CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS Plant Operations Subcommittee

Docket Number: (Not Applicable)

Location: Rockville, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Laurie Rossbach

Laurie Rossbach
Official Reporter
Neal R. Gross & Co., Inc.

STATUS OF THE REACTOR OVERSIGHT PROCESS

Inspection Program Branch
May 9, 2001

TOPICS FOR DISCUSSION

- Initial Implementation Status
- Significance Determination Process
- Performance Indicators
- Selected Issues

OVERALL RESULTS

- Substantially Exercised Process
- Made Several Significant Changes
- Maintained Process Stable
- Successful Demonstration of Framework Objectives
- Data on Process Results and Resources

Example SDPs

Two No-color Findings

One Green Finding

One Non-Green Finding

Example No-color Inspection Finding

No-color Findings: Findings which do not affect a cornerstone or which have extenuating circumstances

Inspection Source: Inspection of issues identified in licensee LERs using Inspection Procedure 71153 (Inspection Report 05000286/2000-04)

Finding: Missed Control Room Oxygen Detector Surveillance Tests

Example No-color Inspection Finding (continued)

Documentation: Per IMC 0610* Appendix B, a finding that does not affect a cornerstone and cannot be processed by an SDP is documented as a No-color finding

Disposition of Finding: Confirmed entry into licensee corrective action program and treated as a non-cited violation (NCV) consistent with the NRC Enforcement Policy

Example No-color Inspection Finding

No-color Findings: Findings which do not affect a cornerstone or which have extenuating circumstances

Inspection Source: Inspection of licensee's Problem Identification and Resolution (PI&R) program using Inspection Procedure 71152 (Inspection Report 05000277/2000-13)

Finding: One Operator License application was submitted to the NRC incorrectly stating that certain training had been completed

Example No-color Inspection Finding (continued)

Documentation: Per IMC 0610* Appendix B, a finding that potentially impacts the NRC's ability to perform its regulatory function (e.g., failure to provide complete and accurate information) is documented as a No-color finding

Disposition of Finding: Confirmed entery into licensee corrective action program and treated as a non-cited violation consistent with the NRC Enforcement Policy

Example Green Inspection Finding

Inspection Source: Inspection of Surveillence Testing using Inspection Procedure 71111.22 (Inspection Report 05000260/2000-06)

Finding: Inadequate evaluation of RHR system flow rate test results. No evaluation was performed following temporary modifications which reduced RHR system flow rate to ensure that Technical Specification flow rate requirements were satisfied. Subsequent evaluations showed that system flow met all surveillence test requirements.

Example Green Inspection Finding (continued)

Documentation: Meets IMC 0610* documentation threshold based on affecting the mitigation systems cornerstone

Disposition of Finding: Confirmed entry into licensee corrective action program. Phase 1 SDP: Green finding based on system function affected, but operability and function maintained.

Example White Inspection Finding

Finding: Oil leak rate on one Emergency Feedwater (EFW) Pump bearing forced operators to make daily oil additions to maintain a visible level in the oiler sightglass. Upon questioning by resident inspectors, licensee determined that all four bolts on the outboard bearing housing inner cover had been loose for 39 days and that the pump would have overheated its bearing within a few hours of operation.

Example White Inspection Finding (continued)

Documentation: Meets IMC 0610* documentation threshold based on affecting the mitigation systems cornerstone

Phase 1 SDP

Continue to Phase 2 based on actual loss of safety function of a single train for greater than its Tech Spec Allowed Outage Time.

Example White Inspection Finding (continued)

Phase 2 SDP

Dominant accident sequence

Transient with Loss of PCS - Loss of EFW - Loss of Feed/Bleed

Initiating Event Likelihood = "A"
(SDP Table 1 using IE frequency > 0.1/yr and exposure time > 30 days)

Mitigating System Credit = 2 (remaining MDEFW pump)
1 (for available TDEFW pump)
2 (for feed/bleed availability)

5 (total credit - no operator recovery)

Significance Result = White (1E-6/yr to 1E-5/yr)

Example White Inspection Finding (continued)

Phase 3 SDP

Licensee PRA result for unrecoverable loss of MDEFW pump for 39 days is a change in CDF of 2.7E-6/yr

Neither result includes external event contributions (considered not to increase risk contribution beyond White, based on available external event risk insights)

Enforcement Action

Notice of Violation of 10CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" would be issued as is appropriate for an inspection finding of White or greater significance. Formal licensee response is required.

SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES

Reference/Title: NRC Inspection Report[redacted]
Motor Driven Emergency Feedwater Pump Inoperaable Due to Oil Leak

Factual Description of Identified Condition: On February 12, 2001, the resident inspectors found the oiler on the 'A' motor driven emergency feedwater pump (EF-P-2A) outboard bearing empty. An oil leak developed on the pump outboard bearing during performance of a quarterly surveillance run of the pump on February 1, 2001. The leak rate was of sufficient magnitude to require auxiliary operators to make daily oil additions to the pump bearing to maintain a visible level in the oiler sightglass. On February 14, 2001, engineers identified all four bolts on the outboard bearing housing inner cover were loose. Two of the four bolts were tightened one full turn each, and the other two one-half turn each. Tightening the bolts stopped the oil leak and corrected an unexplained step increase in pump vibrations observed during the February 1, 2001 surveillance test.

System(s)affected by identified condition: Emergency Feedwater System

Train(s) affected by identified condition: 'A' motor driven emergency feedwater pump train

Licensing Basis Function of System(s) or Train(s) (as applicable): The emergency feedwater system consists of three independent pumps (two motor driven and one turbine driven) and associated flowpaths to each of two steam generators. The system is designed to automatically actuate and remove secondary heat when the main feedwater system fails to function. Two of three pumps are required to meet the most limiting design basis flow requirement. The technical specification limiting condition for operation requires three pumps to be operable and permits an allowed outage time of 72 hours for one inoperable pump. An inservice test of each pump is required every 92 days.

Other Safety Function of System(s) or Train(s) (as applicable): None

Maintenance Rule category (check one): risk-significant

Time that identified condition existed or is assumed to have existed: Prior to the February 1, 2001 surveillance test, EF-P-2A was last run on January 6, 2001, for testing of the emergency feedwater system automatic start circuit. Any time after January 6, 2001, that EF-P-2A was called on to operate, would have resulted in the same condition that occurred following the February 1, 2001 surveillance test. Namely, the bearing housing cover bolts would have loosened and an excessive oil leak would have developed. Based on the observed rate of oil loss following the February 1, 2001 surveillance test, no credit is given for operator action to maintain the pump operable. The pump was inoperable from January 6, 2001, until the pump was repaired on February 14, 2001, a period of 39 days.

Functions and Cornerstones affected as a result of this identified condition (check ✓)

INITIATING EVENT CORNERSTONE

_____ Transient initiator contributor (e.g., reactor/turbine trip, loss offsite power)

_____ Primary or Secondary system LOCA initiator contributor (e.g., RCS or main steam/feedwater pipe degradations and leaks)

MITIGATION SYSTEMS CORNERSTONE

_____ Core Decay Heat Removal Degraded

_____ Initial Injection Heat Removal Degraded

_____ Primary (e.g., Safety Inj)

____ Low Pressure

____ High Pressure

__X__ Secondary - PWR only (e.g., AFW)

_____ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool cooling)

_____ Reactivity Control Degraded

_____ Fire/Flood/Seismic/WeatherProtection Degraded

BARRIERS CORNERSTONE

_____ RCS LOCA Mitigation Boundary Degraded (e.g., PORV block valve, PTS issue)

_____ Containment Barrier Degraded

_____ Reactor Containment Degraded

_____ Actual Breach or Bypass

_____ Heat Removal, Hydrogen or Pressure Control Degraded

_____ Control Room, Aux Bldg, or Spent Fuel Bldg Barrier Degraded

_____ Fuel Cladding Barrier Degraded

SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES

Seismic, Fire, Flooding, and Severe Weather Screening Criteria

1. Does the finding involve the loss or degradation of equipment or function **specifically** designed to mitigate a seismic, flooding, or severe weather initiating event (e.g., seismic snubbers, flooding barriers, tornado doors)? (Equipment and functions for the mitigation or suppression of fire initiating events, such as thermal wrap or sprinkler systems, should be evaluated using IMC 0609 Appendix F and are not evaluated here)

   ☐ **If YES** → continue to question 2

   ☐ If NO → skip to question 3

2. If the safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of the affected equipment or function by itself, during the external initiating event it was intended to mitigate

   a) would cause a plant trip or any of the Initiating Events used by Phase 2 for the plant in question;

   b) would degrade **more than** a single Train of a multi-train safety system or function;

   c) would degrade the function of any one Train of a support system for a safety system or function.

   ☐ **If YES** → the finding is potentially risk significant due to external initiating event core damage sequences - return to page 2 of this Worksheet

   ☐ If NO, screen as Green

3. Does the finding involve the loss of any safety function, identified by the licensee through a PRA, IPEEE, or similar analysis, that contributes to external event initiated core damage accident sequences (i.e., initiated by a seismic, fire, flooding, or severe weather event)?

