RHR or DGs are not required by TSs during the shutdown period. Default hours (critical hours) can be used to simplify data collection without impacting the validity of the PI by accepting the change to focus the SSU PIs only on power operation. We will need to assess if the Maintenance Rule guidance needs to be changed for consistency.

6. **What changes are needed to the NRC PI thresholds based on these changes?**

   The thresholds need to be reassessed for the impacts of changes to eliminate estimated fault exposure hours and the exception for equipment overhauls. The clarifications associated with front-line and support system scope were used as the basis for the original thresholds.

   NOTE: The question of plant-specific, risk-basis thresholds has been discussed. We need to carefully assess the NRC review and approval process that would be needed to support this approach. There is no clear guidance on PSA standards, update frequencies, and configuration control. In addition, the updated PSAs are not made publicly available. Without a clear process that is efficient and effective, we may under mine public confidence in the process, especially, if utilities can change the thresholds easily and frequently.