   ☐ **If YES** → the finding is potentially risk significant due to external initiating event core damage sequences - return to page 2 of this Worksheet

   ☐ If NO, screen as Green

Result of Phase 1 screening process: ☐screen as Green **X go to Phase 2** ☐ input to Phase 3

Important Assumptions (as applicable):

SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES
Check the appropriate boxes ✔

If the finding is assumed to affect:

1. fire barrier or suppression features, use IMC 0609 Appendix F
2. the safety of a shutdown reactor, use IMC 0609 Appendix G
3. the safety of an operating reactor, identify the affected areas:
   ☐Initiating Event **X** Mitigation Systems ☐RCS Barrier ☐Fuel Barrier ☐Containment Barriers

4. **None** of the above areas affected → screen as Green
5. **Two or more** of the above areas affected → **Go to Phase 2**
6. If **only one** of the above areas is affected, continue **only** in the **appropriate** column below.

Initiating Event	Mitigation Systems	RCS Barrier or Fuel Barrier	Containment Barriers
1. Does the finding contribute to the likelihood of a Primary or Secondary system LOCA initiator? ☐**If YES → Go to Phase 2** ☐If NO, continue 2. Does the finding contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions will not be available? ☐**If YES → Go to Phase 2** ☐If NO, continue 3. Does the finding increase the likelihood of a fire or internal/external flood? ☐**If YES →** Use the IPEEE or other existing plant-specific analyses to identify core damage scenarios of concern and factors that increase the frequency. Provide this input for **Phase 3** analysis. ☐If NO, screen as Green	1. Is the finding a design or qualification deficiency that does NOT affect operability per GL 91-18 (rev 1)? ☐**If YES →** screen as Green **X** If NO, continue 2. Does the finding represent an actual loss of safety function of a System? ☐**If YES → Go to Phase 2** **X** If NO, continue 3. Does the finding represent an actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time? **X If YES → Go To Phase 2** ☐If NO, continue 4. Does the finding represent an actual loss of safety function of one or more non-Tech Spec Trains of equipment designated as risk-significant per 10CFR50.65, for >24 hrs? ☐**If YES → Go To Phase 2** ☐If NO, continue 5. Does the finding screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event, using the criteria on page 3 of this Worksheet? ☐**If YES →** Use the IPEEE or other existing plant-specific analyses to identify core damage scenarios of concern and provide this input for **Phase 3** analysis. ☐If NO, screen as Green	1. RCS Barrier **Go to Phase 2** 2. Fuel Barrier screen as Green	1. Does the finding represent a degradation of the radiological barrier function provided for the control room, auxiliary building, or spent fuel? ☐**If YES →** screen as Green ☐If NO, continue 2. Does the finding represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere? ☐**If YES → Go to Phase 3** ☐If NO, continue 3. Does the finding represent an actual open pathway in the physical integrity of reactor containment or an actual reduction of the atmospheric pressure control function of the reactor containment? ☐**If YES → Go to Phase 2 in Appendix H of IMC 0609** ☐If NO, screen as Green

Table 1 Categories of Initiating Events for Nuclear Generating Station, Unit 1

Row	Approximate Frequency	Example Event Type	Estimated Likelihood Rating		
I	> 1 per 1-10 yr	Reactor Trip (TRANS), Loss of Power Conversion System (TPCS)	A	B	C
II	1 per 10-10^2 yr	Loss of offsite power (LOOP)	B	C	D
III	1 per 10^2 - 10^3 yr	SGTR, Stuck open PORV/SRV (SORV), Small LOCA including RCP seal failures (SLOCA), Main Steam Line Break (MSLB), Loss of Instrument Air (LIA), Loss of a L4kVBUS (L4kVBUS), Loss of Nuclear Service River Water (LNSRW)	C	D	E
IV	1 per 10^3 - 10^4 yr	Medium LOCA (MLOCA), LOOP with loss of one division of emergency AC (LOOP1EDG), Loss of River Water (LRW)	D	E	F
V	1 per 10^4 - 10^5 yr	Large LOCA (LLOCA)	E	F	G
VI	less than 1 per 10^5 yr	ATWS (mechanical only), ISLOCA	F	G	H
			> 30 days	3-30 days	< 3 days
			Exposure Time for Degraded Condition		

Note:

1. The SDP worksheets for ATWS core damage sequences assume that the ATWS is not recoverable by manual actuation of the reactor trip function or by ARI for BWRs. Thus, the ATWS frequency to be used by these worksheets must represent the ATWS condition that can only be mitigated by the systems shown in the worksheet (e.g., boration). Any inspection finding that represents a loss of manual reactor trip capability for a postulated ATWS scenario should be evaluated by a risk analyst for consideration of the probability of a successful manual trip.

Table 2 Initiators and System Dependency for Nuclear Generating Station, Unit 1 [1]

Affected Systems	Major Components	Support Systems	Initiating Event
AC Power System	AC Power Distribution & AC Instrument Power	DC	All
EFW	2 MDPs	AC , DC	All except MLOCA, LLOCA and LIA
	1 TDP	Vital AC, DC	
Fire Service Water System[2]	3 pumps, 2 taking suction from river, 1 from circulating water flume	AC(FS-P2 only), DC(FS-P2 only)	LOOP, LRW
Nuclear Service Closed Cooling Water (NSCCW)	3 50% pumps and 4 1/3 capacity heat exchangers	AC, DC, NSRW	All except LLOCA and LNSRW
Nuclear Service River Water System (NSRW)	3 50% pumps	AC, DC	LNSRW
Condensate / MFW	Three Condensate pumps	AC, DC	TRANS, L4kVBUS, SGTR, LNSRW
	Two TDMFW Pumps	Vital instrument bus, DC, IA, SSCCW	
Decay Heat Closed Cooling Water System (DHCCW)	2 pumps	AC, DC, DHRW backed up by fire service water system	All
Decay Heat River Water System (DHRW)	2 pumps	AC, DC	All
HPI / Makeup and Purification	3 HPI pumps (300 gpm at 2400 psi) in 2 injection trains	AC, DC, NSCCW (pump B cooling), DHCCW (Pumps A and C only, backed up by NSCCW)	All except LLOCA and LRW
DC Power System	2 Buses, 2 battery chargers, and two batteries	6 hours battery depletion time	All

Table 2 (Continued)

Affected Systems	Major Components	Support Systems	Initiating Event
Emergency AC (EDG)	2 EDGs, 1 SBO DG	DC, Fire service water (for SBO DG), Fuel transfer pumps	LOOP, LOOP1EDG
Instrument Air (IA)	IA: 3 air compressors	AC, DC, SSCCW backup by fire service water	LIA
Intermediate Closed Cooling Water System (ICCW)	2 Pumps	AC, DC, NSRW (heat exchangers), IA	All except LNSRW, LIA, and LRW
Main Steam	Per SG: 1 ADV, 2 steam lines, 10 safety valves, 2 MSIVs and 3 turbine bypass valves (capacity 21.4%)	DC, IA, AC (for MSIVs)	All except MLOCA and LLOCA
Pressurizer Pressure Relief and Pressurizer Venting for SGTR depressurization	2 Pressurizer Safety valves, 1 PORV with associated block valve	AC (block valve), vital AC, DC (PORV)	All except MLOCA, LLOCA and LRW
	1 Pressurizer vent line with 1 MOV and 1 SOV in series	Class 1E AC train B, Class B DC train B	
RCP	Westinghouse Seals	3 HPI pumps for seal injection, ICCW for thermal barrier cooling, and IA for injection valve MU-V20, and ICCW valves IC-V3 and V4, NSCW (RCP motors)	SLOCA
LPI / DHR	2 RHR/LPSI pumps and heat exchangers	AC, DC, DHCCW, DHRW, ESFAS	All except ATWS and LNSRW
Secondary Service Closed Cooling Water System (SSCCW)	3 50% pumps and 4 1/3 capacity heat exchangers	AC, DC, SSRW	LIA, TRANS, L4kVBUS, SGTR, LNSRW
Secondary Service River Water System (SSRW)	3 pumps	AC, DC	Same as SSCCW

Table 2 (Continued)

Notes:

1. Plant internal event CDF = 4.1 E-5/yr, including contribution 3.E-6 from internal floods. (See page 10-6).

2. Fire service water system is included in maintenance rule scope.

Initiating Event Likelihood	Remaining Mitigation Capability Rating (with Examples)						
	6	5	4	3	2	1	0
	3 diverse trains OR 2 multi-train systems OR 1 train + 1 multi-train system + recovery of failed train	1 train + 1 multi-train system OR 2 diverse trains + recovery of failed train	2 diverse trains OR 1 multi-train system + recovery of failed train	1 train + recovery of failed train OR 1 multi-train system OR Operator action + recovery of failed train	1 train OR Operator action OR Operator action under high stress + recovery of failed train	Recovery of failed train OR Operator action under high stress	none
A	Green	White	Yellow	Red	Red	Red	Red
B	Green	Green	White	Yellow	Red	Red	Red
C	Green	Green	Green	White	Yellow	Red	Red
D	Green	Green	Green	Green	White	Yellow	Red
E	Green	Green	Green	Green	Green	White	Yellow
F	Green	Green	Green	Green	Green	Green	White
G	Green	Green	Green	Green	Green	Green	Green
H	Green	Green	Green	Green	Green	Green	Green

Table 4 - Risk Significance Estimation Matrix

Table 3.2 SDP Worksheet for Nuclear Generating Station Unit 1 — Transients with Loss of PCS (TPCS)

Estimated Frequency (Table 1 Row) I **Exposure Time** >30days **Table 1 Result (circle): A**

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Secondary Heat Removal (EFW)	1/2 MDEFW trains (1 multi-train system) or 1/1 TDEFW train (1 ASD train) with steam relief through 1/2 ADVs or 1/20 safety valves
Primary Bleed (FB)	1/2 SRVs open (1 multi-train system) or (1/1 PORV open or 1/1 Pressurizer vent line open) (operator action = 2) [1]
Early Inventory, HPI Injection (EIHP)	1/2 HPI trains (3 pumps) injecting from BWST (1 multi-train system)
High Pressure Recirculation (HPR)	1/2 HPI trains (3 pumps) taking suction from 1/2 LPI trains (operator action = 3) [2]

Circle Affected Functions	**Recovery of Failed Train**	**Remaining Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1. TPCS - EFW - HPR (3)		2(MDEFW)+1(TDEFW)+3(HPR)=6	GR/NTW
2 TPCS - EFW - EIHP (4)		2(MDEFW)+1(TDEFW)+3(EIHP)=6	GR/NTW
3 TPCS - EFW - FB (5)		2(MDEFW)+1(TDEFW)+2(FB)=5	WHITE

Notes:

1. The HEP used in the IPE is 3.44E-2 for the failure of the operator to manually establish HPI cooling (feed and bleed). (Event HBW1, Table 6.1-2.)
2. Operator action is required to establish recirculation. The HEP assessed in the IPE for switchover to recirculation is 1.27E-4 (event HSR2, Table 6.1-2) which is lower than the generic credit of 3 based on the HEPs of XXX plants. In this worksheet, the generic credit is used.

Table 3.7 SDP Worksheet for Nuclear Generating Station Unit 1 — Loss of Offsite Power (LOOP) [1]

Estimated Frequency (Table 1 Row) II **Exposure Time** >30 days **Table 1 Result (circle):** B

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Emergency AC Power (EAC)	1/2 EDGs (1 multi-train system) or SBO DG (operator action = 1) [2]
Turbine-driven EFW Pump (TDEFW)	1/1 TDEFW train (1 ASD train) with steam relief through 1/2 ADVs or 1/20 safety valves
Recovery of AC Power in < 1 hrs (REC1)	Recovery of an AC source (operator action = 1) [3]
Recovery of AC Power in < 4 hrs (REC4)	Recovery of an AC source (operator action = 2) [4]
Secondary Heat Removal (MDEFW)	1/2 MDEFW train after AC recovered-Excluding TDEFW credited earlier (1 multi-train system) with steam relief through 1/2 ADVs or 1/20 safety valves
Secondary Heat Removal (EFW)	1/2 MDEFW trains (1 multi-train system) or 1/1 TDEFW train (1 ASD train)
High Pressure Injection (HPI)	1/2 HPI trains (3 pumps) injecting from BWST (1 multi-train system)
Primary Bleed (FB)	1/2 SRVs open (1 multi-train system) or (1/1 PORV open or 1/1 Pressurizer vent line open) (operator action = 2) [5]
High Pressure Recirculation (HPR)	1/2 HPI trains (3 pumps) taking suction from 1/2 LPI trains (operator action = 3) [6]

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 LOOP - EFW - HPR (1) [6]		2(MDEFW)+1(TDEFW)+3(HPR)=6	GR
2 LOOP - EFW - HPI (1)		2(MDEFW)+1(TDEFW)+3(HPI)=6	GR
3 LOOP - EFW - FB (1)		2(MDEFW)+1(TDEFW)+2(FB)=5	GR/NTW
4 LOOP - EAC - REC1 - HPR (4) (AC recovered, Seal LOCA)			
5 LOOP - EAC - REC1 - HPI (5) (AC recovered, Seal LOCA)			

6 LOOP - EAC - REC4 (6) (SBO, Seal LOCA)			
7 LOOP - EAC - TDEFW - MDEFW - HPR (9) (AC recovered)		3(EAC)+1(SBO)+2(MDEFW)+1(TDEFW)+3(HPR)=10	GR
8 LOOP - EAC - TDEFW - MDEFW - FB (10) (AC recovered)		3(EAC)+1(SBO)+2(MDEFW)+1(TDEFW)+2(FB)=9	GR
9 LOOP - EAC - TDEFW - MDEFW - HPI (11) (AC recovered)		3(EAC)+1(SBO)+2(MDEFW)+1(TDEFW)+3(HPI)=10	GR
10 LOOP - EAC - TDEFW - REC1 (12)			

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event:

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use.

Notes:

1. The frequency of LOOP is 1.92E-2 / year. The IPE does not explain how seal LOCA is considered in a SBO. In this worksheet, it is assumed that in a SBO a RCP seal LOCA occurs at 1 hour and core damage takes place at 4 hours.

2. Based on generic consideration, a credit of 1 is given to this operator action. The HEP for operator failure to start SBO DG and connect it to an emergency bus is 2.34E-3. (Event HEO1A, Table 6.1-2.)

3. The probability of operator failure to recover AC power, given failure of TDEFW, is 8.46E-2. (Event HRE3, Table 6.1-2.)

4. The probability of operator failure to recover AC power, given TDEFW initially available, is 8.31E-3. (Event HRE1, Table 6.1-2.)

5. The HEP used in the IPE is 3.44E-2 for the failure of the operator to manually establish HPI cooling (feed and bleed). (Event HBW1, Table 6.1-2.)

6. Operator action is required to establish recirculation. The HEP assessed in the IPE for switch over to recirculation is 1.27E-4 (event HSR2, Table 6.1-2) which is lower than the generic credit of 3 based on the HEPs of XXX plants. In this worksheet, the generic credit is used.

FIRE PROTECTION SIGNIFICANCE DETERMINATION PROCESS

by

J.S. Hyslop, SPSB
Mark H. Salley, SPLB

Given to ACRS, May 9, 2001

OVERVIEW

- General Remarks
- Example: Evaluation of specific fire protection findings
  - Clear identification of findings
  - Configuration of room in which findings exist
  - Applying fire protection SDP to estimate risk (color findings)
    - Basis for degradation levels and failure probabilities

GENERAL REMARKS

- Uses PRA techniques and data generally accepted by fire risk community
- Is an evolving process
- Communicating with stakeholders
  - Fire Protection Information Forum
  - Reactor Oversight Process Workshop
- Coordinating with Office of Research - fire research plan

EXAMPLE

- Clear identification of findings
  - Manual fixed fire suppression system (CO_2) would not maintain minimum concentration for the fire hazard
  - Electrical raceway fire barrier system protecting redundant trains did not meet one hour rating
  - Each finding existed simultaneously for greater than thirty days

EXAMPLE: phase 2

- Configuration of room in which findings exist
  - 4160V Essential Switchgear room divided into 3 sections by two partial-height marinite walls
  - Each section contains a 4160V Vital Bus, where two electrical buses needed to support one mechanical train
  - Cables from all electrical trains come together in the overhead of the center section in vicinity of 4160V Vital Switchgear cabinet
- Fire scenario: fire starts in 4160V Vital Switchgear cabinet in center section ; fire plume damages cabling from both remaining electrical trains

EXAMPLE: phase 2

- Evaluate FMF (fire mitigation frequency) = IF + AS + MS + FB + CC
  - Determine the fire ignition frequency (IF) of the 4160V Vital Switchgear cabinet in center bay - IPEEE
  - Evaluate extent of degradations identified in fixed suppression (AS) and the fire barrier (FB) - choice of moderate or high for either
  - No degradation in manual suppression, i.e. fire brigade, identified (MS); no dependency/common cause (CC) contribution

EXAMPLE: phase 2 (cont.)

- Degradations
  - Moderate degradation for auto-suppression system (AS)
    - Manual actuation
    - CO2 system only reached 46% concentration (minimum required was 50%)
  - Moderate to high degradation for one hour fire barrier (FB)
    - Tests indicate the barrier had a rating of 10 to 15 minutes
- No degradation in fire brigade (normal operating state)
  - Professionally trained fire brigade, performed drill satisfactorily and arrived within 11 minutes of alarm notification

EXAMPLE: phase 2 (cont.)

- Evaluate FMF (fire mitigation frequency) = IF + AS + MS + FB + CC
  - Determine the fire ignition frequency (IF) of the 4160V Vital Switchgear cabinet in center bay - IPEEE
  - Include extent of degradations identified in fixed suppression (AS) and the fire barrier (FB)
  - No degradation in manual suppression, i.e. fire brigade, identified (MS); no dependency/common cause (CC) contribution

- FMF = -3 - 0.75 - 0.25 - 1 = -5 since
  - Fire ignition frequency = $\log_{10}(1E\text{-}3) = -3$
  - Moderate degradation for autosuppression (AS) = -0.75
  - Moderate to high degradation for one hour barrier (FB) = -0.25
  - Normal operating state for fire brigade (MS) = -1

EXAMPLE: phase 2 (cont.)
FAILURE PROBABILITIES FOR DID

Level of Degradation	3 Hour Barrier	1 Hour Barrier	Auto-Suppress	Fire Brigade
High	0	0	0	-0.25
Moderate	-1.25	-0.5	-0.75	-0.5
Normal Operating State (NOS)	-2 (door) -2.5 -3	-1	-1.25	-1

EXAMPLE: phase 2 (cont.)

- Utilize reactor safety worksheets
  - Fire induces a SLOCA - RCP Seal LOCA
    - Loss of CCW and charging with no high pressure injection available
  - Core damage - no credit for mitigating systems
- Resulting evaluation is white
- Higher degradation in any DID element produces a yellow; repairing fire barrier produces green/white threshold.

PHASE 2 RISK ESTIMATION WORKSHEET — Small LOCA

Estimated Frequency (Table 1 Row) -5 | Exposure Time > 30 DAYS | Table 1 Result (circle): A B C D E *F* G H

Safety Functions Needed:	*Full* Creditable Mitigation Capability for each Safety Function:
Early Inventory, HP Injection (EIHP)	1 / 4 Charging or SI trains (2 multi-train systems)
Power Conversion System (PCS)	1/3 condensate pump (operator action)
Secondary Heat Removal (AFW)	1 / 2 MDAFW trains (1 multi-train system) or 1 TDAFW train (1 ASD train)
Primary Heat Removal, Feed/Bleed (FB)	1 / 2 PORVs open for Feed/Bleed (operator action)
High Pressure Recirculation (HPR)	1 / 4 Charging or SI trains taking suction from 1 / 2 LPSI trains with successful switchover to sump (operator action)

Circle Affected Functions	**Recovery of Failed Train**	***Remaining* Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1 SLOCA - EIHP (8)		**Fire induced SLOCA - no EIHP available - no mitigation credit**	**WHITE**
2 SLOCA - AFW - PCS - FB (7)			
3 SLOCA - HPR (2,4,6)			

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event:

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use.

Table 5.6 - Risk Significance Estimation Matrix

Initiating Event Likelihood	Remaining Mitigation Capability Rating (with Examples)						
	-6	-5	-4	-3	-2	-1	0
	3 diverse trains OR 2 multi-train systems OR 1 train + 1 multi-train system + recovery of failed train	1 train + 1 multi-train system OR 2 diverse trains + recovery of failed train	2 diverse trains OR 1 multi-train system + recovery of failed train	1 train + recovery of failed train OR 1 multi-train system OR Operator action + recovery of failed train	1 train OR Operator action OR Operator action under high stress + recovery of failed train	Recovery of failed train OR Operator action under high stress	none
A	Green	White	Yellow	Red	Red	Red	Red
B	Green	Green	White	Yellow	Red	Red	Red
C	Green	Green	Green	White	Yellow	Red	Red
D	Green	Green	Green	Green	White	Yellow	Red
E	Green	Green	Green	Green	Green	White	Yellow
F	Green	Green	Green	Green	Green	Green	White
G	Green	Green	Green	Green	Green	Green	Green
H	Green	Green	Green	Green	Green	Green	Green

Performance Indicators

General Intent

Process for developing Thresholds

PI Reporting

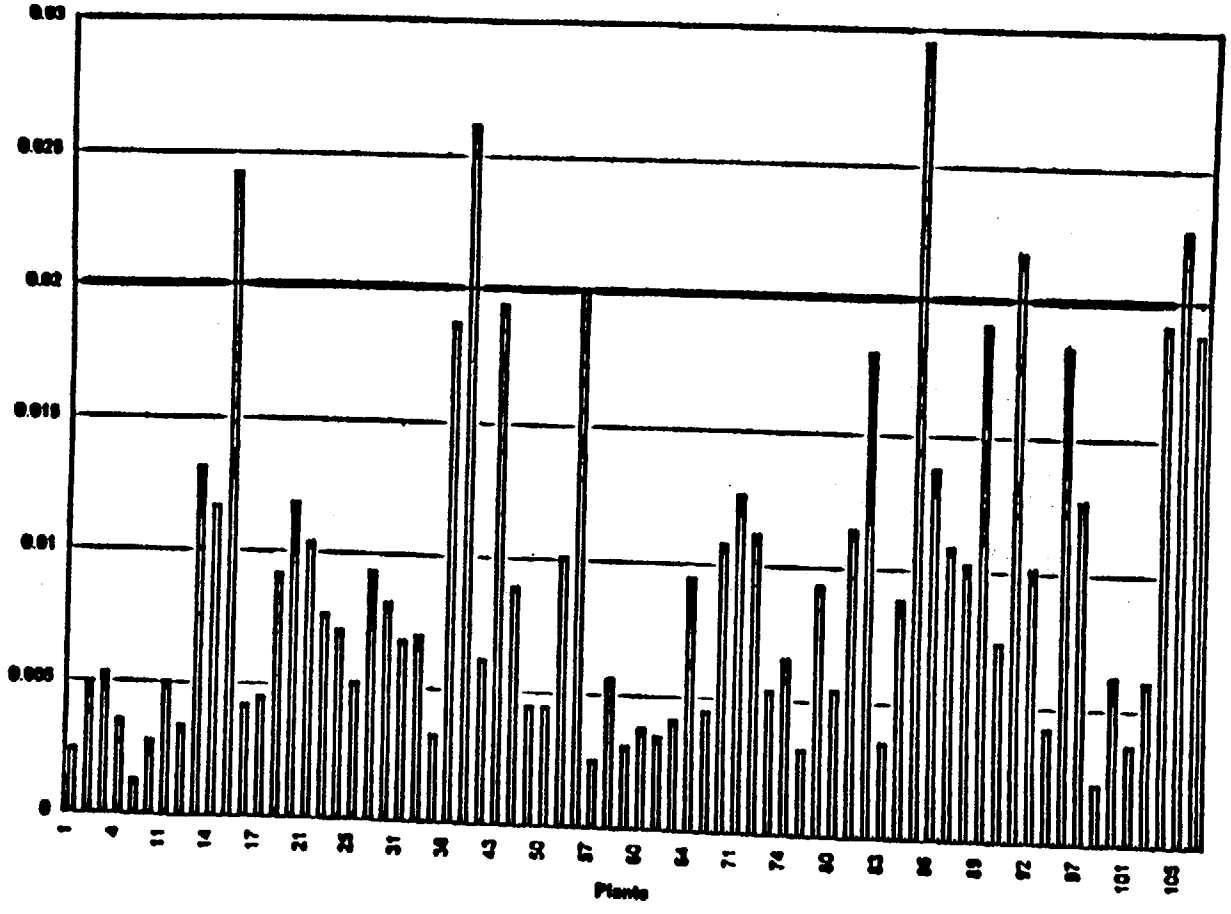
PI INDICATORS

General Intent

Process for Developing Thresholds

- The Green-White Threshold Was Determined by Experience Data Such That Only a Few Outlier Values Would Be in the White.
- The White-Yellow Threshold Was Established At a Value Such That a Change of the PI Would Result in a Δ CDF >1E-05.
- The Yellow-Red Threshold Was Established Such That a Change in PI Value Greater than the Threshold Would Result in a Δ CDF > 1E-04.
- The Thresholds Were Established Using a Set of PRA Models with the Lower Threshold from the Set Being Used.

PWR AFW UNAVAILABILITY



PI REPORTING

EXAMPLE: EDG SYSTEM UNAVAILABILITY

- PI Definition (from NEI 99-02)

$$\text{Train unavailability} = \frac{\text{unavailable hours (planned + unplanned + fault exposure)}}{\text{hours train required}}$$

$$\text{System unavailability} = \frac{\sum \text{Train unavailability}}{\text{no. of trains}}$$

- Licensee collects unavailable hours for each EDG in latest quarter from logs, equipment histories, etc.
- Licensee submits data to NRC via email
- NRC system automatically calculates PI value per above algorithm

SELECTED ISSUES

- Threshold for the "Green" band
- Results of cross-cutting issue inspections (corrective action)
- Defense in depth aspects of fire protection

Cross Cutting Issues and Initial Implementation of the ROP

Fundamental Assumption of ROP - Cross Cutting Issues Will Be Detected via Baseline Inspection or Performance Indicators

Initial Implementation shows strong tie between plants with weak corrective action programs and plants that move out of licensee response band -(IP 2, Kewaunee, Millstone, Cooper)

No significant precursors caused by cross cutting issues

No additional cross cutting issues identified that require special treatment

Cross Cutting Issues and Initial Implementation of the ROP

Additional actions planned to evaluate adequacy of ROP with regard to cross cutting issues

Review of ASP events and yellow and red inspection findings

Review of inspection reports

Performance metrics to evaluate plants that jump two or more action matrix
columns

Assessment of ROP engagement at plants that reach the degraded cornerstone column of the action matrix